ENI SPA
Form 20-F
April 07, 2011

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, 2010

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)

Alessandro Bernini
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

4,005,358,876

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

* This requirement does not apply to the registrants until their fiscal year ending December 31, 2011.

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 and gas terms used herein and certain conversions, see "Glossary" and "Conversion Table".

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

The Consolidated Financial Statements of Eni, included in this annual report, have been prepared in accordance with International Financial Reporting Standards (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" and "U.S. $" are to the currency of the United States, and references to "euro" and " " are to the currency of the European Monetary Union.

Unless otherwise specified or the context otherwise requires, references herein to "division" and "segment" are to Eni s business activities: Exploration & Production, Gas & Power, Refining & Marketing, Engineering & Construction, Petrochemicals and other activities.

STATEMENTS REGARDING COMPETITIVE POSITION

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

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GLOSSARY

A glossary of oil and gas terms is available on Eni s web page at the address www.eni.it. 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".

Business terms

AEEG (Authority for Electricity and Gas)	The Regulatory Authority for Electricity and Gas is the Italian independent body which regulates, controls and monitors the electricity and gas 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.
Contingent resources	Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.
Conversion capacity	Maximum amount of feedstock that can be processed in certain dedicated facilities of a refinery to obtain finished products. Conversion facilities include catalytic crackers, hydrocrackers, visbreaking units, and coking units.
Conversion index	Ratio of capacity of conversion facilities to primary distillation capacity. The higher the ratio, the higher is the capacity of a refinery to obtain high value products from the heavy residue of primary distillation.
Deep waters	Waters deeper than 200 meters.
Development	Drilling and other post-exploration activities aimed at the production of oil and gas.

Enhanced recovery	Techniques used to increase or stretch over time the production of wells.
EPC	Engineering, Procurement and Construction.
EPIC	Engineering, Procurement, Installation and Construction.
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 and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Reserves are classified as either developed and undeveloped. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
Reserves	Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
Reserve life index	Ratio between the amount of proved reserves at the end of the year and total production for the year.
Reserve replacement ratio	Measure of the reserves produced replaced by proved reserves. Indicates the company s ability to add new reserves through exploration and purchase of property. A rate higher than 100% indicates that more reserves were added than produced in the period. The ratio should be averaged on a three-year period in order to reduce the distortion deriving from the purchase of proved property, the revision of previous estimates, enhanced recovery, improvement in recovery rates and changes in the amount of reserves in PSAs due to changes in international oil prices.
Ship-or-pay	Clause included in natural gas transportation contracts according to which the customer is requested to pay for the transportation of gas whether or not the gas is

	actually transported.
Strategic Storage	According to current Italian regulation, 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 and 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	= 5,550 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 0.00615 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)

(*) In this Annual Report on Form 20-F, the Company presents oil and gas production volumes and reserves expressed in barrels of oil-equivalent whereby natural gas volumes are converted on the base of an equivalency. In 2010, Eni updated the natural gas conversion factor from 5,742 to 5,550 standard cubic feet of gas per barrel of oil equivalent. This update reflected changes in Eni s gas properties that took place in recent years and was assessed by collecting data on the heating power of gas in all Eni s 230 gas fields on stream at the end of 2009. The effect of this update on production expressed in BOE was 26 KBOE/d for the full year 2010 and on the initial reserves balances as of January 1, 2010 amounted to 106 mmBOE. Other per-BOE indicators were only marginally affected by the update (e.g. realization prices, costs per BOE) and also negligible was the impact on depletion charges. Other oil companies may use different conversion rates.

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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 issued by the International Accounting Standards Board (IASB). The tables below show Eni selected historical financial data prepared in accordance with IFRS as of and for the years ended December 31, 2006, 2007, 2008, 2009 and 2010. The selected historical financial data presented herein are derived from Eni s Consolidated Financial Statements included in Item 18.

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

	Year ended December 31,				
	2006	2007	2008	2009	2010
	(euro million except data per share and per ADR)				
CONSOLIDATED PROFIT AND LOSS STATEMENT DATA					
Net sales from operations	86,105	87,204	108,082	83,227	98,523
Operating profit by segment (1)					
Exploration & Production	15,580	13,433	16,239	9,120	13,866
Gas & Power	3,802	4,465	4,030	3,687	2,896
Refining & Marketing	319	686	(988)	(102)	149
Petrochemicals	172	100	(845)	(675)	(86)
Engineering & Construction	505	837	1,045	881	1,302
Other activities (2)	(622)	(444)	(466)	(436)	(1,384)
Corporate and financial companies (2)	(296)	(312)	(623)	(420)	(361)
Impact of unrealized intragroup profit elimination (3)	(133)	(26)	125		(271)
Operating profit	19,327	18,739	18,517	12,055	16,111
Net profit attributable to Eni	9,217	10,011	8,825	4,367	6,318
Data per ordinary share (euro) (4)					
Operating profit:					

- basic	5.23	5.11	5.09	3.33	4.45
- diluted	5.22	5.11	5.09	3.33	4.45
Net profit attributable to Eni basic and diluted	2.49	2.73	2.43	1.21	1.74
Data per ADR ($) (4) (5)					
Operating profit:					
- basic	13.13	14.01	14.97	9.27	11.81
- diluted	13.12	14.00	14.97	9.27	11.81
Net profit attributable to Eni basic and diluted	6.26	7.48	7.14	3.36	4.62

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	As of December 31,				
	2006	**2007**	**2008**	**2009**	**2010**
	(euro million except number of shares and dividend information)				
CONSOLIDATED BALANCE SHEET DATA					
Total assets	88,312	101,460	116,673	117,529	131,860
Short-term and long-term debt	11,699	19,830	20,837	24,800	27,783
Capital stock issued	4,005	4,005	4,005	4,005	4,005
Non-controlling interest	2,170	2,439	4,074	3,978	4,522
Shareholders equity - Eni share	39,029	40,428	44,436	46,073	51,206
Capital expenditures	7,833	10,593	14,562	13,695	13,870
Weighted average number of ordinary shares outstanding (fully diluted - shares million)	3,701	3,668	3,639	3,622	3,622
Dividend per share (euro)	1.25	1.30	1.30	1.00	1.00
Dividend per ADR ($) (4)	3.24	3.74	3.72	2.91	2.64

(1) From 2009, gains and losses on non-hedging commodity derivative instruments, including both fair value re-measurement and gains and losses on settled transactions are reported as items of operating profit. Also results of the gas storage business are reported within the Gas & Power segment reporting unit, as part of the regulated businesses results, following the restructuring of Eni s regulated gas businesses in Italy. In past years, results of the gas storage business were reported within the Exploration & Production segment. Data for the years ended December 31, 2008 and 2007 have been restated. Prior year data have not been restated.

(2) From 2010 certain environmental provisions incurred by the Parent Company Eni SpA due to inter-company guarantees on behalf of Syndial have been reported within the segment reporting unit "Other activities". Data for the years 2008 and 2009 have been restated by increasing the operating loss of the "Other activities" segment by euro 120 million and euro 54 million, respectively. Prior-year data have not been restated.

(3) This item mainly pertained to intra-group sales of commodities, services and capital goods recorded in the assets of the purchasing business segment as of the end of the period.

(4) 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 2010 is based on the proposal of Eni s management which is submitted to approval of the Annual General Shareholders Meeting scheduled on April 29 and May 5, 2011 on first and second calls, respectively.

(5) Eni s financial statements are stated in euro. The translations of certain euro amounts into U.S. dollars are included solely for the convenience of the reader. The convenient translations should not be construed as representations that the amounts in euro have been, could have been, or could in the future be, converted into U.S. dollars at this or any other rate of exchange. Data per ADR, with the exception of dividends, were translated at the EUR/U.S. $ average exchange rate as recorded by in the Federal Reserve Board official statistics for each year presented (see the table on page 5). Dividends per ADR for the years 2006 through 2009 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 2010 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 1 per ADR) at the Noon Buying Rate recorded on the payment date on September 30, 2010, while the balance of euro 1 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2010. The balance dividend for 2010 once the full-year dividend is approved by the Annual General Shareholders Meeting is payable on May 26, 2011 to holders of Eni shares, being the ex-dividend date May 23, while ADRs holders will be paid late in May 2011.

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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, 2006, 2007, 2008, 2009 and 2010. Data on production of oil and natural gas and hydrocarbon production sold includes Eni s share of production of affiliates and joint ventures accounted for under the equity or cost method of accounting. In presenting data on production volumes and reserves for total hydrocarbons, natural gas volumes have been converted to oil-equivalent barrels on the basis of a certain equivalency. In 2010, Eni updated the natural gas conversion factor from 5,742 to 5,550 standard cubic feet of gas per barrel of oil equivalent. This update reflected changes in Eni s gas properties that took place in recent years and was assessed by collecting data on the heating power of gas in all Eni s 230 gas fields on stream at the end of 2009. The effect of this update on production expressed in boe was 26 KBOE/d for the full year 2010 and on the initial reserves balances as of January 1, 2010 amounted to 106 mmBOE. Prior-year converted amounts were not restated. Other per-boe indicators were only marginally affected by the update (e.g. realization prices, costs per boe) and also negligible was the impact on depletion charges. Other oil companies may use different conversion rates.

	Year ended December 31,				
	2006	2007	2008	2009	2010
Proved reserves of liquids of consolidated subsidiaries at period end (mmBBL)	3,457	3,127	3,243	3,377	3,415
of which developed	*2,126*	*1,953*	*2,009*	*2,001*	*1,951*
Proved reserves of liquids of equity-accounted entities at period end (mmBBL)	24	142	142	86	208
of which developed	*18*	*26*	*33*	*34*	*52*
Proved reserves of natural gas of consolidated subsidiariesat period end (BCF)	16,897	16,549	17,214	16,262	16,198
of which developed	*10,949*	*10,967*	*11,138*	*11,650*	*10,965*
Proved reserves of natural gas of equity-accounted entities at period end (BCF)	68	3,022	3,015	1,588	1,684
of which developed	*48*	*428*	*420*	*234*	*246*
Proved reserves of hydrocarbons of consolidated subsidiaries in mmBOE at period end [1]	6,400	6,010	6,242	6,209	6,332
of which developed	*4,032*	*3,862*	*3,948*	*4,030*	*3,926*
Proved reserves of hydrocarbons of equity-accounted entities in mmBOE at period end [a]	36	668	666	362	511
of which developed	*27*	*101*	*107*	*74*	*96*
Reserve replacement ratio [2]	38	38	136	95	104
Average daily production of liquids (KBBL/d)	1,079	1,020	1,026	1,007	997
Average daily production of natural gas available for sale (mmCF/d) [3]	3,679	3,819	4,143	4,074	4,222
Average daily production of hydrocarbonsavailable for sale (KBOE/d) [3]	1,720	1,684	1,748	1,716	1,757
Hydrocarbon production sold (mmBOE)	625.1	611.4	632.0	622.8	638.0
Oil and gas production costs per BOE [4]	5.79	6.90	7.65	7.41	8.89
Profit per barrel of oil equivalent [5]	15.03	14.19	16.00	8.14	11.91

(a) Proved gas reserve of equity-accounted entities mainly pertained to three Russian companies that were jointly purchased with the Italian partner Enel in 2007 (Eni s interest in the venture being 60%). In 2009 following the divestment of a 51% interest to Gazprom upon exercise of a call option arrangement, Eni s interest in the venture decreased to 29.4%.

(1) Includes approximately 754, 749, 746, 769 and 767 BCF of natural gas held in storage in Italy as of December 31, 2006, 2007, 2008, 2009 and 2010, respectively.

(2) Referred to Eni s subsidiaries. Consists of: (i) the increase in proved reserves of consolidated subsidiaries attributable to: (a) purchases of minerals in place; (b) revisions of previous estimates; (c) improved recovery; and (d) extensions and discoveries, less sales of minerals in place; divided by (ii) production during the year as set forth in the reserve tables, in each case prepared in accordance with Topic 932. See the unaudited supplemental oil and gas information in Item 18 Notes to the Consolidated Financial Statements. Expressed as a percentage.

(3) Natural gas production volumes exclude gas consumed in operations (286, 296, 281, 300 and 318 mmCF/d in 2006, 2007, 2008, 2009 and 2010, respectively).

(4) Expressed in U.S. dollars. Consists of production costs of consolidated subsidiaries (costs incurred to operate and maintain wells and field equipment including also royalties) prepared in accordance with IFRS divided by production on an available-for-sale basis, expressed in barrels of oil equivalent. See the unaudited supplemental oil and gas information in "Item 18 Notes to the Consolidated Financial Statements".

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

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Selected Operating Information *continued*

	Year ended December 31,				
	2006	2007	2008	2009	2010
Sales of natural gas to third parties (5)	79.63	78.75	83.69	83.79	75.81
Natural gas consumed by Eni (5)	6.13	6.08	5.63	5.81	6.19
Sales of natural gas of affiliates (Eni s share) (5)	7.65	8.74	8.91	7.95	9.41
Total sales and own consumption of natural gas of the Gas & Power segment (5)	93.41	93.57	98.23	97.55	91.41
E&P natural gas sales in Europe and in the Gulf of Mexico (5)	4.69	5.39	6.00	6.17	5.65
Worldwide natural gas sales (5)	98.10	98.96	104.23	103.72	97.06
Transport of natural gas for third parties in Italy (5)	30.90	30.89	33.84	37.32	47.87
Length of natural gas transport network in Italy at period end (6)	30.9	31.1	31.5	31.5	31.6
Electricity sold (7)	31.03	33.19	29.93	33.96	39.54
Refinery throughputs (8)	36.27	37.15	35.84	34.55	34.80
Balanced capacity of wholly-owned refineries (9)	534	544	544	554	564
Retail sales (in Italy and rest of Europe) (8)	12.48	11.80	12.03	12.02	11.73
Number of service stations at period end (in Italy and rest of Europe)	6,294	6,441	5,956	5,986	6,167
Average throughput per service station (in Italy and rest of Europe) (10)	2,470	2,486	2,502	2,477	2,353
Petrochemical production (8)	7.07	8.80	7.37	6.52	7.22
Engineering & Construction order backlog at period end (11)	13,191	15,390	19,105	18,730	20,505
Employees at period end (units)	72,850	75,125	78,094	77,718	79,941

(6) Expressed in BCM.
(7) Expressed in thousand kilometers.
(8) Expressed in TWh.
(9) Expressed in mmtonnes.
(10) Expressed in KBBL/d.
(11) Expressed in euro million.

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,				
2006	1.33	1.19	1.26	1.32
2007	1.49	1.29	1.37	1.46
2008	1.60	1.24	1.47	1.39
2009	1.51	1.25	1.39	1.43
2010	1.46	1.19	1.33	1.34

(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 2010	1.41	1.37	1.39
November 2010	1.42	1.30	1.30
December 2010	1.34	1.31	1.34
January 2011	1.34	1.29	1.34
February 2011	1.38	1.34	1.35
March 2011	1.42	1.38	1.42

Fluctuations in the exchange rate between the euro and the U.S. dollar affect the dollar equivalent of the euro price of the Shares on the Mercato Telematico Azionario (Electronic Share Market or "MTA") and the U.S. dollar price of the ADRs on the NYSE. Exchange rate fluctuations also affect the U.S. 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, 2011 was $1.42 per euro 1.00.

Risk Factors

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 Exploration & Production business, Eni faces competition from both international oil companies 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 in many of these markets 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 cost increases, its growth prospects and future results of operations and cash flows may be adversely affected.

In its natural gas business, Eni faces increasingly strong competition on both the Italian market and the European market driven by moderate growth prospects for demand over the short and medium-term, in the face of large gas availability on the marketplace. The latter was driven by material investments to expand import capacity to Europe via pipeline which have been made by a number of operators, including Eni, in recent years. Also large availability of LNG on a worldwide scale has found an outlet at the European continental hubs driving the development of highly liquid spot gas markets. LNG availability was fuelled by the ramp-up of important upstream projects worldwide (new treatment trains in Qatar, Yemen and Russia) and commercial development of non-conventional gas resources in the USA which have reduced dependence on LNG imports. As natural gas is a commodity, gas oversupplies have caused suppliers to compete more aggressively on pricing thus pressuring gas margins in the whole sector. Management believes that a better balance between demand and supply on the European market will not be achieved until 2014 at the earliest.

The described trends may negatively affect the Company s future results of operations and cash flow in its natural gas business, also taking into account the Company s contractual obligations to off-take minimum annual volumes of natural gas in accordance to its long-term gas supply contracts that include take-or-pay clauses. See the sector-specific risk section below.

Eni also faces competition from large, well-established European utilities and other international oil and gas companies in growing its market share and acquiring or retaining clients. A number of large clients, particularly electricity producers, in both the domestic market and other European markets have entered the wholesale market of natural gas by directly purchasing gas from producers and reselling it to wholesale or retail markets. At the same time, a number of national gas producers from countries with large gas reserves are planning to sell natural gas directly to final clients, which would threaten the market position of companies like Eni which resell gas purchased from producing countries to final customers. These developments may increase the level of competition in both the Italian and other European markets for natural gas and reduce Eni s operating profit and cash flows.

In its domestic electricity business, Eni competes with other producers and traders from Italy or outside of Italy who sell electricity on the Italian market. The Company expects in the near future that increasing competition due to the weak GDP growth expected in Italy and Europe over the next one to two years will cause outside players to place excess production on the Italian market.

In retail marketing of refined products both in and outside Italy, Eni competes with third parties (including international oil companies and local operators such as supermarket chains) to obtain concessions to establish and operate service stations. Once established, Eni s service stations compete primarily on the basis of pricing, services and availability of non-petroleum products. In Italy, there is pressure from political and administrative entities, including the Italian Antitrust Authority, to increase levels of competition in the retail marketing of fuels. Eni expects developments on this issue to further increase pressure on selling margins in the retail marketing of fuels.

In the Petrochemical segment, we face intense competition from well-established international players and state-owned petrochemical companies, particularly in the most commoditized market segments. Many of those competitors may benefit from cost advantages due to larger scale, looser environmental regulations, availability of oil-based feedstock, and more favorable location and proximity to end-markets. Excess capacity and sluggish economic growth may exacerbate competitive pressures. The Company expects continuing margin pressures in the foreseeable future as a result of those trends.

Competition in the oil field services, construction and engineering industries is primarily based on technical expertise, quality and number of services and availability of technologically advanced facilities (for example, vessels for offshore construction). Lower oil prices could result in lower margins and lower demand for oil services.

The Company s failure or inability to respond effectively to competition could adversely impact the Company s growth prospects, future results of operations and cash flows.

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

The exploration and production of oil and natural gas requires high levels of capital expenditures and entails particular economic risks. It is subject to natural hazards and other uncertainties including those relating to the physical characteristics of oil and natural gas fields.

Eni s results depend on its ability to identify and mitigate the risks and hazards inherent to operating in the crude oil and natural gas industry. The Company seeks to minimize these operational risks by carefully designing and building its facilities and conducting its operations in a safe and reliable manner. However, failure to manage these risks effectively could result in unexpected incidents, including releases, explosions or mechanical failures resulting in personal injury, loss of life, environmental damage, loss of revenues, legal liability and/or disruption to operations. As recent events in the Gulf of Mexico have shown, exploration and production carries certain inherent risks, especially deep water drilling. Accidents at a single well can lead to loss of life, environmental damage and consequently potential economic losses that could have a material and adverse effect on the business, results of operation and prospects of the Group. Eni has implemented and maintains a system of policies, procedures and compliance mechanisms to manage safety, health, environmental, reliability and efficiency risks; to verify compliance with applicable laws and policies; and to respond to and learn from unexpected incidents. Nonetheless, 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 maintains insurance coverage that include coverage for physical damage to our assets, third party liability, workers compensation, pollution and other damage to the environment and other coverage. Our insurance is subject to caps, exclusion and limitation, and there is no assurance that such coverage will adequately protect us against liabilities from all potential consequences and damages. In light of the accident at the Macondo well in the Gulf of Mexico, we may not be able to secure similar coverage for the same costs. Future insurance coverage for our industry could increase in cost and may include higher retentions. Also, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable.

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 interests, 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.

Exploratory drilling efforts may be unsuccessful

Drilling for oil and gas involves numerous risks including the risk of dry holes or failure to find commercial quantities of hydrocarbons. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be unsuccessful as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or fires, blow-outs and various forms of accidents, marine risks such as collisions and adverse weather conditions and shortages or delays in the delivery of equipment. Exploring or drilling in offshore areas, particularly in deep waters, is generally more complex and riskier than in onshore areas; the same is true for exploratory activity in remote areas or in challenging environmental conditions such as those we are experiencing in the Caspian region or Alaska. 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 invest significant capital expenditures in executing high risk exploration projects, it is likely that Eni will incur significant exploration and dry hole expenses in future years. Eni plans to explore for oil and gas offshore; a number of projects are planned in deep and ultra-deep waters or at deep drilling depths, where operations are more difficult and costly than in other areas. Deep water operations generally require a significant amount of time before commercial production of reserves can commence, increasing both the operational and financial risks associated with these activities. The Company plans to conduct risky exploration projects offshore the Gulf of Mexico, Egypt, Angola, Italy, Australia, Nigeria and Norway. In 2010, the Company invested approximately euro 1 billion in executing exploration projects and it plans to spend approximately euro 0.9 billion per annum on average over the next four years.

Furthermore, shortage of deep water rigs and failure to find additional commercial reserves could reduce future production of oil and natural gas which is highly dependent on the rate of success of exploratory activity.

The oil and gas industry may face increased regulation both in the USA and elsewhere that could increase the cost of regulatory compliance and may require changes to our drilling operations and exploration and development plans and may lead to higher royalties and taxes

The recent incident at the BP-operated Macondo well in the Gulf of Mexico is likely to result in more stringent regulation of oil and gas activities in the U.S. and elsewhere, particularly relating to environmental and health and safety protection controls and oversight of drilling operations, as well as access to new drilling areas. The U.S.

Government had imposed a six-month moratorium, which was suspended in October 2010, on certain offshore drilling activities. The moratorium forced Eni s management to reschedule certain projects and caused delays in linking a few wells to production facilities, which had a negligible impact on the Company s production for the year. In addition, the Group incurred operating costs related to inactivity or redeployment of certain drilling rigs which were booked before the moratorium. During the first months of 2011, Eni expects to resume the operations that had been previously authorized and then suspended following the moratorium. Planned activities for which authorizations have still to be granted may be rescheduled due to uncertainties in the timing of obtaining the necessary authorizations from the U.S. Authorities. Similar actions have been taken by governments elsewhere in the world. The European Parliament has increased regulations in the area of environmental protection in the field of hydrocarbon extraction and Italian Authorities have passed legislation that would introduce certain restrictions to activities for exploring and producing hydrocarbons. These new regulations and legislation, as well as evolving practices, could increase the cost of compliance and may require changes to our drilling operations and exploration and development plans and may lead to higher royalties and taxes.

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

Eni is involved in a number of development projects for producing hydrocarbon reserves. Certain projects are planned to develop reserves in high risk areas, particularly offshore and in remote and hostile environments. Eni s future results of operations and liquidity rely upon its ability to 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, suppliers, customers or others including, for example, Eni s ability to negotiate favorable long-term contracts with customers; the development of reliable spot markets that may be necessary to support the development of particular production projects, or commercial arrangements for pipelines and related equipment to transport and market hydrocarbons. Furthermore, 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, behaviors and performance of its partners;
- timely issuance of permits and licenses by government agencies;
- the Company s relative size compared to its main competitors which may prevent it from affording opportunities to participate 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 goods and services;
- the ability to design development projects so as to prevent the occurrence of technical inconvenience;
- delays in manufacturing and delivery of critical equipment, or shortages in the availability of such equipment, causing cost overruns and delays;
- 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;
- changes in operating conditions and costs. The industry has been impacted for a few years to date by rising trends in the cost for certain critical productive factors including specialized labor, procurement costs and costs for leasing third party equipment or purchase services such as drilling rigs as a result of industry-wide cost inflation. The Company expects that costs in its upstream operations will continue to rise in the foreseeable future;
- 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.

Furthermore, deep waters and other hostile environments, where the majority of Eni s planned and existing development projects are located, can exacerbate these problems. Delays and differences between scheduled and actual timing of critical events, as well as cost overruns may adversely affect actual returns of development projects. Finally, developing and marketing hydrocarbons reserves typically requires 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 and gas prices which may be substantially lower with respect to prices assumed when the investment decision was actually made, leading to lower rates of return. For example, we have experienced material cost overruns and a substantial delay in the scheduling of production start-up at the Kashagan field, where development is ongoing. Those negative trends were driven by a number of factors including depreciation of the U.S. dollar versus the euro and other currencies; cost escalation of goods and services required to execute the project; an original underestimation of the costs and complexity to operate in the North Caspian Sea due to lack of benchmarks; design changes to enhance the operability and safety standards of the offshore facilities. The partners of the venture are currently discussing an update of the expenditures and time schedule to complete the Phase 1 which were included in the development plan approved in 2008 by the relevant Kazakh Authorities. The Consortium continues to target the achievement of first commercial oil production by end of 2012. However, the timely delivery of Phase 1 depends on a number of factors which are presently under review.

See "Item 4 Exploration & Production Caspian Sea" for a full description of the material terms of the Kashagan project.

In the event 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 charges associated with reduced future cash flows of those projects on capitalized costs.

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.

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In addition to being a function of production, revisions and new discoveries, the Company s reserve replacement is also affected by the entitlement mechanism in its Production Sharing Agreements ("PSAs") and similar contractual schemes. In accordance with such 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. In 2010, the Company s reserve replacement was negatively affected by lower entitlements in its PSAs for an estimated amount of 80 mmBOE, which however did not impair the Company s ability to fully replace reserves produced in the year. Due to ongoing trends in crude oil prices, the Company expects a risk of lower production and reserve entitlement relating to its PSA contracts to occur in 2011. See "Item 4 Business Overview Exploration & Production" and "Item 5 Management s Expectations of Operations". Future oil and gas production is dependent on the Company s ability to access new reserves through new discoveries, application of improved techniques, success in development activity, negotiation with countries and other owners of known reserves and acquisitions. An inability to replace reserves could adversely impact future production levels and growth prospects, thus negatively affecting Eni s future results of operations and financial condition.

Changes in crude oil and natural gas prices may adversely affect Eni s results of operations

The exploration and production of oil and gas is a commodity business with a history of price volatility. The single largest variable that affects the Company s results of operations and financial condition is crude oil prices. Lower crude oil prices have an adverse impact on Eni s results of operations and cash flow. Eni generally does not hedge exposure to fluctuations in future cash flows due to crude oil price movements. As a consequence, Eni s profitability depends heavily on crude oil and natural gas prices.

Crude oil and natural gas prices are subject to international supply and demand and other factors that are beyond Eni s control, including among other things:

(i) the control on production exerted by the Organization of the Petroleum Exporting Countries ("OPEC") member countries which control a significant portion of the world s supply of oil and can exercise substantial influence on price levels;
(ii) global geopolitical and economic developments, including sanctions imposed on certain oil-producing countries on the basis of resolutions of the United Nations or bilateral sanctions;
(iii) global and regional dynamics of demand and supply of oil and gas; in the current economic downturn we have experienced a significant reduction in worldwide demand for crude oil and in the European gas demand which have negatively impacted crude oil and natural gas prices;
(iv) prices and availability of alternative sources of energy;
(v) governmental and intergovernmental regulations, including the implementation of national or international laws or regulations intended to limit greenhouse gas emissions, which could impact the prices of hydrocarbons; and
(vi) success in developing and applying new technology.

All these factors can affect the global balance between demand and supply for oil and prices of oil. Such factors can also affect the prices of natural gas because natural gas prices for the major part of our supplies are typically indexed to the prices of crude oil and certain refined petroleum products.

Furthermore, lower oil and gas prices over prolonged periods may also adversely affect Eni s results of operations and cash flow by: (i) reducing rates of return of development projects either planned or being implemented, leading the Company to reschedule, postpone or cancel development projects, or accept a lower rate of return on such projects; (ii) reducing the Group s liquidity, entailing lower resources to fund expansion projects, further dampening the

Company s ability to grow future production and revenues; and (iii) triggering a review of future recoverability of the Company s carrying amounts of oil and gas properties, which could lead to the recognition of significant impairments charges.

Uncertainties in Estimates of Oil and Natural Gas Reserves

Numerous 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 depends 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 timing of development expenditures;
- whether the prevailing tax rules, other government regulations and contractual conditions will remain the same as on the date estimates are made;
- results of drilling, testing and the actual production performance of Eni s reservoirs after the date of the estimates which may require substantial upward or downward revisions; and

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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 those estimates are made. In particular the reserves estimates are subject to revisions as prices fluctuate due to the cost recovery mechanism under the Company s PSAs and similar contractual schemes.

Many of these factors, assumptions and variables involved in estimating proved reserves are beyond Eni s control and may change over time and impact the estimates of oil and natural gas reserves. Accordingly, the estimated reserves could be significantly different from the quantities of oil and natural gas that will ultimately be recovered. Additionally, 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.

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

The oil and 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 and gas operations in a number of countries where the Company conducts its upstream operations. As a result of those trends, management estimates that the tax rate applicable to the Company s oil and gas operations is materially higher than the Italian statutory tax rate of 38%. In 2010, management estimates that the tax rate of the Company s Exploration & Production segment was approximately 60%.

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 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.

Political Considerations

A substantial portion of our oil and gas reserves and gas supplies are located in politically, socially and economically unstable countries where we are exposed to material disruptions to our operations

Substantial portions of Eni s hydrocarbon reserves are located in countries outside the EU and North America, some of which may be politically or economically less stable than EU or North American countries. As of December 31, 2010, approximately 80% of Eni s proved hydrocarbon reserves were located in such countries. Similarly, a substantial portion of Eni s natural gas supplies comes from countries outside the EU and North America. In 2010, approximately 60% of Eni s supplies of natural gas came from such countries. See "Item 4 Gas & Power Natural Gas Supplies". Adverse political, social and economic developments in any of those countries may affect Eni s ability to continue operating in an economic way, either temporarily or permanently, and Eni s ability to access oil and gas reserves. Particularly Eni faces risks in connection with the following issues:

(i) lack of well-established and reliable legal systems and uncertainties surrounding enforcement of contractual rights;
(ii) unfavorable developments in laws, regulations and contractual arrangements leading, for example, to expropriations or forced divestitures of assets and unilateral cancellation or modification of contractual terms.

Eni is facing increasing competition from state-owned oil companies who are partnering Eni in a number of oil and gas projects and properties in the host countries where Eni conducts its upstream operations. These state-owned oil companies can change contractual terms and other conditions of oil and gas projects in order to obtain a larger profit share from a given project, thereby reducing Eni s profit share. For example, Sonatrach, the Algerian national oil company, is seeking to modify the contractual terms of certain PSAs in which Eni is a party to achieve a redistribution of the tax burden of such PSAs. Sonatrach alleges that it is currently bearing part of the tax burden attributable to Eni following the enactment of certain modifications to the country s tax regime. In case those negotiations result in a negative outcome for Eni, the future profitability of certain of Eni s PSAs in Algeria will be reduced. For more information on this matter see "Item 4 Exploration & Production Algeria". Furthermore, as of the balance sheet date receivables for euro 482 million relating cost recovery under a petroleum contract in a non-OECD country were the subject of an arbitration proceeding. Similar issues are also being experienced in Kazakhstan where there is a dispute in relation to certain unresolved items of expenditure incurred by the operating company Karachaganak Petroleum Operating BV which has led to the Kazakh Authorities making certain claims against the company on the base of audits performed relating to prior years 2003-2007. Parties are negotiating in order to settle the dispute;

(iii) restrictions on exploration, production, imports and exports;

(iv) tax or royalty increases (including retroactive claims); and

(v) civil and social unrest leading to sabotages, acts of violence and incidents.

See "Item 4 Exploration & Production Oil and Natural Gas Reserves". While the occurrence of those events is unpredictable, it is likely that the occurrence of such events could cause Eni to incur material losses or facility disruptions, by this way adversely impacting Eni s results of operations and cash flows.

Risks associated with continuing political instability in North Africa and Middle East

In recent months, several North African and Middle Eastern oil producing countries have experienced and continue to experience an extreme level of political instability that has resulted in changes in governments, unrest and violence and consequential economic disruptions. Further material changes are likely but largely unpredictable. Such instability is affecting, in particular, Libya. In 2010, approximately 15% of Eni s production originated from Libya and a material amount of Eni s proved reserves were located in Libya. Following suspension of activities at several of Eni s producing sites in Libya and the closure of the GreenStream pipeline transporting gas from Libya to Italy, Eni s production in Libya as of end of March 2011, was flowing at a rate ranging from 70 to 75 KBOE/d compared to an expected level for 2011 of approximately 280 KBOE/d. Production is continuing to decline. Closure of the GreenStream pipeline has also been impacting our gas sales in the Gas & Power Division. The majority of Eni s employees in Libya have left the country. Due to the outbreak of political unrest in Libya, in February and March 2011, the US, the UN, the EU and several countries implemented certain sanctions in relation to Libya. Future developments in Libya, which we are currently unable to predict, may have a material adverse effect on Eni s financial condition, results of operations and Libyan assets. Please see Item 4 for additional details of our operations in Libya and the impact of recent developments on our operations.

Our activities in Iran could lead to sanctions under relevant U.S. legislation

Eni is currently conducting oil and gas operations in Iran. The legislation and other regulations of the USA that target Iran and persons who have certain dealings with Iran may lead to the imposition of sanctions on any persons doing business in Iran or with Iranian counterparties.

The USA enacted the Iran Sanctions Act of 1996 (as amended, "ISA"), which required the President of the USA to impose sanctions against any entity that is determined to have engaged in certain activities, including investment in Iran s petroleum sector. The ISA was amended in July 2010 by the Comprehensive Iran Sanctions, Accountability and Divestment Act of 2010 ("CISADA"). As a result, in addition to sanctions for knowingly investing in Iran s petroleum sector, parties engaging in business activities in Iran now may be sanctioned under the ISA for knowingly providing to Iran refined petroleum products, and for knowingly providing to Iran goods, services, technology, information or support that could directly and significantly either (i) facilitate the maintenance or expansion of Iran s domestic production of refined petroleum products, or (ii) contribute to the enhancement of Iran s ability to import refined petroleum products. CISADA also expanded the menu of sanctions available to the President of the USA by three, from six to nine, and requires the President to impose three of the nine sanctions, as opposed to two of six, if the President has determined that a party has engaged in sanctionable conduct. The new sanctions include a prohibition on transactions in foreign exchange by the sanctioned company, a prohibition of any transfers of credit or payments between, by, through or to any financial institution to the extent the interest of a sanctioned company is involved, and a requirement to "block" or "freeze" any property of the sanctioned company that is subject to the jurisdiction of the USA. Investments in the petroleum sector that commenced prior to the adoption of CISADA appear to remain subject to the pre-amended version of the ISA, except for the mandatory investigation requirements described below, but no definitive guidance has been given. The new sanctions added by CISADA would be available to the President with respect to new investments in the petroleum sector or any other sanctionable activity occurring on or after July 1, 2010.

CISADA also adopted measures designed to reduce the President s discretion in enforcement under the ISA, including a requirement for the President to undertake an investigation upon being presented with credible evidence that a person is engaged in sanctionable activity. CISADA also added to the ISA provisions that an investigation need not be initiated, and may be terminated once begun, if the President certifies in writing to the U.S. Congress that the person whose activities in Iran were the basis for the investigation is no longer engaging in those activities or has taken significant steps toward stopping the activities, and that the President has received reliable assurances that the person will not knowingly engage in any sanctionable activity in the future. The President also may waive sanctions, subject to certain conditions and limitations.

The USA maintains broad and comprehensive economic sanctions targeting Iran that are administrated by the U.S. Treasury Department s Office of Foreign Assets Control ("OFAC sanctions"). These sanctions generally restrict the dealings of U.S. citizens and persons subject to the jurisdiction of the USA. In addition, we are aware of initiatives by certain U.S. states and U.S. institutional investors, such as pension funds, to adopt or consider adopting laws, regulations or policies requiring divestment from, or reporting of interests in, companies that do business with countries designated as states sponsoring terrorism. CISADA specifically authorized certain state and local Iran-related divestment initiatives. If our operations in Iran are determined to fall within the scope of divestment laws or policies, sales resulting from such divestment laws and policies, if significant, could have an adverse effect on our share price. Even if our activities in and with respect to Iran do not subject us to sanctions or divestment, companies with investments in the oil and gas sectors in Iran may suffer reputational harm as a result of increased international scrutiny.

Other sanctions programs have been adopted by various governments and regulators with respect to Iran, including a series of resolutions from the United Nations Security Council, and measures imposed by various countries based on and to implement these United Nations Security Council resolutions. On July 26, 2010, the European Union adopted new restrictive measures regarding Iran (referred to as the "EU measures"). Among other things, the supply of equipment and technology in the following sectors of the oil and gas industry in Iran are prohibited: refining, liquefied natural gas, exploration and production. The prohibition extends to technical assistance, training and financing and financial assistance in connection with such items. Extension of loans or credit to, acquisition of shares in, entry into joint ventures with or other participation in enterprises in Iran (or Iranian-owned enterprises outside of Iran) engaged in any of the targeted sectors also is prohibited.

Eni Exploration & Production Division 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 National Iranian Oil Co (NIOC) between 1999 and 2001, and no other exploration and development contracts have been entered into since then. Under such Service Contracts, Eni has carried out development operations in respect of certain oil fields, and is entitled to recovery of expenditures made, as well as a service fee. The service contracts do not provide for payments to be made by Eni, as contractor, to the Iranian Government (e.g. leasing fees, bonuses, significant amounts of local taxes); all material future cash flows relate to the payment to Eni of its dues. All projects mentioned above have been completed or substantially completed; the last one, the Darquain project, is in the process of final commissioning and is being handed over to the NIOC. Eni Exploration & Production projects in Iran are currently in the cost recovery phase. Therefore, Eni has ceased making any further investment in the country and is not planning to make additional capital expenditures in Iran in any year subsequent to 2010. Eni s other significant involvement in Iran is that, from time to time, Eni may purchase Iranian-origin crude oil. Eni has no involvement in Iran s refined petroleum sector, and does not export refined petroleum to Iran. In addition, we have occasionally entered into licensing agreement with certain Iranian counterparties for the supply of technologies in the petrochemical sector. In 2010, Eni s production in Iran averaged 21 KBOE/d, representing approximately 1% of the Eni Group s total production for the year. Eni s entitlement in 2010 represented less than 10% of the overall production from the oil and gas fields that we have developed in Iran. Eni does not believe that the results from its Iranian activities have or will have a material impact on the Eni Group s results.

After passage of CISADA, Eni engaged in discussions with officials of the U.S. State Department, which administers the ISA, regarding Eni s activities in Iran. On September 30, 2010, the U.S. State Department announced that the U.S. Government, pursuant to a provision of the ISA added by CISADA that allows it to avoid making a determination of sanctionability under the ISA with respect to any party that provides certain assurances, would not make such a determination with respect to Eni based on Eni s commitment to end its investments in Iran s energy sector and not to undertake new energy-related activity. The U.S. State Department further indicated at that time that, as long as Eni acts in accordance with these commitments, we will not be regarded as a company of concern for our past Iran-related activities.

With respect to segments other than Exploration & Production, our Refining & Marketing segment has historically purchased amounts of Iranian crude oil under a term contract with the NIOC and on a spot basis. We purchased 1.42

mmtonnes, 980 ktonnes and 1.63 mmtonnes in 2008, 2009 and 2010, respectively. We paid NIOC $953 million in 2008, $419 million in 2009 and $888 million in 2010 for those purchases.

In addition in the three-year period 2008-2010 we purchased crude oil from international traders and oil companies who, based on bills of loading and shipping documentation available to us, we believe purchased the crude oil from Iranian companies. Purchases were mainly on spot basis. In 2008, we purchased 1.3 mmtonnes of crude oil amounting to $830 million; in 2009, we purchased 278 ktonnes of crude oil amounting to $147 million and in 2010, we purchased 2.09 mmtonnes of crude oil amounting to $1.1 billion.

We will continue to monitor closely legislative and other developments in the USA and the European Union in order to determine whether our remaining interests in Iran could subject us to application of either current or future sanctions under the OFAC sanctions, the ISA, the EU Measures or otherwise. If any of our activities in and with respect to Iran are found to be in violation of any Iran-related sanctions, and sanctions are imposed on Eni, it could have an adverse effect on our business, plans to raise financing, sales and reputation.

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We have commercial transactions with Syria where we mainly purchase from time to time volumes of crude oil

Our operations in Syria have mainly been limited to transactions carried out by our Refining & Marketing Division with Syrian Petrol Company, an entity controlled by the Syrian Government, for the purchase of crude oil under term purchase contracts or on a spot basis, based on prevailing market conditions.

We purchased 329 ktonnes, 241 ktonnes and 321 ktonnes in 2008, 2009 and 2010, respectively. We paid Syrian Petrol Company $227 million in 2008, $92 million in 2009 and $163 million in 2010 for those purchases.

In 2008, we also purchased 184 ktonnes of crude oil amounting to $73 million and in 2010 we purchased 115 ktonnes of crude oil amounting to $59 million, in each case from international traders who, based on bills of loading and shipping documentation available to us, we believe purchased those raw materials from Syrian companies.

Other than as described above, Eni is not currently investing in the country, and it has no contractual arrangements in place to invest in the country. However, we have recently been exploring investment opportunities in Syria.

Cyclicality of the Petrochemical Industry

The petrochemical industry is subject to cyclical fluctuations in demand in response to economic cycles, with consequential effects on prices and profitability exacerbated by the highly competitive environment of this industry. Eni s petrochemical operations have been in the past and may be adversely affected in the future by worldwide economic slowdowns, intense competitive pressures and excess installed production capacity. Furthermore, Eni s petrochemical operations face increasing competition from Asian companies and national oil companies petrochemical divisions which can leverage on long-term competitive advantages in terms of lower operating costs and feedstock purchase costs. Particularly, Eni s petrochemical operations are located mainly in Italy and Western Europe where the regulatory framework and public environmental sensitivity are generally more stringent than in other countries, especially Far East countries, resulting in higher operating costs of our petrochemical operation compared to the Company s Asiatic competitors due to the need to comply with applicable laws and regulations in environmental and other related matters. Additionally, our petrochemical operations lack sufficient scale and competitiveness in a number of sites. Due to weak industry fundamentals, intense competitive pressures and high feedstock costs, our petrochemicals operations incurred substantial operating losses in both 2009 and 2008 of euro 675 million and euro 845 million, respectively. However, results in 2010 improved substantially and operating loss diminished to euro 86 million due to demand recovery, cost efficiencies and better unit margins, while the overall profitability was impaired by higher oil-based feedstock costs. Looking forward, management expects that while any strengthening in the global recovery may benefit demand for our products, continuing increases in the cost of oil represent a risk to the profitability of the Company s petrochemicals operation as it may be difficult transferring higher feedstock costs to end-prices of products due to the high level of competition in the industry and the commoditized nature of many of Eni s products.

Risks in the Company Gas & Power business segment

i) Risks associated with the Trading Environment and Competition in the Industry

In 2010, the Company s results of operations and cash flow were negatively affected by lower sales volumes and reduced unit margins due to increasing competitive pressures arising from large gas availability on the marketplace. We expect continuing competitive pressures and oversupply to affect our results in 2011 and beyond

In 2010, gas demand in Italy and Europe rebounded from the depressed levels registered in the previous year, growing by 6% and 4%, respectively. Consumption volumes, however, remained below the pre-crisis levels seen in 2007. The Eni gas business failed to benefit from demand growth in 2010 as sales volumes declined by 6.4% from 2009 with Italy posting the largest decrease, with direct sales to customers down by 14.4% and sales to importers to Italy down by 19.5% driven by rising competitive pressures which also dragged down unit selling margins on gas sales in Italy. The Company s results in its European markets business unit were affected by lowering average gas selling margins as gas spot prices at continental hubs were dragged down by large availability of LNG and competitive pressures. While spot prices have increasingly been adopted as contractual benchmarks in selling formulae outside Italy, the Company s cost of supplies remained linked to trends in oil prices as provided by its long-term contractual arrangements to purchase gas from suppliers. As a result the Company s unit margins outside Italy fell sharply in 2010. Management believes that those trends will continue weighing on the gas business future results of operations and cash flows over the next three years.

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A recovery in profitability of the Company s marketing business depends heavily on the management s assumption to be able to renegotiate better contractual terms within the Company s long-term gas supply contracts

The industrial and financial forecasts for the next four-year plan of the gas business as well as the amount of the impairment loss recognized in 2010 Consolidated Financial Statements both take into consideration management assumptions that the Company s long-term gas purchase contracts will be renegotiated at better economic terms for Eni, so as to restore the competitiveness of the Company s cost position in the current depressed scenario for the gas sector. The renegotiation of revised contractual terms, including any price revisions and contractual flexibility, is established by such contractual clauses whereby parties are held to bring the contract back to the economic equilibrium in case of significant changes in the market environment, like the ones that have been occurring since the second half 2008. In the course of 2010, Eni has finalized a number of important contractual renegotiations by obtaining improved economic conditions for supplies and wider contractual flexibility with a benefit to its commercial programs. A number of renegotiations have been commenced or are due to commence in the upcoming months involving all the Company s main suppliers of gas based on long-term contracts. Should the outcome of those renegotiations fall short of management s expectations and absent a solid recovery in fundamentals of the gas sector, management believes that future results of operations and cash flows of the Company s gas business will be negatively affected with further consequences in terms of recoverability of the carrying amounts of the gas business assets. In 2010 Consolidated Financial Statements, the Company recorded an impairment loss of euro 425 million related to its goodwill in the European gas business; for further information see "Item 5 Operating and Financial Review and Prospects Group Results of Operations".

We expect that current imbalances between demand and supply in the European gas market will persist for sometime

Management estimates that long-term demand growth will achieve an average rate of 1.7% and 1.1% in Italy and Europe, respectively, until 2020. Those estimates have been revised down from previous management projections to factor in the expected impacts associated with a number of ongoing trends:

- uncertainties and volatility in the current macroeconomic cycle;
- growing adoption of consumption patterns and life-style characterized by wider sensitivity to energy efficiency;
- EU policies intend to reducing GHG emissions and promoting renewable energy source. For further information about the Company s outlook for gas demand see "Item 4 Gas & Power".

The projected moderate dynamics in demand development will not be sufficient to balance current oversupplies on the marketplace over the next three years according to management s estimates. Gas oversupplies have been increasing in recent years as new, large investments to upgrade import pipelines to Europe have come online from Russia, Libya and Algeria, and large availability of LNG on a worldwide scale has found an outlet at the European continental hubs driving the development of very liquid spot gas markets. Also, certain Eni s competitors are currently assessing the economic feasibility of new gas import infrastructures, targeting 5-10 BCM of capacity expansion online from 2015-2016 according to management s assumptions.

Management believes that a better balance between demand and supply will not be achieved until 2014, at the earliest. Those trends represent risks to the Company s future results of operations and cash flows in its gas business.

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, Eni has signed a number of long-term gas supply contracts with key producing countries that supply the European gas markets. Those contracts have been ensuring approximately 80 BCM of gas availability from 2010 (including the Distrigas portfolio of supplies) with a residual life of approximately 19 years and a pricing mechanism indexed to the price of crude oil and its derivatives (gasoil, fuel oil, etc.). The contracts provide take-or-pay clauses whereby the Company is required to collect minimum pre-determined 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, applied to uncollected volumes up to the minimum contractual quantity. The take-or-pay clause entitles the Company to collect pre-paid volumes of gas in later years during the period of contract execution. Amounts of cash pre-payments and time schedules for collecting 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 of non-fulfillment with the balance due in the year when the gas is actually collected. Amounts of pre-payments range from 10 to 100 percent of the full price. The right to collect pre-paid gas expires within a ten-year term in some contracts or remains in place until contract expiration in other arrangements. In addition, rights to collect pre-paid gas in future years can be exercised provided that the Company

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has fulfilled its minimum take obligation in a given year and within the limit of the maximum annual quantity that can be collected in each contractual year. In this case, Eni will pay the residual price calculating it as the percentage that complements 100%, based on the arithmetical average of monthly base prices current in the year of the off-take. Similar considerations apply to ship-or-pay contractual obligations.

Management believes that the current outlook for moderate gas demand growth and large gas availability on the marketplace, the possible evolution of sector-specific regulation, as well as the de-coupling between trends in gas prices indexed to oil versus gas benchmark prices at spot markets, represent risks factors to the Company s ability to fulfill its minimum take obligations associated with its long-term supply contracts.

In 2009 and 2010, Eni incurred the take-or-pay clause as the Company collected lower volumes than its minimum take obligations in each of those years accumulating deferred costs for an amount of euro 1.44 billion as of December 31, 2010. The Company s ability to recover those pre-paid volumes within contractual terms will depend in future years on a number of factors, including the possible evolution of the market environment and the competitiveness of Eni s cost position, with this latter being influenced by the Company s ability to renegotiate better contractual terms of its long-term purchase contracts (see paragraph above).

In case Eni fails to off-take the contractual minimum amounts, it will be exposed to a price risk, because the purchase price Eni will ultimately be required to pay is based on prices prevailing after the date on which the off-take obligation arose. In addition, Eni is subject to the risk of not being able to dispose of pre-paid volumes. The Company also expects to incur financing costs to pay cash advances corresponding to contractual minimum amounts. As a result, the Company s selling margins, results of operations and cash flow may be negatively affected.

For further information on the Company s take-or-pay contracts see "Item 4 Gas & Power Purchases".

Eni plans to increase natural gas sales in Europe. If Eni fails to achieve projected growth targets, this could adversely impact future results of operations and liquidity

Over the medium-term, Eni plans to increase its natural gas sales in Europe leveraging on its natural gas availability under take-or-pay purchase contracts, availability of transport rights and storage capacity, and widespread commercial presence in Europe which benefited from synergies from integrating the Belgian gas operator Distrigas acquired in 2009. Should Eni fail to increase natural gas sales in Europe as planned due to poor strategy execution or competition, Eni s future growth prospects, results of operations and cash flows might be adversely affected also taking account that Eni might be unable to fulfill its contractual obligations to purchase certain minimum amounts of natural gas based on its take-or-pay purchase contracts currently in force.

ii) Risks associated with sector-specific regulations in Italy

The natural gas market in Italy is highly regulated in order to favor the opening of the market and development of competition

In 2010, the regulated period for gas antitrust thresholds defined by Legislative Decree No. 164 of May 23, 2000 expired. Those thresholds defined maximum allowed limits of gas volumes (imported or domestically produced) input into the national transport network and marketed to final customers, applicable to each operator.

That system of antitrust thresholds was replaced with a mechanism of market shares enacted by Legislative Decree No. 130 of August 13, 2010. The Decree introduced a 40% ceiling to the wholesale market share of each Italian gas operator. This ceiling can be raised to 55.9% in case an operator commits itself to building new storage capacity in Italy for a total of 4 BCM within five years. The new capacity shall be allocated to industrial and power generation customers. In case of breaching the mandatory thresholds, an operator is obliged to execute gas release measures at regulated prices. Eni plans to build new storage capacity and, in the meantime, intends to adopt measures and bear the associated expenses to make 50% of that planned capacity available to requesting customers (for further information see "Operating Review of the Gas & Power Division   Paragraph Regulation"). Eni believes that this new gas regulation will increase competitiveness in the wholesale natural gas market in Italy.

Further material aspects regarding the Italian gas sector regulations are regulated access to infrastructures (transport backbones, storage fields, distribution networks and LNG terminals), the unbundling of activities relating to infrastructures within vertically-integrated group companies, from July 1, 2008 (as defined by Decision No. 11/2007 and updated by Resolution No. 253/2007 of the Authority for Electricity and Gas). Also the Italian Authority for Electricity and Gas is entrusted with certain powers in the matters of setting tariffs for transport, distribution, storage and re-gasification services, as well as in approving specific codes for each regulated activity, monitoring natural gas prices and setting pricing mechanisms for supplies to residential users consuming less than 200,000 CM/y. See next paragraph.

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

The Authority for Electricity and Gas is entrusted with certain powers in the matters of natural gas pricing. Specifically, the Authority for Electricity and Gas holds a general surveillance power on pricing in the natural gas market in Italy and the power to establish selling tariffs for the supply of natural gas to residential and commercial users consuming less than 200,000 CM/y (qualified as non eligible customers as of December 31, 2002 as defined by Legislative Decree No. 164/2000) taking into account the public goal of containing the inflationary pressure due to rising energy costs. Accordingly, decisions of the Authority for Electricity and Gas 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. The indexation mechanism set by the Authority for Electricity and Gas with Resolution No. 64/2009 basically provides that the cost of the raw material in pricing formulae to the residential sector be indexed to movements in a basket of hydrocarbons. In 2010, the Authority for Electricity and Gas with Resolution ARG/gas 89/10 amended that indexation mechanism and established a fixed reduction of 7.5% of the raw material cost component in the final price of supplies to residential users be applied in the thermal year October 1, 2010-September 30, 2011. This resolution will negatively affect Eni s future results of operations and cash flows, considering the negative impact on unit margins in sales to residential customers. Administrative appeals against the Authority s resolution, which have been filed by many operators including Eni, might possibly impact that matter.

Management cannot exclude the possibility that in the future the Authority for Electricity and Gas could implement further measures in this matter which may negatively affect Eni results of operations and liquidity.

Due to the regulated access to natural gas transport infrastructures in Italy, Eni may not be able to sell in Italy all the natural gas volumes it planned to import and, as a consequence, the Company may be unable to sell all the natural gas volumes which it is committed to purchase under take-or-pay contract obligations

Other risk factors deriving from the regulatory framework are associated with regulation of the access to the Italian gas transport network that is currently set by Decision No. 137/2002 of the Authority for Electricity and Gas. The decision is fully-incorporated into the network code presently in force as prepared by the system s operator. The decision sets priority criteria for transport capacity entitlements at points where the Italian transport network connects with international import pipelines (the so-called entry points to the Italian transport system). Specifically, operators that are party to take-or-pay contracts, as in the case of Eni, are entitled to a priority in allocating available transport capacity within the limit of average daily contractual volumes. Gas volumes exceeding average daily contractual volumes are not entitled to any priority and, in case of congestion at any entry points, they are entitled available capacity on a proportionate basis together with all pending requests for capacity assignments. Under its take-or-pay purchase contracts, Eni may off-take daily volumes in excess of average daily contractual volumes. This flexibility is important to Eni s commercial programs as it is used when demand peaks, usually during the wintertime. In the event congestion occurs at entry points to the Italian transport network, based on current regulations, available transport capacity would be entitled firstly to operators having a priority right, i.e. holders of take-or-pay contracts within the limits of average daily contractual volumes. Then any residual available transport capacity would be allocated in proportion to all pending capacity requests. Eni believes that Decision No. 137/2002 is in contrast with the rationale of the European regulatory framework on the gas market as provided in European Directive No. 2003/55/EC. The Company, based on that belief, has commenced an administrative procedure to repeal Decision No. 137/2002 before an administrative court which recently confirmed in part Eni s position. An administrative appeals court also confirmed the Company s position. Specifically, the Court stated that the purchase of the contractual flexibility is an obligation on part of the importer, which responds to a collective interest. According to the Court, there is no reasonable motivation whereby volumes corresponding to such contractual flexibility should not be granted priority in access to the network, also in case congestion occurs. At the moment, however, no case of congestion occurred at entry points to the Italian transport infrastructure such to impairing Eni s marketing plans.

Management believes that Eni s results of operations and cash flows could be adversely affected should a combination of market conditions and regulatory constraints prevent Eni from fulfilling its minimum take contract obligations. See "Item 5 Outlook".

A number of mandatory gas release measures and other administrative measures have been recently implemented in Italy resulting in a negative impact on Eni s results of operations and liquidity. It is possible that similar measures will be implemented in future years

Gas release measures are administrative acts whereby Eni is obliged to dispose of certain amounts of gas at set prices and conditions as provided in the relevant gas release measure. Those measures are intended to increase flexibility and liquidity in the gas market. This measure strongly affected Eni s marketing activity in Italy. In 2007, Eni agreed to adhere to a gas release program involving 4 BCM which were disposed of in a two-year period (from October 1, 2007 to September 30, 2009). For thermal year 2009/2010 Italian Law No. 99/2009 obliged Eni to dispose of 5 BCM of gas in yearly and half-yearly amounts. Although the allotment procedure (bid) was based on a minimum price set by the Ministry for Economic Development, only 1.1 BCM were awarded out of the planned 5 BCM. The price set by the Ministry was lower than the average price of Eni s sales in Italy.

For the next few years, based on indications made by the AEEG (in a report to the Parliament on the situation of the gas and electricity market in Italy as provided in Resolution PAS 3/2010), Eni cannot exclude the possibility that the Company may be obliged to implement new gas release programs. As a consequence, future results and cash flows could be negatively affected.

In 2010, a national trading platform was implemented where gas importers must trade volumes of gas corresponding to a legal obligation on part of Italian importers and producers. Under those provisions, importers from extra-EU countries are required to supply a set percentage of imported volumes in a given thermal year and to trade them at the national trading platform on a spot basis. Fulfillment of that obligation is a condition for the importer to be permitted to import gas from extra-EU countries. Also royalties in-kind owed to the Italian State on gas production are to be traded on that trading platform. The new trading platform is expected to develop a spot market for natural gas in Italy.

The Italian Government, Parliament and the regulatory authorities in Italy and in Europe may take further steps to increase competition in the Italian natural gas market and such regulatory developments may adversely affect Eni s results of operations and cash flows

Italian administrative and governmental institutions and political forces are urging a higher degree of competition in the Italian natural gas market and this may produce significant developments in this area.

In 2003, Law No. 290 was enacted in Italy which prohibits Eni from holding an interest higher than 20% in undertakings owning natural gas transport infrastructures in Italy (Eni currently holds a 52.54% interest in Snam Rete Gas). A decree is expected to be enacted by the Italian Prime Minister to establish the relevant provisions to implement this mandatory disposal. The deadline for the disposal, which was initially scheduled for December 31, 2008, is to be rescheduled in a 24-month deadline following enactment of the decree from the Italian Prime Minister. Currently, Eni is unable to predict any development of this matter.

In recent years, both the Italian Authority for Electricity and Gas and the Italian Antitrust Authority (the "Antitrust Authority") have conducted several reviews and inquiries on the status of Italian natural gas market, targeting the overall level of competition, the degree of opening to competition of the residential sector, levels of entry-exit barriers, and other areas such as sub-investment in the storage sector. Both the Authority for Electricity and Gas and the Antitrust Authority believe that the vertical integration of Eni in the supply, transport, distribution, storage and marketing of gas may hamper development of a competitive gas market in Italy.

Management believes the institutional debate on the degree of competition in the Italian natural gas market and the regulatory activity to be areas of attention and cannot exclude negative impacts deriving from developments on these matters on Eni s future results of operations and cash flows.

For more information on these issues see "Item 4 Regulation Gas & Power".

Antitrust and competition law

The Group s activities are subject to antitrust and competition laws and regulations in many countries of operations, especially in Europe. In the years prior to 2008, Eni recorded significant loss provisions due to unfavorable developments in certain antitrust proceedings before the Italian Antitrust Authority, and the European Commission. It is possible that the Group may incur significant loss provisions in future years relating ongoing antitrust proceedings or new proceedings that may possibly arise. The Group is particularly exposed to this risk in its natural gas and refining and marketing activities due to the fact that Eni is the incumbent operator in those markets in Italy and a large European gas player. See Note 34 to the Consolidated Financial Statements for a full description of Eni s main pending antitrust proceedings.

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Furthermore, based on the findings of antitrust proceedings, plaintiffs could seek payment to compensate for any alleged damages as a result of antitrust business practices on part of Eni. Both these risks could adversely affect the Group s future results of operations and cash flows.

Environmental, Health and Safety Regulation

Eni may incur material operating expenses and expenditures in relation to compliance with applicable environmental, health and safety regulations

Eni is subject to numerous EU, international, national, regional and local environmental, health and safety laws and regulations concerning its oil and gas operations, products and other activities. Generally, these laws and regulations require the 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, petrochemicals and other Group operations, limit or prohibit drilling activities in certain protected areas, 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, petrochemical and other Group s operations.

These laws and regulations also regulate emissions of substances and pollutants, handling of hazardous materials and discharges to surface and subsurface 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. In 2009, new regulations were enacted in Italy relating to monitoring the route of waste from production up to its disposal/recycling, also prosecuting any unlawful conducts. The Company anticipates that it will incur operating costs to comply with this new regulation in 2011 when the new system of monitoring waste becomes fully-operational. Breach of environmental, health and safety laws exposes the Company s employees to criminal and civil liability and the Company to the incurrence of liabilities associated with compensation for environment health or safety damage. Additionally, in the case of violation of certain rules regarding safety in the workplace, the Company can be liable as provided for by a general EU rule on businesses liability due to negligent or willful conduct on part of their employees as adopted in Italy with 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 to comply with environmental, health and safety laws and regulations, also taking into account possible future developments in environmental regulations in Italy and in other countries where Eni operates, particularly current and proposed fuel and product specifications, emission controls and implementation of increasingly strict measures decided at both international and country level to reduce greenhouse gas emissions. For more discussion about this latter topic see "Item 4 Environmental Regulations".

Eni has incurred in the past and may incur in the future material environmental liabilities in connection to the environmental impact of its past and present industrial activities. Also plaintiffs may seek to obtain compensation for damage resulting from events of contamination and pollution

Risks of environmental, health and safety incidences and liabilities are inherent in many of Eni s operations and products. Notwithstanding management s beliefs that Eni adopts high operational standards to ensure safety of its operations and to protect the environment and health of people and employees, it is possible that incidents like blow-outs, oil spills, contaminations and similar events could occur that would result in damage to the environment, employees and communities. Environmental laws also require the Company to remediate and clean-up the environmental impacts of prior disposals or releases of chemicals or petroleum substances and pollutants by the Company. Such contingent liabilities may exist for various sites that the Company disposed of, closed or shut down in prior years where the Group products have been produced, processed, stored, distributed or sold, such as chemicals plants, mineral-metallurgic plants, refineries and other facilities. The Company is particularly exposed to the risk of environmental liabilities in Italy where the vast majority of the Group industrial installations are localized and also due to the circumstance that the Group engaged in a number of industrial activities in past years that were subsequently divested, closed, liquidated or shut down. At those industrial sites Eni has commenced in recent years a number of remedial plans to restore and clean-up proprietary or concession areas that were contaminated and polluted by the Group s industrial activities in previous years. Notwithstanding the Group claimed that it cannot be held liable for such past contaminations as permitted by applicable regulations in case of declaration rendered by a guiltless owner particularly regulations that enacted into Italian legislation the Directive No. 2004/35/EC a number of civil and administrative proceedings have arisen relating to both the environmental damage and administrative prescriptions on how to perform individual cleaning-up project. In 2010, Eni proposed a global transaction to the Italian Ministry for the Environment related to nine sites of national interest where the Group has been performing clean-up activities in order to define the scope of work of each clean-up project and settle all pending administrative and civil litigation. To account for this proposal, the Group accrued a pre-tax risk provision amounting to euro 1.1 billion in its 2010 Consolidated Financial Statements.

Remedial actions with respect to other Company s sites are expected to continue in the foreseeable future, impacting our liquidity as 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 amount represents the management s best estimates of future environmental expenses to be incurred.

Notwithstanding this, management believes that it is possible that in the future Eni may incur significant environmental expenses and liabilities in addition to the amounts already accrued due to: (i) the likelihood of as yet unknown contamination; (ii) the results of ongoing surveys or surveys to be carried out on the environmental status of certain Eni s industrial sites as required by the applicable regulations on contaminated sites; (iii) unfavorable developments in ongoing litigation on the environmental status of certain Company s site where a number of public administrations and the Italian Ministry for 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 future environmental restoration and remediation programs are often inherently difficult to estimate.

Legal Proceedings

Eni is party to a number of civil actions and administrative proceedings arising in the ordinary course of business. In addition to existing provisions accrued as of the balance sheet date to account for ongoing proceedings, it is possible that in future years Eni may incur significant losses in addition to 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. See disclosure of pending litigation in Note 34 to the Consolidated Financial Statements.

Risks related to Changes in the Price of Oil, Natural Gas, Refined Products and Chemicals

Operating results in Eni s Exploration & Production, Refining & Marketing, and Petrochemical segments are affected by changes in the price of crude oil and by the impacts of movements in crude oil prices on margins of refined and petrochemical products.

Eni s results of operations are affected by changes in international oil prices

Overall, lower oil prices have a net adverse impact on Eni s results of operations. The effect of lower oil prices on Eni s average realizations for produced oil is generally immediate. Furthermore, Eni s average realizations for produced oil differ from the price of Brent crude marker primarily due to the circumstance that Eni s production slate, which also includes heavy crude qualities, has a lower API gravity compared with Brent crude (when processed the latter allows for higher yields of valuable products compared to heavy crude qualities, hence higher market price).

The favorable impact of higher oil prices on Eni s results of operations may be offset in part by different trends in margins for Eni s downstream businesses

The impact of changes in crude oil prices on Eni s downstream businesses, including the Gas & Power, the Refining & Marketing and the Petrochemical businesses, depends upon the speed at which the prices of gas and products adjust to reflect movements in oil prices.

In the Gas & Power segment, increases in the oil price represent a risk to the Company as gas supplies are mainly indexed to the cost of oil and certain refined products, while selling prices, particularly outside Italy, are increasingly linked to certain market benchmarks quoted at continental hubs. In the current trading environment,

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spot prices at those hubs are particularly depressed due to oversupply conditions. In addition, the Italian Authority for Electricity and Gas may limit the ability of the Company to pass cost increases linked to higher oil prices onto selling prices in supplies to residential customers and small businesses as the Italian Authority for Electricity and Gas regulates the indexation mechanism of the raw material cost in selling formulae to those customers. See the paragraph "Risks in the Company s gas business" above for more information.

In addition, in light of changes in the European gas market environment, Eni has recently adopted new risk management policies. These policies contemplate the use of derivative contracts to mitigate the exposure of Eni s future cash flows to future changes in gas prices; such exposure had been exacerbated in recent years by the fact that spot prices at European gas hubs have ceased to track the oil prices to which Eni s long-term supply contracts are linked. These policies also contemplate the use of derivative contracts for speculative purposes whereby Eni will seek to profit from opportunities available in the gas market based, among other things, on its expectations regarding future prices. These contracts may lead to gains as well as losses, which, in each case, may be significant. All derivative contracts that are not entered into for hedging purposes in accordance with IFRS will be accounted through profit and loss, resulting in higher volatility of the gas business operating profit. Please see "Item 5 Financial Review Outlook" and "Item 11 Quantitative and Qualitative Disclosures About Market Risk".

In the Refining & Marketing and Petrochemical businesses a time lag exists between movements in oil prices and in prices of finished products.

Eni s results of operations are affected by changes in European refining margins

Results of operations of the Eni s Refining & Marketing segment are substantially affected by changes in European refining margins which reflect changes in relative prices of crude oil and refined products. The prices of refined products depend on global and regional supply/demand balances, inventory levels, refinery operations, import/export balances and weather. Furthermore, Eni s realized margins are also affected by relative price movements of heavy crude qualities versus light crude qualities, taking into account the ability of Eni s refineries to process complex crudes that represent a cost advantage when market prices of heavy crudes are relatively cheaper than the marker Brent price. In 2010, Eni s refining margins were unprofitable as the high cost of oil was only partially transferred to final prices of fuels at the pump pressured by weak demand, high worldwide and regional inventory levels and excess refining capacity. Management does not expect any significant recovery in industry fundamentals over the next four-year industrial plan. The sector as a whole will continue to suffer from weak demand and excess capacity, while the cost of oil feedstock may continue rising and price differentials may remain compressed. In this context, management expects that the Company s refining margins will remain at below break-even levels in 2011 and possibly beyond.

Eni s results of operations are affected by changes in petrochemical margins

Eni s margins on petrochemical products are affected by trends in demand for petrochemical products and movements in crude oil prices to which purchase costs of petroleum-based feedstock are indexed. Given the commoditized nature of Eni petrochemical products, it is difficult for the Company to transfer higher purchase costs for oil-based feedstock to selling prices to customers. Rising oil-based feedstock costs will continue to negatively affect Eni s results of operations and liquidity in this business segment in 2011.

Risks from Acquisitions

Eni constantly monitors the oil and gas market in search of opportunities to acquire individual assets or companies in order to achieve its growth targets or complement its asset portfolio. Acquisitions entail an execution risk an important risk, among other matters, 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. We also may incur unanticipated costs or assume unexpected liabilities and losses in connection with companies or assets we acquire. If the integration and financial risks connected to acquisitions materialize, our financial performance may be adversely affected.

Credit risk

Credit risk is the potential exposure of the Group to losses in case counterparties fail to perform or pay due amounts. Credit risks arise from both commercial partners and financial ones. In recent years, the Group has experienced a higher than normal level of counterparty failure due to the severity of the economic and financial downturn. In our 2010 Consolidated Financial Statements, we accrued an allowance against doubtful accounts amounting to euro 201 million, mainly relating the Gas & Power business. Management believes that the Gas & Power business is particularly exposed to credit risks due to its large and diversified customer base which include a large number of middle and small businesses and retail customers where impacts of the economic and financial downturn were particularly severe.

Exchange Rates

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 denominated in euros. Similarly, prices of Eni s petrochemical products are generally denominated in, or linked to, the euro, whereas expenses in the Petrochemical segment are denominated both in euros and U.S. dollars. Accordingly, a depreciation of the U.S. dollar against the euro generally has an adverse impact on Eni results of operations and liquidity because it reduces booked revenues by an amount greater than the decrease in U.S. dollar-denominated expenses. 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.

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 is higher. Accordingly, the results of operations of the Gas & Power segment and, to a lesser extent, the Refining & Marketing segment, as well as the comparability of results over different periods may be affected by such changes in weather conditions.

Furthermore, our operations, particularly offshore production of oil and natural gas, are exposed to extreme weather phenomena that can result in material disruption to our operations and consequent loss or damage of properties and facilities.

Interest Rates

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.

Critical Accounting Estimates

The preparation of financial statements requires management to make certain accounting estimates that are characterized by a high degree of uncertainty, complexity and judgment. These estimates affect the reported amount of the Company s assets and liabilities, as well as the reported amount of the Company s income and expenses for a given period. Although management believes these estimates to represent the best outcome of the estimation process, actual results could differ from such estimates, due to, among other things, the following factors: uncertainty, lack or limited availability of information, availability of new informative elements, variations in economic conditions such as prices, costs, other significant factors including evolution in technologies, industrial practices and standards (e.g. removal technologies) and the final outcome of legal, environmental or regulatory proceedings. See "Item 5 Critical Accounting Estimates".

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Item 4. INFORMATION ON THE COMPANY

History and Development of the Company

Eni SpA with its consolidated subsidiaries is engaged in the oil and gas exploration and production, gas marketing operations, management of gas infrastructures, power generation, petrochemicals, oil field services and engineering industries. Eni has operations in 79 countries and 79,941 employees as of December 31, 2010.

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: www.eni.com.

The name of the agent of Eni in the USA is Salzano Pasquale, 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 43 countries, including Italy, the UK, Norway, Libya, Egypt, Angola, Nigeria, Congo, the USA, Kazakhstan, Iraq, Russia, Venezuela and Australia. In 2010, Eni produced 1,757 KBOE/d on an available for-sale basis. As of December 31, 2010, Eni s total proved reserves of subsidiaries stood at 6,332 mmBOE; Eni s share of reserves of equity-accounted entities amounted to 511 mmBOE. In 2010, Eni s Exploration & Production segment reported net sales from operations (including inter-segment sales) of euro 29,497 million and operating profit of euro 13,866 million.

Eni s Gas & Power segment engages in supply, trading and marketing of gas and electricity, managing gas infrastructures for transport, distribution, storage, re-gasification, and LNG supply and marketing. This segment also includes the activity of power generation that is ancillary to the marketing of electricity. In 2010, Eni s worldwide sales of natural gas amounted to 97.06 BCM, including 5.65 BCM of gas sales made directly by the Eni s Exploration & Production segment in Europe and the USA. Sales in Italy amounted to 34.29 BCM, while sales in European markets were 54.52 BCM that included 8.44 BCM of gas sold to certain importers to Italy.

Through Snam Rete Gas, Eni operates an Italian network of high and medium pressure pipelines for natural gas transport that is approximately 31,600-kilometer long, while outside Italy, Eni holds capacity entitlements on a network of European pipelines extending for approximately 4,400 kilometers made up of high pressure pipelines to import gas from Russia, Algeria, Libya and Northern European production basins to European markets. Snam Rete Gas, through its 100-percent owned subsidiary Italgas and other subsidiaries, is engaged in natural gas distribution activity in Italy serving 1,330 municipalities through a low pressure network consisting of approximately 50,307 kilometers of pipelines as of December 31, 2010. Snam Rete Gas, through its wholly-owned subsidiary Stoccaggi Gas Italia operates in natural gas storage activities in Italy through eight storage fields. Eni produces power and steam at its operated sites of Livorno, Taranto, Mantova, Ravenna, Brindisi, Ferrera Erbognone, Ferrara and Bolgiano with a total installed capacity of 5.3 GW as of December 31, 2010. In 2010, sales of power totaled 39.54 TWh. Eni operates a re-gasification terminal in Italy and holds indirect interest or capacity entitlements in a number of LNG facilities in Europe, Egypt and the USA. In 2010, Eni s Gas & Power segment reported net sales from operations (including inter-segment sales) of euro 29,576 million and operating profit of euro 2,896 million.

Eni s Refining & Marketing segment engages in crude oil supply, refining and marketing of petroleum products mainly in Italy and in the rest of Europe, as well as crude oil and trading and shipping products. In 2010, processed volumes of crude oil and other feedstock amounted to 34.80 mmtonnes and sales of refined products were 46.80 mmtonnes, of which 27.01 mmtonnes were in Italy. Retail sales of refined product at operated service stations amounted to 11.73 mmtonnes including Italy and the rest of Europe. In 2010, Eni s retail market share in Italy through its "eni" and "Agip" branded network of service stations was 30.4%. In 2010, Eni s Refining & Marketing segment reported net sales from operations (including inter-segment sales) of euro 43,190 million and operating profit of euro 149 million.

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Eni s petrochemical activities include production of olefins and aromatics, basic intermediate products, polyethylene, polystyrenes, and elastomers. Eni s petrochemical operations are concentrated in Italy and Western Europe. In 2010, Eni sold 6.1 mmtonnes of petrochemical products. In 2010, Eni s Petrochemical segment reported net sales from operations (including inter-segment sales) of euro 6,141 million and an operating net loss of euro 86 million.

Eni engages in oil field services, construction and engineering activities through its partially-owned subsidiary Saipem and subsidiaries of Saipem (Eni s interest being 42.92%). Saipem provides a full range of engineering, drilling and construction services to the oil and gas industry and downstream refining and petrochemicals sectors, mainly in the field of performing large EPC (Engineering, Procurement and Construction) contracts offshore and onshore for the construction and installation of fixed platforms, subsea pipelaying and floating production systems and onshore industrial complexes. In 2010, Eni s Engineering & Construction segment reported net sales from operations (including intra-group sales) of euro 10,581 million and operating profit of euro 1,302 million.

A list of Eni s subsidiaries is included as an exhibit to this Annual Report on Form 20-F.

Strategy

Eni s strategy is to expand the Company s principal businesses over both the medium and the long-term, with improving profitability. Specifically, the Company is planning for:

- growing profitably oil and gas production in the Exploration & Production business leveraging on the development of the Company s portfolio of assets and pipeline of capital projects. The Company plansto drive higher returns by reducing the time to market of our projects, focusing on continued cost control and deploying our competencies and technologies to manage technical risks;
- improving profitability in the Gas & Power business by leveraging on the Company s assets (long-term supply contracts, transport rights, storage capacity), renegotiation of the principal long-term supply contracts to boost the competitiveness of the Company s cost position and implementation of effective marketing initiatives against the backdrop of a challenging competitive landscape in the European gas market reflecting increasing competition and ongoing oversupply conditions;
- improving profitability and cash generation in the Refining & Marketing business in the face of weak industry fundamentals and a poor outlook for refining margins expected to remain below their historical averages across the plan period. Management plans to implement cost reduction initiatives, integration of refinery cycles to capture cost savings or margin expansions, and selective capital projects to upgrade refinery complexity. In the marketing business, we plan to enhance profitability through a number of initiatives for improving service quality and client retention and non-oil profit contribution;
- enhancing revenues and profitability in our Engineering & Construction business by leveraging on our strong order backlog, technologically-advanced assets and competencies in engineering and project management and execution; and
- managing efficiently and effectively our petrochemicals business, and re-launching development initiatives in the field of environmentally-friendly projects.

In executing this strategy, management intends to pursue integration opportunities among and within businesses and strongly focus on efficiency improvement through technology upgrading, cost efficiencies, commercial and supply optimization and continuing process streamlining across all businesses. Over the next four years, Eni plans to execute a capital expenditure program amounting to euro 53.3 billion to support continuing organic growth in its businesses, mainly Exploration & Production. In 2011, Eni intends to invest approximately euro 14 billion, an amount roughly in line with 2010. Eni plans to fund those capital expenditure projects mainly by means of cash flows provided by operating activities. Capital projects will be assessed and implemented in accordance with strict financial criteria. Management intends to progressively reduce the ratio of net borrowings to shareholders equity leveraging on projected cash flows from operations at our Brent scenario of $70 a barrel flat in the next four years and planned divestments amounting to euro 2 billion in 2011. This target includes expected cash outflows to remunerate Eni s shareholders through a progressive dividend policy. In 2010 management plans to distribute a dividend of euro 1 a share subject to approval from the General Shareholders Meeting scheduled on May 5, 2011. In subsequent years, management plans to increase dividends in line with OECD inflation. This dividend policy is based on the Company s planning assumptions for Brent prices and other assumptions (see "Item 5 Outlook" and "Item 3 Risk Factors").

Further details on each business segment strategy are discussed throughout this Item 4. For a description of risks and uncertainties associated with the Company s outlook, including any possible impact associated with ongoing political instability and war in Libya, and the capital expenditure program see "Item 5 Outlook" and "Item 3 Risk Factors".

In the next four-year period, Eni plans to spend euro 1.1 billion for technological research and innovation activities. Management believes that technological leadership is a key driver of the Company s competitive advantages in the long-term. Eni concentrates most of its efforts in upstream projects focused on maximizing the recovery rate of hydrocarbons from reservoirs, optimizing drilling and well performance, exploiting unconventional oil and gas resources and improving exploration performance. Projects in the refining sector target the development of advanced fuels, that allow higher engine performance with minimum environmental impact, and the increase in valuable products yields from refining heavy and sour crude qualities (in particular the Eni Slurry Technology (EST) project). In the petrochemical sector, efforts are focused on developing high value added elastomers and polymers. We also intend to enhance our long-term options to contribute to sustainable development by progressing our capabilities in renewable sources of energy, particularly in the field of solar and photovoltaic energy, carbon capture and sequestration, clean fuels, operations safety and integrity in upstream, and environmental clean-up and remediation.

Significant Business and Portfolio Developments

The significant business and portfolio developments that occurred in 2010 and to date in 2011 were the following:

From February 22, 2011, liquids and natural gas production at a number of fields in Libya and supplies through the GreenStream pipeline have been halted as a result of ongoing political instability and unrest in the Country. Facilities have not suffered any damage and such standstills do not affect Eni s ability to ensure natural gas supplies to its customers. Eni is technically able to resume gas production at or near previous level once the situation stabilizes. The overall impact of the political instability and conflict in Libya on Eni s results of operations and cash flows will depend on how long such tensions will last as well as on their outcome, which management is currently unable to predict. Eni s oil and natural gas production as of end of March 2011, was flowing at a rate ranging from 70 to 75 KBBL/d, down from the expected level of approximately 280 KBBL/d. Production is continuing to decline. Current production mainly consists of gas that is entirely delivered to local power generation plant. For further discussion on risks and management outlook on the Libyan situation see "Item 3 Risk Factors Political Considerations" and "Item 5 Outlook".

In November 2010, Eni and the Venezuelan State Company PDVSA established a joint venture in charge of developing the Junín 5 oil field, located in the Orinoco Oil Belt. Management believes that the field contains important volumes of resources, mainly heavy oil. The two partners plan to achieve first oil by 2013.

In 2010, appraisal activities were performed in the gas discovery of Perla located in the Cardón IV Block, in the shallow water of the Gulf of Venezuela. Based on the assessment made, management believes that Perla contains significant amount of gas reserves. The initiative is conducted through a 50/50 joint venture with another international oil. The two partners are planning for starting production in 2013.

At the beginning of the fourth quarter 2010, Eni achieved project milestones at the Zubair oil field in Iraq by increasing production by more than 10% above the initial production rate of approximately 180 KBBL/d. Increasing production above that level means that Eni has begun the cost recovery for its work on the field by booking its share of production, including receiving a remuneration fee for every extra barrel of oil produced above the 10% target. Eni, with a 32.8% share, is leading the consortium in charge of redeveloping the Zubair field over a 20-year period, targeting a production plateau of 1.2 mmBBL/d in the next six years.

In October 2010, with a view to rationalizing its upstream portfolio, Eni divested its subsidiary Società Padana Energia to Gas Plus. The divested subsidiary includes exploration leases and concessions for developing and producing oil and natural gas in Northern Italy. For further details, see "Exploration & Production Italy", below.

In May 2010, Eni signed a preliminary agreement with an affiliate of Petrobras for the divestment of its 100% interest in Gas Brasiliano Distribuidora, a company that markets and distributes gas in an area of the S. Paulo State, Brazil. The completion of the transaction is subject to approval of the relevant Brazilian Authorities. The expected cash consideration amounts to $250 million.

In April 2010, Eni sold to NOC (Libyan National Oil Corp) a 25% stake in the share capital and the control of GreenStream BV, the company owning and managing the gas pipeline for importing to Italy natural gas produced in Libya.

Procedures for divesting Eni s interests in the German TENP, the Swiss Transitgas and the Austrian TAG gas transport pipelines and carrier companies are progressing and the Company targets to finalize the divestiture in 2011. The divestment program has been agreed upon with the European Commission as remedial actions to settle an antitrust proceeding without the ascertainment of any illicit behavior and consequently without imposition of any fines or sanctions on the Company. The proceeding was started by the Commission in the year 2006 to investigate allegedly anti-competitive behavior ascribed to Eni in the natural gas market. The commitments have been ratified as of September 29, 2010.

In addition, in 2010 and up to date in 2011 Eni closed the following transactions:

In March 2011, Eni signed a Memorandum of Understanding with the Minister of Ecology and Natural Resources in Ukraine. The agreement provides for a joint study to cooperate in conventional and unconventional oil and gas resources and evaluate upstream initiatives.

In January 2011, Eni was awarded rights to explore retaining operatorship of offshore Block 35 in Angola, with a 30% interest. The agreement foresees drilling 2 wells and 3D seismic surveys to be carried out in the first 5 years of exploration. This deal is subject to the approval of the relevant authorities.

In January 2011, Eni signed a Memorandum of Understanding with PetroChina to promote common opportunities to jointly expand operations in research and development of conventional and unconventional hydrocarbons in China and outside China, particularly in Africa. In addition, PetroChina is evaluating to purchase an interest in certain of Eni s assets.

In December 2010, Eni acquired Minsk Energy Resources which operates 3 exploration licenses in the Polish Baltic Basin. Management believes that the acquired acreage may contain unconventional gas resources. Drilling operations are expected to start in the second half of 2011.

In December 2010, Eni acquired a controlling interest in Altergaz, a company marketing natural gas in France to retail and middle market clients, as the other partners of the company exercised a put option on a 15% stake.

In November 2010, Eni signed with the Government of Ecuador new terms for the service contract for the Villano oil field, due to expire in 2023. Under the new agreement, the operated area is enlarged to include the Oglan oil discovery, which is planned to be developed in synergy with existing facilities.

In October 2010, Eni was awarded operatorship of offshore Block 1 and Block 2 (Eni 100%) in the Dahomey Basin in the Gulf of Guinea as part of its agreements with the Government of Togo to develop the country s offshore mineral resources.

In August 2010, Eni signed an agreement with UK-based Surestream Petroleum to acquire a 55% stake and operatorship in the Ndunda Block located in the Democratic Republic of Congo. The agreement has been sanctioned by the relevant authorities.

In January 2010, Eni finalized an acquisition of downstream activities in Austria, including a retail network, wholesale activities, as well as commercial assets in the aviation business and related logistic and storage activities.

In 2010, capital expenditures amounted to euro 13,870 million, of which 87% related to Exploration & Production, Gas & Power and Refining & Marketing businesses, and primarily related to: (i) the development of oil and gas reserves (euro 8,578 million) deployed mainly in Egypt, Kazakhstan, Congo, the USA and Algeria, and exploration projects (euro 1,012 million) carried out mainly in Angola, Nigeria, the USA, Indonesia and Norway; (ii) the development and upgrading of Eni s natural gas transport and distribution network in Italy (euro 842 million and euro 328 million, respectively) as well as development and increase of storage capacity (euro 250 million); (iv) projects aimed at improving the conversion capacity and flexibility of refineries, and at building and upgrading service stations in Italy and outside Italy (totaling euro 692 million); and (v) the upgrading of the fleet used in the Engineering & Construction segment (euro 1,552 million). There were no significant acquisitions in the year.

In 2009, capital expenditures amounted to euro 13,695 million, of which 86% related to the Exploration & Production, Gas & Power and Refining & Marketing businesses, and primarily related to: (i) the development of oil and gas reserves (euro 7,478 million) deployed mainly in Kazakhstan, the USA, Egypt, Congo, Italy and Angola, and exploration projects (euro 1,228 million) carried out mainly in the USA, Libya, Egypt, Norway and Angola; (ii) the acquisition of proved and unproved properties amounting to euro 697 million mainly related to the acquisition of a 27.5% interest in assets with gas shale reserves from Quicksilver Resources Inc and extension of the duration of oil and gas properties in Egypt following the agreement signed in May 2009; (iii) the development and upgrading of Eni s natural gas transport and distribution networks in Italy (euro 919 million and euro 278 million, respectively) as well as the development and increase of the storage capacity (euro 282 million); (iv) projects aimed at improving the conversion capacity and flexibility of refineries, and at building and upgrading service stations in Italy and outside Italy (totaling euro 608 million); and (v) the upgrading of the fleet used in the Engineering & Construction segment (euro 1,630 million).

In 2009, Eni s acquisitions amounted to euro 2.32 billion and mainly related to the completion of the acquisition of Distrigas NV. Following the acquisition of the 57.243% majority stake in the Belgian company Distrigas NV from French company Suez-Gaz de France, Eni made an unconditional mandatory public takeover bid on the minorities of Distrigas (42.76% stake). On March 19, 2009, the mandatory tender offer on the minorities of Distrigas was finalized. Shareholders representing 41.61% of the share capital of Distrigas, including the second largest shareholder, Publigaz SCRL with a 31.25% interest, tendered their shares. The squeeze-out of the residual 1.14% of the share capital was finalized on May 4, 2009. After this, Distrigas shares have been delisted from Euronext Brussels. The total cash consideration amounted to approximately euro 2.05 billion.

In 2008, capital expenditures amounted to euro 14,562 million, of which 84% related to the Exploration & Production, Gas & Power and Refining & Marketing Divisions and concerned mainly: (i) the development of oil and gas reserves (euro 6,429 million) deployed mainly in Kazakhstan, Egypt, Angola, Congo and Italy and exploration projects (euro 1,918 million), primarily in the USA, Egypt, Nigeria, Angola and Libya; (ii) the purchase of proved and unproved property for euro 836 million related mainly to the extension of mineral rights in Libya following an agreement signed in October 2007 with the state company NOC and the purchase of a 34.81% interest in the ABO project in Nigeria; (iii) the development and upgrading of Eni s natural gas transport and distribution networks in Italy (euro 1,130 million and euro 233 million, respectively) and upgrading of natural gas import pipelines to Italy (euro 233 million); (iv) the ongoing construction of combined cycle power plants (euro 107 million); (v) projects designed to upgrade the conversion capacity and flexibility of Eni s refineries, including construction of a new hydrocracking unit at the Sannazzaro refinery in Italy, and to build of new service stations and upgrade of existing ones in Italy and outside Italy (totaling euro 965 million); and (vi) the upgrading of the fleet used in the Engineering & Construction Division (euro 2,027 million).

In 2008, Eni s acquisitions amounted to euro 5.85 billion (euro 4.3 billion net of acquired cash of euro 1.54 billion) and mainly related to: (i) the acquisition of the 57.243% majority stake in Distrigas NV in Belgium; (ii) the completion of the acquisition of Burren Energy Plc in the UK; (iii) the purchases of certain upstream properties and gas storage assets, related to the entire share capital of the Canadian company First Calgary operating in Algeria, a 52% stake in the Hewett Unit in the North Sea, a 20% stake in the Indian company Hindustan Oil Exploration Co; and (iv) other investments in non-consolidated entities mainly related to funding requirements for a LNG project in Angola.

BUSINESS OVERVIEW

Exploration & Production

Eni s Exploration & Production segment engages in oil and natural gas exploration and field development and production, as well as LNG operations, in 43 countries, including Italy, Libya, Egypt, Norway, the UK, Angola, Congo, the USA, Kazakhstan, Russia, Algeria, Australia, Venezuela and Iraq. In 2010, Eni average daily production amounted to 1,757 KBOE/d on an available for-sale basis. As of December 31, 2010, Eni s total proved reserves amounted to 6,843 mmBOE; proved reserves of subsidiaries stood at 6,332 mmBOE; Eni s share of reserves of equity-accounted entities amounted to 511 mmBOE.

Eni s strategy in its Exploration & Production operations is to pursue profitable production growth leveraging on the Company s portfolio of assets and pipeline of development projects. We plan to achieve a compound average growth rate in our production in excess of 3% in the next 2011-2014 four-year period, targeting a production plateau above 2.05 mmBOE/d by 2014. Those targets are based on our long-term Brent price assumptions of 70 $/BBL. The production outlook for 2011 is uncertain due to ongoing political instability and unrest in Libya. Following suspension of activities at several of Eni s producing sites in Libya and the closure of a pipeline transporting gas from Libya to Italy, Eni s production in Libya as of end of March 2011, was flowing at a rate ranging from 70 to 75 KBOE/d compared to an expected level for 2011 of approximately 280 KBOE/d. Production is continuing to decline. Future developments in Libya, which we are currently unable to predict, may have a material adverse effect on Eni s production targets. However, in our planning assumptions to 2014 we assumed that the Libyan production would resume flowing at its normal rate at some point in the future. For further information on this issue as well as certain other trading environment assumptions including an indication of Eni s production volume sensitivity to oil prices see "Item 5 Outlook" and "Item 3 Risk Factors".

Management plans to achieve the target of production growth to 2014 via organic developments, leveraging on the planned start-ups of a number of fields and material expenditures to support current production levels at our producing fields. We project that new fields start-ups will add approximately 630 KBOE/d to the Company s production level by 2014. Main production start-ups are planned in Angola, Norway, Russia, Kazakhstan, Algeria and Venezuela. We have a good level of visibility on those new projects as most of them have been already sanctioned.

The second leg of our growth strategy is to maximize the production recovery rate at our current fields by counteracting natural field depletion. To achieve this, we plan to execute infilling and work-over activities, apply our advanced recovery technologies and reservoir management capabilities.

In exploration activities, Eni plans to perform the major part of exploration projects in well-established areas of presence targeting to extend the plateau of producing fields. Those areas include Egypt, Pakistan, Nigeria, Congo and the Gulf of Mexico where availability of production facilities will enable the Company to readily put in production discovered reserves. Other projects will be executed offshore of West Africa, Venezuela and in deepwater plays in the Gulf of Mexico where the Company believes to have the necessary know-how and skills to discover new reserves. A third layer of exploration projects is planned to be executed in high risk/high reward areas including Mozambique, Togo, Ghana and offshore Australia and East Timor where the Company believes important resources can be discovered. Eni expects to purchase new exploration permits and to divest or exit marginal or non-strategic areas.

Eni intends to focus on reserve replacement in order to ensure the medium to long-term sustainability of the business. Management intends to implement a number of initiatives to support profitability in its upstream operations by exercising tight cost control and reducing the time span which is necessary to put reserves in production. We expect that costs to develop and operate fields will increase in the next years due to sector-specific inflation, and growing complexity of new projects. We plan to counteract those cost increases by leveraging on cost efficiencies associated with: (i) increasing the scale of our operations as we concentrate our resources on fields of greater dimensions than in the past where we plan to achieve economies of scale; (ii) expanding the scope of operated production. We believe that is a key driver of profitability as 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; and (iii) applying our technologies which we believe can reduce drilling and completion costs.

Eni intends to optimize its portfolio of development properties by focusing on areas where its presence is established, and divesting non-strategic or marginal assets. Eni also intends to develop certain LNG project in order to monetize its large base of gas reserves mainly in West Africa.

Management plans to invest approximately euro 39.1 billion to explore for and develop new reserves over the next four years. Exploration projects will account for approximately euro 3.6 billion. Approximately euro 1.8 billion will be spent to build transportation infrastructures and LNG projects through equity-accounted entities. For the year 2011, management plans to spend euro 9.8 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 and 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 and 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 and gas reserves are inherently uncertain. Although authoritative guidelines exist regarding engineering criteria that have to be met before estimated oil and gas reserves can be designated as "proved", the accuracy of any reserve 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 Production Sharing Agreements are calculated so that the sale of production entitlements should cover expenses incurred by the Group to develop a field (cost oil) and on the profit oil set contractually (profit oil). A similar scheme applies to buy-back and service contracts.

Reserves Governance

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

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Company guidelines have been reviewed by DeGolyer and MacNaughton (D&M), an independent petroleum engineering company, which has stated that those guidelines comply with the SEC rules[1]. D&M has also stated that the Company guidelines provide reasonable interpretation of facts and circumstances in line with generally accepted practices in the industry whenever SEC rules may be less precise. When participating in exploration and production activities operated by others 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 expenditures, 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 at the head office verify estimates carried out by business unit managers; (iv) the Planning and Control Department provides the economic evaluation of reserves; (v) the Reserve Department, through the Division Reserves Evaluators (DRE), provides independent reviews of fairness and correctness of classifications carried out by the abovementioned units and aggregates worldwide reserve data.

The head of the Reserve Department attended the "Politecnico di Torino" and received a Master of Science degree in Mining Engineering in 1985. She has more than 20 years of experience in the oil and gas industry and more than 10 years of experience specifically in evaluating reserves.

Staff involved in the reserves evaluation process fulfills 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 established by the Society of Petroleum Engineers.

Reserves independent evaluation

Since 1991, Eni has requested independent oil engineering companies to carry out an independent evaluation[2] of part of its proved reserves on a rotational basis. Management believes that those engineering firms are qualified and experienced on the marketplace. The description of qualifications of the persons primarily responsible for the reserve audit is included in the third party audit report[3]. In the preparation of their reports, independent evaluators rely, without independent verification, upon information furnished by Eni with respect to property interests, production, current costs of operations and development, sale agreements, prices and other factual information and data that were accepted as represented by the independent evaluators. This 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, reservoir performance, long-term 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. In 2010, Ryder Scott Company and DeGolyer and MacNaughton provided an independent evaluation of 28% of Eni s total proved reserves at December 31, 2010[4], confirming, as in previous years, the reasonableness of Eni internal evaluation[5].

In the 2008-2010 three-year period, 78% of Eni total proved reserves were subject to an independent evaluation. As at December 31, 2010 the principal Eni properties not subjected to independent evaluation in the last three years were Karachaganak (Kazakhstan), Samburgskoye and Yaro-Yakhinskoye (Russia).

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, 2010, 2009 and 2008. Reserves data for 2010 and 2009 are based on the un-weighted 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. Data for 2008 is based on the last day price of the Company s fiscal year in accordance with then applicable rules.

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(1) See "Item 19 Exhibits" in the Annual Report on Form 20-F 2009.
(2) From 1991 to 2002, DeGolyer and MacNaughton; from 2003, also Ryder Scott.
(3) See "Item 19 Exhibits".
(4) SIncludes Eni s share of proved reserves of equity-accounted entities.
(5) See "Item 19 Exhibits".

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HYDROCARBONS

(mmBOE)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total consolidated subsidiaries	Equity-accounted entities	Total reserves
Year ended Dec. 31, 2008	**681**	**525**	**1,922**	**1,146**	**1,336**	**265**	**235**	**132**	**6,242**	**666**	**6,908**
Developed	465	417	1,229	827	647	168	133	62	3,948	107	4,055
Undeveloped	216	108	693	319	689	97	102	70	2,294	559	2,853
Year ended Dec. 31, 2009	**703**	**590**	**1,922**	**1,141**	**1,221**	**236**	**263**	**133**	**6,209**	**362**	**6,571**
Developed	490	432	1,266	799	614	139	168	122	4,030	74	4,104
Undeveloped	213	158	656	342	607	97	95	11	2,179	288	2,467
Year ended Dec. 31, 2010 (a)	**724**	**601**	**2,096**	**1,133**	**1,126**	**295**	**230**	**127**	**6,332**	**511**	**6,843**
Developed	554	405	1,215	812	543	139	141	117	3,926	96	4,022
Undeveloped	170	196	881	321	583	156	89	10	2,406	415	2,821

(a) In 2010, Eni has updated the natural gas conversion factor. See page vi for further information.

LIQUIDS

(mmBBL)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total consolidated subsidiaries	Equity-accounted entities	Total reserves
Year ended Dec. 31, 2008	**186**	**277**	**823**	**783**	**911**	**106**	**131**	**26**	**3,243**	**142**	**3,385**
Developed	111	222	613	576	298	92	74	23	2,009	33	2,042
Undeveloped	75	55	210	207	613	14	57	3	1,234	109	1,343
Year ended Dec. 31, 2009	**233**	**351**	**895**	**770**	**849**	**94**	**153**	**32**	**3,377**	**86**	**3,463**
Developed	141	218	659	544	291	45	80	23	2,001	34	2,035
Undeveloped	92	133	236	226	558	49	73	9	1,376	52	1,428
Year ended Dec. 31, 2010	**248**	**349**	**978**	**750**	**788**	**139**	**134**	**29**	**3,415**	**208**	**3,623**
Developed	183	207	656	533	251	39	62	20	1,951	52	2,003
Undeveloped	65	142	322	217	537	100	72	9	1,464	156	1,620

NATURAL GAS

(BCF)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total consolidated subsidiaries	Equity-accounted entities	Total reserves
Year ended Dec. 31, 2008	**2,844**	**1,421**	**6,311**	**2,084**	**2,437**	**911**	**600**	**606**	**17,214**	**3,015**	**20,229**
Developed	2,031	1,122	3,537	1,443	2,005	439	340	221	11,138	420	11,558
Undeveloped	813	299	2,774	641	432	472	260	385	6,076	2,595	8,671

Year ended Dec. 31, 2009	**2,704**	**1,380**	**5,894**	**2,127**	**2,139**	**814**	**629**	**575**	**16,262**	**1,588**	**17,850**
Developed	2,001	1,231	3,486	1,463	1,859	539	506	565	11,650	234	11,884
Undeveloped	703	149	2,408	664	280	275	123	10	4,612	1,354	5,966
Year ended Dec. 31, 2010	**2,644**	**1,401**	**6,207**	**2,127**	**1,874**	**871**	**530**	**544**	**16,198**	**1,684**	**17,882**
Developed	2,061	1,103	3,100	1,550	1,621	560	431	539	10,965	246	11,211
Undeveloped	583	298	3,107	577	253	311	99	5	5,233	1,438	6,671

Volumes of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator totaled 683 mmBOE as of December 31, 2010 (674 and 679 mmBOE as of December 31, 2009 and 2008, respectively). Said volumes are not included in reserves volumes shown in the table herein.

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Activity of the year

	Subsidiaries			Equity-accounted entities		
	2008	2009	2010	2008	2009	2010
	(mmBOE)					
Additions to proved reserves	882	605	776	6	(296)	158
of which purchases and sales of reserves-in-place	*32*	*25*	*(12)*		*(314)*	
Production for the year	(650)	(638)	(653)	(8)	(8)	(9)

	Subsidiaries and equity-accounted entities		
	2008	2009	2010
	(%)		
Proved reserves replacement ratio of subsidiaries and equity-accounted entities	135	96	125

Eni s proved reserves of subsidiaries as of December 31, 2010 totaled 6,332 mmBOE (oil and condensates 3,415 mmBBL; natural gas 16,198 BCF) representing an increase of 123 mmBOE, or 2%, from December 31, 2009. Additions to proved reserves booked in 2010 were 776 mmBOE (including the impact of gas conversion factor update equal to 97 mmBOE) and derived from: (i) revisions of previous estimates were 661 mmBOE mainly reported in Libya, Nigeria, Egypt, Iraq and Italy; (ii) extensions, discoveries and other factors were 125 mmBOE, with major increase booked in the UK and Algeria; and (iii) improved recovery were 2 mmBOE. The unfavorable effect of higher oil price on reserve entitlements in certain PSAs and service contracts (down 80 mmBOE) resulted from higher oil prices compared to year ago (the Brent price used in the reserve estimation process was $79 per barrel in 2010 compared to $59.9 per barrel in 2009). Higher oil prices also resulted in upward revisions associated with improved economics of marginal productions.

In 2010, sales of mineral-in-place resulted mainly from the divestment of wholly-owned subsidiary Società Padana Energia to Gas Plus, which held exploration, development and production properties in Northern Italy.

As of December 31, 2010 Eni s share of proved reserves of equity-accounted entities amounted to 511 mmBOE, an increase of 149 mmBOE, or 41.2%, compared to December 31, 2009, with an increase mainly reported in Venezuela.

The current SEC rules allow the use of reliable technology to justify the reserves estimate if it produces consistent and repeatable results. We did not have any material additions of proved reserves due to application of "reliable technologies".

Proved developed reserves of subsidiaries as of December 31, 2010 amounted to 3,926 mmBOE (1,951 mmBBL of liquids and 10,965 BCF of natural gas) representing 62% of total estimated proved reserves (65% and 63% as of December 31, 2009 and 2008, respectively).

The reserve replacement ratio for Eni s subsidiaries and equity-accounted entities was 125% in 2010 (96% in 2009 and 135% in 2008). The ratio did not include the impact associated with adoption of a new conversion factor of natural gas to barrel-of-oil equivalent on the initial balances of proved reserves as of January 1, 2010 as management believes that

that change did not pertain to the Company s reserve performance for the year. The reserve replacement ratio was calculated by dividing additions to proved reserves 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 the Consolidated Financial Statements). The reserve replacement ratio is a measure used by management to assess the extent to which produced reserves in the year are replaced by reserve additions booked. Management considers the reserve replacement ratio to be an important indicator of the Company ability to sustain its growth perspective. 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, as well as changes in oil and gas prices, political risks and geological and other environmental risks. Specifically, in recent years Eni s reserves replacement ratio has been affected by the impact of higher oil prices on reserves entitlements in the Company s Production Sharing Agreements (PSAs) and similar contractual schemes. In accordance with such contracts, Eni is entitled to a portion of field reserves, the sale of which should cover expenditures incurred by the Company to develop and operate the field. The higher the reference prices for Brent crude oil used to determine year end amounts of Eni s proved reserves, the lower the number of barrels necessary to cover the same amount of expenditures. In 2010, this trend resulted in a lower amount of booked reserves associated with the Company s PSAs as the average oil price used in reserve computation was higher than the previous year. See "Item 3 Risks associated with exploration and production of oil and natural gas and Uncertainties in Estimates of Oil and Natural Gas Reserves".

The average reserve life index of Eni s proved reserves was 10.3 years as of December 31, 2010 which included reserves of both subsidiaries and equity-accounted entities.

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2010 totaled 2,821 mmBOE. At year end, liquids proved undeveloped reserves amounted to 1,620 mmBBL, mainly concentrated in Africa and Kazakhstan. Natural gas proved undeveloped reserves accounted for 6,671 BCF, mainly located in Africa and Russia.

In 2010, total proved undeveloped reserves increased by 354 mmBOE. The principal reasons for the increase are revisions and new projects sanction, mainly in Libya, Venezuela and Iraq.

During 2010, Eni converted approximately 295 mmBOE of proved undeveloped reserves to proved developed reserves. The main reclassification to proved developed were related to development activities, revisions and production start-up of the following fields/projects: Cerro Falcone (Italy), M Boundi (Congo), Wafa (Libya), Bhit and Sawan (Pakistan), Morvin (Norway), Tuna and Hapy (Egypt) and Karachaganak (Kazakhstan).

In 2010, capital expenditures amounted to approximately euro 1.7 billion and were made to progress the development of proved undeveloped reserves.

Reserves that remain proved undeveloped for five or more years are a result of several physical 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 infrastructure or plant capacities and contractual limitations that establish production levels.

The Company estimates that approximately 0.9 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 (0.6 BBOE) where development activities are progressing and start-up production is targeted by the end of 2012. For more details regarding this project please refer to part 1, Item 4, page 46, where the project is disclosed. See also our discussion under the "Risk Factors" section about risks associated with oil and gas development projects on page 6; (ii) certain Libyan gas fields where development activities and production start-up is dependent upon fulfilling contractual delivery obligations under a long-term gas supply agreement; and (iii) other minor projects where development activities are progressing.

Delivery commitments

Eni 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 over the next three years natural gas to third parties for a total of approximately 1,852 BCF from producing properties located in Australia, Egypt, India, Indonesia, Libya, Nigeria, Norway, Pakistan, Tunisia and the UK.

The temporary shut down of the GreenStream pipeline due to ongoing political instability and unrest in Libya will not materially impair the Company s ability to fulfill its contractual delivery commitments with third parties as the Company can make use of its gas availability from various sources to meet those commitments.

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 68% of outstanding delivery commitments in the next three years.

Eni has met all contractual delivery commitments as of December 31, 2010.

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Oil and gas production, production prices and production costs

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

In 2010, oil and natural gas production available for sale averaged 1,757 KBOE/d. Production for the year expressed in barrel-of-oil equivalent was calculated assuming a natural gas conversion factor which was updated to 5,550 CF of gas equaling 1 barrel of oil. On a comparable basis, i.e. when excluding the effect of the update gas conversion factor, production showed an increase of 0.9% for the full year. Production growth was driven by additions from new field start-ups, particularly the Zubair field (Eni s interest 32.8%) in Iraq, and production ramp-ups at fields which were started-up in 2009 (for a total increase of 40 KBOE/d). These increases were offset in part by mature field declines. Lower entitlements in the Company s PSA due to higher oil prices, as well as lower gas uplifts in Libya as a result of oversupply conditions in the European market were partly offset by lower OPEC restrictions resulting in a net negative impact of approximately 7 KBOE/d. The share of oil and natural gas produced outside Italy was 90% (90% in 2009).

Liquids production (997 KBBL/d) decreased by 10 KBBL/d from 2009 (down 1%). The impact of mature field declines was partly offset by organic growth and production start-ups achieved in particular in Nigeria, due to the ramp-up of the Oyo project (Eni s interest 40%), in Italy as a result of the ramp-up of the Val d Agri enhanced development project (Eni s interest 60.77%), in Tunisia due to the production start-up/ramp-up of the Baraka and Maamoura projects (Eni operator with a 49% interest) as well as Zubair in Iraq.

Natural gas production (4,222 mmCF/d) increased by 148 mmCF/d from 2009 (up 3.6%). The main increases were registered in Nigeria, due to projects start-up in the Block OML 28 (Eni s interest 5%), in Australia, due to ramp-up of the Blacktip project (Eni s interest 100%), in Congo, due to ramp-up of the M Boundi gas project (Eni operator with an 83% interest) in Egypt, due to start-up of the Tuna field (Eni operator with a 50% interest), in Italy, due to the start-up of the Annamaria field (Eni operator with an 90% interest) and in India, due to organic growth of PY-1 project (Eni s interest 47.18%). These increases were offset in part by mature field declines.

Oil and gas production sold amounted to 638 mmBOE. The 24.5 mmBOE difference over production (662.5 mmBOE for the year ended December 31, 2010) reflected volumes of natural gas consumed in operations (20.9 mmBOE).

Approximately 58% of liquids production sold (361.3 mmBBL) was destined to Eni s Refining & Marketing Division (of which 18% was processed in Eni s refinery); about 28% of natural gas production sold (1,536 BCF) was destined to Eni s Gas & Power Division.

The tables below provide Eni s production, by final product sold of liquids and natural gas by geographical area for each of the last three fiscal years.

LIQUIDS PRODUCTION [1]

(KBBL/d)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total

2008	68	140	338	289	69	49	63	10	**1,026**
2009	56	133	292	312	70	57	79	8	**1,007**
2010	61	121	301	321	65	48	71	9	**997**

(1) Data includes Eni s share of production of affiliates and joint venture accounted for under the equity method of accounting amounting to 19, 17 and 14 KBBL/d in 2010, 2009 and 2008, respectively.

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NATURAL GAS PRODUCTION AVAILABLE FOR SALE (1) (2)

(mmCF/d)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2008	725	588	1,661	204	227	396	304	38	**4,143**
2009	630	608	1,503	213	241	417	416	46	**4,074**
2010	648	517	1,559	365	221	436	385	91	**4,222**

(1) Data includes Eni s share of production of affiliates and joint venture accounted for under the equity method of accounting amounting to 27, 29 and 26 mmCF/d in 2010, 2009 and 2008, respectively.

(2) It excludes production volumes of natural gas consumed in operations. Said volumes were 318, 300 and 281 mmCF/d in 2010, 2009 and 2008, respectively.

Volumes of oil and natural gas purchased under long-term supply contracts with foreign governments or similar entities in properties where Eni acts as producer totaled 105 KBOE/d, 97 KBOE/d and 93 KBOE/d in 2010, 2009 and 2008, respectively.

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

AVERAGE SALES PRICES AND PRODUCTION COST PER UNIT OF PRODUCTION

($)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total consolidated subsidiaries	Equity-accounted entities
2008 Oil and condensate, per BBL	84.87	71.90	85.38	91.58	79.06	75.29	88.88	82.80	**84.31**	**56.04**
Natural gas, per KCF	13.06	10.55	7.15	1.50	0.53	5.05	8.81	9.59	**7.99**	**11.91**
Average production cost, per BOE	9.40	8.67	3.62	15.33	5.86	3.63	8.48	8.50	**7.65**	**18.97**
2009 Oil and condensate, per BBL	56.02	56.46	56.42	59.75	52.34	55.34	55.66	50.40	**57.02**	**44.43**
Natural gas, per KCF	9.01	7.06	5.79	1.66	0.45	4.09	4.05	8.14	**5.62**	**6.81**
Average production cost, per BOE	9.69	8.28	3.99	13.19	5.20	3.44	7.39	9.56	**7.41**	**13.72**
2010 Oil and condensate, per BBL	72.19	67.26	70.96	78.23	66.74	75.20	72.84	73.00	**72.95**	**58.86**
Natural gas, per KCF	8.71	7.40	6.87	1.87	0.49	4.35	4.70	7.40	**6.01**	**8.73**
Average production cost, per BOE	9.42	9.42	5.63	15.19	6.40	5.62	8.15	9.75	**8.89**	**17.45**

Drilling and other exploratory and development activities

In 2010, a total of 47 new exploratory wells were drilled (23.8 of which represented Eni s share), which includes drilled exploratory wells that have been suspended pending further evaluation, as compared to 69 exploratory wells drilled in 2009 (37.6 of which represented Eni s share) and 111 exploratory wells drilled in 2008 (58.4 of which represented Eni s share).

Overall commercial success rate was 41% (39% net to Eni) as compared to 41.9% (43.6% net to Eni) and 36.5% (43.4% net to Eni) in 2009 and 2008, respectively.

In 2010, a total of 399 development wells were drilled (178 of which represented Eni s share) as compared to 418 development wells drilled in 2009 (175.1 of which represented Eni s share) and 366 development wells drilled in 2008 (155.1 of which represented Eni s share). The drilling of 122 development wells (43 of which represented Eni s share) is currently underway.

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The table below provides the number of net productive and dry exploratory and development oil and natural gas wells completed in the years indicated by the Group companies and its equity-accounted entities.

NET EXPLORATION AND DEVELOPMENT DRILLING ACTIVITY

(units)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2008 Exploratory	**0.7**	**3.7**	**22.9**	**7.4**		**16.2**	**3.4**	**1.4**	**55.7**
Productive		0.7	8.7	4.0		9.4	1.4		24.2
Dry [(a)]	0.7	3.0	14.2	3.4		6.8	2.0	1.4	31.5
Development	**12.9**	**5.5**	**47.6**	**37.2**	**2.6**	**43.0**	**6.3**		**155.1**
Productive	11.3	5.5	46.4	36.4	2.6	36.5	6.3		145.0
Dry [(a)]	1.6		1.2	0.8		6.5			10.1
2009 Exploratory	**1.0**	**4.3**	**8.6**	**2.7**		**6.2**	**4.8**	**2.2**	**29.8**
Productive		4.1	4.8			2.3	1.0	0.8	13.0
Dry [(a)]	1.0	0.2	3.8	2.7		3.9	3.8	1.4	16.8
Development	**18.3**	**12.5**	**41.1**	**37.7**	**3.8**	**42.9**	**16.6**	**2.2**	**175.1**
Productive	18.3	12.5	40.7	35.8	3.8	38.6	15.6	2.2	167.5
Dry [(a)]			0.4	1.9		4.3	1.0		7.6
2010 Exploratory	**0.5**	**2.8**	**17.4**	**7.0**		**3.8**	**6.3**	**1.4**	**39.2**
Productive		1.7	9.3	2.3		1.0		1.0	15.3
Dry [(a)]	0.5	1.1	8.1	4.7		2.8	6.3	0.4	23.9
Development	**24.9**	**3.1**	**44.6**	**30.5**	**1.8**	**43.5**	**28.1**	**1.5**	**178.0**
Productive	23.9	2.9	44.3	28.0	1.8	41.7	27.6	1.5	171.7
Dry [(a)]	1.0	0.2	0.3	2.5		1.8	0.5		6.3

(a) A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Present activities

The table below provides the number of exploratory and development oil and natural gas wells in the process of being drilled by the Group companies and its equity-accounted entities as of December 31, 2010. A gross well is a well in which Eni owns a working interest.

DRILLING ACTIVITY IN PROGRESS

(units)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
As of December 31, 2010 Exploratory [(a)]									
Gross	6.0	19.0	11.0	52.0	13.0	22.0	13.0	1.0	**137.0**
Net	4.4	5.0	8.7	12.6	2.3	11.7	4.0	0.4	**49.1**
Development									
Gross	4.0	18.0	18.0	23.0	8.0	11.0	40.0		**122.0**
Net	3.5	2.9	8.1	8.4	1.5	5.8	12.8		**43.0**

(a) Includes temporary suspended wells pending further evaluation.

Oil and gas properties, operations and acreage

As of December 31, 2010, Eni s mineral right portfolio consisted of 1,176 exclusive or shared rights for exploration and development in 43 countries on five continents for a total acreage of 320,961 square kilometers net to Eni of which developed acreage was 41,386 square kilometers and undeveloped acreage was 279,575 square kilometers.

In 2010, changes in total net acreage mainly derived from: (i) new leases in Poland, Democratic Republic of Congo, Togo, Angola, Pakistan and Venezuela for a total acreage of approximately 13,000 square kilometers; (ii) the divestment of wholly-owned subsidiary Società Padana Energia and leases in Nigeria for a total acreage of approximately 1,500 square kilometers; (iii) the total relinquishment of mainly exploration leases in Pakistan, Australia, Congo, Italy, Egypt, Russia and East Timor, covering an undeveloped acreage in excess of 23,000 square kilometers; and (iv) the decrease in net acreage due to partial relinquishment or interest reduction in Mali and Indonesia for a total net acreage of approximately 15,000 square kilometers.

The table below provides certain information about the Company s oil and 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, 2010. A gross acreage is one in which Eni owns a working interest.

	December 31, 2009	December 31, 2010						
	Total net acreage [(a)]	Number of interests	Gross developed [(b)] acreage [(a)]	Gross undeveloped acreage [(a)]	Total gross acreage [(a)]	Net developed [(b)] acreage [(a)]	Net undeveloped acreage [(a)]	Total net acreage [(a)]
EUROPE	**31,607**	**287**	**17,430**	**28,293**	**45,723**	**11,142**	**17,937**	**29,079**
Italy	**22,038**	**154**	**10,951**	**12,945**	**23,896**	**8,995**	**10,102**	**19,097**
Rest of Europe	**9,569**	**133**	**6,479**	**15,348**	**21,827**	**2,147**	**7,835**	**9,982**
Croatia	987	2	1,975		1,975	987		987
Norway	3,412	49	2,276	5,956	8,232	338	2,080	2,418
Poland		3		1,968	1,968		1,968	1,968
United Kingdom	1,469	73	2,228	1,364	3,592	822	329	1,151
Other countries	3,701	6		6,060	6,060		3,458	3,458
AFRICA	**158,749**	**274**	**68,350**	**211,830**	**280,180**	**20,153**	**132,518**	**152,671**
North Africa	**46,011**	**116**	**31,723**	**48,530**	**80,253**	**13,802**	**30,475**	**44,277**
Algeria	17,244	38	2,177	17,433	19,610	730	16,514	17,244
Egypt	8,328	54	5,135	12,669	17,804	1,847	4,747	6,594
Libya	18,165	13	17,947	18,428	36,375	8,951	9,214	18,165
Tunisia	2,274	11	6,464		6,464	2,274		2,274
West Africa	**60,524**	**152**	**36,627**	**86,076**	**122,703**	**6,351**	**49,830**	**56,181**
Angola	3,393	68	4,532	15,569	20,101	589	3,931	4,520
Congo	8,188	25	1,900	9,680	11,580	1,044	5,030	6,074
Democratic Republic of Congo		1		1,118	1,118		615	615
Gabon	7,615	6		7,615	7,615		7,615	7,615
Ghana	1,086	2		2,300	2,300		1,086	1,086
Mali	31,668	1		32,458	32,458		21,640	21,640
Nigeria	8,574	47	30,195	11,144	41,339	4,718	3,721	8,439
Togo		2		6,192	6,192		6,192	6,192
Other countries	52,214	6		77,224	77,224		52,213	52,213
ASIA	**125,641**	**78**	**18,825**	**191,203**	**210,028**	**6,352**	**106,393**	**112,745**
Kazakhstan	880	6	324	4,609	4,933	105	775	880
Rest of Asia	**124,761**	**72**	**18,501**	**186,594**	**205,095**	**6,247**	**105,618**	**111,865**
China	18,322	10	138	18,256	18,394	22	18,210	18,232
East Timor	7,999	4		8,087	8,087		6,470	6,470
India	10,089	14	303	27,861	28,164	143	9,946	10,089
Indonesia	16,519	12	1,735	24,054	25,789	656	12,256	12,912
Iran	820	4	1,456		1,456	820		820
Iraq	640	1	1,950		1,950	640		640

Pakistan	18,201	18	9,122	17,224	26,346	2,708	8,639	11,347
Russia	2,323	4	3,597	1,529	5,126	1,058	449	1,507
Saudi Arabia	25,844	1		51,687	51,687		25,844	25,844
Turkmenistan	200	1	200		200	200		200
Yemen	20,560	2		23,296	23,296		20,560	20,560
Other countries	3,244	1		14,600	14,600		3,244	3,244
AMERICAS	**11,523**	**522**	**4,659**	**17,356**	**22,015**	**3,063**	**8,124**	**11,187**
Brazil	1,067	1		745	745		745	745
Ecuador	2,000	1	2,000		2,000	2,000		2,000
Trinidad and Tobago	66	1	382		382	66		66
USA	6,450	506	1,899	8,536	10,435	899	4,997	5,896
Venezuela	614	5	378	2,528	2,906	98	1,056	1,154
Other countries	1,326	8		5,547	5,547		1,326	1,326
AUSTRALIA AND OCEANIA	**20,342**	**15**	**1,057**	**43,153**	**44,210**	**676**	**14,603**	**15,279**
Australia	20,304	14	1,057	42,389	43,446	676	14,565	15,241
Other countries	38	1		764	764		38	38
Total	**347,862**	**1,176**	**110,321**	**491,835**	**602,156**	**41,386**	**279,575**	**320,961**

(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 interests as of December 31, 2010. 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 8,153 (2,895.6 of which represent Eni s share).

PRODUCTIVE OIL AND GAS WELLS

(units)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
Number of productive wells at Dec. 31, 2010 (a)									
Oil wells									
Gross	224.0	408.0	1,240.0	3,002.0	91.0	618.0	134.0	4.0	5,721.0
Net	184.4	63.1	601.1	515.3	29.6	383.8	63.6	2.6	1,843.5
Gas wells									
Gross	525.0	206.0	131.0	505.0		762.0	289.0	14.0	2,432.0
Net	479.3	93.2	52.6	37.1		290.5	96.1	3.3	1,052.1

(a) Includes approximately 2,320 gross (700 net) multiple completion wells (more than one producing into the same well bore).

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

Italy

Eni has been operating in Italy since 1926. In 2010, Eni s oil and gas production amounted to 178 KBOE/d. Eni s activities in Italy are deployed in the Adriatic 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.

In October 2010, with a view to rationalizing its upstream portfolio, Eni closed the divestment of the entire share capital of its subsidiary Società Padana Energia to Gas Plus. The divested subsidiary includes exploration leases and concessions for developing and producing oil and natural gas in Northern Italy. Cash consideration for the deal amounted to euro 179 million, subject to a possible adjustment of up to euro 25 million related to achieving certain production targets at assets under development. Further price adjustments are foreseen in connection with appraising the underlying exploration resources.

The Law Decree No. 128 issued by the Italian Government on June 29, 2010 that introduced certain restrictions for exploration and production hydrocarbons activities mainly in certain offshore and coastline areas due to environmental constrains without impacting the leases already granted to conduct oil and gas operations became effective on August 26, 2010. Eni and other operators in the industry have commenced discussions with the Ministry for Economic Development and the Ministry for the Environment to clarify uncertainties in correctly interpreting and applying the new regulations. During the year the Group did not incur any significant impact on its operations related to this new decree, while certain projects initially planned for 2011 have been rescheduled. For further information on this matter, see "Environmental matters" below.

The Adriatic Sea represents Eni s main production area in Italy, accounting for 55% of Eni s domestic production in 2010. Main operated fields are Barbara, Angela-Angelina, Porto Garibaldi, Cervia and Bonaccia (for an overall production of approximately 212 mmCF/d).

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 fed by 24 production wells and is treated by the Viggiano oil center with an oil capacity of 104 KBBL/d. Oil produced is carried to Eni s refinery in Taranto via a 136-kilometer long pipeline. Gas produced is treated at the Viggiano oil center and then delivered to the national grid system. In 2010, the Val d Agri concession produced 88 KBOE/d (47 net to Eni) representing 26% of Eni s production in Italy.

Eni is the operator of 15 production concessions onshore and offshore in Sicily. Its main fields are Gela, Ragusa, Giaurone, Fiumetto and Prezioso, which in 2010 accounted for 10% of Eni s production in Italy.

In 2010, production was started-up at: (i) the Annamaria B production platform (Eni operator with a 90% interest), located at the border with Croatian territorial waters. During the course of the year the field reached its production plateau at approximately 40 mmCF/d; and (ii) the Bonaccia Est field flowing at the initial rate of approximately 36 mmCF/d.

In 2010, development activities progressed at the Val d Agri concession (Eni s interest 60.77%) as wells at Cerro Falcone were connected to the oil treatment centre. Other activities were performed including: (i) optimization of producing fields by means of sidetrack and work over activities (Barbara, Annalisa and Azalea); (ii) sidetrack programs and facility upgrading in Val d Agri; (iii) upgrading activities of compression plants and treatment facilities at the Crotone plants; and (iv) development activities at the Capparuccia, Tresauro and Guendalina fields.

In the medium-term, management expects production in Italy to slightly increase due to the production ramp-up of the Val d Agri fields and ongoing new field projects and continuing production optimization activities partly offset by mature fields decline and divested fields.

Rest of Europe

Eni s operations in the Rest of Europe are conducted mainly in Croatia, Norway and the UK. In 2010, the Rest of Europe accounted for 12% of Eni s total worldwide production of oil and natural gas.

Croatia. Eni has been present in Croatia since 1996. In 2010, Eni s production of natural gas averaged 42 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 B (start-up in 2010, as disclosed above), Ivana, Ika & Ida, Marica and Katarina 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 1964. Eni s activities are performed in the Norwegian

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Sea, in the Norwegian section of the North Sea and in the Barents Sea. Eni s production in Norway amounted to 120 KBOE/d in 2010.

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 any given number of years with possible extensions.

Eni currently holds interests in 6 production areas in the Norwegian Sea. The principal producing fields are Aasgard (Eni s interest 14.82%), Kristin (Eni s interest 8.25%), Heidrun (Eni s interest 5.12%), Mikkel (Eni s interest 14.9%), Yttergryta (Eni s interest 9.8%), Norne (Eni s interest 6.9%) and Urd (Eni s interest 11.5%) which in 2010 accounted for 72% of Eni s production in Norway.

In 2010, production was started-up at the Morvin field (Eni s interest 30%) as three wells of the development program were put into production. Production is expected to peak at 15 KBOE/d net to Eni in 2011 when the project is completed.

Development activities progressed to put in production discovered reserves near the Aasgard field with the Marulk development plan (Eni operator with a 20% interest). Start-up is expected in 2012.

Eni holds interests in four 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 2010 produced approximately 34 KBOE/d net to Eni and accounted for 28% of Eni s production in Norway. The license expires in 2028, and negotiations are ongoing to grant an extension. Activities were performed during the year to maintain and optimize the production rate by means of infilling wells, the development of the South Area extension, upgrading of existing facilities and optimization of water injection.

Eni is currently performing exploration and development activities in the Barents Sea. 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. The project is progressing according to schedule. In 2010, EPC contracts have been awarded for building an FPSO unit that will be linked to an underwater production system, onshore facilities and an offshore supply system designed to reduce CO_2 emissions. Start-up is expected in 2013 while the production peak of 100 KBBL/d will be reached the following year.

Exploration activities yielded positive results in: (i) the Prospecting License 128 (Eni s interest 11.5%) with the Fossekal oil discovery that will exploit synergies with the Norne (Eni s interest 6.9%) production facilities; (ii) in the PL 473 license (Eni s interest 29.4%) with the Flyndretind oil discovery; and (iii) the PL 532 (Eni s interest 30%) with the Skrugard oil and gas discovery.

Poland. In December 2010, Eni acquired Minsk Energy Resources, which operates 3 licenses in the Polish Baltic Basin. Management believes that is a highly prospective shale gas play. Drilling operations are expected to start in the second half of 2011 with a total exploration commitment of 6 wells.

United Kingdom. Eni has been present in the UK since 1964. Eni s activities are carried out in the British section of the North Sea, the Irish Sea and certain areas East and West of the Shetland Islands. In 2010, Eni s net production of oil and gas averaged 87 KBOE/d.

Exploration and production activities in the UK are regulated by concession contracts.

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In 2010, Eni signed a Sale and Purchase Agreement to divest its 18% stake of the Blane producing field and completed the divestment of its entire working interest in the Laggan (Eni s interest 20%) and Tormore (Eni s interest 22.5%) pre-development fields. Production started-up in Burghley field (Eni s interest 21.92%).

Eni holds interests in 13 production areas; in 1 of these Eni is operator. The main fields are Elgin/Franklin (Eni s interest 21.87%), West Franklin (Eni s interest 21.87%), Liverpool Bay (Eni s interest 53.9%), J Block Area (Eni s interest 33%), Andrew (Eni s interest 16.21%), Farragon (Eni s interest 30%), Flotta Catchment Area (Eni s interest 20%) and MacCulloch (Eni s interest 40%), which in 2010 accounted for 85% of Eni s production in the UK.

Ongoing activities are aimed at optimizing production at the Elgin/Franklin field and infilling activity at the J-Block. In the fourth quarter of 2010, the following projects were sanctioned by partners and relevant authorities: (i) the development plan of the Jasmine discovery (Eni s interest 33%). Engineering activities are currently ongoing and start-up is expected in 2012; and (ii) Phase 2 of the development program of the West Franklin field. This project comprises the construction of a production platform and the drilling of additional wells with production processed by Elgin/Franklin treatment plant.

Pre-development activities started in Kinnoull oil and gas discovery (Eni s interest 16.67%) to be developed through Andrew field s production facilities.

Exploration activity concerned the drilling of an appraisal well in Culzean gas discovery (Eni s interest 16.95%), near the Elgin/Franklin producing field for assessing its possible development options.

North Africa

Eni s operations in North Africa are conducted in Algeria, Egypt, Libya and Tunisia. In 2010, North Africa accounted for 33% of Eni s total worldwide production of oil and natural gas.

Algeria. Eni has been present in Algeria since 1981. In 2010, Eni s oil and gas production averaged 74 KBOE/d. Operating activities are located in the Bir Rebaa area in the South-Eastern Desert and include the following exploration and production blocks: (i) Blocks 403a/d (Eni s interest up to 100%); (ii) Blocks 401a/402a

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(Eni s interest 55%); (iii) Blocks 403 (Eni s interest 50%) and 404a (Eni s interest 12.25%); (iv) Blocks 208 (Eni s interest 12.25%) and 405b (Eni s interest 75%) with ongoing development activities; (v) Block 212 (Eni s interest 22.38%) with discoveries already made; and (vi) Blocks 316b, 319a and 321a (Eni operator with a 100% interest) in the Kerzaz area with ongoing exploration activities.

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

Production in Block 403a/d comes mainly from the HBN and Rom and satellite fields and represented approximately 23% of Eni s production in Algeria in 2010. The main project underway is the integrated development of Rom and satellites reserves (Zea, Zek and Rec) following the mineral potential revaluation. The development plan has been approved by the relevant authorities. Current production is collected at the Rom Central Production Facility (CPF) and delivered to the treatment plant in Bir Rebaa North. An export pipeline has been completed and a new multiphase pumping system is under finalization in compliance with applicable country law to reduce gas flaring.

Production in Blocks 401a/402a comes mainly from the Rod and satellite fields and accounted for approximately 23% of Eni s production in Algeria in 2010. Infilling activities are being performed in order to maintain the current production plateau.

The main fields in Block 403 are BRN, BRW and BRSW which accounted for approximately 17% of Eni s production in Algeria in 2010.

In Block 405b, the development activity relates to the MLE and CAFC integrated project. The final investment decision was sanctioned for both projects (MLE in 2009; CAFC in April 2010). The MLE development plan provides for the construction of a natural gas treatment plant with a capacity of 350 mmCF/d and of four export pipelines with linkage to the national grid system. These facilities will also receive gas from the CAFC field.
As of December 31, 2010, 61% of MLE project was completed. The CAFC project provides the construction of an oil treatment plant and will also benefit from synergies with existing MLE production facilities. As of December 31, 2010, 27% of CAFC project was completed. MLE and CAFC start-up are expected in 2011 and 2012, respectively, with a production plateau of approximately 33 KBOE/d net to Eni by 2014.

Block 208 is located South of Bir Rebaa. The El Merk project is progressing with the drilling activities and the construction of treatment facilities. 60% of the project scope was completed at year end. Production start-up is expected in 2012.

The new Algerian hydrocarbon Law No. 5 of 2007 introduced a higher tax burden for the national oil company Sonatrach which has requested to renegotiate the economic terms of certain PSAs in order to restore the initial economic equilibrium. Eni signed an agreement for Block 403 in this respect while agreements have not yet been reached for Blocks 401a/402a (Eni s interest 55%) and Block 208 (Eni s interest 12.25%).

In the medium-term, management expects to increase Eni s production in Algeria to approximately 120 KBOE/d, reflecting the development and integration of the First Calgary acquired assets.

Egypt. Eni has been present in Egypt since 1954. In 2010, Eni s share of production in this country amounting to 222 KBOE/d and accounted for 13% of Eni s total annual hydrocarbon production. Eni s main producing liquid fields are located in the Gulf of Suez, primarily in Belayim field (Eni s interest 100%) and in the Western Desert mainly Melehia concession (56% interest) and Ras Qattara (75% interest). Gas production mainly comes from the operated or participated concession of North Port Said (Eni s interest 100%), El Temsah (50% interest), Baltim (50% interest) and Ras el Barr (50% interest, non-operated) and all located in the offshore the Nile Delta. In 2010, production from these main concessions accounted for approximately 90% of Eni s production in Egypt.

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

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In July 2010, Eni signed a Strategic Framework Agreement with the Egyptian Ministry of Petroleum for new upstream and downstream initiatives. The agreement provides for: (i) a joint study to evaluate a number of upstream activities in the Mediterranean Basin and outside Egypt, including Gabon and Iraq; and (ii) an initiative to secure rights for Eni to acquire gas transport capacity in the Arab Gas Pipeline system in compliance with existing intergovernmental agreements.

In May 2010, Eni divested a 50% interest in the Ashrafi offshore field located in the Gulf of Suez. Eni will retain operatorship and a 50% interest.

Production start-up was achieved from Tuna field (Eni operator with a 50% interest) through linkage to the El Gamil facility with a production plateau at approximately 70 mmCF/d net to Eni.

Other development activities mainly regarded: (i) the basic engineering of the Belayim field for the upgrading of water injection facilities to recover remaining reserves; (ii) the second phase of the Denise field (Eni operator with a 50% interest); and (iii) the upgrading of the El Gamil plant by adding new compression capacity to support production.

Through its affiliate Unión Fenosa Gas, Eni has an indirect interest in the Damietta natural gas liquefaction plant with a producing capacity of 5.1 mmtonnes/y of LNG corresponding to approximately 268 BCF/y of feed gas. Eni is currently supplying 35 BCF/y for a 20-year period. Natural gas supplies derived from the Taurt and Denise fields with 17 KBOE/d net to Eni of feed gas.

Exploration activities yielded positive results in the: (i) Belayim concession (Eni s interest 100%) with two discovery wells containing oil that were linked to existing facilities; (ii) El Qara North (Eni s interest 75%) and Zaafaran East (Eni s interest 75%) gas discoveries which were linked to the existing nearby facilities; (iii) Melehia development lease (Eni s interest 56%) with the Jana and Arcadia oil discoveries. The latter was started-up in the second half of the year.

In the medium-term, management expects that Egypt will remain among Eni s largest oil and gas producing countries.

Libya. Eni started operations in Libya in 1959. In 2010, Eni s oil and gas production averaged 267 KBOE/d, the portion of liquids being 43%. Production activity is carried out in the Mediterranean Sea near Tripoli and in the Libyan Desert area and includes six contract areas. Onshore contract areas are: (i) Area A consisting in the former concession 82 (Eni s interest 50%); (ii) Area B, former concessions 100 (Bu Attifel field) and the NC 125 Block (Eni s interest 50%); (iii) Area E with El Feel (Elephant) field (Eni s interest 33.3%); and (iv) Area F with Block 118 (Eni s interest 50%). Offshore contract areas are: (i) Area C with the Bouri oil field (Eni s interest 50%); and (ii) Area D with Blocks NC 41 and NC 169 (onshore) that feed the Western Libyan Gas Project (Eni s interest 50%).

In the exploration phase, Eni is operator of four onshore blocks in the Muzurk Basin (161/1, 161/2&4, 176/3), in the Kufra area (186/1, 2, 3 & 4) and in the contract Areas A, B and D.

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

From February 22, 2011, some liquids and natural gas production activities and the gas export through the GreenStream pipeline have been halted. Facilities have not suffered any damage and such standstill does not affect Eni s ability to ensure natural gas supplies to its customers. Eni is technically able to resume gas production at or near previous level once the situation stabilizes. The overall impact of instability and conflict in Libya on Eni s results in terms of operations and cash flows will depend on how long such political instability and unrest will last, which management is currently unable to predict. Eni s production as of end of March

2011, was flowing at around 70-75 KBOE/d, down from the expected level of approximately 280 KBOE/d, and is made of gas which is totally delivered to local power generation plants. Production is continuing to decline..

Eni has limited investments planned in Libya over the course of the next two years, and no major project start-up are planned for the next four years.

Main development activities underway concerned the Western Libyan Gas Project (Eni s interest 50%) for the monetization of gas reserves ratified in the strategic agreements between Eni and NOC. Activities were performed for maintaining in the future gas production profiles at the Wafa and Bahr Essalam fields through increasing compression capacity at the Wafa field and drilling additional wells at both fields. In 2010, volumes delivered through the GreenStream pipeline were 309 BCF. In addition, 53 BCF were sold on the Libyan market for power generation and approximately 7 BCF to feed the GreenStream compressor station.

Tunisia. Eni has been present in Tunisia since 1961. In 2010, Eni s production amounted to 19 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.

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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), MLD (Eni s interest 50%) and El Borma (Eni s interest 50%) onshore blocks.

In 2010, Eni signed new terms for the El Borma concession (Eni s interest 50%), due to expire in 2043.

Development activities concerned the completion of the operated Baraka project and ramp-up of production at Maamoura field.

Optimization of production was carried out at the Adam, Djebel Grouz (Eni s interest 50%), Oued Zar and El Borma fields.

In the medium-term, Eni expects production in Tunisia as a result of the development of recent offshore discoveries.

West Africa

Eni s operations in West Africa are conducted mainly in Angola, Congo and Nigeria. In 2010, West Africa accounted for 22% of Eni s total worldwide production of oil and natural gas.

Angola. Eni has been present in Angola since 1980. In 2010, Eni s production averaged 113 KBOE/d. Eni s activities are concentrated in the conventional and deep offshore.

The main blocks with Eni s participation are: (i) Block 0 in Cabinda (Eni s interest 9.8%) West of the Angolan coast; (ii) Development Areas in the former Block 3 (Eni s interest ranging from 12% to 55%) in the offshore of the Congo Basin; (iii) Development Areas in the former Block 14 (Eni s interest 20%) in the deep offshore West of Block 0; and (iv) Development Areas in the former Block 15 (Eni s interest 20%) in the deep offshore of the Congo Basin.

Eni also holds interests in other minor concessions, in particular in the Lianzi Development Area (former 14K/A IMI Unit Area - Eni s interest 10%). In the exploration and development phase, Eni is operator of Block 15/06 (35% interest), holds 12% interest in Block 3/05-A, 15% interest in Cabinda North (onshore) and 20% interest in the Open Areas of the Gas Project.

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

In January 2011, Eni was awarded rights to explore and the operatorship of deep offshore Block 35, with a 30% interest. The agreement foresees drilling 2 wells to be carried out in the first 5 years of exploration. This deal is subject to the approval of the relevant authorities.

West Hub is the main project underway in the Development Area of operated Block 15/06 (Eni s interest 35%), with start-up expected in 2013 and peaking production at 22 KBBL/d net to Eni.
Within the activities for reducing gas flaring in Block 0, activity progressed at the Nemba field in Area B. The completion is expected in 2013 reducing flared gas by approximately 85%. Other ongoing projects include: (i) completion of linkage and treatment facilities at the Malongo plant; and (ii) installation of a second compression unit at the platform in the Nemba field in Area B. Flaring down of the Malongo area is still underway with completion 2011.

In the Development Areas of former Block 14, infilling activity was carried out at the Benguela-Belize/Lobito-Tomboco fields. Drilling of wells in Tombua-Landana field is ongoing as per field development plan.

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Main projects underway in the Development Areas of former Block 15 (Eni s interest 20%) regarded: (i) the satellites of Kizomba Phase 1, with start-up expected before mid 2012 and peaking production at 100 KBBL/d (21 KBBL/d net to Eni) in 2013; and (ii) drilling activity at the Mondo and Saxi/Batuque fields to finalize their development plan. The subsea facility of the Gas Gathering project has been already completed. The project provides the construction of a pipeline collecting all the gas of the Kizomba, Mondo and Saxi/Batuque fields.

Eni holds a 13.6% interest in the Angola LNG Ltd (A-LNG) consortium responsible for the construction of an LNG plant in Soyo, 300 kilometers North of Luanda. It has been designed with a processing capacity of approximately 1.1 BCF/d of natural gas and production of 5.2 mmtonnes/y of LNG, condensates and LPG. The project has been sanctioned by relevant Angolan Authorities. It envisages the development of 10,594 BCF of gas in 30 years. Start-up is expected in the first quarter of 2012. LNG was originally expected to be delivered to the USA market at the re-gasification plant in Pascagoula, currently under construction, (Eni s capacity amounting to approximately 205 BCF/y) in Mississippi. During the year, Eni signed a Memorandum of Understanding with the other project partners to assess possible further marketing opportunities. In 2010, the principal following activities were carried out: (i) engineering and procurement; (ii) linkage from offshore to onshore facilities; (iii) implementation of the construction of storage tanks for the processed products and onshore plant facilities; and (iv) fuel gas supplies from Block 15.

In addition, Eni is part of a second gas consortium with the national Angolan company and other partners that will explore further potential gas discoveries to support the feasibility of a second LNG train or marketing projects to deliver gas and associated liquids. Eni is technical advisor with a 20% interest.

Exploration activities yielded positive results in: (i) operated Block 15/06 (Eni s interest 35%) with the appraisal wells of the Cinguvu (Cinguvu-1), Cabaça (Cabaça South East-2) and Mpungi (Mpungi 1 e 2) oil discoveries. The appraisal activities were completed ahead of schedule with commitments increasing the initial resource estimation to develop the East Hub and West Hub projects. In February 2010, the West Hub concept definition (FEED) was approved while the final investment decision was sanctioned at year end; (ii) Development Areas in former Block 14 (Eni s interest 20%) with the Lucapa 6 appraisal oil well. Activities are underway for assessing its possible development opportunities following the area s mineral potential revaluation; and (iii) Block 0 (Eni s interest 9.8%) with the liquids and gas discovery located in the Vanza area.

In the medium-term, management expects to increase Eni s production to approximately 190 KBBL/d reflecting contributions from ongoing development projects.

Congo. Eni has been present in Congo since 1968. In 2010, production averaged 107 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 65%) and Loango (Eni s interest 50%), Ikalou (Eni s interest 100%), Djambala, Foukanda and Mwafi (Eni s interest 65%), Kitina (Eni s interest 35.75%), Awa Paloukou (Eni s interest 90%), M Boundi (Eni s interest 83%) and Kouakouala (Eni s interest 75%) fields.

Other relevant producing areas are a 35% interest in the Pointe Noire Grand Fonde, PEX and Likouala permits. In the exploration phase, Eni also holds interests in the Mer Très Profonde Sud deep offshore block (Eni s interest 30%), the Noumbi onshore permit (Eni s interest 37%) and the Marine XII offshore permit (Eni operator with a 65% interest).

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

Production started-up at Zingali and Loufika (Eni operator with an 85% interest) onshore satellites of the M Boundi field. Ongoing development activities concerned offshore fields with start-up expected in 2011-2012.

Activities on the M Boundi field (Eni operator with an 83% interest) moved forward with the application of advanced recovery techniques and a design to monetize associated gas within the activities aimed at reducing flared gas. Eni signed a long-term agreement to supply associated gas from the M Boundi field to feed three facilities in the Pointe Noire area: (i) the under construction potassium plant, owned by Canadian Company MAG Industries; (ii) the existing Djeno power plant (CED - Centrale Electrique du Djeno); and (iii) the recently built CEC Centrale Electrique du Congo power plant (Eni s interest 20%). These facilities will also receive gas in the future from the offshore discoveries of the Marine XII permit. Development activities to build the CEC power plant moved forward as scheduled in the cooperation agreement signed by Eni and the Republic of Congo in 2007, with the start-up of the first and second turbo-generator.

Within the activities aimed to monetize gas reserves, the RIT project moved forward with the rehabilitation plan of the Pointe Noire-Brazzaville power grid. In 2010 the project DEPN - Phase 1 (Distribution Electrique à Pointe Noire) started-up in the town of Pointe Noire.

In the medium-term, management expects to increase Eni s production in Congo due to the integration and development of recently acquired assets as well as projects underway, targeting a level in excess of 120 KBOE/d by 2014.

Democratic Republic of Congo. In August 2010, Eni acquired a 55% stake and operatorship in the Ndunda Block located in the Democratic Republic of Congo which may lead to future developments after exploration activities. At present no activities are conducted in this country.

Nigeria. Eni has been present in Nigeria since 1962. In 2010, Eni s oil and gas production averaged 167 KBOE/d located mainly in the onshore and offshore of the Niger Delta.

In the development/production phase Eni is operator of onshore Oil Mining Leases (OML) 60, 61, 62 and 63 (Eni s interest 20%) and offshore OML 125 (Eni s interest 85%), OMLs 120-121 (Eni s interest 40%), holding interests in OML 118 (Eni s interest 12.5%) as well as 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 26 onshore blocks and a 12.86% interest in 5 conventional offshore blocks.

In the exploration phase Eni is operator of offshore Oil Prospecting Leases (OPL) 244 (Eni s interest 60%), OML 134 (former OPL 211 - Eni s interest 85%) 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 (former OPL 219).

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 companies.

In Blocks OML 60, 61, 62 and 63 (Eni operator with a 20% interest), within the activities aimed at supplying production of feed gas to the Bonny liquefaction plant (Eni s interest 10.4%), the following development activities have been implemented: (i) the completion of basic engineering to increase capacity at the Obiafu/Obrikom plant; and (ii) the installation of a new treatment plant and transport facility aiming to 155 mmCF/d of feed gas for a 20-year period.

Exploration activity yielded positive results with the Tuomo 4 oil discovery (Eni s interest 20%) and the development plan of the Tuomo gas field has been progressing with an early production through a linkage from Tuomo 4 well to the Ogbainbiry treatment plant. In 2010, a new compressor plant was started-up aiming to feed gas for the liquefaction trains 4 and 5, amounting to 311 mmCF/d (60 mmCF/d net to Eni).

In Block OML 61 flaring down of the Ebocha oil plant was completed.

In Block OML 28 (Eni s interest 5%) within the integrated oil and natural gas project in the Gbaran-Ubie area, the first treatment unit started-up with first gas production. The Phase-2 is currently ongoing and start-up is expected in 2012. The development plan, currently ongoing, foresees for the construction of a Central Processing Facility (CPF) with treatment capacity of about 1 BCF/d of gas and 120 KBBL/day of liquids, the drilling of producing wells and the construction of a pipeline to carry the gas to the Bonny liquefaction plant.

The Forcados/Yokri oil and gas field (Eni s interest 5%) is under development as part of the integrated associated gas gathering project aimed at supplying gas to the domestic market. First gas is expected in 2013 and project completion in 2015.

Eni holds a 10.4% interest in Nigeria LNG Ltd responsible for the management of the Bonny liquefaction plant, located in the Eastern Niger Delta. The plant has a design treatment capacity of approximately 1,236 BCF/y of feed gas corresponding to a production of 22 mmtonnes/y of LNG on 6 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 provided under gas supply agreements with a 20-year term from the SPDC joint venture (Eni s interest 5%) and the NAOC JV, the latter operating the Blocks OMLs 60, 61, 62 and 63. In 2010, total supplies were 1,870 mmCF/d (191 mmCF/d net to Eni corresponding to 34 KBOE/d). LNG production is sold under long-term contracts and exported to European and American markets by the Bonny Gas Transport fleet, wholly owned by Nigeria LNG Co.

Eni holds a 17% interest of the Brass LNG Ltd Company for the construction of a natural gas liquefaction plant to be built near the existing Brass terminal, 100 kilometers West of Bonny. This plant is expected to start operating in 2016 with a production capacity of 10 mmtonnes/y of LNG corresponding to 590 BCF/y (approximately 60 net to Eni) of feed gas on 2 trains for twenty years. Supplies to this plant will derive from the gathering of associated gas from nearby producing fields and from the development of gas reserves in the onshore OMLs 60 and 61. The venture signed preliminary long-term contracts to sell the whole LNG production capacity. Eni acquired 1.67 mmtonnes/y of LNG capacity (corresponding to approximately 81 BCF/y). LNG will be delivered to the USA market mainly at the re-gasification plant in Cameron, in Louisiana. Eni s capacity amounts to approximately 201 BCF/y. Front end engineering activities progressed. EPC tender exercise is ongoing. The final investment decision is envisaged in 2011.

In the medium-term, management expects to increase Eni s production in Nigeria to approximately 190 KBOE/d, reflecting the development of gas reserves.

Togo. In October 2010, Eni awarded operatorship of offshore Block 1 and Block 2 (Eni 100%) in the Dahomey Basin as part of its agreements with the Government of Togo to develop the country s offshore mineral resources.

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 2010, Eni s operations in Kazakhstan accounted for 6% of its total worldwide production of oil and natural gas.

Kashagan. Eni holds a 16.81% working interest in the NCSPSA. The NCSPSA defines terms and conditions for the exploration and development activities to be performed in an area encompassing approximately 4,600 square kilometers. The Kashagan field was discovered in the Northern section of the contractual area in the year 2000.

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Management believes this field contains a large amount of hydrocarbon resources which will eventually be developed in phases. The PSA on Kashagan will expire at the end of 2041.

The participating interest in the NCSPSA has been redefined, effective as of January 1, 2008, in line with an agreement signed in October 2008 with Kazakh Authorities which proportionally diluted the participating interest of the international companies in favor of the Kazakh national oil company, KazMunaiGas. The Kazakh partner will pay the other co-venturers an aggregate amount of $1.78 billion for the transaction. Eni partners of the international consortium are the Kazakh national oil company, KazMunaiGas, and the international oil companies Total, Shell and ExxonMobil, each with a participating interest currently of 16.81%, ConocoPhillips with 8.40%, and Inpex with 7.56%.

The exploration and development activities of the Kashagan field and the other discoveries made in the contractual area are executed through an operating model which entails an increased role of the Kazakh partner and defines the international parties responsibilities in the execution of the subsequent development phases of the project. The new North Caspian Operating Co (NCOC) BV participated by the seven partners of the consortium has taken over the operatorship of the project. Subsequently development, drilling and production activities have been delegated by NCOC BV to the main partners of the Consortium: Eni has retained the responsibility for the development of Phase 1 of the project (the so-called "Experimental Program") and the onshore part of Phase 2.

The consortium is currently focused on completing Phase 1 and starting commercial oil production. Phase 1 completion as at December 2010 was around 80%, of which the completion of tranches 1 and 2 allowing the first production was around 90%.

The partners of the venture are currently discussing an update of the expenditures and time schedule to complete the Phase 1 which were included in the development plan approved in 2008 by the relevant Kazakh Authorities. The consortium continues to target the achievement of first commercial oil production by end of 2012. However, the timely delivery of Phase 1 depends on a number of factors which are presently under review.

The Phase 1 of the project targets an initial production capacity of 150 KBBL/d. In the 12-15 months following the start-up, the treatment plant and the compression facilities for gas re-injection will be started-up enabling an increase of the production capacity to 370 KBBL/d by 2014. A further increase of production capacity to 450 KBBL/d is expected as additional compression capacity for gas re-injection becomes available with the start-up of Phase 2 offshore facilities. Early engineering studies of Phase 2 are underway aiming at optimizing the development scheme.

Management believes that significant capital expenditures will be required in case the partners of the venture would sanction Phase 2 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 subsequently to the production start-up, management does not expect a 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 from Phase 2 and subsequent phases to the international markets.

As of December 31, 2010, Eni s proved reserves booked for the Kashagan field amounted to 569 mmBOE, recording a decrease of 19 mmBOE with respect 2009 mainly due to price effect.

As of December 31, 2009, Eni s proved reserves booked for the Kashagan field amounted to 588 mmBOE, recording a decrease of 6 mmBOE with respect to 2008.

As of December 31, 2008, Eni s proved reserves booked for the Kashagan field amounted to 594 mmBOE determined according to Eni s participating interest of 16.81%, recording an increase of 74 mmBOE with respect to 2007 despite the divestment of a 1.71% stake in the Kashagan project following the finalization of the agreements implementing the new contractual and governance framework of the project.

As of December 31, 2010, the aggregate costs incurred by Eni for the Kashagan project capitalized in the Consolidated Financial Statements amounted to $5.8 billion (euro 4.4 billion at the EUR/USD exchange rate of December 31, 2010). This capitalized amount included: (i) $4.5 billion relating to expenditures incurred by Eni for the development of the oil field; and (ii) $1.3 billion relating primarily to accrue finance charges and expenditures

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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 in West onshore 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 both with a 32.5% interest.

In 2010, production of the Karachaganak field averaged 228 KBBL/d of liquids (65 net to Eni) and 812 mmCF/d of natural gas (221 net to Eni). This field is developed by producing liquids from the deeper layers of the reservoir and re-injecting the associated gas in the higher layers. Approximately 70% of liquid production are stabilized at the Karachaganak Processing Complex (KPC) with a capacity of approximately 200 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 and associated gas not re-injected in the reservoir are marketed at the Russian terminal in Orenburg.

The execution of the fourth treatment unit has been progressing towards completion and will enable to increase export of oil volumes to Western markets of currently non-stabilized liquids delivered to the Orenburg terminal.

Phase 3 of the Karachaganak project targets to increase the development of gas and condensates reserves. The engineering activities identified a phased approach as the preferred development strategy with stage 1 of the project providing for the installation of gas producing and re-injection facilities to increase liquid production and gas sales in accordance with the foreseeable future market conditions. Technical and marketing discussion on Phase 3 with the relevant Kazakh Authorities are underway.
As of December 31, 2010, Eni s proved reserves booked for the Karachaganak field amounted to 557 mmBOE, recording a decrease of 76 mmBOE with respect to 2009 due to price effect and production of the year.

As of December 31, 2009, Eni s proved reserves booked for the Karachaganak field amounted to 633 mmBOE, recording a decrease of 107 mmBOE with respect to 2008 in connection to downward revisions due to the impact of higher oil prices and the production of the year.

As of December 31, 2008, Eni s proved reserves booked for the Karachaganak field amounted to 740 mmBOE, recording an increase of 200 mmBOE with respect to 2007 as a result of the upward revisions of previous estimates that were mainly related to higher entitlements reported in PSA resulting from lower year end oil prices from a year ago.

Rest of Asia

In 2010, Eni s operations in the rest of Asia accounted for 7% of its total worldwide production of oil and natural gas.

China. Eni has been present in China since 1984 and its activities are located in the South China Sea. In 2010 Eni s production amounted to 7 KBOE/d.

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

Hydrocarbons are produced from the offshore Blocks 16/08 and 16/19 through eight platforms connected to a FPSO. Natural gas production from the HZ21-1 field is delivered through a sealine to the Zhuhai Terminal and sold to the Chinese National Company CNOOC. Oil, which is sold into the domestic market, is mainly produced from HZ25-4 field (Eni s interest 49%). Activity is operated by the CACT-Operating Group (Eni s interest 16.33%).

In January 2011, Eni signed a Memorandum of Understanding with the national oil company PetroChina to promote common opportunities to jointly expand operations in conventional and unconventional hydrocarbons in China and outside China.

India. Eni has been present in India since 2005 and its activities are located in the offshore Cauvery Basin near the South-Eastern coast. In 2010, Eni s production amounted to 7 KBOE/d.

Production mainly comes from the PY-1 gas field which is part of the assets belonging to Hindustan Oil Exploration Co Ltd (Eni s interest 47.18%) acquired within Burren acquisition. Gas production is sold to the local national oil company.

Indonesia. Eni has been present in Indonesia since 2001. In 2010, Eni s production mainly composed of gas, amounted to 16 KBOE/d. Activities are concentrated in the Eastern offshore and onshore of East Kalimantan, the offshore Sumatra, and the offshore and onshore area of the West Timor; in total, Eni holds interest in 12 blocks.

Exploration and production activities in Indonesia are regulated by PSAs.

Eni is also involved in the ongoing study phase of joint development of the oil and gas discoveries in the Bukat permit (Eni operator with a 66.25% interest), the Muara Bakau permit (Eni operator with a 55% interest) and the five discoveries in the Kutei Deep Water Basin area (Eni s interest 20%).

In 2010, the exploration activities related to the coal bed methane project were started in the Sanga Sanga PSC (Eni s interest 37.8%). In case of commercial discovery, the project will exploit the synergy opportunities provided by the existing production and treatment facilities also including the Bontang LNG plant.

Exploration activity yielded positive results in the Muara Bakau permit (Eni operator with a 55% interest), located offshore East Kalimantan, where the Jangkrik 2 and 3 appraisal wells significantly increased the initial reserve evaluations.

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 National Iranian Oil Co (NIOC) between 1999 and 2001, and no other exploration and development contracts have been entered into since then. All projects mentioned above have been completed or substantially completed; the last one, the Darquain project, is in the process of final commissioning and is being handed over to NIOC. Operatorship has already been transferred to a NIOC affiliate. When hand over of operations is completed, Eni s involvements will essentially consist of being reimbursed for its past investments. In 2010, Eni s production in Iran was 21 KBOE/d, approximately 1% of the Group s worldwide production. Eni does not believe that its activities in Iran have a material impact on the Group s results. See "Item 3 Risk Factors Political Consideration Iran" for a full discussion of risks involved by our presence in Iran.

Iraq. In January 2010, Eni leading a consortium of partners including international companies and the national oil company Missan Oil signed a technical service contract to develop the Zubair oil field (Eni 32.8%) with the Iraqi South Oil Company, under a 20-year term with an option for further 5 years extension. The field was awarded to the Eni-led consortium following a successful first bid round and was offered under a competitive bid starting on June 30, 2009. The development of the project foresees to gradually increase production to a target plateau level of 1.2 mmBBL/d over the next six years. The contract provides the recovery of expenditures incurred from the incremental production of the field and the recognition of a remuneration fee once the production has been raised by 10% from its initial level of approximately 180 KBBL/d. Development provides for two phases: (i) Rehabilitation plan, approved in June 2010, aimed at improving the current production level and the knowledge of the reservoir; and (ii) Redevelopment plan allowing to reach the scheduled targets.

In 2010 all the milestones planned for the initial phase of the project were achieved. In particular in September 2010, production was raised by more than 10% above the initial production rate allowing the consortium, based on the contact provision, to begin recovery of costs and recognition of remuneration fee. Therefore Eni starting from the last quarter of 2010 booked its equity production in relation to its share of cost recovery and remuneration.

Pakistan. Eni has been present in Pakistan since 2000. In 2010, Eni s production averaged 58 KBOE/d and is mainly gas.

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

Eni s main permits in the Country are Bhit (Eni s interest 40%), Sawan (Eni s interest 23.68%) and Zamzama (Eni s interest 17.75%), which in 2010 accounted for 86% of Eni s production in Pakistan.

Development activities concerned: (i) the Bhit field (Eni operator with a 40% interest) with the completion of a compressor plant and the drilling of new wells aimed at maintaining current production plateau; (ii) the Sawan field (Eni s interest 23.68%) with a review of production facilities and reservoir to mitigate the current decline; and (iii) the Zamzama permit (Eni s interest 17.75%) with the start-up of the Front End Compressor.

Exploration activity yielded positive results with the Latif North 1 appraisal well (Eni s interest 33.33%) which started-up in 2010.

Russia. Eni has been present in Russia since 2007 following the acquisition of Lot 2 in the liquidation of Yukos.

As part of the transaction to divest a 51% stake in Eni-Enel s joint venture Llc SeverEnergia to Gazprom, based on the call option exercised by the Russian company in September 2009, Eni collected a second installment of the transaction by March 31, 2010. This amounted to euro 526 million ($710 million, approximately 75% of the total amount of the transaction).

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Ongoing activities mainly concerned the development of the Samburskoye gas field. Start-up is planned by 2012, targeting a production plateau of 150 KBOE/d.

Turkmenistan. Eni started its activities in Turkmenistan with the purchase of British company Burren Energy plc in 2008. Activities are mainly focused in the Western part of the country. In 2010 Eni s production averaged 12 KBOE/d.

Exploration and production activities in Turkmenistan are regulated by PSAs.

Eni is operator of the Nebit Dag producing block (with a 100% interest). Production derives mainly from the Burun oil field. Oil production is shipped to the Turkmenbashi refinery plant. Eni receive, by mean of a swapping with the Turkmen Authorities, an equivalent amount of oil at the Okarem field, close to the South coast of Caspian Sea. Eni s entitlement is sold FOB. Associated natural gas is used to own consumption and gas lift system. The remaining amount is delivered to Turkmenneft, via national grid.

America

In 2010, Eni s operations in America area accounted for 8% of its total worldwide production of oil and natural gas.

Ecuador. Eni has been present in Ecuador since 1988 and activities are performed in Block 10 (Eni s interest 100%) located in the Amazon forest. In 2010, Eni s production averaged 11 KBBL/d.

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

Production derives from the Villano field and is carried out by means of a Central Production Facility linked by pipeline to the storage facility.

In November 2010, Eni signed with the Government of Ecuador new terms for the service contract for the Villano oil field, due to expire in 2023. Under the new agreement, the operated area is enlarged to include the Oglan oil discovery, with volumes in place of 300 mmBBL. In case of a successful appraisal campaign on Oglan, development will be carried out in synergy with existing facilities.

Trinidad and Tobago. Eni has been present in Trinidad and Tobago since 1970. In 2010, Eni s production averaged 64 mmCF/d and its activity is concentrated offshore North of Trinidad.

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

Production is provided by the Chaconia, Ixora and Hibiscus gas fields in the North Coast Marine Area 1 Block (Eni s interest 17.4%). Production is supported by fixed platforms linked to the Hibiscus treatment facility. Natural gas is used to feed trains 2, 3 and 4 of the Atlantic LNG liquefaction plant under long-term contracts. LNG production is sold in the USA, Spain and the Dominican Republic.

In 2010, the development plan of the Poinsettia, Bougainvillea and Heliconia fields in the North Coast Marine Area 1 Block (Eni s interest 17.4%) was completed through the installation of a production platform on the Poinsettia field and the linkage to the Hibiscus treatment facility which was already upgraded. The new scheme platform was started-up in 2010.

USA. Eni has been present in the USA since 1968. Activities are performed in the conventional and deep offshore in the Gulf of Mexico and more recently onshore and offshore in Alaska.

In 2010, Eni s oil and gas production is mainly derived from the Gulf of Mexico with an average of 108 KBOE/d.

Exploration and production activities in the USA are regulated by concessions.

Eni holds interests in 354 exploration and production blocks in the Gulf of Mexico of which 61% are operated by Eni.

The main fields operated by Eni are Allegheny, East Breaks and Morphet (Eni s interest 100%), Longhorn-Leo, Devils Towers and Triton (Eni s interest 75%) as well as King Kong (Eni s interest 54%) and Pegasus (Eni s interest 58%). Eni also holds interests in the Medusa (Eni s interest 25%), Europa (Eni s interest 32%), and Thunder Hawk (Eni s interest 25%) fields.

Drilling activities in the Gulf of Mexico were impacted by the incident at the BP-operated Macondo well. The U.S. Government imposed a six-month moratorium on new offshore drilling activities that was suspended in

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October 2010. Through the end of 2010, development or drilling activities were still suspended, due to the delay in getting the relevant authorizations. For further information, see "Item 3 Risk Factors".

In 2010, the development plan of the Alliance area (Eni s interest 27.5%), in the Fort Worth Basin in Texas moved forward. This area, including gas shale reserves, was acquired in 2009 following a strategic alliance that Eni signed with Quicksilver Resources Inc. Production plateau at 10 KBOE/d net to Eni is expected in 2012.

Exploration activity yielded positive results with the oil and natural gas Hadrian West appraisal well, located in offshore Block KC 919 (Eni s interest 25%), in the Gulf of Mexico.

Eni holds interests in 151 exploration and development blocks in Alaska, with interests ranging from 10 to 100% and for over half of these blocks, Eni is the operator.

Production is provided by the Oooguruk oil field (Eni s interest 30%), in the Beaufort Sea and amounted to 10 KBBL/d (3 KBBL/d net to Eni) in 2010.

The main development activities concerned the Nikaitchuq operated field (Eni s interest 100%), located in North Slope Basins offshore Alaska, with resources of 220 mmBBL. Production start-up was achieved at the end of January 2011. Peak production is expected at 28 KBBL/d.

Venezuela. Eni has been present in Venezuela since 1998. In 2010, Eni s production averaged 10 KBBL/d.

Activity is concentrated in the Gulf of Venezuela and in the Gulfo de Paria.

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).

The Corocoro (Eni s interest 26%) field is Eni s only producing asset in the country. A second development phase is expected to be designed based on the results achieved in the first development phase relating to the well

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production rate and field performance under water and gas injection. A production peak more than 40 KBBL/d (approximately 11 net to Eni) is expected in 2012.

In June 2010, Eni was awarded gas exploration and development permits with a 40% interest in Punta Pescador and Gulfo de Paria Ovest, the latter coinciding with the Corocoro oil field area (Eni s interest 26%). Commitment activities are under negotiation with the relevant authorities.

On January 26, 2010, Eni and PDVSA signed an agreement for the joint development of the giant field Junin 5 with 35 BBBL of certified heavy oil in place, located in the Orinoco oil belt. The two partners plan to achieve first oil by 2013 at an initial rate of 75 KBBL/d, targeting a long-term production plateau of 240 KBBL/d to be reached in 2018.

As part of the agreement, on November 22, 2010, Eni and PDVSA signed the contracts to set up two Empresas Mixtas (Eni s interest 40%, PDVSA s interest 60%) for the development of the Junin 5 field and the construction and operation of a refinery with a capacity of 350 KBBL/d that will allow also the treatment of intermediate streams from other PDVSA facilities. Eni, at the publication of the contract of incorporation of the Junin 5 project "Empresa Mixta" in December 2010 paid the first tranche of the bonus of $300 million; the balance of $346 million will be paid in additional tranches according to the achievement of milestones of the project.

Exploration activities yielded positive results with the successful appraisal campaign of the Perla gas field, located in the Cardon IV Block (Eni s interest 50%) in the Gulf of Venezuela. This block is under a Concession Agreement for gas exploration and exploitation licensed and operated by a Venezuelan Joint Venture Company. PDVSA owns a 35% back-in-right to be exercised in the development phase, and at that time Eni will hold a 32.5% joint controlled interest in the company. Perla 2, 3 and 4 appraisal wells results exceeded the initial resource estimation by 50%. A Front End Engineering Design contracts related to offshore facility and transport infrastructure were assigned in 2010 targeting an early production phase of 300 mmCF/d with start-up in 2013. The early production phase includes the utilization of the already successfully drilled wells and the installation of four light offshore platforms linked, through a gas pipeline, to a Central Processing Facility (CPF) located onshore. The development of Perla is currently planned to continue with the full field phase, which includes additional producer wells and the CPF upgrade, to reach a plateau production of 1,200 mmCF/d.

Eni is also participating with a 19.5% interest in the Gulfo de Paria Centrale offshore exploration block, where the Punta Sur oil discovery is located.

Australia and Oceania

Eni s operations in Australia and Oceania area are conducted mainly in Australia. In 2010, Australia and Oceania area accounted for 2% of Eni s total worldwide production of oil and natural gas.

Australia. Eni has been present in Australia since 2000. In 2010, Eni s production of oil and natural gas averaged 26 KBOE/d. Activities are focused on conventional and deep offshore fields.

The main production blocks in which Eni holds interests are WA-33-L (Eni s interest 100%), WA-25-L (Eni operator with a 65% interest) and JPDA 03-13 (Eni s interest 10.99%). In the exploration phase Eni holds interests in 9 licenses (in 2 of which with a 100% interest), of particular interest are the Alberts Blocks (WA-362/363/386/387-P) and JPDA 06-15 (Eni s interest 40%), where the Kitan discovery is located. The project is progressing according to schedule. Start-up is expected in 2011.

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

In the medium-term, management expects to increase Eni s production in Australia through ongoing development activities.

Capital Expenditures

See "Item 5 Liquidity and Capital Resources Capital Expenditures by Segment".

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Gas & Power

Eni s Gas & Power segment engages in supply, trading and marketing of gas and electricity, managing gas infrastructures for transport, distribution, storage, re-gasification, and LNG supply and marketing. This segment also includes the activity of power generation that is ancillary to the marketing of electricity. In 2010, Eni s worldwide sales of natural gas amounted to 97.06 BCM, including 5.65 BCM of gas sales made directly by the Eni s Exploration & Production segment in Europe and the USA. Sales in Italy amounted to 34.29 BCM, while sales in European markets were 54.52 BCM that included 8.44 BCM of gas sold to certain importers to Italy.

Gas transport, distribution and storage, as well as re-gasification of LNG in Italy are regulated activities as tariffs for the services rendered to gas operators and return on capital employed are set by an independent administrative body. For further description on those regulated activities see below.

Marketing of natural gas

The competitive landscape in the marketing of gas in the pan-European sector has changed dramatically from late 2008 to date. Gas demand across Europe was severely impacted by the economic downturn and has been struggling to recover to pre-crisis levels as the industrial activity is slowly progressing, particularly in Italy.

On the supply side, gas availability has considerably increased on the marketplace due to capacity upgrading at the major international pipelines which carry natural gas from producing countries to Europe, including the TAG line from Russia and the TTPC line from Algeria. Also large quantities of LNG have been directed towards Europe as a number of important upstream projects started operations worldwide, and the U.S. market has progressively reduced its LNG imports due to commercial exploitation of large gas reserves from non-conventional sources. Several LNG terminals and facilities which were recently finalized commenced to receive those surpluses of LNG in Europe. The build up of LNG supplies at the European hubs has driven down spot prices which have fallen below the level of gas prices based on oil-linked formulas. That trend has impaired the profitability of gas operators, including Eni, whose portfolio of supplies is mainly indexed to the cost of oil and certain refined products as provided in purchasing formulas of long-term take-or-pay contracts, while spot prices have increasingly become the benchmark in selling formulas, particularly outside Italy.

In 2010, our gas marketing operations reported significantly lower operating profit driven by lower sales in Italy due to mounting competitive pressures and compressed unit margins in sales outside Italy. Operating profit for the year in the gas marketing business decreased by 64% from a year ago and represented less than 5% of the Group s consolidated operating profit for 2010. The short-term outlook for the European gas sector remains challenging. Weak underlying fundamentals and strong competitive pressures are expected to stay in place for some time. Risks still exist in the next couple of years that the Company may be unable to fulfill its minimum take obligations associated with its long-term gas purchase contracts providing take-or-pay clauses. For a description of those risks see "Item 3 Risk Factors" and "Item 5 Outlook". However, management expects that the European gas market will rebalance by the end of the 2011-2014 period due to a number of trends. In fact, it is expected that demand will continue to recover to pre-crisis level and be driven by economic expansion and increased consumption by the power generation sector. Production from European fields will continue to deplete, increasing the need for gas imports. Also, LNG oversupplies will be progressively absorbed due to increasing energy requirements in other parts of the world and limited new capacity additions in the Atlantic Basin. In such a scenario, Eni s long-term supply contracts and access to transport and storage infrastructures will again become a competitive advantage.

Against this backdrop, management plans to improve results in its gas marketing operations which management expects to recover to 2009 profitability levels by 2014. We intend to renegotiate better economic terms and operating conditions in our long-term gas purchase contracts, so as to restore the competitiveness of the Company s cost position in the current weak scenario for the gas sector. The renegotiation of revised contractual terms, including any price revisions and contractual flexibility, is established by such contractual clauses whereby parties are held to bring the contract back to the economic equilibrium in case of significant changes in the market environment, like the ones that have been occurring from the second half of 2008. In the course of 2010, Eni has finalized a number of important contractual renegotiations by obtaining improved economic conditions for supplies and wider contractual flexibility with a benefit to its commercial programs. A number of renegotiations have commenced or are due to commence in the near future involving all the Company s main suppliers of gas based on long-term contracts. The Company targets to grow sales volumes at an average annual rate of 5% both in Europe and Italy over the plan period; particularly we plan:

(i) to increase gas sales volumes in European markets leveraging on the increased competitiveness of the Company s cost position and its multiple presence in a number of markets. We target to expand sales mainly in France, Germany and Austria leveraging on new customized commercial offers and to retain the leadership in the Benelux market;

(ii) to regain market share in the Italian market and preserve marketing margins leveraging on the commercial strength and capabilities of the Company, as well as the increased competitiveness of the Company s cost position. Measures will be implemented to select the customer portfolio and retain clients by proposing new pricing offers and schemes and improve the service quality;

(iii) to reduce the cost-to-serve, marketing and general and business support expenses;

(iv) to monitor and effectively manage working capital requirements; and

(v) to boost margins by means of new risk management activities.

For a description of uncertainties and risks associated with this strategy including a discussion of the possible consequences of the Libyan political instability and conflict see "Item 3 Risk Factors" and "Item 5 Outlook".

In the next four-year period, management plans to invest euro 1.1 billion in marketing activities mainly directed to: (i) power plant upgrading, including building a new bio-mass power generation plant at Eni s Porto Torres industrial site where a reconversion plan is underway; and (ii) increasing flexibility of generation facilities.

The matters regarding future natural gas demand and sales target discussed in this section 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 natural gas demand include changes in underlying economic factors, changes in regulation, population growth or shrinkage, changes in the relative mix of demand for natural gas and its principal competing fuels, and unexpected developments in the markets for natural gas and its principal competing fuels.

Demand outlook

In 2010, gas demand in Italy and Europe rebounded from the depressed levels registered in the previous year, growing by 6% and 4%, respectively. Consumption volumes however remained below the pre-crisis levels seen in 2007. Looking forward, management estimates that long-term gas demand growth will achieve an average rate of 1.7% and 1.1% in Italy and Europe, respectively, until 2020. Those projections imply a consumption level of approximately 590 BCM for the Europe as a whole by 2020; while in Italy a consumption level of approximately 97 BCM is projected at 2020.

Those estimates have been revised down from previous management projections to factor in the expected impacts associated with a number of ongoing trends:

- uncertainties and volatility in the current macroeconomic cycle;
- growing adoption of consumption patterns and life-style characterized by wider sensitivity to energy efficiency; and
- EU policies intended to reduce GHG emissions and promoting renewable energy sources. Specifically, legislation was voted by the European Parliament in December 2008 to enact a package of interventions in the European energy sector, the so-called "Climate Change and Renewable Energy Package". The package includes a commitment to reduce greenhouse gas (GHG) emissions by 20% by 2020 compared to emission levels recorded in 1990 (the target being 30% if an international agreement is reached), as well as an improved energy efficiency within the EU member states of 20% by 2020 and a 20% renewable energy target by 2020.

Among positive drivers for demand growth, it is worth mentioning the growing adoption of natural gas to fuel thermoelectric production via combined cycles and the higher environmental compatibility of natural gas than other fossil fuels to produce energy.

Supply of natural gas

In 2010, Eni s consolidated subsidiaries supplied 82.49 BCM of natural gas, representing a decrease of 6.16 BCM, or 6.9% from 2009 reflecting lower sales for the year.

Gas volumes supplied outside Italy (75.20 BCM from consolidated companies), imported in Italy or sold outside Italy, represented approximately 92% of total supplies, a decrease of 6.59 BCM, or 8.1%, from 2009, mainly reflecting a decline in natural gas sales. In 2010, lower volumes were purchased from: (i) Russia (down 7.73 BCM), where Eni reduced its off-takes in particular of volumes directed to Italy; (ii) the Netherlands (down 1.57 BCM); and (iii) Norway (down 1.17 BCM) also due to the impact of an accident that occurred at the import pipeline Transitgas in August 2010.

In 2010, increases were recorded in gas purchases from Algeria (up 2.41 BCM) and from the UK (up 1.8 BCM), as well as in LNG availability.

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Supplies in Italy (7.29 BCM) increased by 0.43 BCM from 2009, or 6.3%, also due to higher domestic production.

In 2010, main gas volumes from equity production derived from: (i) Italian gas fields (6.7 BCM); (ii) the Wafa and Bahr Essalam fields in Libya linked to Italy through the GreenStream pipeline. In 2010, these two fields supplied 2.5 BCM net to Eni; (iii) certain Eni fields located in the British and Norwegian sections of the North Sea (2.6 BCM); and (iv) other European areas (Croatia with 0.4 BCM).

Considering also the direct sales of the Exploration & Production Division in Europe and in the Gulf of Mexico and LNG supplied from the Bonny liquefaction plant in Nigeria, supplied gas volumes from equity production were approximately 20 BCM representing 21% of total volumes available for sale.

In 2010, volumes input to storage deposits owned by Eni s subsidiary Stoccaggi Gas Italia amounted to 0.20 BCM compared to withdrawals from storage deposit 1.25 BCM in 2009.

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

Natural gas supply	**2008**	**2009**	**2010**
		(BCM)	
Italy	**8.00**	**6.86**	**7.29**
Outside Italy	**81.65**	**81.79**	**75.20**
Russia	*22.91*	*22.02*	*14.29*
Algeria (including LNG)	*19.22*	*13.82*	*16.23*
Libya	*9.87*	*9.14*	*9.36*
the Netherlands	*9.83*	*11.73*	*10.16*
Norway	*6.97*	*12.65*	*11.48*
the United Kingdom	*3.12*	*3.06*	*4.14*
Hungary	*2.84*	*0.63*	*0.66*
Qatar (LNG)	*0.71*	*2.91*	*2.90*
Other supplies of natural gas	*4.07*	*4.49*	*4.42*
Other supplies of LNG	*2.11*	*1.34*	*1.56*
Total supplies of subsidiaries	**89.65**	**88.65**	**82.49**
Withdrawals from (input to) storage	(0.08)	1.25	(0.20)
Network losses, measurement differences and other changes	(0.25)	(0.30)	(0.11)
Volumes available for sale of Eni s subsidiaries	**89.32**	**89.60**	**82.18**
Volumes available for sale of Eni s affiliates	**8.91**	**7.95**	**9.23**
E&P volumes	**6.00**	**6.17**	**5.65**
Total volumes available for sale	**104.23**	**103.72**	**97.06**

In order to secure long-term access to gas availability, particularly with a view of supplying the Italian gas market, Eni has signed a number of long-term gas supply contracts with key producing countries that supply the European gas markets. These contracts have been ensuring approximately 80 BCM of gas availability from 2010 (including the Distrigas portfolio of supplies) with a residual life of approximately 19 years and a pricing mechanism indexed to the price of crude oil and its derivatives (gasoil, fuel oil, etc). The contracts provide take-or-pay clauses whereby the Company is required to collect minimum pre-determined 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, applied to uncollected volumes up to the minimum contractual quantity. The take-or-pay clause entitles the Company to collect pre-paid volumes of gas in later years during the period of contract execution. Amounts of cash pre-payments and time schedules for collecting pre-paid gas vary from contract to contract. Generally speaking, cash pre-payments are calculated on the basis of the energy prices current in the year of non-fulfillment with the balance due in the year when the gas is actually collected. Amounts of pre-payments range from 10 to 100 percent of the full price. The right to collect pre-paid gas expires within a ten-year term in some contracts or remains in place until contract expiration in other arrangements. In addition, rights to collect pre-paid gas in future years can be exercised provided that the Company has fulfilled its minimum take obligation in a given year and within the limit of the maximum annual quantity that can be collected in each contractual year. In this case, Eni will pay the residual price calculating it as the percentage that complements 100%, based on the arithmetical average of monthly base prices current in the year of the off-take. Similar considerations apply to ship-or-pay contractual obligations.

Management believes that the current outlook for increasing competition pressures coupled with large gas availability on the marketplace, the possible evolution of sector-specific regulation, as well as the de-coupling between trends in gas prices indexed to oil versus gas benchmark prices at spot markets, represent risks factors to the Company s ability to fulfill its minimum take obligations associated with its long-term supply contracts.

Particularly, management expects that the Company will experience increasing exposure to the risk associated with growing adoption on the marketplace of selling formulas linked to spot prices which movements are independent of those of oil prices and refined products that drive supply costs in Eni s take-or-pay contracts.

In the years 2009 and 2010, Eni incurred the take-or-pay clause as the Company collected lower volumes than its minimum take obligations in each of those years accumulating deferred costs for an amount of euro 1.44 billion as of December 31, 2010. The Company s ability to recover those pre-paid volumes within contractual terms will depend in future years on a number of factors, including the possible evolution of the market environment and the competitiveness of Eni s cost position. Ongoing political instability in Libya and the shut down of the GreenStream pipeline may possibly counteract those negative trends as the Company may be able to replace supplies from Libya with gas from its ample portfolio. The latter trend will evolve depending on how long such political instability and conflict will last and on their outcome which for the time being cannot be foreseen.

In case Eni fails to off-take the contractual minimum amounts, it will be exposed to a price risk, because the purchase price Eni will ultimately be required to pay is based on prices prevailing after the date on which the off-take obligation arose. In addition, Eni is subject to the risk of not being able to dispose of pre-paid volumes. The Company also expects to incur financing costs to pay cash advances corresponding to contractual minimum amounts. As a result, the Company s selling margins, results of operations and cash flow may be negatively affected.

Based on management s projections for sales volumes and unit margins for the four-year plan and subsequent years which incorporated expected trends in the European market fundamentals, and management s assumptions to renegotiate better economic terms within the Company s long-term gas purchase contracts, so as to restore the competitiveness of the Company s cost position, the Company believes that in the long-term it will be in the position to recover volumes of gas which have been pre-paid in 2009 and 2010 due to the take-or-pay clause and also possible new volumes associated with the contractual clause due to the uncertainties and weak conditions in the gas market over the next two years. Even if financing associated with cash advances is factored in, the net present value associated with those long-term purchase contracts discounted at the weighted average cost of capital for the Gas & Power segment still remains a positive and consequently those contracts do not fall within the category of the onerous contract provided by IAS 37.

For further information about this topic and risks associated with those obligations, see "Item 3 Risk Factors" and "Item 5 Outlook".

Marketing

Natural Gas Sales for the Year 2010

In 2010, worldwide natural gas sales were 97.06 BCM, down 6.66 BCM, or 6.4%, mainly due to unfavorable trends on the Italian market. Sales included Eni s own consumption, Eni s share of sales made by equity-accounted entities and upstream sales in Europe and in the Gulf of Mexico.

Natural gas sales in Italy were 34.29 BCM (including own consumption and sales by affiliates) a decline of 5.75 BCM from 2009, or 14.4%, driven by increased competitive pressures and oversupply conditions on the marketplace, resulting in an estimated loss of ten percentage points in the Group market share in Italy. Particularly, lower sales were recorded in the power generation business (down 5.64 BCM), as clients opted to directly purchase gas on the marketplace. Lower sales to industrial customers (down 1.17 BCM) and wholesalers (down 1.08 BCM) were caused by increased competitive pressure fuelled by oversupply and weak demand. Sales on the Italian exchange for gas and spot market increased by 2.28 BCM, while sales volumes to the residential sector (6.39 BCM, up 0.09 BCM) were nearly unchanged. In addition, sales to importers in Italy were down by 2.04 BCM, or 19.5%, due to oversupply on the Italian market.

The Italian market includes large businesses, power generation users, wholesalers, middle-sized enterprises and service and residential customers; they are further grouped as follows: (i) large industrial clients and power generation utilities, directly linked to the national and the regional natural gas transport networks; (ii) wholesalers, mainly local selling companies which resell natural gas to residential customers through low pressure distribution networks and distributors of natural gas for automotive use; and (iii) residential customers, that include households (also referred to as the retail market), the tertiary sector (mainly commercial outlets, hospitals, schools and local administrations) and middle-sized enterprises (also referred to as the middle market) located in large metropolitan areas and urban areas.

As of December 31, 2010, Eni s customers in Italy totaled 6.88 million.

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Despite strong competitive pressures, sales on target markets in Europe showed a positive trend, increasing by approximately 1 BCM, or 2.5%, to 46.08 BCM. The main drivers behind the increase were organic growth achieved in France (up 1.18 BCM), Northern Europe (including the UK, up 0.91 BCM), Germany/Austria (up 0.31 BCM) and the Iberian Peninsula (up 0.30 BCM). Declines were recorded in Turkey (down 0.84 BCM), Belgium (down 0.80 BCM) and Hungary (down 0.22 BCM).

Sales to markets outside Europe (2.60 BCM) increased by 0.54 BCM, or 26.2%, from 2009.

E&P sales in Europe and in the USA (5.65 BCM) declined by 0.52 BCM.

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

Natural gas sales by entities	**2008**	**2009**	**2010**
		(BCM)	
Total sales of subsidiaries	**89.32**	**89.60**	**82.00**
Italy (including own consumption)	*52.82*	*40.04*	*34.23*
Rest of Europe	*35.61*	*48.65*	*46.74*
Outside Europe	*0.89*	*0.91*	*1.03*
Total sales of Eni s affiliates (Eni s share)	**8.91**	**7.95**	**9.41**
Italy	*0.05*	-	*0.06*
Rest of Europe	*7.42*	*6.80*	*7.78*
Outside Europe	*1.44*	*1.15*	*1.57*
Total sales of G&P	**98.23**	**97.55**	**91.41**
E&P in Europe and in the Gulf of Mexico (a)	6.00	6.17	5.65
Worldwide gas sales	**104.23**	**103.72**	**97.06**

(a) E&P sales include volumes marketed by the Exploration & Production Division in Europe (3.36, 2.57 and 2.33 BCM in 2008, 2009 and 2010, respectively) and in the Gulf of Mexico (2.64, 3.60 and 3.32 BCM in 2008, 2009 and 2010, respectively).

Natural gas sales by market	**2008**	**2009**	**2010**
		(BCM)	
ITALY	**52.87**	**40.04**	**34.29**
Wholesalers	7.52	5.92	4.84
Gas release	3.28	1.30	0.68
Italian gas exchange and spot markets	1.89	2.37	4.65
Industries	9.59	7.58	6.41
Medium-sized enterprises and services	1.05	1.08	1.09
Power generation	17.69	9.68	4.04
Residential	6.22	6.30	6.39
Own consumption	5.63	5.81	6.19
INTERNATIONAL SALES	**51.36**	**63.68**	**62.77**
Rest of Europe	**43.03**	**55.45**	**54.52**
Importers in Italy	11.25	10.48	8.44
European markets	31.78	44.97	46.08
Iberian Peninsula	*7.44*	*6.81*	*7.11*

Germany - Austria	*5.29*	*5.36*	*5.67*
Belgium	*4.57*	*14.86*	*14.06*
Hungary	*2.82*	*2.58*	*2.36*
Northern Europe	*3.21*	*4.31*	*5.22*
Turkey	*4.93*	*4.79*	*3.95*
France	*2.66*	*4.91*	*6.09*
Other	*0.86*	*1.35*	*1.62*
Extra European markets	**2.33**	**2.06**	**2.60**
E&P in Europe and in the Gulf of Mexico	**6.00**	**6.17**	**5.65**
WORLDWIDE GAS SALES	**104.23**	**103.72**	**97.06**

Marketing of Electricity

As part of its marketing activities in Italy, Eni engages in selling electricity on the Italian market principally on the open market, at industrial sites and on the Italian Exchange for electricity. Supplies of electricity include both own production volumes through gas-fired, combined-cycles facilities and purchases on the open market. This activity has been developed in order to capture further value along the gas value-chain leveraging on the Company s large gas availability. In addition, with the aim of developing and retaining valuable customers in the residential space and middle to large industrial users, the Company has been developing a commercial offer that provides the combined supply of gas and power. In 2010, the program for expanding the combined integrated offer of gas and power progressed in accordance with the Company s expansion plans.

In 2010, electricity sales increased by 16.4% to 39.54 TWh, driven by a slight recovery in electricity demand and growth in the client base, in particular the retail market following intensive marketing campaigns, and mainly related to higher sales on open-markets (up 2.74 TWh) benefiting from higher trading and higher volumes traded on the Italian power exchange (up 2.43 TWh).

In 2010, electricity sales (39.54 TWh) were directed to the free market (70%), the Italian power exchange (18%), industrial sites (8%) and others (4%).

Power availability	**2008**	**2009**	**2010**
		(TWh)	
Power generation sold	23.33	24.09	25.63
Trading of electricity [a]	6.60	9.87	13.91
	29.93	**33.96**	**39.54**
Power sales by market			
Free market	22.89	24.74	27.48
Italian Exchange for electricity	3.82	4.70	7.13
Industrial plants	2.71	2.92	3.21
Other [a]	0.51	1.60	1.72
	29.93	**33.96**	**39.54**

(a) Include positive and negative imbalances.

Planned Actions and Sales Target

(i) Italy

Over the next four years, management plans to increase sales and regain market share in Italy by leveraging on the competitiveness of the Company s cost position, and the quality of its offer, including the offer of pricing formulas and services that are designed to suit the customers needs. The Company intends to deploy tailored solutions and customized contracts to retain clients in the business segment, and expand its customer base in the retail segment by means of new marketing initiatives, the bundling of a range of valuable services to commercial offer and wider geographic presence through an integrated network of agencies and stores. Based on those actions, management targets to expand sales volumes in Italy by 12 BCM within 2014 and to regain market share. In the last quarter of 2010, the adoption of a more volume-oriented approach led to an increase in Italian sales and market share by an estimated 7% and 1.5 percentage points, respectively, compared to a 38.3% market share and 9.8 BCM sales for the fourth quarter of the previous year.

(ii) European Markets

In Europe, the Company plans to increase sales volumes by 8 BCM by 2014 boosting direct sales in key European markets, particularly in France, Germany and Austria and maintaining its leadership position in the Benelux countries. To achieve these targets, management plans to leverage on the competitiveness of the Company s cost position and new customized commercial offers, a multi-country approach and an integrated pan-European commercial platform.

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

Benelux. Eni s holds a leadership position in the Benelux countries (Belgium, the Netherlands and Luxembourg) granted by the integration with Distrigas operations and its significant exposure to spot markets in Western Europe. In 2010, Distrigas sales were mainly directed to industrial companies, wholesalers and power generation and amounted to 14.87 BCM from 2009, down 0.85 BCM, or 5.4%, due to rising competition. The Company plans to maintain steady sales in this region over the plan period.

France. Eni sells natural gas to industrial clients, wholesalers and power generation as well as to the segments of retail and middle market. Eni is present in the French market through its direct commercial activities and through its subsidiary Altergaz, in which the Company acquired a controlling interest by increasing its share to 55.2% in December 2010. Altergaz supplies approximately 119,800 clients, of which 104,000 are residential customers (69,000 in 2009, of which 58,000 residentials). Furthermore, Eni holds a 34% interest in Gaz de Bordeaux SAS (with a 17% direct interest and a further 17% held by Altergaz) which is engaged in selling natural gas in the Municipality of Bordeaux. Eni plans to develop this partnership. Management plans to expand sales in France over the plan period growing volumes supplied to the business segments and increasing retail customers leveraging on the Altergaz integration. In 2010, sales in France amounted to 6.09 BCM (4.91 BCM in 2009), an increase of 1.18 BCM, or 24%, from a year ago.

Germany-Austria. Eni is present in the German natural gas market through its associate GVS (Gasversorgung Süddeutschland GmbH - Eni 50%) which sold approximately 3.92 BCM in 2010 (1.96 BCM being Eni s share), and through a direct marketing structure which sold in 2010 approximately 2.85 BCM in Germany and 1.09 BCM in Austria. Management plans to drive growth in direct sales leveraging on the quality of its commercial offer. In 2010, sales in Germany-Austria market amounted to 5.67 BCM, an increase of 0.31 BCM, or 5.8%, from a year ago.

Iberian Peninsula

Portugal. Eni operates on the Portuguese market through its affiliate Galp Energia (Eni s interest 33.34%) which sold approximately 5.10 BCM in 2010 (1.70 BCM being Eni s share).

Spain. Eni operates in the Spanish gas market through a direct marketing structure that markets its portfolio of LNG and Unión Fenosa Gas (UFG) (Eni s interest 50%) which mainly supplies natural gas to industrial clients, wholesalers and power generation utilities. In 2010, UFG gas sales in Europe amounted to 5.28 BCM (2.64 BCM Eni s share). UFG holds an 80% interest in the Damietta liquefaction plant, on the Egyptian coast (see below), and a 7.36% interest in a liquefaction plant in Oman. In addition, it holds interests in the Sagunto (Valencia) and El Ferrol (Galicia) re-gasification plants (42.5% and 18.9%, respectively). In 2010, Eni sales in Spain amounted to 5.41 BCM representing a slight increase from a year ago. In 2010, total sales in the Iberian Peninsula amounted to 7.11 BCM, an increase of 0.30 BCM, or 4.4%, from a year ago.

Turkey. Eni sells gas supplied from Russia and transported via the Blue Stream pipeline. In 2010, sales amounted to 3.95 BCM, a decrease of 0.84 BCM, or 17.5% from a year ago.

UK/Northern Europe. Eni through its subsidiary North Sea Gas & Power (Eni UK Ltd) markets in the UK the equity gas produced at Eni s fields in the North Sea and operates in the main continental natural gas hubs (NBP, Zeebrugge, TTF). In 2010, sales amounted to 5.22 BCM, an increase of 21.1% from a year ago.

Deborah Gas Storage Project in the Hewett area, UK. Eni has progressed in developing the Gas Storage Project on the Deborah field within the Hewett area located in the Southern Gas Basin in the North Sea, near the Bacton terminal, UK. The Deborah Gas Storage Project is designed to provide the UK and North Western Europe markets with 4.6 BCM of working gas. Eni, the single owner of the project, completed the Front End Engineering Design ("FEED") after an appraisal well had been successfully drilled, and obtained most of the permits requested to sanction the project from the relevant national and local authorities. At the end of 2010, a Capacity Allocation Process aiming at selling long-term storage capacity was launched. A number of market players participated to the process and Eni Hewett, the Eni affiliate managing the project, ensured long-term contractual commitments to sell more than 20% of the capacity. Some of the participants to the capacity allocation process show interest in getting a participation in the investment as well. Based on that, Eni Hewett is currently managing a process to sell equity participation in the Deborah Gas Storage project and is progressing in bilateral discussions to sell further gas storage capacity. FID is expected to be taken by end of 2011/beginning 2012 based on the outcome of the equity sale process and discussions on capacity sales.

The LNG Business

Eni is present in all phases of the LNG business: liquefaction, shipping, re-gasification and sale through operated activities or interests in joint ventures and associates. Eni s presence in the business is tied to the Company s plans to develop its large gas reserve base in Africa and elsewhere in the world. The LNG business has been deeply impacted by the economic downturn of 2009 and structural modifications in the U.S. market where large availability of gas from unconventional sources have reduced the country s dependence on gas imports via LNG.

Eni s main assets and projects in the LNG business are described below.

Qatar. Though its subsidiary Distrigas, Eni increased its development opportunities in the LNG business with access to new supply sources mainly from Qatar, under a 20-year agreement with RasGas (owned by Qatar Petroleum with a 70% interest and ExxonMobil with a 30% interest) and the Zeebrugge LNG terminal on the Western coast of Belgium.

Egypt. Eni, through its interest in Unión Fenosa Gas, owns a 40% interest in the Damietta liquefaction plant with a capacity of approximately 5 mmtonnes/y of LNG which equates to a feedstock of 7.56 BCM/y in natural gas out of which the Gas & Power segment interest is up to 2.2 BCM/y to be marketed in Europe.

Spain. Eni through Unión Fenosa Gas holds a 21.25% interest in the Sagunto re-gasification plant, near Valencia, with a capacity of 8.8 BCM/y and a LNG storage capacity of 450,000 CM which will be increased to 600,000 CM after the ongoing construction of a fourth tank. At present, Eni s re-gasification capacity entitlement amounts to 1.9 BCM/y of gas.

Eni through Unión Fenosa Gas also holds a 9.45% interest in the El Ferrol re-gasification plant, located in Galicia, with a treatment capacity of approximately 3.6 BCM/y, of which 0.34 BCM/y being Eni s capacity entitlements. The LNG storage capacity of the plant is 300,000 CM in two tanks.

USA

Cameron. The Cameron LNG terminal is situated 18 miles from the Gulf of Mexico along the Calcasieu Channel in Hackberry, Louisiana. The facility where Eni owns a capacity entitlement to treat LNG commenced operations in the third quarter of 2009. In consideration of a changed demand outlook for gas in the USA, on March 1, 2010, Eni renegotiated certain terms of the contract with the U.S. company Cameron LNG, owner of the facility, to farm out a share of the re-gasification capacity of the terminal. The new agreement provides that Eni is entitled to a daily send-out of 572,000 mmbtu (approximately 5.7 BCM/y) and a dedicated storage capacity of 160 KCM, giving Eni more flexibility in managing seasonal swings in gas demand. Furthermore, on March 3, 2011 Eni USA Gas Marketing Llc obtained from the American Department of Energy the authorization to export the LNG previously imported in the USA. This authorization will enhance operation flexibility, and will enable the company to exploit price differentials between American and European gas markets. Start-up of the Brass project (West Africa) to develop and liquefy gas reserves to fuel the Cameron plant is expected in 2016.

Pascagoula. This project is part of an upstream development project related to the construction of an LNG plant in Angola designed to produce 5.2 mmtonnes of LNG (approximately 7.3 BCM/y) destined to the North American market in order to monetize part of the Company s gas reserves. As part of the downstream leg of the project, Eni signed a 20-year contract with Gulf LNG to buy 5.8 BCM/y of the re-gasification capacity of the plant under construction near Pascagoula in Mississippi. The start-up of the re-gasification facility is scheduled by the end of 2012 which is in line with the expected start-up of the upstream project in Angola.

At the same time Eni USA Gas Marketing Llc entered a 20-year contract for the purchase of approximately 0.9 BCM/y of re-gasified gas downstream the terminal owned by Angola Supply Services, a company whose partners also own Angola LNG.

LNG sales	**2008**	**2009**	**2010**

		(BCM)	
G&P sales	**8.4**	**9.8**	**11.2**
Italy	0.3	0.1	0.2
Rest of Europe	7.0	8.9	9.8
Extra European markets	1.1	0.8	1.2
E&P sales	**3.6**	**3.1**	**3.8**
Liquefaction plants:			
- Bontang (Indonesia)	0.7	0.8	0.7
- Point Fortin (Trinidad and Tobago)	0.5	0.5	0.6
- Bonny (Nigeria)	2.0	1.4	2.2
- Darwin (Australia)	0.4	0.4	0.3
	12.0	**12.9**	**15.0**

Power Generation

Eni s power generation sites are located in Ferrera Erbognone, Ravenna, Livorno, Taranto, Mantova, Brindisi, Ferrara and in Bolgiano.

In 2010, power generation was 25.63 TWh, up 1.54 TWh, or 6.4% from 2009, mainly due to higher production in particular at the Brindisi and Livorno plant.

As of December 31, 2010, installed operational capacity was 5.3 GW (5.3 GW in 2009).

Power availability in 2010 was supported by the growth in electricity trading activity (up 4.04 TWh, or 40.9%) due to higher volumes traded on the Italian power exchange benefiting from lower purchase prices.

By 2014, Eni intends to complete its plan for expanding its power generation capacity, targeting an installed operational capacity of 5.7 GW[6].

At full capacity in 2014, production is expected to amount to approximately 29.2 TWh, corresponding to approximately 7.9% of power expected to be generated in Italy at that date.

This expansion will allow Eni to consolidate its market share and its position as the third largest power producer in Italy.

Supplies of natural gas are expected to amount to approximately 6 BCM/y from Eni s diversified supply portfolio.

The power generation development plan is underway and mainly refers to: (i) the revamping at the recently acquired Bolgiano plant (Eni 100%); (ii) the upgrading at Taranto plant (Eni 100%); and (iii) the construction of a new bio-mass power generation plant at Eni s Porto Torres industrial site which is currently under remediation.

New installed generation capacity uses the combined cycle gas fired technology (CCGT), ensuring a high level of efficiency and low environmental impact. In particular, management estimates that for a given amount of energy (electricity and heat) produced, using the CCGT technology instead of conventional power generation technology, the emission of carbon dioxide reduces by approximately 5 mmtonnes, on an energy production of 26.5 TWh. The CCGT technology has been acknowledged by the Authority for Electricity and Gas as a production technology that entails priority on the national dispatching network and the exemption from the purchase of "green certificates". Article 11 of Legislative Decree No. 79/1999 concerning the opening up of the Italian electricity market requires importers and producers of power from non renewable sources to input into the national power system a share of power produced from renewable sources set at 2% of power imported or produced from non renewable sources exceeding 100 GWh. Calculations are made on total amounts net of cogeneration and own consumption. This obligation can be met also by purchasing volumes or rights from other producers employing renewable sources (the so-called green certificates) to cover all or part of such 2% share. Legislative Decree No. 387/2003 provides that from 2004 to 2006 the minimum amount of power from renewable sources to be input in the grid in the following year be increased by 0.35% per year. The Minister of Productive Activities, with decrees issued in consent with the Minister for the Environment, has defined a 0.75% increase of this ratio for the periods from 2007 to 2010.

Eni s main operated power plants are described below.

Ferrera Erbognone. This power plant has an installed capacity of approximately 1,030 MW divided between three combined cycle units, two of which have a capacity of approximately 390 MW and are fired with natural gas. The third unit has capacity of approximately 250 MW and is fired with a mixed fuel containing natural gas and refinery gas obtained from the gasification of a heavy residue from crude processing at the nearby Eni-operated Sannazzaro refinery.

Ravenna. Two new combined cycle units with the capacity of 390 MW each started operations in 2004. Adding to the existing capacity, the power plant s installed capacity has reached a total of approximately 1,100 MW.

Brindisi. This power plant has been upgraded by installing three new combined cycle units, each with a capacity of 390 MW, which has increased the overall capacity to approximately 1,500 MW.

Mantova. This power plant has been upgraded by installing two new combined cycle units, each with a capacity of 390 MW, which has increased the overall capacity to approximately 900 MW. This power plant also provides steam for heating purposes delivered to the Mantova urban network through a heat exchanger.

(6) Capacity available after completion of dismantling of obsolete plants.

Livorno. This power plant has an installed capacity of approximately 200 MW, divided between gas and steam turbines with steam generators.

Taranto. The existing power units have a capacity of approximately 75 MW, divided between gas and steam turbines with steam generators.

Ferrara. Two new combined cycle units with the capacity of 390 MW each started operations in 2008. Adding to already existing gas and steam turbines, the power plant s installed capacity has reached a total of approximately 840 MW.

Bolgiano. The existing power plant has an installed capacity of approximately 39 MW divided between four gas turbines associated with four super-heated water generators.

Power Generation		2008	2009	2010
Purchases				
Natural gas	(mmCM)	4,530	4,790	5,154
Other fuels	(ktoe)	560	569	547
- of which steam cracking		*131*	*82*	*103*
Production				
Electricity	(TWh)	23.33	24.09	25.63
Steam	(ktonnes)	10,584	10,048	10,983
Installed generation capacity	(GW)	**4.9**	**5.3**	**5.3**

Infrastructures

Eni operates a large European network of integrated infrastructure for transporting natural gas, which links key consumption basins with the main producing areas (Russia, Algeria, Libya and the North Sea).

In Italy, Eni operates almost all lines which form the national transport network, gas underground storage deposits and related facilities, a re-gasification plant in Panigaglia and can rely on an extended system of local distribution networks. Eni is currently implementing plans for expanding and upgrading its national transport and distribution networks and storage capacity.

Transport infrastructure

Route	Lines	Length of main line	Diameter	Transport capacity (1)	Pressure min-max	Compression stations
ITALY	**(units)**	**(km)**	**(inch)**	**(mmCM/d)**	**(bar)**	**(No.)**
Mazara del Vallo-Minerbio (under upgrading)	2/3	1,480	48/42 - 48	105.0	75	7
Tarvisio-Sergnano-Minerbio	3	433	42/36, 34 e 48/56	119.2	58/75	3
Passo Gries-Mortara	1/2	177	48/34	64.8	55/75	1

	Lines	Total length	Diameter	Transport capacity (2)	Transit capacity (3)	Compression stations
OUTSIDE ITALY	**(units)**	**(km)**	**(inch)**	**(BCM/y)**	**(BCM/y)**	**(No.)**

TENP (Bocholtz-Wallbach)	2 lines of km 500	1,000	36/38/40	22.9	15.5	4
Transitgas (Rodersdorf-Lostorf)	3 lines of km 165, 71 and 55	291	36/48	24.9	19.9	1
TAG (Baumgarten-Tarvisio)	3 lines of km 380	1,140	36/38/40/42	45.2	37.4	5
TTPC (Oued Saf Saf-Cap Bon)	2 lines of km 370	740	48	34.0	33.2	5
TMPC (Cap Bon-Mazara del Vallo)	5 lines of km 155	775	20/26	33.2	33.2	
GreenStream (Mellitah-Gela)	1 line of km 520	520	32	8.0	8.0	1
Blue Stream (Beregovaya-Samsun)	2 lines of km 387	774	24	16.0	16.0	1

(1) Transport capacity refers to the capacity at the entry point connected to the import pipelines.

(2) Includes both transit capacity and volumes of natural gas destined to local markets and withdrawn at various points along the pipeline.

(3) The maximum volume of natural gas which is input at various entry points along the pipeline and transported to the next pipeline.

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International Transport Activities

Eni owns capacity entitlements in an extensive network of international high pressure pipelines for a total length of approximately 4,400 kilometers enabling the Company to import natural gas produced in Russia, Algeria, the North Sea, including the Netherlands and Norway, and Libya to Italy. The Company invests in certain entities which own and operate those international pipelines, the pipeline owners, as well as in the entities which manage transportation rights, the carrier companies. For financial reporting purposes, such entities are either fully-consolidated or equity-accounted depending on the Company s interest or agreements with other shareholders.

The structure of the Company s interests in those entities may significantly change in the near future due to ongoing procedures for divesting Eni s interests in the German TENP, the Swiss Transitgas and the Austrian TAG gas transport pipelines. The divestment is part of the commitments agreed upon by Eni and the European Commission to settle an antitrust proceeding related to alleged anti-competitive behavior in the natural gas market. In light of the strategic importance of the Austrian TAG pipeline to the supply of the Italian system, which transports gas from Russia to Italy, Eni negotiated a solution with the Commission which called for the transfer of its stake to an entity controlled by the Italian State. The Company expects to complete the divestment procedures within 2011. The prospected divestments will not affect Eni s contractual gas transport rights.

A description of the main international pipelines participated or operated by Eni is provided below.

- The TAG pipeline, 1,140-kilometer long, made up of three lines, each about 380-kilometer long, with a transport capacity of 37 BCM/y and five compression stations. This pipeline transports Russian natural gas from Baumgarten, the delivery point at the border of Austria and Slovakia, to Tarvisio, point of entry in the Italian natural gas transport system. In 2009, the upgrading of this facility was finalized by completing construction of two new compression stations that increased transport capacity by 6.5 BCM/y. The entire new capacity has been entirely awarded to third parties.
- The TTPC pipeline, 740-kilometer long, made up of two lines that are each 370-kilometer long with a transport capacity of 33.2 BCM/y and five compression stations. This pipeline transports natural gas from Algeria across Tunisia from Oued Saf Saf at the Algerian border to Cap Bon on the Mediterranean coast where it links with the TMPC pipeline. The pipeline was recently upgraded by increasing compression capacity in order to enable transportation of an additional 6.5 BCM/y. The upgrade was finalized in 2008 and became fully-operational during 2009.
- The TMPC pipeline for the import of Algerian gas is 775-kilometer long and consists of five lines that are each 155-kilometer long with a transport capacity of 33.5 BCM/y. It crosses the underwater Sicily Channel from Cap Bon to Mazara del Vallo in Sicily, the point of entry into the Italian natural gas transport system. In 2009, the operation of TMPC gas pipeline was fully-restored.
- The TENP pipeline is 1,000-kilometer long (two 500-kilometer long lines) and has transport capacity of 15.5 BCM/y and four compression stations. It transports natural gas through Germany, from the German-Dutch border of Bocholtz to Wallbach at the German-Swiss border.
- The Transitgas pipeline is 291-kilometer long and has one compression station, that transports natural gas across Switzerland with its 165-kilometer long main line and a 71-kilometer long doubling line, from Wallbach where it joins the TENP pipeline to Passo Gries at the Italian border. It has a transport capacity of 20 BCM/y. A new 55-kilometer long line from Oltingue/Rodersdorf at the French-Swiss border to Lostorf, an interconnection point with the line coming from Wallbach, was built for the transport of Norwegian gas. In July 2010, a large landslide interrupted the transportation through the Transitgas gas pipeline which was restored at the end of December 2010. Currently, a new variant of the trunkline is under construction with expected start-up by May 2011.
- The GreenStream pipeline started operations in October 2004 for the import of Libyan gas produced at Eni operated fields Bahr Essalam and Wafa. It is 520-kilometer long with a transport capacity of 8 BCM/y and crosses underwater in the Mediterranean Sea from Mellitah on the Libyan coast to Gela in Sicily, the point of entry into

the Italian natural gas transport system. In 2009, the pipeline was upgraded by 3 BCM/y, which is expected to come fully on stream in 2010, bringing total capacity to 11 BCM/y. In 2010 Eni divested a 25% stake in the company which operates the pipeline. See "Item 4 Significant Business and Portfolio Developments" above. From February 22, 2011, in consideration of the current crisis in Libya, supplies of natural gas through the GreenStream pipeline have been suspended. Assets were not damaged and the abovementioned suspension does not affect Eni s ability to fulfill its supply obligations with customers. For further details about this issue, see "Item 5 Outlook".

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

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The South Stream project

Eni and Gazprom are jointly assessing the technical and economic aspects of a project to build a new import route to Europe to market gas produced in Russia.

The South Stream pipeline will provide transport capacity of 63 BCM/y and is expected to be composed by two sections: (i) an offshore section crossing the Black Sea from the Russian coast at Beregovaya (the same starting point of the Blue Stream pipeline) to the Bulgarian coast at Varna; and (ii) an onshore section crossing Bulgaria for which two options are currently being evaluated: one pointing North West and another one pointing South West. The second option envisages crossing Greece and the Adriatic Sea before linking to the Italian network.

On June 18, 2010, Eni and Gazprom signed a Memorandum of Understanding to define terms and conditions for the French company EDF entering the South Stream project. As part of the agreement, EDF is expected to acquire an interest in the venture that is planning to build a new infrastructure to transport Russian gas across the Black Sea and Bulgaria to European markets.

Discussions among Eni, Gazprom and EdF in order to implement the latter s accessions to the offshore section of the Project are ongoing.

Regulated businesses in Italy

Over the medium-term, management intends to sustain the Company s strategies by a selective capital expenditure plan focused in particular on the regulated businesses in Italy with guaranteed returns. Specifically, in the next four-year period Eni plans to invest approximately euro 7.5 billion in the Gas & Power segment of which euro 6.4 billion will mainly be devoted to: (i) expanding and upgrading transport networks in order to match the requirements of additional flexibility and security of the system. More than 80% of the total transport capital expenditures will continue to receive a 2% or 3% premium on the base allowed return; (ii) developing storage capacity by 4 BCM, according to government guidelines provided by Legislative Decree No. 130/2010 (for further information see below "Regulation of Eni s Businesses Gas & Power"), both through the development of new fields and the expansion of existing capacity; and (iii) upgrading and developing local distribution networks.

Eni, through Snam Rete Gas, a company listed on the Italian Stock Exchange, in which Eni holds a 52.54% interest, operates most of the Italian natural gas transport network, a re-gasification terminal located in Panigaglia, an extensive local distribution network and gas underground storage deposits and related facilities.

Management plans to invest approximately euro 6.4 billion in the next four years in the regulated businesses mainly directed to upgrading and developing the transport and distribution networks and storage capacity, aiming at strengthening security, flexibility and service quality of the gas infrastructures.

Specifically, in the next four-year period Eni plans to expand and upgrade transport networks, the storage regulated capacity, also in accordance with the requirements of Legislative Decree No. 130/2010, both through the development of new fields and the expansion of existing capacity, and upgrade and develop local distribution networks as well as to provide the substitution of old gas metering.

Eni, through Snam Rete Gas, operates the re-gasification terminal operating in Italy at Panigaglia (Liguria). At full capacity, this terminal can re-gasify 17,500 CM of LNG per day and input 3.5 BCM/y into the Italian transport network.

Italian Transport Activity

Under Legislative Decree No. 164/2000 concerning the opening up of the natural gas market in Italy, transport and re-gasification activities are regulated by the Authority for Electricity and Gas which determines the methods for calculating tariffs and fixing the return on capital employed. This makes transport a low risk business capable of delivering stable returns.

Eni s network extends more than 31,600 kilometers and comprises: (i) a national transport network extending over 8,894 kilometers, made up of high pressure trunk-lines mainly with a large diameter, which carry natural gas from the entry points to the system import lines, storage sites and main Italian natural gas fields to the linking points with regional transport networks. The national network includes also some interregional lines reaching important markets; and (ii) a regional transport network extending over 22,786 kilometers, made up of smaller lines and allowing the transport of natural gas to large industrial complexes, power stations and local distribution companies in the various local areas served. The major pipelines interconnected with import trunk-lines that are part of Eni s national network are:

for natural gas imported from Algeria (Mazara del Vallo delivery point):

- two lines with a 48/42-inch diameters, each approximately 1,500-kilometer long, including the smaller pipes that cross underwater the Messina Strait, connect Mazara del Vallo on the Southern coast of Sicily where they link with the TMPC pipeline carrying Algerian gas, to Minerbio (near Bologna). This pipeline is undergoing upgrades with the laying of a third line with a 48-inch diameter 583-kilometer long (of these 525 are already operating). At the Mazara del Vallo entry point the available transport capacity, which is measured at the beginning of each thermal year starting on October 1, is approximately 105 mmCM/d;

for natural gas imported from Libya (Gela delivery point):

- a 36-inch diameter line, 67-kilometer long linking Gela, the entry point of the GreenStream underwater pipeline, to the national network near Enna along the trunkline transporting gas coming from Algeria. Transport capacity at the Gela entry point is approximately 35 mmCM/d;

for natural gas imported from Russia (Tarvisio and Gorizia delivery points):

- two lines with 42/36/34-inch diameters extending for a total length of approximately 900 kilometers connecting the Austrian network at Tarvisio. This facility crosses the Po Valley reaching Sergnano (near Cremona) and Minerbio. This pipeline has been upgraded by the laying of a third 264-kilometer long line with a diameter from 48 to 56 inches. The pipeline transport capacity at the Tarvisio entry point amounts to approximately 119 mmCM/d plus the transport capacity available at the Gorizia entry point of approximately 5 mmCM/d;

for natural gas imported from the Netherlands and Norway (Passo Gries delivery point):

- one line, with a 48-inch diameter and 177-kilometer long that extends from the Italian border at Passo Gries (Verbania), to the node of Mortara, in the Po Valley. The pipeline transport capacity at the Passo Gries entry point amounts to 65 mmCM/d;

for natural gas coming from the Panigaglia LNG terminal:

- one line, with a 30-inch diameter and 170-kilometer long that links the Panigaglia terminal to the national transport network near Parma. The pipeline transport capacity at the Panigaglia entry point amounts to 13 mmCM/d;

for natural gas coming from the Rovigo Adriatic LNG terminal:

- a 36-inch diameter connection at the Minerbio junction with the Cavarzere-Minerbio pipeline belonging to Edison Stoccaggio SpA, which receives gas from the LNG terminal located offshore of Porto Viro. The pipeline transport capacity at the Cavarzere entry point amounts to 26 mmCM/d.

Eni s system is completed by: (i) eleven compressor stations with a total power of 860 MW used to increase gas pressure in pipelines to the level required for its flow; and (ii) four marine terminals linking underwater pipelines with the on-land network at Mazara del Vallo and Messina in Sicily and Favazzina and Palmi in Calabria. The interconnections managed by Snam Rete Gas in the Italian transport network are guaranteed by 22 linkage and dispatching nodes and by 568 plant units including pressure reduction and regulation plants. These plants allow the regulation of the flow of natural gas in the network and guarantee the connection of pipes working at different pressures.

In 2010, volumes of natural gas input in the national grid (83.32 BCM) increasing by 6.42 BCM from 2009 due to higher gas deliveries due to a demand recovery. Eni transported 47.87 BCM of natural gas on behalf of third parties, up 10.55 BCM from 2009, or 28.3%.

Gas volumes transported [a]	**2008**	**2009**	**2010**
		(BCM)	
Eni	51.80	39.58	35.45
On behalf of third parties	33.84	37.32	47.87
	85.64	**76.90**	**83.32**

(a) Includes amounts destined to domestic storage.

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Transport capacity in Italy

Entry points	2009-2010 Thermal year Available capacity	Awarded capacity	Saturation	2010-2011 Thermal year Available capacity	Awarded capacity	Saturation
	(mmCM/d)	(mmCM/d)	(%)	(mmCM/d)	(mmCM/d)	(%)
Tarvisio	119.7	102.8	85.9	119.2	110.3	92.5
Mazara del Vallo	103.6	98.7	95.3	105.0	98.9	94.2
Passo Gries	64.9	59.0	90.9	64.8	55.0	84.9
Gela	33.0	32.9	99.7	35.2	34.3	97.4
Cavarzere (LNG)	26.4	21.0	79.5	26.4	24.6	93.2
Panigaglia (LNG)	13.0	7.2	55.4	13.0	7.2	55.4
Gorizia	4.8			4.8	0.5	10.4
	365.4	**321.6**	**88.0**	**368.4**	**330.8**	**89.8**

In 2010, the LNG terminal in Panigaglia (La Spezia) re-gasified 1.98 BCM of natural gas (1.32 BCM in 2009).

Distribution Activity

Distribution involves the delivery of natural gas to residential and commercial customers in urban centers through low pressure networks. The Company s subsidiary Italgas and other subsidiaries operate in the distribution activity in Italy serving 1,330 municipalities through a low pressure network consisting of approximately 50,300 kilometers of pipelines supplying 5.8 million customers and distributing 8.15 BCM in 2010.

Under Legislative Decree No. 164/2000, distribution activities are considered a public service and therefore are regulated by the Authority for Electricity and Gas which determines the methods for calculating tariffs and fixing the return on capital employed. This business, therefore, presents low risk and a steady cash generation profile.

Distribution activities are conducted under concession agreements whereby local public administrations award the service of gas distribution to companies. According to Legislative Decree No. 164/2000, the award of the service has to take place by a competitive bid process from the end of a transition period no later than December 31, 2012. Future concessions will have a term as long as twelve years.

Distribution activity in Italy		2008	2009	2010
Volumes distributed:	(BCM)	7.63	7.73	8.15
- on behalf to Eni		6.33	6.26	6.30
- on behalf to third parties		1.30	1.47	1.85
Installed network	(km)	49,410	49,973	50,307
Active meters	(No. of users)	5,676,105	5,770,672	5,848,478
Municipalities served	(No.)	1,320	1,322	1,330

In particular, in the medium-term Eni intends to consolidate its presence in Italy, by increasing the profitability of its asset base, security across the network, and improve the service quality as well as efficiency of services rendered.

Storage

The storage gas business in Italy is a fully-regulated activity which returns are preset by the Italian Authority for Electricity and Gas. Italian regulated storage services are provided through eight storage fields, based on ten storage concessions vested by the Ministry of Productive Activities, with a total modulation capacity of 9.2 BCM.

From the beginning of its operations, Stogit progressively increased the number of customers served and the share of revenues from third parties.

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Storage		2008	2009	2010
Total storage capacity:	(BCM)	13.7	13.9	14.2
- of which strategic storage		5.1	5.0	5.0
- of which available storage		8.6	8.9	9.2
Available capacity:	(%)			
- share utilized by Eni		39	30	29
- share utilized by third parties		61	70	71
Total offtake from (input to) storage:	(BCM)	11.57	16.52	15.59
- input to storage		6.30	7.81	8.00
- offtake from storage		5.27	8.71	7.59
Total customers	(No.)	48	56	60

In 2010, 8 BCM of gas were inputted to Company s storage deposits (an increase of 0.19 BCM from 2009) while 7.59 BCM were supplied (down 1.12 BCM compared to 2009).

In 2010, storage capacity amounted to 14.2 BCM, of which 5 were destined to strategic storage.

The share of storage capacity used by third parties was 71% (70% in 2009).

Capital Expenditures

See "Item 5 Liquidity and Capital Resources Capital Expenditures by Segment".

Refining & Marketing

Eni s Refining & Marketing segment engages in the supply of crude oil, refining and marketing of refined products, trading and shipping of crude oil and product primarily in Italy and in Central-Eastern Europe. In Italy, Eni is the largest refining and marketing operator in terms of capacity and market share. The Company s operations are fully-integrated through refining, supply, trading, logistics and marketing so as to maximize cost efficiencies and effectiveness of operations.

In 2010, the refining business was hit by a weak trading environment due to higher costs of oil-based feedstock that was not followed by a corresponding increase in product prices, pressured by weak demand, high inventories and excess refining capacity. In addition, the increased oil price triggered higher costs of energy utilities, which are typically indexed to it. However, those negative trends were more than offset by cost efficiencies, supply optimization, lower impairment and amortization charges and stable marketing results enabling the Company to achieve a significant improvement from the year-earlier results.

In the medium-term, management expects the trading environment in Europe to show limited improvements as demand for refined products will stagnate and excess capacity and high worldwide and regional inventory levels and product imbalances will persist on the marketplace. Although an overall reduction in refining capacity is expected. Management also warns against risks of further oil price increases.

To face expected negative trends in the refining scenario, Eni intends to focus on:

efficiency improvements mainly by achieving energy savings, reducing operating costs and streamlining logistic operations;
integration of refining cycles which will enable the Company to capture cost reductions or margin expansions; and making selective capital projects to increase refining complexity.

In marketing, management plans to improve results by leveraging on better services to customers at Eni s network of service stations, growing its market share in selective European markets and expanding the contribution to results from non-oil activities.

In the 2011-2014 period, we plan to make capital expenditures amounting to euro 2.9 billion, in line with the previous plan, carefully selecting capital projects. Management plans to invest approximately euro 2 billion to upgrade the Company s best refineries mainly by completing and starting-up the EST (Eni Slurry Technology) project at the Sannazzaro unit which will upgrade the conversion capacity of the refinery. In marketing, the Company intends to invest in retail network upgrading and rebranding and for developing non-oil activities.

As a result of all these actions, management believes that the Refining & Marketing segment will break-even in 2011 and then continue to improve profitability and cash generation, under the assumption that there will no improvement in the trading environment compared to 2010.

The matters regarding future plans discussed in this section 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 include difficulties in obtaining approvals from relevant Antitrust Authorities and developments in the relevant market.

Supply and Trading

In 2010, a total of 68.25 mmtonnes of crude were purchased by the Refining & Marketing Division (67.40 mmtonnes in 2009), of which 30.14 mmtonnes from Eni s Exploration & Production Division. Volumes amounting to 20.95 mmtonnes were purchased on the spot market, while 17.16 mmtonnes were purchased under long-term supply contracts with producing countries. Approximately 25% of crude purchased in 2010 came from Russia, 22% from West Africa, 12% from the North Sea, 12% from the Middle East, 11% from North Africa, 5% from Italy, and 13% from other areas.

In 2010, some 36.17 mmtonnes of crude purchased were marketed (up of approximately 60 ktonnes, or 0.2%, from 2009). In addition, 3.05 mmtonnes of intermediate products were purchased (2.92 mmtonnes in 2009) to be used as feedstock in conversion plants and 15.28 mmtonnes of refined products (13.98 mmtonnes in 2009) were purchased to be sold on markets outside Italy (10.72 mmtonnes) and on the domestic market (4.56 mmtonnes) as a complement to available production.

Refining

Against the backdrop of a weak outlook for refining margins, in the medium-term, management plans to improve profitability of the Company s refining operations by focusing on operational efficiency through energy saving, streamlining logistics and fixed cost reductions. Integration actions of Eni s refining system are expected to mainly target Gela and Taranto refineries enabling the Company to cut production of low value fuel oil and reduce supply costs. Management also intends to tightly control capital expenditure and selectively upgrade conversion capacity and flexibility of the best refineries.

As of December 31, 2010, Eni s refining system had total refinery capacity (balanced with conversion capacity) of approximately 37.8 mmtonnes (equal to 757 KBBL/d) and a conversion index of 61%. The conversion index is a measure of a refinery complexity. The higher the index, the wider the spectrum of crude qualities and feedstock that a refinery is able to process thus enabling it to benefit from the cost economies which the Company generally expects to achieve as certain qualities of crude (particularly the heavy ones) may trade at discount with reference to the light crude Brent benchmark. Eni s five 100-percent owned refineries have balanced capacity of 28.2 mmtonnes (equal to 564 KBBL/d), with a 65% conversion rate.

In 2010, refinery throughputs in Italy and outside Italy were 34.80 mmtonnes.

The Company plans to selectively upgrade its refining system by increasing complexity and flexibility at its best refineries. The main capital project will be the completion of a new conversion unit at the Sannazzaro refinery designed on the EST proprietary technology for converting the heavy barrel by almost eliminating residue from conversion processes. The start-up of this facility is confirmed to be 2012. Higher conversion capacity is expected to enable the Company to extract value from equity crude as well as capture opportunities of monetizing heavy crudes and non-conventional resources. Other projects will involve the enhancement of logistic infrastructures at the Taranto unit.

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The table below sets forth certain statistics regarding Eni s refineries as of December 31, 2010.

Refining system in 2010

	Ownership share (%)	Distillation capacity (total) (KBBL/d)	Distillation capacity (Eni s share) (KBBL/d)	Primary balanced refining capacity (Eni s share) (KBBL/d)	Conversion index [(1)] (%)	Fluid catalytic cracking - FCC [(2)] (KBBL/d)	Residue conversion (KBBL/d)	Go-Finer (KBBL/d)	Mild Hydro-cracking/ Hydro-cracking (KBBL/d)	Visbreaking/ thermal cracking (KBBL/d)	Coking (KBBL/d)	Distillation capacity utilization rate (Eni s share) (%)	Balanced refining capacity utilization rate (Eni s share) (%)
Wholly owned refineries		**685**	**685**	**564**	**65**	**69**	**41**	**37**	**29**	**89**	**46**	**70**	**91**
Italy													
Sannazzaro	100	223	223	180	61	34	11		29	29		77	95
Gela	100	129	129	100	142	35		37			46	69	89
Taranto	100	120	120	120	72		30			38		78	78
Livorno	100	106	106	84	11							87	110
Porto Marghera	100	107	107	80	20					22		64	85
Partially owned refineries [(3)]		**874**	**245**	**193**	**50**	**163**	**25**		**99**	**27**		**83**	**109**
Italy													
Milazzo	50	248	124	80	73	41	25		32			74	109
Germany													
Vohburg/Neustadt (Bayernoil)	20	215	43	41	36	49			43			94	98
Schwedt	8.33	231	19	19	42	49				27		96	99
Czech Republic													
Kralupy e Litvinov	32.4	180	59	53	30	24			24			79	87
Total refineries		**1,559**	**930**	**757**	**61**	**232**	**66**	**37**	**128**	**116**	**46**	**73**	**93**

(1) Stated in fluid catalytic cracking equivalent/topping (% by weight), based on 100% of balanced primary distillation capacity.
(2) Conversion plant where vacuum feedstock undergoes cracking at high pressure and moderate temperature thus producing mostly high quality gasoline. This kind of plant guarantees high operating flexibility to the refinery.
(3) Capacity of conversion plant is 100%.

Italy

Eni s refining system in Italy is composed of five wholly owned refineries and a 50% interest in the Milazzo refinery in Sicily. Each of Eni s refineries in Italy have operating and strategic features that aim at maximizing the value associated to the asset structure, the geographic positioning with respect to end markets and the integration with Eni s other activities.

The **Sannazzaro** refinery has balanced refining capacity of 180 KBBL/d and a conversion index of 61.2%. Management believes that this unit is among the most efficient refineries in Europe. Located in the Po Valley, it mainly supplies markets in North-Western Italy and Switzerland. The high degree of flexibility and conversion capacity of this refinery allows it to process a wide range of feedstock. From a logistical standpoint this refinery is located along the route of the Central Europe Pipeline, which links the Genoa terminal with French speaking Switzerland. This refinery contains two primary distillation plants and relevant facilities, including three desulfurization units. Conversion is obtained through a fluid catalytic cracker (FCC), two hydrocrackers (HdCK), with the last unit entered into operations in June 2009, which enable middle distillate conversion and a visbreaking thermal conversion unit with a gasification facility using the heavy residue from visbreaking (tar) to produce syn-gas to feed the nearby EniPower power plant at Ferrera Erbognone. Eni is developing a conversion plant employing the Eni Slurry Technology with a 23 KBBL/d capacity for the processing of extra heavy crude with high sulfur content producing high quality middle distillates, in particular gasoil, and reducing the yield of fuel oil to zero. Start-up of this facility is scheduled in late 2012.

The **Taranto** refinery has balanced refining capacity of 120 KBBL/d and a conversion index of 72%. This refinery can process a wide range of crude and other feedstock. It principally produces fuels for automotive use and residential heating purposes for the Southern Italian markets. Besides its primary distillation plants and relevant facilities, including two units for the desulfurization of middle distillates, this refinery contains a two-stage thermal conversion plant (visbreaking/thermal cracking) and an RHU conversion plant for the conversion of high sulfur content residues into valuable products and catalytic cracking feedstocks. It processes most of the oil produced in Eni s Val d Agri fields carried to Taranto through the Monte Alpi pipeline (in 2010 a total of 1.8 mmtonnes of this oil were processed). A new hydro-cracking unit with a capacity of 17 KBBL/d started production in 2010 expanding the conversion capacity of the refinery.

The **Gela** refinery has balanced refining capacity of 100 KBBL/d and a conversion index of 142.4%. This refinery is located on the Southern coast of Sicily and is highly integrated with upstream operations as it processes heavy crude produced from Eni s nearby offshore and onshore fields in Sicily. In addition, it is integrated downstream as it supplies large volumes of petrochemical feedstock to Eni s in site petrochemical plants. The refinery also manufactures fuels for automotive use and petrochemical feedstock. Its high conversion level is ensured by an FCC unit with go-finer for the upgrading of feedstocks and two coking plants for the vacuum conversion of heavy residues. The power plant of this refinery also contains modern residue and exhaust fume treatment plants which allow full compliance with the tightest environmental standards. An upgrade of the Gela refinery is underway by means of an upgrade of its power plant, mainly through the revamping of its boilers, aimed at increasing profitability by exploiting the synergies deriving from the integration of refining and power generation.

The **Livorno** refinery, with balanced refining capacity of 84 KBBL/d and a conversion index of 11.4%, manufactures mainly gasoline, fuel oil for bunkering and lubricant bases. Besides its primary distillation plants, this refinery contains two lubricant manufacturing lines. Its pipeline links with the local harbor and with the Florence storage sites by means of two pipelines optimizes intake, handling and distribution of products.

The **Porto Marghera** refinery, with balanced refining capacity of 80 KBBL/d and a conversion index of 20.2%, this refinery supplies mainly markets in North-Eastern Italy and Austria. Besides its primary distillation plants, this refinery contains a two-stage thermal conversion plant (visbreaking/thermal cracking) designed to increase yields of valuable products.

Rest of Europe

In Germany, Eni holds an 8.3% interest in the Schwedt refinery and a 20% interest in Bayernoil, an integrated pole that included Vohburg and Neustadt refineries. Eni s refining capacity in Germany amounts to approximately 60 KBBL/d mainly used to supply Eni s distribution network in Bavaria and Eastern Germany.

Eni holds a 32.4% stake in Ceska Rafinerska, which includes two refineries, Kralupy and Litvinov, in the Czech Republic. Eni s share of refining capacity amounts to about 53 KBBL/d.

In addition, through its 33.34% interest in Galp, Eni participates two refineries in Portugal: a small one in Porto specialized in the manufacture of lubricant bases and a larger and more complex refinery in Sines integrated with petrochemicals production.

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

Availability of refined products	**2008**	**2009**	**2010**
		(mmtonnes)	
ITALY			
Refinery throughputs			
At wholly-owned refineries	25.59	24.02	25.70
Less input on account of third parties	(1.37)	(0.49)	(0.50)
At affiliates refineries	6.17	5,87	4.36
Refinery throughputs on own account	**30.39**	**29,40**	**29.56**
Consumption and losses	(1.61)	(1.60)	(1.69)
Products available for sale	**28.78**	**27.80**	**27.87**
Purchases of refined products and change in inventories	2.56	3,73	4.24
Products transferred to operations outside Italy	(1.00)	(0.96)	(0.92)
Consumption for power generation	(1.13)	(1.00)	(0.96)
Sales of products	**28.92**	**26.68**	**27.01**
OUTSIDE ITALY			
Refinery throughputs on own account	**5.45**	**5.15**	**5.24**
Consumption and losses	(0.25)	(0.25)	(0.24)
Products available for sale	**5.20**	**4.90**	**5.00**

Purchases of finished products and change in inventories	15.14	10.12	10.61
Products transferred from Italian operations	1.42	3.89	4.18
Sales of products	**21.76**	**18.91**	**19.79**
Refinery throughputs on own account	**35.84**	**34,55**	**34.80**
of which: refinery throughputs of equity crude on own account	*6.98*	*5,11*	*5.02*
Total sales of refined products	**50.68**	**45.59**	**46.80**
Crude oil sales	**26.00**	**36,11**	**36.17**
TOTAL SALES	**76.68**	**81.70**	**82.97**

In 2010, refining throughputs were 34.80 mmtonnes, up 0.7% from 2009.

Volumes processed in Italy increased by approximately 160 ktonnes, or 0.5%, from 2009 mainly due to a better performance at the Livorno, Gela and Taranto plants as the trading environment improved from a year ago and optimization of refining cycles was implemented. In addition, higher volumes were processed due to the coming on stream of a new hydro-cracking unit in Taranto and lower planned standstills affected the partially-owned Milazzo refinery. These effects were partly offset by the termination of a process contract on the Saras third-party refinery (down 1,966 ktonnes). Eni s refining throughputs outside Italy increased by 1.7% supported by higher refinery throughput in the Czech Republic as a consequence of increased margins and demand recovery.

Total throughputs in wholly-owned refineries were 25.70 mmtonnes, up by approximately 1.68 mmtonnes (or 7%) from 2009, reflecting an improved refinery utilization rate which reached 91%. This increase reflects feedstock integration in refinery cycles and improved throughput margins, in particular for lubricants.

Approximately 15.8% of volumes of processed crude was supplied by Eni s Exploration & Production segment (16.3% in 2009) representing a 0.5 percentage point decrease from 2009, corresponding to a lower volume of approximately 90 ktonnes.

Logistics

Eni is a primary operator in storage and transport of petroleum products in Italy with its logistical integrated infrastructure consisting of 21 directly managed storage sites and a network of petroleum product pipelines for the sale and storage of refined products, LPG and crude.

Eni s logistic model is organized on hub structure including five main areas. These hubs monitor and centralize the handling of products flows aiming to drive forward more efficiency particularly in cost control of collection and delivery of orders.

Eni holds interests in five joint entities established by partnering the major Italian operators. These are located in Vado Ligure-Genova (Petrolig), Arquata Scrivia (Sigemi), Venice (Petroven), Ravenna (Petra) and Trieste (DCT) and aim at reducing logistic costs, and increasing efficiency.

Eni operates in the transport of oil and refined products: (i) by sea through spot and long-term lease contracts of tanker ships; and (ii) on land through the ownership of a pipeline network extending approximately 1,447 kilometer-long. Secondary distribution to retail and wholesale markets is effected through third parties who also own their means of transportation, in some instances with minority participation of Eni.

Marketing

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

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

Oil products sales in Italy and outside Italy	**2008**	**2009**	**2010**
		(mmtonnes)	
Italy			
Retail	8.81	9.03	8.63
Wholesale	11.15	9.56	9.45
	19.96	**18.59**	**18.08**
Petrochemicals	1.70	1.33	1.72
Other sales	7.26	6.76	7.21
Total	**28.92**	**26.68**	**27.01**
Outside Italy			
Retail	3.22	2.99	3.10
Wholesale	4.50	4.07	4.30
	7.72	**7.06**	**7.40**
Other sales	12.52	11.85	12.39
Total	**20.24**	**18.91**	**19.79**
Iberian Peninsula [(a)]	**1.52**		
of which:			
Retail	*0.64*		
Wholesale	*0.88*		
TOTAL SALES	**50.68**	**45.59**	**46.80**

(a) Downstream activities in the Iberian Peninsula were divested to Galp in October 2008.

In 2010, sales volumes of refined products (46.80 mmtonnes) were up of 1.21 mmtonnes from 2009, or 2.7%, mainly due to higher volumes sold to oil companies and traders in Italy and outside Italy.

Retail Sales in Italy

The re-branding of Eni s service stations and the upgrading of Eni s retail network progressed in 2010. In 2010, 463 service stations in Italy were re-branded to the "eni" brand, corresponding to approximately 10% of the retail network, with priority awarded to high throughput service stations with non-oil activities.

In marketing operations, Eni plans to strengthen its competitive positioning in Italy and to expand sales of fuels and non-oil products as well as expanding its share in the domestic retail market for fuels by 2014, up from 30.4% in 2010. To achieve those results, management intends to upgrade the network of service stations by starting-up new outlets with high service standards, improve the quality and range of services offered to the Company s customers in order to boost customer retention, enhancing the offer of premium products, and develop non-oil activities under the "eni" brand.

A strong focus will be devoted to pursue high levels of operating efficiency.

In 2010, retail sales in Italy of 8.63 mmtonnes decreased by approximately 400 ktonnes, down 4.4% driven by lower demand which mainly impacted gasoline and, to a lesser extent gasoil, reflecting a decline in domestic fuel demand, as well as rising competitive pressure and price elasticity. Average throughput related to gasoline and gasoil (2,322 kliters) decreased by approximately 160 kliters from 2009. Eni s retail market share for 2010 was 30.4%, down 1.1 percentage point from 2009 (31.5%).

At December 31, 2010, Eni s retail network in Italy consisted of 4,542 service stations, 68 more than at December 31, 2009 (4,474 service stations), resulting from the positive balance of acquisitions/releases of lease concessions (74 units), the opening of new service stations (11 units), partly offset by the closing of service stations with low throughput (13 units) and the release of 4 service stations under highway concession.

In 2010, also fuel sales of the Blu line fuels with high performance and low environmental impact recorded lower sales from 2009, reflecting weak domestic consumption. In particular, sales of BluDieselTech declined slightly down from 2009, approximately amounting to 573 ktonnes (689 mmliters), and represented 10.3% of gasoil sales on Eni s retail network. At December 31, 2010, service stations marketing BluDieselTech totaled 4,071 units (4,104 at 2009 year end) covering approximately 90% of Eni s network.

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Retail sales of BluSuper amounted to 70 ktonnes (approximately 94 mmliters), decreasing by approximately 12 ktonnes from 2009, and covered 2.6% of gasoline sales on Eni s retail network (down 0.1% from a year ago). At December 31, 2010, service stations marketing BluSuper totaled 2,672 units (2,679 at December 31, 2009), covering approximately 59% of Eni s network.

In February 2010, in replacement of the previous promotional campaign "You&Agip", Eni launched the new "you&eni" loyalty points program, which will last 3 years. This three-year long initiative offered prizes to customers in proportion to their purchases of fuels and convenience items through the accumulation of points on a loyalty card at service stations stores as well as at the ones of certain partners to the program. As of December 31, 2010, the number of customers that actively used the card in the year amounted to approximately 5 million. The average number of cards active each month was approximately 2.8 million. Volumes of fuel marketed under this initiative represented approximately 40% of overall volumes marketed on Eni s network.

In 2010, the success of Eni s "Iperself" promotional campaign continued. This promotion provides a discount to customers purchasing fuel in self-service stations during closing hours. Jointly with other marketing activities this initiative supported sales against the backdrop of a weak demand and increased price elasticity.

Retail Sales in the Rest of Europe

Eni s strategy in the rest of Europe is focused on selectively growing its market share, particularly Eastern and Central Europe leveraging on recent acquisitions in Austria and synergies ensured by the proximity of these markets to Eni s production and logistic facilities, brand awareness and economies of scale.

In 2010, retail sales of refined products marketed in the rest of Europe (3.10 mmtonnes) were up 3.7% from 2009. The increase was driven by volume additions in Austria, reflecting the purchase of service stations, and by enhanced performance in Eastern Europe (particularly in Slovakia and Romania), as well as in Germany and France.

At December 31, 2010, Eni s retail network in the rest of Europe consisted of 1,625 units, an increase of 113 units from December 31, 2009 (1,512 service stations). The network evolution was as follows: (i) positive balance of acquisitions/releases of lease concessions (19 units) with positive changes in Austria and Hungary; (ii) purchased 114 service stations; (iii) opened 5 new outlets; and (iv) 25 low throughput service stations were closed. Average throughput (2,441 kliters) slightly decreased from 2009 (2,461 kliters).

The key markets of Eni s presence are: Austria with a 7% market share, Hungary with 11.9%, Czech Republic with 11.8%, Slovakia with 9.7%, Switzerland with 6.5% and Germany with a 3.4% on national base. These market shares were calculated by Eni based on public data on national consumption and Eni s sales volumes.

Non-oil activities in the rest of Europe are carried out under the CiaoAgip® brand name in 1,146 service stations, of which 395 are in Germany and 173 in France, with a 71% coverage of the network and a virtually complete coverage of owned stations.

Other businesses

Wholesale

Eni markets gasoline and other fuels on the wholesale market in Italy, including diesel fuel for automotive use and for heating purposes, for agricultural vehicles and for vessels and fuel oil. Major customers are resellers, agricultural users, manufacturing industries, public utilities and transports, as well as final users (transporters, condominiums, farmers, fishers, etc.).

Eni provides its customers with its expertise in the area of fuels with a wide range of products that cover all market requirements. Along with traditional products provided with the high quality Eni standard, there is also an innovative low environmental impact line, which includes AdvanceDiesel especially targeted for heavy duty public and private transports. Customer care and product distribution is supported by a widespread commercial and logistical organization presence all over Italy and articulated in local marketing offices and a network of agents and concessionaires.

In 2010, sales volumes on wholesale markets in Italy (9.45 mmtonnes) were down by approximately 110 ktonnes from 2009, or 1.2%, mainly reflecting a decline in domestic consumption in particular of fuel oil by industrial customers. Eni s wholesale market share for 2010 averaged 29.2%, up 1.6 percentage points from 2009 (27.6%).

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Sales on wholesale markets in the rest of Europe (3.88 mmtonnes) increased by approximately 220 ktonnes, or 6%, mainly in Austria, due to purchase of service stations, in France due to higher bitumen sales and in Germany, due to a large product availability and a recovery in consumption.

Supplies of feedstock to the petrochemical industry (1.72 mmtonnes) increased by approximately 390 ktonnes due to demand recovery.

Other sales (19.60 mmtonnes) increased by approximately 990 ktonnes, or 5.3%, mainly due to higher sales volumes to the cargo market and to oil companies.

Eni also markets jet fuel directly at 46 airports, of which 27 are in Italy. In 2010, these sales amounted to 1.8 mmtonnes (of which 1.4 mmtonnes are in Italy).

Eni is also active in the international market of bunkering, marketing marine fuel mainly in 40 ports, of which 23 are in Italy. In 2010, marine fuel sales were 2.03 mmtonnes (1.97 mmtonnes in Italy).

LPG

In Italy, Eni is leader in LPG production, marketing and sale with 592 ktonnes sold for heating and automotive use equal to a 17.6% market share. An additional 217 ktonnes of LPG were marketed through other channels mainly to oil companies and traders.

LPG activities in Italy are supported by direct production, availability from 5 bottling plants and 4 owned storage sites, in addition to products imported at coastal storage sites located in Livorno, Naples and Ravenna.

In order to expand its presence on the marketplace, in the medium-term Eni plans to increase the number of service stations providing dispensers for LPG for automotive use, targeting an increase market share to 26% by 2014.

Lubricants

Eni operates seven (owned and co-owned) blending plants, in Italy, Europe, North and South America and the Far East. With a wide range of products composed of over 650 different blends Eni masters international state-of-the-art know-how for the formulation of products for vehicles (engine oil, special fluids and transmission oils) and industries (lubricants for hydraulic systems, industrial machinery and metal processing).

In Italy, Eni is leader in the manufacture and sale of lubricant bases. Base oils are manufactured primarily at Eni s refinery in Livorno. Eni also owns one facility for the production of additives and solvents in Robassomero.

In 2010, retail and wholesale sales in Italy amounted to 106 ktonnes with a 24.1% market share. Eni also sold approximately 4 ktonnes of special products (white oils, transformer oil and anti-freeze fluids). Outside Italy sales amounted to approximately 120 ktonnes, of these about 60% were registered in Europe (mainly Spain, Germany, and France).

Oxygenates

Eni, through its subsidiary Ecofuel (Eni s interest 100%), sells approximately 1.7 mmtonnes/y of oxygenates mainly ethers (approximately 6.5% of world demand) and methanol (approximately 1.1% of world demand). About 81% of products are manufactured in Italy in Eni s plants in Ravenna, in Venezuela (in joint venture with Pequiven) and Saudi Arabia (in joint venture with Sabic) and the remaining 19% is bought and resold.

Eni also distributes bio-ETBE on the Italian market in compliance with the new legislation indicating the minimum content of bio-fuels. Bio-ETBE is a kind of MTBE that gained a relevant position in the formulation of gasoline in the European Union, due to the fact that it is produced from ethanol from agricultural crops and qualified as bio-component in the European directive on bio-fuels.

Starting from March 1, 2010, Italian regulation on bio-fuels content has been changed from 3% to 3.5%. With the use of Bio-ETBE and FAME Eni covered the compliance within 98%. From January 1, 2011, the content increases to 4%. Eni expects to cover compliance in the same manner as in 2010.

Capital Expenditures

See "Item 5 Liquidity and Capital Resources Capital Expenditures by Segment".

Engineering & Construction

Eni engages in engineering, construction and drilling both offshore and onshore for the oil and gas industry through Saipem, a subsidiary listed on the Italian Stock Exchange (Eni s interest is 43%), and Saipem s controlled subsidiaries. Saipem boasts a strong competitive position in the market for services to the oil industry, particularly in executing large, complex EPC contracts for the construction of offshore and onshore facilities and systems to develop hydrocarbons reserves as well as LNG, refining and petrochemicals plants, pipeline layering and offshore and onshore drilling services. The Company owes its market position to technological and operational skills which we believe are acknowledged in the marketplace due to its capabilities to operate in frontier areas and complex ecosystems, efficiently and effectively managing large projects, engineering competencies and availability of technologically-advanced vessels and rigs which have been upgraded in recent years through a large capital expenditure plan. Management expects to further strengthen Saipem s competitive position in the medium-term, leveraging on its business model articulated across various market sectors combined with a strong competitive position in frontier areas, which are traditionally less exposed to the cyclical nature of this market. In particular, Saipem plans to implement the following strategic guidelines: (i) to maximize efficiency in all business areas at the same time maintaining top execution and security standards, preserve competitive supply costs, optimize the utilization rate of the fleet, increase structure flexibility in order to mitigate the effects of negative business cycles as well as develop and promote a company culture that will permit identification and management of risks and business opportunities; (ii) to continue focusing on the more complex and difficult projects in the strategic segments of deepwater, FPSO, heavy crude and LNG (offshore and onshore, for the gas monetization) upgrading; (iii) to promote local content in terms of employment of local contractors and assets in strategic countries where large projects are carried out supporting the development of delocalized logistic hubs and construction yards when requested by clients in order to achieve a long-term consolidation of its market position in those countries; (iv) to leverage on the capacity to execute internally more phases of large projects on an EPC and EPIC basis, pursuing better control of costs and terms of execution adapting with flexibility to clients needs, thus expanding the Company s value proposition; and (v) to complete the expansion and revamping program of its construction and drilling fleet in consideration of the future needs of the oil and gas industry, in order to confirm the Company s leading position in the segment of complex projects with high profitability.

Saipem expects to invest approximately euro 2.4 billion over the next four years to complete the upgrading program of its fleet of vessels and rigs, further expanding the operational features, the dimension and the geographical reach and of its fleet as well as to support the activities related to the execution of projects in portfolio and the acquisition of new orders.

Orders acquired in 2010 amounted to euro 12,935 million, of these projects 94% are to be carried out outside Italy, while orders from Eni companies represented 7% of the total. Order backlog was euro 20,505 million as of December 31, 2010 (euro 18,730 million as of December 31, 2009). Projects to be carried out outside Italy represented 94% of the total order backlog, while orders from Eni companies amounted to 16% of the total.

		2008	**2009**	**2010**
Orders acquired	(euro million)	**13,860**	**9,917**	**12,935**

Offshore construction		4,381	5,089	4,600
Onshore construction		7,522	3,665	7,744
Offshore drilling		760	585	326
Onshore drilling		1,197	578	265
Originated by Eni companies	(%)	4	32	7
To be carried out outside Italy	(%)	94	79	94
Order backlog and breakdown by business	(euro million)	**19,105**	**18,730**	**20,505**
Offshore construction		4,682	5,430	5,544
Onshore construction		9,201	8,035	10,543
Offshore drilling		3,759	3,778	3,354
Onshore drilling		1,463	1,487	1,064
Originated by Eni companies	(%)	13	22	16
To be carried out outside Italy	(%)	98	93	94

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Offshore construction

Saipem is well positioned in the market of large, complex projects for the development of offshore hydrocarbon fields leveraging on its technical and operational skills, supported by a technologically-advanced fleet, the ability to operate in complex environments, and engineering and project management capabilities acquired on the marketplace over recent years. Saipem intends to consolidate its market share strengthening its EPIC oriented business model and leveraging on its satisfactory long-term relationships with the major oil companies and National Oil Companies ("NOCs"). Higher levels of efficiency and flexibility are expected to be achieved by reaching the technological excellence and the highest economies of scale in its engineering hubs employing local resources in contexts where this represents a competitive advantage, integrating in its own business model the direct management of construction process through the creation of a large construction yard in South-East Asia and revamping/upgrading its construction fleet. Over the next years, Saipem will invest in the upgrading of its fleet, by building a pipelayer, a field development ship for deepwater, an FPSO and other supporting assets for offshore activity.

Saipem s offshore construction fleet is made up 33 vessels and a large number of robotized vehicles able to perform advanced subsea operations. Its major vessels are: (i) the Saipem 7000 semisubmersible dynamic positioned vessel, with 14 ktonnes of lift capacity, capable to lay pipelines using the J-lay technique to the maximum depth of 3,000 meters; (ii) the Field Development Ship for the development of underwater fields in dynamic positioning, provided with cranes lifting up to 600 tonnes and a system for J-lay pipelaying to a depth of 2,000 meters; (iii) the Castoro 6 semisubmersible vessel, capable of laying pipes in waters up to 1,000 meters deep; (iv) the Saipem 3000 multifunction vessel for the development of hydrocarbon fields, able to lay rigid and flexible pipes and provided with cranes capable of lifting over 2 ktonnes; and (v) the Semac semisubmersible vessel used for large diameter underwater pipelaying. The fleet also includes remotely operated vehicles (ROV), highly sophisticated and advanced underwater robots capable of performing complex interventions in deep waters.

The most significant order awarded in 2010 in offshore construction were: (i) the extension of Kashagan Trunklines contract on behalf of Agip KCO for the installation of the offshore facilities system relating to the experimental phase of the Kashagan field development program in Kazakhstan; (ii) the extension of Kashagan Piles and Flares contract on behalf of Agip KCO for the installation of the offshore facilities system relating to the experimental phase of the Kashagan field development program in Kazakhstan; (iii) an EPIC contract on behalf of Petrobras for the P55-SCR project, for risers and flowlines serving the semisubmersible platform P-55 to be installed in the Roncador field, offshore Brazil.

Onshore construction

In the onshore construction business, Saipem is one of the largest engineering and construction operators on turnkey contract base at a worldwide level in the oil and gas segment, especially through the acquisition of Snamprogetti. Saipem operates in the construction of plants for hydrocarbon production (extraction, separation, stabilization, collection of hydrocarbons, water injection) and treatment (removal and recovery of sulfur dioxide and carbon dioxide, fractioning of gaseous liquids, recovery of condensates) and in the installation of large onshore transport systems (pipelines, compression stations, terminals). Saipem preserves its own competitiveness through its technology excellence granted by its engineering hubs, its distinctive know-how in the construction of projects in the high-tech market of LNG and the management of large parts of engineering activities in cost efficient areas. In the medium-term, underpinning upward trends in the oil service market, Saipem will be focused on taking advantage of the opportunities arising from the market in the plant and pipeline segments leveraging on its solid competitive position in the realization of complex projects in the strategic areas of Middle-East, Caspian Sea, Northern and Western Africa and Russia.

The most significant orders awarded in 2010 in Onshore construction were: (i) the EPC contracts on behalf of Abu Dhabi Gas Development for the construction of a gas processing plant (with a treatment capacity of 1 BCF/d of gas), a sulfur recovery unit and the related transporting facilities as part of the Shah Gas development program in the United Arab Emirates; (ii) an EPC contract on behalf of Husky Oil for the realization of the Central Processing Facilities designed for a total of 60 KBBL/d of bitumen production for the first phase of the Sunrise Oil Sands project near Fort Murray, Alberta, Canada; and (iii) an EPC contract on behalf of Kharafi National for the construction of Early Production Facilities, which will have an oil and gas treatment capacity of 150 KBBL/d and a sulfur granulation plant, for the development of the Jurassic field located in Northern Kuwait.

Offshore drilling

Saipem is the only engineering and construction contractor that provides both offshore and onshore drilling services to oil companies. In the offshore drilling segment, Saipem mainly operates in West Africa, the North Sea, the Mediterranean Sea and the Middle East and boasts significant market positions in the most complex segments of deep and ultra-deep offshore, leveraging on the outstanding technical features of its drilling platforms and vessels, capable of drilling exploration and development wells at a maximum depth of 9,200 meters. In order to better meet industry demands, Saipem is finalizing an upgrading program of its drilling fleet providing it with state-of-the-art rigs to enhance its role as high quality player capable of operating also in complex and harsh environments.

In particular, in the following years, Saipem intends to complete the building of: the Scarabeo 8 and 9, new generation semisubmersible platforms, that have been already rented to Eni through multi-year contracts. In parallel, investments are ongoing to renew and to keep up the production capacity of other fleet equipment (upgrade equipment to the characteristics of projects or to clients needs and purchase of support equipment).

Saipem s offshore drilling fleet consists of 15 vessels fully-equipped for its primary operations and some drilling plants installed on board of fixed offshore platforms. Its major vessels are: the Saipem 12000 and Saipem 10000, designed to explore and develop hydrocarbon reservoir operating in excess of 3,600 and 3,000 meters water depth, respectively in full dynamic positioning. In 2010 those vessels operated in West Africa and Far East. Other relevant vessels are Scarabeo 5 and 7, third and fourth generation semisubmersible rigs able to operate at depths of 1,900 and 1,500 meters of water, respectively. Average utilization of drilling vessels in 2010 stood at 100% (90% in 2009).

The most significant orders awarded in 2010 in Offshore drilling were: (i) a 15-month contract (plus additional options) for the use of the semisubmersible platform Scarabeo 3 in Congo and Nigeria on behalf of Addax Petroleum; (ii) a 36-month contract for the lease of the jack-up Perro Negro 5 in Saudi Arabia on behalf Saudi Aramco; and (iii) an extension until June 2013 for the lease of the semisubmersible platform Scarabeo 4 in Egypt on behalf of IEOC.

Onshore drilling

Saipem operates in this area as a main contractor for the major international oil companies and NOCs executing its activity mainly in South America, Saudi Arabia, North Africa and, at a lower extent, in Europe. In this area, Saipem can leverage its knowledge of the market, long-term relations with customers and synergies and integration with other business areas. Saipem boasts a solid track record in remote areas (in particular in the Caspian Sea), leveraging on its own operational skills and its ability to operate in complex environments.

Average utilization of rigs in 2010 stood at 94% (91% in 2009). The 86 rigs owned by Saipem at year end were located as follows: 28 in Venezuela, 19 in Peru, 8 in Saudi Arabia, 7 in Algeria, 6 in Colombia, 4 in Italy, 3 in Kazakhstan, 3 in Brazil, 3 in Ecuador, 2 in Ukraine, 2 in Congo and 1 Bolivia. Saipem also used rigs owned by third parties (6 in Peru and 2 in Kazakhstan) as well as rigs owned by the joint company Saipar.

The most significant orders awarded in 2010 in Onshore drilling were: (i) a contract on behalf on ExxonMobil Kazakhstan Inc. for the decommissioning and transportation of two rigs owned by the client already operated by Saipem. Saipem will also carry out conversion activities on one of the two rigs; (ii) a contract on behalf of Repexa in Peru for the lease of a rig with a contract duration of two years; and (iii) a contract on behalf of ConocoPhillips in Algeria for the lease of a rig with a contract duration of six months (plus an additional 18 months option).

Capital Expenditures

See "Item 5 Liquidity and Capital Resources Capital Expenditures by Segment".

Petrochemicals

Eni operates in the businesses of olefins and aromatics, basic and intermediate products, polystyrene, elastomers and polyethylene. Its major production sites are located in Italy and Western Europe.

Eni s strategy in its petrochemical business is to effectively and efficiently manage operations in order to lower the break-even considering the volatility of costs of oil-based feedstock, cyclicality in demand, strong competitive pressures from operators with lower cost structure, taking into account the commoditized nature of many of Eni s products. In fact, Eni s profitability in the petrochemical businesses is particularly sensitive to movements in product margins that are mainly affected by changes in oil-based feedstock costs and the speed at which product prices adjust to higher oil prices. See "Item 3 Risk Factors". In 2010, the Petrochemicals Division trimmed operating losses from 2009 by improving demand, better products margins and cost efficiencies. Management expects the outlook for 2011 will be shaping favorably to the Company as the world economy strengthens thus boosting worldwide demand for chemical commodities. However, risks will persist due to rising oil prices which could put pressure on unit margins of commodities. In light of this, management is planning for actions intended to strengthen the product mix of the Company by developing new products characterized by higher value added than the current portfolio, particularly in the businesses of elastomers, polyethylene and styrenics. Further measures will be dedicated to reduce operating costs and improve yields and plant efficiency in the production of basic ethylene which is the primary input for all downstream productions. To target those objectives, management plans to make capital expenditures amounting to euro 1 billion over the next four-year period which will be mainly directed to develop the product line in the elastomer and polyethylene businesses, plant upgrading and revamping at the Company s cracking units as well as complying with all applicable regulations on environment, health and safety issues. In addition, the Company plans to develop an initiative to produce plastics from certain bio-components at the Porto Torres unit in Sardinia, Italy. Other initiatives will involve marketing activities with the aim of boosting margins by sales channels optimization, product portfolio rationalization, including elimination of unprofitable products, and revision of pricing policies. Also licensing activities will be pursued in order to expand contribution to results from licensing the Company s technologies. Based on those planned actions, management expects to improve profitability and cash flow of the Company s petrochemicals operations targeting to break-even in 2012 under the Company s assumption relating trends in the prices of crude oil. See "Item 5 Outlook".

In 2010, sales of petrochemical products (4,731 ktonnes) increased by 466 ktonnes (or 10.9%) from 2009 as a result of a recovery in demand from the depressed levels experienced a year-earlier.

Petrochemical production (7,220 ktonnes) increased by 699 ktonnes from 2009, or 10.7% in all business areas driven by the needs to ensure supplies to meet recovery in sales volumes in all Eni s main plants. In addition, the year earlier the Company was forced to shut down production during the course of the year in order to avoid accumulating excess of finished products.

In 2010, nominal production capacity decreased by one percentage point from 2009 due to the closing of the styrene plant in Hythe. The average plant utilization rate, calculated on nominal capacity increased from 65.4% to 72.9% as a result of higher volumes produced, in particular in the Priolo, Brindisi and Porto Torres plants.

Average unit sale prices increased by 35.6% from the depressed levels registered in 2009. The most relevant increase was registered in the average price of olefins (up 48% on average) driven by higher costs for oil-based feedstock (the virgin naphtha prices increased by 41% from a year ago) as demands for basic chemicals increased at a fast pace and supplies were constrained. Average unit prices of styrene and polyethylene increased on average by 30%, while elastomers achieved lower increases.

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

	Year ended December 31,		
	2008	2009	2010
		(ktonnes)	
Basic petrochemicals	5,110	4,350	4,860
Polymers	2,262	2,171	2,360
Total production	**7,372**	**6,521**	**7,220**

Consumption of monomers	(3,539)	(2,701)	(2,912)
Purchases and change in inventories	851	445	423
	4,684	**4,265**	**4,731**

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

	Year ended December 31,		
	2008	2009	2010
	(euro million)		
Basic petrochemicals	3,060	1,832	2,833
Polymers	2,961	2,185	3,126
Other revenues	282	186	182
Total revenues	**6,303**	**4,203**	**6,141**

Basic petrochemicals

Basic petrochemical revenues (euro 2,833 million) increased by euro 1,001 million (up 54.6%) from 2009 in all of the main business segments due to the steep increase in average unit prices (olefins up 48%; intermediates and aromatics up more than 30%) as a result of the pricing environment and higher volumes sold.

In particular, sales volumes of olefins increased by 17%, intermediates by 10%, while aromatics registered lower increases (up 8%) due to the decreases registered in xylene sales (down 5%).

Basic petrochemical production (4,860 ktonnes) increased by 510 ktonnes from 2009 (up 11.7%) due to the recovery in the demand for monomers.

Polymers

Polymer revenues (euro 3,126 million) increased by euro 941 million from 2009 (up 43.1%) as unit prices increased by 30% on average. Sales volumes increased on average by 8% (elastomers up 11%, styrene up 10%, polyethylene up 6%) due to positive trends in demand.

Polymers production (2,360 ktonnes) increased by 189 ktonnes from 2009 (up 8.7%) driven by a recovery in the main end-markets (automotive, construction and packaging).

Production volumes of elastomers and styrene increased on average by 10% from 2009 due to higher production of EPR, nytrilic rubbers, compact polystyrene and ABS. Polyethylene production registered a lower increase (up 7.7%) due to unplanned facility downtime at the Dunkerque plant.

Capital Expenditures

See "Item 5 Liquidity and Capital Resources Capital Expenditures by Segment".

Corporate and Other activities

These activities include the following businesses:

- the "Other activities" segment comprises results of operations of Eni s subsidiary Syndial which runs minor petrochemical activities and reclamation and decommissioning activities pertaining to certain businesses which Eni exited, divested or shut down in past years; and
- the "Corporate and financial companies" segment comprises results of operations of Eni s headquarter and certain Eni s subsidiaries engaged in treasury, finance and other general and business support services. Eni s headquarter is a department of the parent company Eni SpA and performs Group strategic planning, human resources management, finance, administration, information technology, legal affairs, international affairs and corporate research and development functions. Through Eni s subsidiaries Eni Adfin SpA, Eni International BV and Eni Insurance Ltd, Eni carries out lending, factoring, leasing, financing Eni s projects around the world and insurance activities, principally on an inter-company basis. EniServizi, Eni Corporate University, AGI and other minor subsidiaries are engaged in providing Group companies with diversified services (mainly services including training, business support, real estate and general purposes services to Group s companies).

Management does not consider Eni s activities in these areas to be material to its overall operations.

Seasonality

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

Research and Development

Technological research and development ("R&D") and continuous innovation represent key success factors in implementing Eni s business strategies as they support our long-term competitive performance.

The Company believes that the oil industry has to face a number of challenges in the near future and that technology will play a vital role in helping it to effectively manage those challenges:

- continuing uncertainty about the future evolution of prices and demand for oil and gas;
- limited access to new hydrocarbon resources, with the consequent problems for production growth and reserve replacement;
- growing interest for the development of unconventional resources; and
- greater attention to operations safety in the aftermath of the recent accident in the Gulf of Mexico.

The reorganization of R&D structures that Eni started in 2006 was completed in 2010 with the help of some measures:

- reorganization of the research projects portfolio aimed at focusing activity on industrial objectives while reducing time to completion. To this end, the total portfolio was reorganized by strategic themes with priority given to critical projects, thus achieving a balance between breakthrough research and technology upgrading. A new assessment system has been introduced which makes use of Key Performance Indicators (KPI) that allow to assess the tangible and intangible value generated by R&D and to monitor the management of projects;
- new approach to the enhancement and management of intellectual property, based on the recognition of the value of patents generated by R&D activities;
- launch of a cross-business project for operations safety in extreme environment, named "Effective control and mitigation of any well blow-out in super challenging environment";
- enhancement of the program "Along with petroleum" which targets the exploitation of solar energy by means of polymeric plates acting as converters and concentrators of the solar spectrum, and the conversion of bio-mass from waste into bio-fuels by means of a liquefaction process that allows to convert organic waste into a bio-oil and the start-up of activities to develop a possible commercial application in the short-medium term; and
- strengthening of strategic alliances and scientific cooperation projects with international academic institutions and research centers which we believe are qualified in the marketplace. As part of this, in 2008 we signed a research alliance with the Massachusetts Institute of Technology (MIT), Boston (USA), focused on innovative technology in the field of solar energy and in the Oil & Gas business. Within the alliance the Solar Frontiers Center (SFC) was inaugurated on May 4, 2010: a research center shared between MIT and Eni and wholly dedicated to R&D in solar energy. Other agreements were signed with the Milan and Turin Polytechnic universities and with the Italian National Research Center (CNR).

In 2010, Eni filed 88 patent applications (106 in 2009), 61 of these coming from Eni Divisions and Eni Corporate, 10 from Petrochemicals and 17 from the Engineering & Construction activities of Saipem. In particular, 8% of patents concerned refining processes, 49% were in the field of drilling and completion, geology/geophysics of fields and engineering, 8% concerned the environment and 35% concerned innovation on renewable energy sources. The efficacy and efficiency of intellectual property management and of know-how dissemination are monitored within the R&D performance assessment system. In 2010, a review of Eni s patent portfolio was performed that ended with the decision to abandon obsolete and non profitable patents.

In 2010, Eni s overall expenditure in R&D amounted to euro 221 million which were almost entirely expensed as incurred (euro 207 million in 2009 and euro 217 million in 2008).

At December 31, 2010, a total of 1,019 persons were employed in research and development activities (in line with 2009). Below, we describe the main results achieved in research and innovation for sustainability in 2010.

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In the next four-year period, Eni plans to spend euro 1.1 billion for technological research and innovation activities. Management believes that technological developments may ensure the Company a competitive advantages in the long-term.

A summary of the most relevant R&D results obtained during the year by each business segment and at a Corporation level is provided below.

Exploration & Production

Advanced exploration techniques
- *Reverse Time Migration (RTM).* Emerging technology for the processing of in depth seismic data aimed at reconstructing the image of highly complex underground areas. In 2010, the proprietary version has been successfully applied for the first time to an exploration project in Angola, allowing the identification of new oil bearing structures that were not visible with conventional tools.
- *Basin simulation (e-simba™).* This proprietary package contains about 20 integrated software items for assessing the amount and type of hydrocarbons potentially trapped. In 2010, some of the functions have been developed and applied in about 30 exploration projects in countries such as Venezuela, Ghana, Mozambique, Poland Australia, Angola and Congo, allowing a better probabilistic assessment of mineral potential.

Drilling and completion technologies
- *Extended reach drilling.* Proprietary technology and equipment (Eni continuous circulation device, e-cd™ and aluminum rods) have been used to drill wells in China and Alaska. In China, costs were reduced by 50% as compared to earlier works.
- *Innovative technologies to improve drilling safety.* A portfolio of projects for increasing drilling safety reached an advanced stage with the in-field testing of special surface valves to be integrated in the proprietary equipment for an optimal drilling control (e-cd™). An innovative system for blow-out control within the well (downhole blow-out isolation packer) has also been tested. In 2010, Eni continued the development of the Dual ROV assisted top kill system that provides an efficient technique for blow-outs in deepwater wells. The system will be introduced in the sea in 2011.

Technologies for field characterization and increase in recovery rates
- *Polymer enhanced water injection.* The design phase has been completed for the implementation of the project of polymer enhanced water injection in a well in Egypt. The study results suggest an approximately 3% increase in the recovery factor.
- *Bright Water Injection.* This technology is based on an additive that is injected in the ground and selectively blocks the rock parts where water is present, thus potentially increasing the extraction of crude from mature fields. It has been applied in 2010 in two fields in North Africa with positive results and further applications in Congo are scheduled for 2011.
- *Tar recovery from tar sands.* A mixed water-solvent process for obtaining high recovery rates from tar sands (>90% in weight as compared to tar contained in sands) has been developed and applied to different types of sand. A concept design study has been completed for facilities in a pilot plant for the testing of in situ recovery techniques.
- *EOR with acoustic stimulation.* This process is based on sending sound waves into a field through a mechanical lifting system designed for this purpose. In 2010, field tests in Egypt were made in order to assess the potential of this well known but little tested technology in controlled conditions. Early results indicated a positive effect on oil production in the mature field where the test was made.

Refining & Marketing

Eni Slurry Technology (EST). The EST proprietary technology is an innovative process for hydro-conversion by means of a nanodispersed catalyst (slurry) and a peculiar process scheme to refine various kinds of heavy feedstock: residues from the distillation of heavy and extra-heavy crude (such as the ones from the Orinoco Belt in Venezuela) or non-conventional products such as tar sands, characterized by high contents of sulfur, nitrogen, metals, asphaltenes and other pollutants that are hard to manage in conventional refineries. EST does not produce by-products and completely converts feedstocks into distillates. In 2010, testing continued mainly directed to validating the technology from the point of view of the upgrading performance and plant management, and a customized basic on the Zuata crude was prepared. The first industrial plant with a 23 KBBL/d capacity is under construction at the Sannazzaro refinery, with start-up scheduled for 2012.

Hydrogen SCT-CPO (Short Contact Time - Catalytic Partial Oxidation). It is a reforming technology that can convert gaseous and liquid hydrocarbons (also derived from bio-mass) into synthetic gas (carbon monoxide and hydrogen). This technology can contribute to process intensification as it allows to produce synthetic gas and hydrogen using reactors up to 100 times smaller than those currently in use, with relevant savings. The development of this technology, that makes use of oxygen enriched air, has been completed and another version making use of pure oxygen is under development.

Nanomaterials. The use of structured nanomaterials is one of the key elements for innovation and intensification of processes. Projects are underway to study and enhance nanomaterials that could introduce radical improvements in conversion processes. The Dual Catalyst Slurry technology is based on nanocatalysts and its current tests could lead to breakthrough developments in EST, as it can increase productivity and quality of end products. The development of a bi-functional catalyst is underway that hydrogenates and desulphorates feesdtocks and increases the cracking rate and nitrogen removal. In the Flexible FCC (fluid catalytic cracking), new proprietary zeolite and zeolite-like materials have been developed for increasing the conversion of heavier fractions without increasing residues. This additive, associated to a new process scheme could change the gasoline/gasoil ratio in favor of the latter. In 2010, application testing continued and confirmed the results obtained so that scale up has started with the aim of finding the final formulation to be used in industrial reactors. This application is covered by a patent application.

Petrochemicals

Elastomers. A new grade of thermoplastic co-polymer has been industrially homologated to be used in adhesives with lower viscosity (remaining equal its adhesive/cohesive properties) leading to lower energy consumption in the formulation of the final adhesive. At a pilot scale, new hydrogenated styrene-butadiene co-polymers to be used as viscosity index improvers have been produced and are scheduled to be homologated by the reference customer. In the lab and pilot plant the advantage of using a new activator in the polymerization of terpolymers EPDM with vanadium based catalysts has been confirmed and provided higher yields, improved quality and lower consumption of chlorine in the production process.

Polyethylene. The production of two new grades of LLDPE (linear low density polyethylene) continued with wide distribution of molecular weight and therefore improved processability and retention of basic mechanic properties. In a gas phase plant a new grade of LLDPE for rotomolding application with exenes has been produced entailing a significant improvement of certain basic properties (such as resistance to chemicals). New formulas have been developed for HDPE (high density polyethylene) to be used in rotomolding applications in the field of phytochemicals.

Styrenic polymers. A new formula of ABS (acrylonitryl-butadiene-styrene polymer) grade from continuous mass has been developed for injection molding. This formula dramatically increases the mechanical properties of products adjusting their performance to products deriving from emulsions. This allows a relevant recovery in penetration into injection molding. After the first industrial campaign, customers expressed their satisfaction.

Engineering & Construction

Assets
Technological innovation on assets is pursued with the aim of improving sustainability, competition and reliability, and reducing the environmental impact of operations. In particular, in 2010 some of the projects underway reached the testing phase:

Equipment. New systems for the construction of coverage for soldering joints on board of pipelaying vessels, techniques for the remote control of anomalous deformations during the laying of pipes into the sea and some technologies complementary to excavation activities for critical operating scenarios have been validated. Studies were completed on technologies for the sustainability of construction of infrastructure in environmentally highly sensitive areas.

Vessels. Detailed development and implementation of the main technical systems and subsystems for production and laying of pipes on the new pipelaying vessel CastorOne continued.

Offshore

Activities were focused on programs dedicated to the continued improvement of innovative solutions for the development of oil and natural gas fields in the sea. Main activities concerned fields in frontier areas such as deep waters and the Arctic, monetization of offshore natural gas reserves by means of liquefaction technologies applied on floating plants (LNG offshore) and production from offshore renewable sources:

Subsea processing. A new proprietary multi-pipe system for the gravitational separation of gas and liquids successfully completed the second testing phase in the framework of a Joint Industry Project supported by important oil companies. Results achieved confirmed the efficacy of the separator in real flow conditions.

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SURF. Activities started in 2009 on projects for developing solutions for new risers to be used in ultra-deep (up to 3,000 meters) or intermediate depth (between 300 and 600 meters) waters continued. Work continued on technologies for thermal isolation and anticorrosion solutions for underwater operations.

Offshore renewable sources. Activities focus mainly on a large scale prototype of an underwater turbine with 10-meter diameter called Sabella to be installed in the future off the coast of Brittany. The participation of the French Government to the financing of the project was officially announced at the end of 2010.

Onshore

Activity is dedicated to process technologies and their know-how and to the application of the most modern and state-of-the-art technologies from third parties supporting our clients worldwide in the upstream, midstream and downstream areas in the various phases of completion from engineering to construction.

Urea plants. Work was aimed at increasing the performance of our Snamprogetti™ Urea proprietary technology for the production of fertilizers, licensed worldwide and applied to date in 120 plants. After having planned and in some cases also built the largest urea plants in the world (Engro in Pakistan, Qafco V and VI in Qatar and Matix in India) based on the operation of single lines for 3,859 tonnes/d, we developed a conceptual study for a future 5,000 tonnes/d train using the same well-established sequence of technologies. In addition, we are designing a pilot unit for the recovery of ammonia within the Zero emission project that will be then built in a commercial plant.

CCS. Within the Eni/Enel pilot program on Carbon Capture and Storage, Saipem is following the design of a pipe for carrying dense CO_2. We completed the project phase of a line for pilot transport to be located in the Brindisi power station.

ENSOLVEX. The first commercial unit based on this proprietary technology for the remediation of contaminated soil is under construction at the Gela refinery.

Microalgae. The first semicommercial unit for removing carbon dioxide from refinery effluents through bio-fixation by means of microalgae was completed and delivered. The ensuing bio-mass can be used for the production of bio-fuels.

Sulfur treatment. Saipem obtained a new patent for the technology for the treatment and transport of sulfur with zero emissions, a new method for solidifying liquid sulfur in blocks, thus consolidating its first class position in sulfur treatment technologies.

An overview of the main research projects developed during the year at the Corporate level is provided below.

Exploration & Production Division

Cube. To cope with events similar to that occurred at the Macondo well in the Gulf of Mexico and the failed attempt to collect the crude plume with a containing device, Eni prepared a device (in 1:4 proportion) for the collection and separation of gas from water and oil near the wellhead on the seabed and tested it in-house up to a flow of 10,000 BBL/d.

Development of reaction capacity to oil spills on the coast of the Barents Sea and sub-Arctic areas. The Norwegian project led by Eni achieved relevant results in 2010 in preparing an emergency plan for the Goliat field in the Barents Sea. Standards for testing disperdents and beach cleaners have been developed in order to use them in case of oil spills near the coast. These standards will be upheld by Norwegian law and later suggested at international level.

GHG program (Green House Gases). Activities are progressing part of the pilot project for injecting CO_2 in the Cortemaggiore gas storage site. Authorizations are pending to build and operate the plant.

Water management. This project promotes the application of innovative technologies for the treatment of reinjected waters. In 2010, the contract for the supply of a system for the removal of oil and solids from production waters in the Egyptian Desert has been awarded.

Organic Rankine Cycle (ORC) Technology for Energy Recovery. A feasibility study has been completed and the installation of Organic Fluid Cycle is underway in the gas powered Fano power station (3 MW) by recovering the thermal power dissipated by turbocompressors. This would represent the first application of the ORC technique to Eni s Group.

Feeding pumps in desert areas with photovoltaic devices. A contract has been prepared and the engineering is underway for a the supply of photovoltaic systems to be applied onto diesel generators for feeding sucker rod pumps in desert areas in Egypt.

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Gas & Power Division

Transport of carbon dioxide by pipeline (TACC). This project is part of the program of long distance transport of gases under different pressures with the aim of developing standards, guidelines and recommendations for future applications in carbon capture and storage. In 2010, the technical part of the program was laid out as well as the participants in the joint industrial project. Eni will promote the creation of JIP action with other integrated gas companies, e.g. Gasunie and Statoil.

Monitoring of advanced gas transport systems (MAST and Dionisio project). Eni has developed proprietary technologies for the advanced monitoring of gas transport systems (pipelines and compression stations). In 2010, technologies have been successfully tested for the identification of structural defaults (MAST) that can generate criticalities in transport. The development of the Dionisio technology that is based on vibro-acoustic sensors for noticing intrusions and leaks along transport pipelines continued. A prototype monitoring system has been installed on the Chivasso-Aosta pipeline.

Refining & Marketing Division

Blu fuels and products. Eni has been working for years in R&D for advanced fuels and lubricants that aim at optimizing engine efficiency and reducing noxious emissions. In February 2010, the Lombardia Region and Eni signed an agreement for the distribution of "formula Milano" in 50 outlets. This is a type of BluDieselTech with: (i) a total aromatics content lower than 18% in weight, as compared to an average 25% currently on sale; (ii) a total polyaromatics content lower 3% in weight as compared to an average 8%; and (iii) cetane number >55 as compared to current standards providing for a minimum 51.

Biofuels. Eni developed the Ecofining™ technology in cooperation with UOP that allows for the conversion of vegetables into Green Diesel. In November 2010, the American Institute of Chemical Engineers (AICHE) awarded Eni and UOP the 2010 Sustainable Energy Award for the activities developed in this area. Aim of the Ecofining™ technology is the production of bio-fuel by means of an integrated refining process that allows for the hydrotreatment of the renewable portion (vegetable oil, exhausted oil, animal fat) and obtain a superior product in terms of heating value and cetane number than conventional bio-diesel (FAME).

Zero waste. Eni intends to develop a system for the disposal of industrial sludge alternative to landfills, possibly associated to thermal treatment in order to minimize waste. For the treatment of industrial, oily and biological waste generated by the oil industry a thermal process has been studied that allows for the gasification of sludge that is turned into an inert residue. A patent application has been filed on this project. Basic design has been completed of a pilot plant with a 50 kg/h capacity along with a feasibility study for an annual volume of 5,000 tonnes of sludge.

Polimeri Europa

Basic petrochemicals. Positive testing of catalytic oxidation of phenilcyclohexane on a pilot plant was performed as part of a study aiming at completing a proprietary process for the direct production of phenol and cyclohexanone, which uses benzene as sole feedstock, eliminating the production of acetone as by-product (a toxic and flammable fluid).

Elastomers. The first industrial production of new grades of SBR (styrene-butadiene rubber) has been completed with application to high performance (lower energy consumption and reduction in resistance to rolling) in tire materials. In the lab Eni developed a proprietary technology for new grades of elastomers for Tyre Green application (with lower emissions) with even better performance. ESBR and NBR rubber grades have been obtained at industrial level with low VOCs content.

Styrenic polymers. At the Mantova site, in the new patented technology plant for the expandable polystyrene production, the industrialization of expandable polystyrene was successfully completed through a continuous mass system with a 38 ktonnes/y capacity. The new products allow a 15% reduction in VOCs which are released in the atmosphere during transformation.

Eni Corporate

Photoactive materials. A Luminescent Solar Concentrator consists of a slab of transparent material (polymeric or glassy) doped with fluorescent molecules, patented by Eni, which work as microscopic light emitters. The emitted

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radiation is partially concentrated within the slab by total internal reflections and is waveguided toward its edges where PV cells are placed. LSCs allow for a substantial decrease in standard PV module costs by reducing the effective cell surface with respect to the absorbing surface. The positive results obtained at lab level allow the commencement of a pre-commercial phase.

Use of waste for energy production. At lab scale Eni developed a "liquefaction" process for the conversion of the organic waste into bio-oil with a nearly 42% yield (on dry weight) corresponding to an 80% energy recovery. This new technology has been patented and successfully applied to the organic fraction of solid urban waste (FORSU) and to sludge from waste purification plants.

Micro-organisms for bio-diesel. Purpose of the project is the use of micro-organisms (yeasts and bacteria) that accumulate lipids similar to those deriving from oil-bearing vegetables, that can easily be turned into bio-diesel. The raw material employed by these micro-organisms derives from the treatment of wood-cellulose bio-mass in order to not compete with food products. The identified yeasts have higher productivity than the traditional oil crops, including palm.

EKRT (ElectroKinetic Remediation Technology). It is a technology for environmental remediation applicable to mercury polluted soils. An electrolytic solution is circulated in order to dissolve the metallic part of mercury, separating it by means of electro kinesis. This process does not affect the inert portions of mercury and acts selectively only on the mobile portion of mercury, that is also its toxic portion.

Results derived from the Eni-MIT alliance

Oil spills in marine environment. The project derives from the discovery of an innovative material with great selective capacity for the absorption of oil dispersed in water. This could be a first step towards new systems for treating oil spills in marine environments.

Ultraflexible solar cell. One of the most relevant results obtained by the Solar Frontier Center: these cells made of a thin photoactive material covered by a layer of transparent plastic can be bent without breaking or reducing performance and this allows to cover irregular surfaces without using metal stilts.

Solar cells on paper. In this case the photoactive device is made on paper as a printed document. The innovative technique is the same used for producing cells on plastic and flexible substrata. A paper cell can be a low cost solution for application where the key aspect is not duration but fast installation and easy transport.

Photochemical splitting of water. Aim of this project is to devise processes for generating oxygen and hydrogen from water by means of biological agents using solar light. The main actors here are nanomaterials synthesized by exploiting the self-assembling capacity of viruses. With this technique we proceeded with the synthesis of new active materials that can be useful in promoting a sustainable generation of hydrogen from renewable sources.

Biofixation of CO_2. CO_2 in the sea is captured by living organisms that convert it into calcium carbonate that is a component of their shell. These biological systems have been successfully reproduced in the lab with the use of yeasts. This paves the way for exploiting CO_2 while producing calcium carbonate and other materials that are considered eco-friendly.

Insurance

In order to control the insurance costs incurred by each of Eni s business units, the Company constantly assesses its risk exposure in both Italian and foreign activities. The Company has established a subsidiary, Eni Insurance Ltd, in order to efficiently manage transactions with mutual entities and third parties providing insurance policies. Internal insurance risk managers work in close contact with business units in order to assess potential underlying business and other type of risks and possible financial impact on the Group results of operations and liquidity. This process allows Eni to accept risks in consideration of results of technical and risk mitigation standards and practices, to define the appropriate level of risk retention and, finally, the amount of risk to be transferred to the market.

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Eni enters into insurance arrangements through its shareholding in the OIL Insurance Ltd ("OIL") and with other insurance partners in order to limit possible economic impacts associated with damages to both third parties and the environment occurring in case of both onshore and offshore accidents. The main part of this insurance portfolio is related to operating risks associated with oil and gas operations which are insured making use of insurance policies provided by the OIL, a mutual insurance and re-insurance company that provides its members a broad coverage of insurance services tailored to the specific requirements of oil and energy companies. In addition, Eni makes recourse to insurance companies who we believe are established on the marketplace. Insured liabilities vary depending on the nature and type of circumstances; however underlying amounts represent significant shares of the plafond granted by insuring companies. In particular, in the case of oil spills and other environmental damage, current insurance policies cover costs of cleaning-up and remediating polluted sites, damage to third parties and containment of physical damage up to $1.1 billion for offshore events and $1.5 billion for onshore plants (refineries). These are complemented by insurance policies that cover owners, operators and renters of vessels with the following maximum amounts: $1 billion for the fleet owned by the subsidiary LNG Shipping in the Gas & Power segment and FPSOs used by the Exploration & Production segment for developing offshore fields; $500 million for time charters.

Management believes that the level of insurance maintained by Eni is generally appropriate for the risks of its businesses.

Environmental Matters

Environmental Regulation

Eni is subject to numerous EU, international, national, regional and local environmental, health and safety laws and regulations concerning its oil and gas operations, products and other activities, including legislation that implements international conventions or protocols. In particular, these laws and regulations require the 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, limit or prohibit drilling activities on certain protected areas, provide for measures to be taken to protect the safety of the workplace and health of communities affected by the company s activities, and impose criminal or civil liabilities for pollution resulting from oil, natural gas, refining and petrochemical operations. These laws and regulations may also restrict emissions and discharges to surface and subsurface water resulting from the operation of natural gas processing plants, petrochemical plants, refineries, pipeline systems and other facilities that Eni owns. In addition, Eni s operations are subject to laws and regulations relating to the production, handling, transportation, storage, disposal and treatment of waste materials. Environmental laws and regulations have a substantial impact on Eni s operations. Some risk of environmental costs and liabilities is inherent in certain operations and products of Eni, and there can be no assurance that material costs and liabilities will not be incurred.

A brief description of major environmental laws impacting Eni s activities located in Italy and Europe is outlined below.

Italy

On April 29, 2006, Legislative Decree No. 152/2006 "Environment Regulation" came into force. This was designed to rationalize and coordinate the whole regulation of environmental matters by setting:

procedures for Strategic Environment Assessment (SEA), Environmental Impact Assessment (EIA) and Integrated Pollution Prevention and Pollution Control (IPPC);
procedures to preserve soil, prevent desertification, effectively manage water resources and protect water from pollution;
procedures to effectively manage waste and remediate contaminated sites;
air protection and reduction of atmospheric pollution; and
environmental liability.

The most important changes introduced by the Decree regarded reclamation and remediation activities as this Decree provided a site-specific risk-based approach to determine objectives of reclamation and remediation projects, cost-effective analysis required to evaluate remediation solutions, and criteria for waste classification.

Decree No. 152/2006 was amended by four subsequent decrees: Legislative Decrees No. 284/2006, No. 4/2008, No. 128/2010 and No. 205/2010.

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Decree No. 4/2008 introduced important changes regarding SEA and EIA procedures, landfill, waste and remediation. The most important aspects of these regulations to Eni are those regulating permits for industrial activities, waste management, and remediation of polluted sites, water protection and environmental liability.

Decree No. 128/2010 introduced IPPC regulations and additional restricting emission limits for certain critical pollutants, in compliance with the IED directive. In relation to the accident occurred in the Gulf of Mexico, the Decree also introduced permit restrictions regarding offshore activities, in line with the European Parliament Resolution of October 7, 2010 on EU action on oil exploration and extraction in Europe. Eni is planning to reschedule certain offshore activities in the Mediterranean Sea and the North European Sea to take account of such developments.

Decree No. 205/2010 implemented the Directive No. 2008/98/EC about waste and adopted the new Special Waste Tracking System (SISTRI) aimed to track waste transfers at national level and to allow a real-time control by authorities. The full operability of the system, initially forecasted by July 2010, has been rescheduled to June 2011.

Decree No. 155/2010 adopted in the Italian law, the European prescriptions on ambient air quality, established by the Directive No. 2008/50/EC. Its main innovation is the definition of monitoring criteria and emission limits for fine particulate substances (PM 2.5), to be achieved by January 1, 2015.

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

At the European level, Eni continued its work for applying the REACH Regulation (Registration, Evaluation, Authorization and Restriction of Chemicals, EC Regulation No. 197/2006).

The complexity and range of situations where Eni is operating imposed the definition and application of principles for consolidating its performance in health and prevention. To this end Eni upholds:

- clear policies;
- an ethical code;
- endorsement of international conventions and principles;
- guidelines and procedures; and
- sharing of knowledge.

European Union

The European Commission has put forward its new Energy Policy for Europe - EPE, so-called "20-20 by 2020", a far-reaching package of proposals that will deliver on the European Union s ambitious commitments to fight climate change, promote renewable energy and increase energy security. The following regulations were published in order to define the criteria for cutting emissions cost-effectively by 2020 compared with levels in 2005:

- Directive No. 2009/28/EC: fixing target of 20% share of energy from renewable sources in 2020. It creates cooperation mechanisms so that the EU can achieve the targets in a cost effective way. It also includes a flat 10% target for renewables in transport (bio-fuels, "green" electricity, etc.); this legislation also sets out sustainability

criteria that bio-fuels should meet to ensure they deliver real environmental benefits.
Directive No. 2009/29/EC: improves and extends to the third phase (2013-2020) the greenhouse gas emission allowance trading scheme of the European Community to provide for a more efficient, homogeneous and fair system. It defines criteria and targets for cutting GHG emissions from the sectors covered by the system (energy and manufacturing industries) by 21% by 2020 compared with levels in 2005. The Auctioning Regulation contains a set of rules for the auctioning processes that should be undertaken for the auction of allowances from 2013. On December 14, 2010, Climate Change Committee voted the benchmark decision, which describes the rules for the free allocation from 2013.
Directive No. 2009/30/EC: defines the fuel quality and places an obligation on suppliers to reduce greenhouse gases from the entire fuel life cycle of 6% by 2020, mostly by an increased use of bio-fuels.
Directive No. 2009/31/EC: defines a scenario in order to promote the development and safe use of Carbon Capture & Storage (CCS), a suite of technologies that allows the carbon dioxide emitted by industrial processes to be captured and stored underground.
Regulation 443/2009/CE: sets emissions standards for new passenger cars and targets a reduction to an average of 120 g CO_2/km by 2015, decreasing to a stringent long-term target of 95 g CO_2/km by 2020.
Decision 406/2009/CE: defines, for sectors not included in the EU ETS, such as transport, housing, agriculture and waste, emissions reduction target of 10% from 2005 levels by 2020 (the Italian reduction target is fixed at 13%).

Directive No. 2008/1/EC contains the new IPPC and rationalizes all existing regulations on this issue. member states of the EU have to communicate their national values of emissions into the atmosphere, wastes produced and managed and discharges of compounds into waste that are to be included in the European Pollutant Release and Transfer Register (E-PRTR). According to the E-PRTR, Eni installations shall report data on the Italian Register website, by the end of March of each year.

In 2010, Eni has completed the implementation of an Integrated Environmental Information System, able to gather, manage and report the data on all the pollutants released and off-site transferred as requested by PRTR Regulations.

On December 21, 2007, the European Commission published its proposal of directive on Industrial Emissions. In view of the general call for "better regulation", the draft incorporates the review of six sector-specific directives (IPPC, Large Combustion Plants, VOC Volatile Organic Compounds emissions, incineration of waste and titanium industry). The proposed directive intends to enforce BAT definition, together with a tightening of current minimum emission values in some sectors. The new proposal also introduces more robust monitoring and inspections on installations, the review of permit conditions and the reporting of compliance. The proposal reached the final reading phase on July 7, 2010 and the directive was formally adopted on October 25, 2010 and expected to be published by 2011. The directive defines more restricting emission limits to be observed by the end of 2012, although includes some derogation, as the TNP Transitional National Plan and the option Opt-Out for those installations that are going to shut down their operations by 2023. The member states must transpose the Directive into national legislation by 24 months from publication.

Moreover in September 2010, the European Commission started a public internet consultation on the Review of the Environmental Impact Assessment (EIA) Directive (Directive No. 85/337/EC on the assessment of the effects of certain public and private projects on the environment, as amended). The objective of this public consultation is to collect opinions on the overall view on the functioning and effectiveness of the EIA Directive and possible areas to be improved/amended. Eni participates to the consultation, answering the web-questionnaire.

On November 22, 2008, the new directive on waste (Directive No. 2008/98/EC) was published in the Official Journal of the European Union. The new directive simplifies the existing legislative framework by clarifying definitions, streamlining provisions and integrating the directives on hazardous waste (No. 1991/689/EC) and on waste oils (No. 1975/439/EC). The directive introduces a life-cycle approach, focuses on waste policy by improving the way of resources consumption. The scope is to improve the recycling market by setting environmental standards, specifying under which conditions certain recycled waste are no longer considered such. The directive requires that member states take appropriate measures to encourage the prevention or reduction of waste production and its harmfulness. This can be done by a combination of several strategies particularly through the development of clean technologies, the technical development and marketing of products designed so to contribute as little as possible to increasing the amount of waste. The directive also sets new recycling targets.

The core of the directive is the introduction of a waste management hierarchy. This hierarchy is as follows: 1. Waste prevention, 2. Re-use, 3. Recycling, 4. Recovery (including energy recovery), 5. Disposal.

Moreover the directive bolsters the importance of the extended producer responsibility in the future waste management measures.

The promising results of the UN Conference of Cancun (December 2010) related to the definition of a Climate Agreement after 2012, have led the European Commission, on March 15, 2011, to present a Roadmap for transforming the European Union into the worldwide forerunner of low carbon economy by 2050. The Roadmap objective is cutting greenhouse gas emissions by 80-95% of 1990 levels within 2050, by implementing cost-effective measures aiming mostly at improving energy efficiency. The analysis takes into consideration costs and savings related to potential measures such as sectoral policies, national and regional low-carbon strategies and long-term investments. The Commission s analysis shows that the global transition to a low carbon and resource-efficient economy will generate multiple benefits for the EU: energy importation costs savings, improvements in energy security and economy competitiveness.

Following the incident at the Macondo well in the Gulf of Mexico the U.S. Government and other governments have adopted or are likely to adopt more stringent regulations targeting safety and reliable oil and gas operations in the USA and elsewhere, particularly relating to environmental and health and safety protection controls and oversight of drilling operations, as well as access to new drilling areas. The U.S. Government imposed a moratorium on certain offshore drilling activities through November 30, 2010 (it was suspended in October), and similar actions may be taken by governments elsewhere in the world. Confirming this approach, Italian Authorities have passed legislation with Law Decree No. 128 on June 29, 2010 that introduces certain restrictions to activities for exploring and producing hydrocarbons; however existing projects for conducting oil and gas operation would not be affected. Eni and other operators in the industry have commenced discussions with the Italian Ministry for Economic Development and the Ministry for the Environment to clarify uncertainties in correctly interpreting and applying the new regulations.

Also the European Parliament has increased its activities in the area of environmental protection in the field of hydrocarbon extraction. On October 7, 2010 the European Parliament approved a resolution on this issue and rejected a proposed moratorium on new oil platforms until global adoption of uniformly more stringent environmental protection laws. The resolution highlighted need for a single European system for prevention and response to intra-community oil spills which would entail amending three EU directives: Seveso II, the directive on environmental responsibility and VIA. The Italian Government confirmed its intention to harmonize Italian laws with European laws also according to the approved resolution. Adoption of stricter regulation both at national and European or international level and expected evolution in industrial practices could trigger cost increases to comply with new HSE standards which the Company might adopt either on a mandatory or voluntary basis. Also our exploration and development plans to produce hydrocarbons reserves and drilling programs could be affected by changing HSE regulations and industrial practices. Lastly, the Company expects that production royalties and income taxes in the oil and gas industry will likely increase compared to previous years. The assessments made by Eni s management regarding the impacts on our operations following the Macondo well incident in the Gulf of Mexico and the rescheduling of certain projects due to the moratorium called by the U.S. Government caused delays in linking few wells to production facilities which had a negligible impact on the Company s production for the year. In addition, the Group incurred operating costs related to inactivity or redeployment of certain drilling rigs which were booked before the moratorium. During the first months of 2011, Eni expects to resume the operations that had been previously authorized and suspended following the moratorium. Planned activities for which authorizations still have to be granted might be rescheduled due to uncertainties in the timing of obtaining the necessary authorizations from the U.S. Authorities. In order to achieve the highest security standards of our operations in the Gulf of Mexico, we entered into a consortium led by Helix that worked at the containment of the oil spill at the Macondo well. The Helix Fast Response System (HFRS) performs certain activities associated with underwater containment of erupting wells, evacuation of hydrocarbon on the sea surface, storage and transport to the coastline.

HSE Activity for the Year 2010

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

In 2010, Eni s business units continued to obtain certifications of their management systems, industrial installations and operating units according to the most stringent international standards. The total number of certifications achieved was 271 (247 in 2009), of which 97 certifications according to the ISO 14001 standard, 9 certifications according to the EMAS regulation (EMAS is the Environmental Management and Audit Scheme recognized by the European Union) and 62 according to the OHSAS 18001 standard (Occupational Health and Safety management Systems - requirements).

Environment. In 2010, Eni incurred total expenditures amounting to euro 1,151 million for the protection of environment, down 13% from 2009. Current environmental expenses decreased by approximately 13% from 2009, and mainly related to costs incurred with respect to remediation and reclamation activities, carried out mainly in Italy. Capitalized environmental expenditure decreased by 13% and mainly related to soil and subsoil protection, air emissions, energy efficiency and climate change. Eni expects to continue incurring amount of environmental expenditures and expenses in line with or above 2010 levels in future years.

Safety. Safety of our employees and contractors as well as of all people living in the area where activities and assets are located is important to our company. In 2010, there were no significant impacts resulting from new regulations on safety in the workplace. Eni s business units focused on completing the important organizational changes required by new regulations enacted in 2008.

The improvement and dissemination of safety awareness through all levels of the Company s organization continued in 2010; this is one of the foundations of Eni s safety strategy, through a large communication campaign with the target of improving the conduct of workers in the specific field of safety at work. The campaign will be completed this year and will involve 35,000 workers and 25,000 contractors. At the end it will be possible to evaluate the effectiveness of the campaign.

From the end of 2009 and throughout 2010, a number of safety seminars involving the top and middle management of various Business Units have taken place, with the aim of sharing the experiences coming from the implementation of process safety audits in the downstream sector and asset integrity verification tools in the upstream sector. The process safety knowledge improvement effort is continuing with courses targeted at specific areas like functional safety and alarms management.

Results of efforts to achieve a better safety in all activities has brought an improvement of Eni injury frequency rate to 0.91 and of the injury severity rate to 0.03, both decreasing from 2009 and representing the best results ever.

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Costs incurred in 2010 to support the safety levels of operations and to comply with applicable rules and regulations were euro 283.5 million, down 45% from 2009. Eni expects to continue incurring amounts of expenses for safety which will be in line with or above 2010 levels in future years.

Health. Eni s activities for protecting health aim at the continuous improvement of work conditions. Results have been achieved through:

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

To protect the health and safety of its employees, Eni relies on a network of more than 300 health care centers located in its main operating areas. A set of international agreements with the best local and international health centers ensures efficient services and timely responses to emergencies. The experience acquired in this field, have brought to the elaboration of Health Impact Assessment (HIA) and relative standards to be applied to all new projects of evaluation of working exposure in foreign environment.

In 2010, Eni incurred a total expense of euro 57.8 million, down 28.6% from 2009, to protect the health of its employees. Eni expects to continue incurring amounts of expenses for health which will be in line with or above 2010 levels in future years.

In 2010, Eni total HSE expenses (including cross-cutting issues such as HSE management systems implementation and certification, etc.) amounted to euro 1,578 million, down 18% from 2009.

Managing GHG emissions and Implementation of the Kyoto Protocol

On February 16, 2005, the Kyoto Protocol entered into force along with commitments provided by Annex I to the Protocol which was ratified by the same parties who joined the Protocol, including the EU and Italy. According to Law No. 120/2002, Italy committed itself to reduce greenhouse gas (GHG) emissions by 6.5% in the period 2008-2012, as compared to GHG levels emitted in 1990. Reductions can be achieved through both internal measures and complementary initiatives.

The latter include the so-called flexible mechanisms, which enables a Party to carry out projects in developing countries (CDM - Clean Development Mechanism) and in industrial countries with transition economies (JI - Joint Implementation) in order to obtain emission credits to fulfill the Kyoto compliance.

Italy is a party to the EU Emission Trading Scheme ("ETS") that was established by Directive No. 2003/87/EC. Effective from January 1, 2005, ETS is the largest virtual market in the world for exchanging emission allowances targeting industrial installations with high carbon dioxide emissions.

As foreseen by the Directive, Italy has issued two National Allocation Plans (NAP) covering the periods 2005-2007 and 2008-2012 which set out the allowances awarded to each sector and installation. The ETS EU directive provides that each member state shall ensure that any operators who produce GHG emissions in excess of the amounts entitled on the base of national allocation plan, will provide allowances to cover excess emissions and also to pay a penalty. The excess emissions penalty amounts to euro 100 (euro 40 for the first period 2005-2007) for each tonne of carbon dioxide equivalent emitted in excess of entitled amounts. All companies are expected to identify and carry out projects for emission reductions.

Eni is part to the ETS. Eni participates in the ETS scheme with 55 plants in Italy and 4 outside Italy, which collectively represent about a third of all greenhouse gas emissions generated by Eni s plants worldwide. In the period 2005-2007 Eni was entitled to allowances equal to 77.2 mmtonnes of carbon dioxide for existing and new installations. In the period 2008-2012 Eni was entitled to allowances equal to 126.4 mmtonnes of carbon dioxide for existing installations and to further 2.0 mmtonnes in relation to new installations for the 2008-2012 period. Based on the implementation of projects designed to reduce emissions, particularly the start-up of high efficiency combined cycles for the cogeneration of electricity and steam, the amount of carbon dioxide emitted by Eni s plants has complied with mandatory limits in each of the reported periods up to 2010.

Moreover, Eni monitors the opportunities deriving the Kyoto Flexible Mechanisms. In fact, due to its presence in about 70 Countries, Eni is an elective partner for carrying out CDM and JI projects thus contributing to the Italian program of greenhouse gas emissions reduction. In December 2003, during the Conference of Parties to the Kyoto Protocol COP9 , Eni and the Ministry for the Environment signed a Voluntary Agreement for using flexible mechanisms, promoting CDM and JI and contributing to the sustainable development of host countries.

Management believes that the best solutions for complying with the Kyoto Protocol are use of low emission energy sources and adoption of highly efficient technologies. To address the greenhouse gas challenge, Eni performed a detailed analysis for defining its strategy to respond to climate change and to participate in the European emissions trading system, identifying a number of projects for energy saving and emission reductions from its plants.

Management plans to target GHG emissions reduction by implementing certain gas projects designed to exploit associated gas in foreign countries where such gas is flared or released in the atmosphere absent local outlets for that gas. The elimination of flaring and the use of associated gas for the development of local economies enable sustainable development while reducing greenhouse gas emissions. The validation, where possible, of such projects as CDM and JI will provide emission credits and support the Company in achieving its GHG reduction targets in Italy, as set by the Kyoto Protocol. The flaring down project of Kwale Okpai in Nigeria was already registered as a CDM.

More projects are being assessed or implemented in Libya, Congo, Nigeria, Angola and Algeria. Management plans to invest approximately euro 1.1 billion in those projects over the next four years. Moreover, Eni endorsed the Global Gas Flaring Reduction Initiative of the World Bank, in order to move forward completion of gas flaring reduction projects. In the period 2010-2013, a reduction in the trend of Eni total GHG emissions is foreseen due to the planned implementation of the abovementioned projects designed to reduce gas flaring or venting, measures targeting energy efficiency at various Eni s installations and facilities including refineries, petrochemicals plants and electricity plants, and actions to better manage gas emissions in transport and distribution activities. However, due to new facilities and installations, management believes that Eni s GHG emissions under the ETS scheme will exceed the entitled allowances in the next four-year period resulting in the incurrence of higher operating expenses in the range of euro 650-750 million. Most of those projected expenses are expected to be incurred in the years 2013-2014, which correspond to the third Phase of Emission Trading. In fact, from 2013, full auctioning will be in force in power sector, while energy-intensive industries exposed to international competition will receive their allowances free of charge as benchmarked to the average performance of the 10% most efficient installations in a specific sector.

To ensure comprehensive, transparent and accurate reporting for GHG emissions, Eni introduced in 2005 its own Protocol for accounting and reporting of greenhouse gas emissions (GHG Accounting and Reporting Protocol), which is an essential requirement for emission certification. Indeed, accurate reporting supports the strategic management of risks and opportunities related to greenhouse gases, the definition of objectives and the assessment of progress. The Eni GHG Protocol has been updated during 2009 to be in compliance with the European and Italian regulation (as the new Monitoring and Reporting Guide Line) and with the best practices reference document (American Petroleum Industry Compendium - August 2009). For safer and more accurate management of GHG emissions and with a view to supporting effective reporting, Eni provided all its business units with a dedicated database, in order to gather and report GHG emissions according to the Protocol and to ensure completeness, accuracy, transparency and consistency of GHG accounting as required by certification needs.

In the medium-term, work is underway on the separation of carbon dioxide and its permanent storage in geologic reservoirs, a part of the CO_2 Capture Project, an international R&D program carried out in conjunction with other oil companies. Eni is currently implementing Italy s first CO_2 injection project in Cortemaggiore: its Environmental Impact Assessment procedure is in course of approval by the competent Ministries.

In the long-term, Eni is actively engaged in the political process regarding future emission reduction regulations. Between 2008 and 2009 the feasibility and environmental impact evaluation studies were carried out and completed. Now the project will go under authorization process (VIA). In particular, Eni is involved in bio-energy and bio-fuels.

In both the medium and long-term, management believes that compliance with changes in laws, regulations and obligations relating to climate change could result in substantial capital expenditure, taxes, reduced profitability from changes in operating costs, and revenue generation and strategic growth opportunities being impacted. Eni s commitment to the transition to a lower-carbon economy may create expectations for our activities and related liabilities, and the level of participation in alternative energies carries reputational, economic and technology risks.

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Regulation of Eni s Businesses

Overview

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

Regulation of Exploration and Production Activities

Eni s exploration and production activities are conducted in many countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as license acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and conditions of the leases, licenses and contracts under which these oil and gas interests are held vary from country to country. These leases, licenses and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These arrangements usually take the form of licenses or production sharing agreements. See "Regulation of the Italian Hydrocarbons Industry" and "Environmental Matters" in this Item 4 for a description of the specific aspects of the Italian regulation and of environmental regulation concerning Eni s exploration and production activities.

Licenses (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a license, the holder bears the risk of exploration, development and production activities and provides the financing for these operations.

In principle, the license holder is entitled to all production minus any royalties that are payable in kind. A license holder is generally required to pay production taxes or royalties, which may be in cash or in kind. Both exploration and production licenses are generally for a specified period of time (except for production licenses in the USA which remain in effect until production ceases). The term of Eni s licenses and the extent to which these licenses may be renewed vary by area.

In Production Sharing Agreements (PSA), entitlements to production volumes are defined on the basis of contractual agreements drawn up with state oil companies which hold the concessions. Such contractual agreements regulate the recovery of costs incurred for the exploration, development and operating activities (cost oil) and give entitlement to a portion of the production volumes exceeding volumes destined to cover costs incurred (profit oil).

A similar scheme to PSA applies to Service and "Buy-Back" contracts.

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

Regulation of the Italian Hydrocarbons Industry

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

Exploration & Production

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

Exploration permits and production concessions. Pursuant to the Hydrocarbons Laws, all hydrocarbons existing in their natural condition in strata in Italy or beneath its territorial waters (including its continental shelf) are the property of the State. Exploration activities require an exploration permit, while production activities require a

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production concession, in each case granted by the Ministry of Productive Activities through competitive auctions. The initial duration of an exploration permit is six years, with the possibility of obtaining two three-year extensions and an additional one-year extension to complete activities underway. Upon each of the three-year extensions, 25% of the area under exploration must be relinquished to the State. The initial duration of a production concession is 20 years, with the possibility of obtaining a ten-year extension and an additional five-year extension until the field depletes.

Royalties. The Hydrocarbons Laws require the payment of royalties for hydrocarbon production. As per Law No. 99 of July 23, 2009 royalties are equal to 10% and 4%, respectively, for onshore and offshore production of oil and 10% and 7%, respectively, for onshore and offshore production of natural gas.

Gas & Power

Natural gas market in Italy

Legislative Decree No. 130 August 13, 2010 containing measures for increasing competition in the natural gas market and transferring the ensuing benefits to final customers according to Article 30, lines 6 and 7, of Law July 23, 2009, No. 99

In 2010, the regulated period for gas antitrust thresholds defined by Legislative Decree No. 164 of May 23, 2000 expired. Those thresholds defined maximum allowed limits of gas volumes (imported or domestically produced) input into the national transport network and marketed to final customers, applicable to each operator.

Implementing the provisions of Law 99/2009, that system of antitrust thresholds was replaced with a mechanism of market shares enacted by Legislative Decree No. 130 of August 13, 2010 "New measures to improve competitiveness in the natural gas market and to ensure the transfer of economic benefits to final customers" approved by the Italian Council of Ministers. The Decree provides that antitrust ceilings be calculated with reference to the market share of each operator, taking into account the amount of natural gas input into the national network, purchases on spot markets, and sales to importers in Italy made at national network entry points. Consequently, market shares will not be lower than the amount input to the network. Operators in the natural gas market will have to comply with a maximum share of 40% of domestic consumption. A mechanism of gas release at regulated prices is provided in case an operator fails to comply with the mandatory ceilings on the market share. This ceiling can be raised to 55% in case an operator commits to building new storage capacity in Italy for a total of 4 BCM within five years. In this case, the operator is obliged: (i) to allow third parties (such as industrial customers, groups of companies, consortia of final customers and power generation customers) participate in the construction of storage infrastructure either by means of direct investment or long-term contracts for storage services; and (ii) bear the costs associated with giving to third parties 50% of the expected benefits of new capacities under conditions defined by the Ministry for Economic Development and the Authority for Electricity and Gas ("AEEG").

Eni is planning to make the necessary investments to increase storage capacity in Italy so as to benefit from a higher allowed market share.

The Decree introduces measures for increasing competition in the natural gas market aiming at transferring the ensuing benefits to final customers, increasing storage capacity, supporting the security of supplies and enhancing flexibility in the gas system. To achieve this target, compensation to municipalities interested by the construction of new storage fields has been provided.

Eni s management is monitoring this area and evaluating any possible financial or economic impact associated with the proposed measures and their regulatory evolution. Management also believes that this new gas regulation will increase competition in the wholesale natural gas market in Italy resulting in further margin pressures.

Law No. 239 of August 23, 2004 on the restructuring of the energy sector in Italy

This law provides for:

a derogation to third party access granted to companies that make direct or indirect investments for the construction of new infrastructure or the upgrading of existing ones such as: (i) interconnections between EU member states and national networks; (ii) interconnections between non-EU States and national networks for importing natural gas to Italy; (iii) LNG terminals in Italy; and (iv) underground storage facilities in Italy. Investing companies can obtain priority on the assignment of new capacity for a portion of not less than 80% of the new capacity installed and for a period of at least 20 years; and

paragraph 69 provides interpretation of the rule introduced by Legislative Decree No. 164/2000 concerning the transitional regime of concessions for natural gas distribution activities in urban centers existing at June 21, 2000, which allows for an anticipated repayment of the distribution service, despite being provided through a bid procedure rather than direct entitlements. This law changes the provisions defined by Legislative Decree No. 164/2000 by: (i) extending to December 31, 2007, the transitional period for the continuation of existing concessions, with a possible extension of one further year when public interest is considered important by local authorities; and (ii) canceling the adding up of possible extensions, as provided for by Legislative Decree No. 164/2000, in case of certain conditions (business restructuring, size parameters, shareholding composition). The end of concessions awarded on the basis of a bid procedure remains set as of December 31, 2012. Currently, the Ministry for Economic Development is drafting a revision of the distribution gas market with the aim of reducing the number of distribution companies by providing for an extension of the territory reach of each concession.

Law No. 290/2003

Law No. 290/2003 prohibits companies operating in the natural gas and power industries to hold stakes higher than 20% in the share capital of companies owning and managing national networks for the transmission of natural gas and power. The term by which companies must comply with this provision, which was initially fixed as of December 31, 2008, has been rescheduled in a 24-month period deadline following enactment of a specific decree from the Italian Prime Minister which is to establish terms and conditions of the divestments. Currently, Eni is unable to predict any evolution of this matter.

In addition, on March 23, 2006 a Presidential Decree defined criteria and methods for the divestment of the interest held by Eni in Snam Rete Gas SpA, introducing the special powers of the Ministry of Economy and Finance provided for by the regulations on the divestment of interests held by the Italian Government ("golden share") in the By-laws of Eni. Management believes that this decree may impact Eni in case the Company makes plans to divest the whole or a portion of its interest in Snam Rete Gas. Eni s interest in Snam Rete Gas will also be affected by the due steps that Italian institutions have been implementing to enact Directive No. 2009/73/EC in Italian laws. See below.

Regulations aimed at increasing competition in the Italian wholesale segment of natural gas

In order to implement measures defined by the Italian Government to face the economic downturn, a number of administrative provisions relating to the so-called gas release measures have been enacted in an effort by Italian administrative Authorities to boost the level of competition and liquidity of the Italian gas market. Those measures have strongly affected Eni s marketing activity in Italy. Legislative Decree No. 78/2009 obliged Eni to make a gas release at the virtual exchange point for a total of 5 BCM of gas in yearly and half-yearly amounts. Although the allotment procedure (bid) was based on a minimum price set by the Ministry for Economic Development as proposed by the AEEG (Eni considering this point discriminatory, filed a claim with the competent authority), only a 1.1 BCM portion of the gas release was awarded out of the 5 BCM which had been planned. For the next few years, also based on indications of the Authority for Electricity and Gas, Eni believes that it is possible that the Company will be forced to implement additional gas release measures.

Negotiation Platform for gas trading

In compliance with the provisions of Law No. 99 of July 23, 2009, on March 18, 2010, the Ministry for Economic Development published a Decree that implements a trading platform for natural gas starting from May 10, 2010 aimed at increasing competition and flexibility on wholesale markets. Management and organization of this platform are entrusted to an independent operator, the GME (Gestore del Mercato Elettrico). On this platform are traded volumes of gas corresponding to the legal obligations on part of Italian importers and producers as per Law Decree No. 7/2007. Under these provisions, importers from non-European countries were expected to supply given amounts of gas (from 5% to 10% of total gas import) to the virtual exchange in order to receive permission to import, as well as volumes corresponding to royalties due by owners of mineral rights to the Italian state (and to Basilicata and Calabria Regions). Eni was required to offer at that platform about 200 mmCM related to the residual obligation for volumes imported in thermal year October 1, 2008-September 30, 2009, and to the offer obligation for the October 1, 2009-September 30, 2010 thermal year, as well as approximately 215 mmCM related to royalties due for 2009 full year. Operators, also non-importers, are allowed to negotiate additional gas volumes over the compulsory amounts on the platform according to the supply rules determined by the AEEG. Since December 2010, the GME is also trader s counterparty in transactions on the spot market for natural gas (divided into day-ahead market and intraday market).

Natural gas prices

Following the liberalization of the natural gas sector introduced in 2000 by Decree No. 164, prices of natural gas sold to industrial and power generation customers as well as to wholesalers are freely negotiated. However the AEEG holds a power of surveillance on this matter (see below) under Law No. 481/1995 (establishing the AEEG) and Legislative Decree No. 164/2000.

Furthermore, the AEEG is entrusted by the Presidential Decree dated October 31, 2002 with the power of regulating natural gas prices to residential and commercial customers which were not eligible until December 31, 2002, also after the full opening up of the gas market from January 1, 2003, additionally targeting the public goal of containing inflationary pressure deriving from increasing energy costs. Consistently with this decree, at present on the basis of different resolutions of the AEEG companies selling natural gas through local networks have to offer to residential customers and customers who live in buildings consuming, on the whole, less than 200,000 CM/y the regulated tariffs beside their own price proposals.

Change in the criteria for determining and upgrading tariffs applied to residential customers: Resolution ARG/gas 89/2010

On June 18, 2010, the AEEG published a resolution ARG/gas 89/2010, applied to the October 1, 2010-September 30, 2011 thermal year, providing for a 7.5% reduction in the raw material cost component of those supplies in determining tariffs for residential users consuming less than 200,000 CM/y. Considering that the new calculation does not cover the supply costs of an efficient portfolio of long-term contracts and considering the relevant impact on its consolidated accounts deriving from this new resolution, Eni s management has appealed against the ARG/gas 89/2010 resolution. This appeal is part of an ongoing administrative litigation which follows the partial annulment of AEEG Resolution No. 79/2007, pronounced by the Administrative Court of Lombardy in November 2010, with reference to the mechanism of indexation of the cost of raw material supplies to residential customers.

Directive No. 2009/73/EC of the European Parliament and Council on common regulations for the internal natural gas market

On July 13, 2009, European Directive No. 2009/73/EC on the regulation of the internal natural gas market was issued. Member states are expected to implement it in their legislation by March 3, 2011, and to choose one of two options for guaranteeing the independence of transport companies.

The two options provided are:

(i) Separation of ownership under two alternative modes:
  - Ownership Unbundling (OU): the company that owns the networks and manages transport activities is unbundled from its integrated parent company that will retain supply/production and sale activities; and
  - Independent System Operator (ISO): the vertically integrated company retains ownership of the networks but confers their management to a third independent party.

(ii) Strengthened functional separation:
  -

Independent Transmission Operator (ITO): the vertically integrated company retains control of the company that manages transport activities and owns transport networks, provided the vertically integrated company refrains from interfering in the decision making process of the controlled carrier company.

On March 3, 2010, the Italian Council of Ministers presented a draft legislative decree to implement Directive No. 2009/73/EC. Among the possible options, the decree provides for the adoption of the ITO model by Snam Rete Gas by March 3, 2012.

Fully-Regulated Businesses in the Italian Gas Market

Transport

Transport tariffs. The AEEG set transport criteria companies have to apply in determining natural gas transport and dispatching tariffs on national and regional transport networks, for each regulatory period made up of four years, as provided for by Decree No. 164/2000. Tariffs are subject to approval by the Authority, which ensures their compliance with preset criteria.

Criteria established by the AEEG set allowed revenues that are calculated as the sum of: (i) operating costs including storage and modulation costs; (ii) amortization and depreciation of transport assets; and (iii) return on net capital employed.

With Resolution ARG/gas 184/2009, published on December 2, 2009, the Authority set the criteria regulating the tariffs for natural gas transport on the national and regional gas pipeline network for the third regulatory period (January 1, 2010-December 31, 2013).

The Regulated Asset Base (RAB) is calculated with the re-valuated historical cost methodology.

The allowed pre-tax rate of return (WACC) on the Regulatory Asset Base (RAB) has been set equal to 6.4% in real terms.

The new tariff structure confirms recognition in tariff of expenditures incurred for network upgrading, providing for a higher remuneration than WACC, in a measure ranging from one to three percentage points of additional remuneration in relation to the nature of expenditures and for a period of 5 to 15 years.

Depreciation charges of gas transport infrastructures (gas pipelines) are determined on a 50-year useful technical life and are excluded from the price cap mechanism. Operating costs are defined with reference to operating costs incurred during 2008 and increased by a 50% rate to factor in productivity gains achieved in the second regulatory period. Fuel gas is excluded from the price cap mechanism.

The revenue component related to volumes transported is determined on the basis of operating costs recognized in tariff and amounts to approximately 15% of revenue cap.

With Resolution ARG/gas 218/2010, the AEEG also recognized to Snam Rete Gas a total amount of euro 54.9 million as settlement of additional costs incurred from October 1, 2008 to December 31, 2009 relating to the purchase of fuel gas for compression stations.

Network Code. From 2003, Snam Rete Gas Network Code is in force, regulating entitlements of transport capacity, obligations on part of both the transporter and the customer and the procedures through which customers can resell capacity to other users. Transport capacity at entry points to the national gas pipeline network (point of interconnection with import gas lines) is entitled on an annual basis with duration of up to five thermal years. Capacity products with duration shorter than one year are also available.

The Network Code, approved by the AEEG with Resolution No. 75 of July 1, 2003, is based on the criteria set by the same Regulator with Resolution No. 137/2002. This resolution sets priority criteria for transport capacity entitlements at points where the Italian transport network connects with international import pipelines (the so-called entry points to the Italian transport system). Specifically, operators that are party to take-or-pay purchase contracts, as in the case of Eni, are entitled to a priority in allocating available transport capacity within the limit of average daily contractual volumes. Gas volumes exceeding average daily contractual volumes are not entitled to any priority and, in case of congestion at any entry points, they are entitled available capacity on a proportionate basis together with all pending requests for capacity entitlements. The ability of Eni to collect gas volumes exceeding average daily volumes as provided by its take-or-pay purchase contracts represents an important operational flexibility that the Company uses to satisfy demand peaks. In planning its commercial flows, the Company normally assumes to fully utilize its contractual flexibility and to obtain the necessary capacity entitlements at the entry points to the national transport network. Eni believes that Resolution No. 137/2002 is in contrast with the rationale of the European regulatory framework on the gas market as provided in Directive No. 2003/55/EC. Based on that belief, the Company has opened an administrative procedure to repeal it before an administrative court which has recently confirmed in part Eni s position. An upper grade court also confirmed the Company s position. Specifically, the Administrative Court stated that the purchase of contractual flexibility is an obligation on part of the importer, which responds to a collective interest. According to the Administrative Court, there is no reasonable motivation whereby volumes corresponding to such contractual flexibility should not be granted priority in the access to the network, also in case congestion occurs. At the moment, however, no case of congestion occurred at entry points to the Italian transport infrastructure so as to impair Eni s marketing plans.

Re-gasification

Re-gasification tariffs. The AEEG has set the criteria regulating the tariffs for the use of LNG terminals in the 3rd regulatory period (October 2008-September 2012) with its Resolution ARG/gas 92/2008.

The Regulatory Asset Base (RAB) is calculated with the re-valuated historical cost methodology. The yearly adjustment of revenues and tariffs will follow the same methodologies applied in the previous regulatory period, except for depreciation that will be adjusted on a yearly basis and excluded from the price cap mechanism. The allowed rate of return (WACC) on Regulatory Asset Base has been set equal to 7.6% in real terms pre tax.

Furthermore, it established an additional remuneration, up to 3% above WACC, for new capital expenditures for a maximum of 16 years.

Operating costs will be adjusted every year taking into account inflation and efficiency gains (X-factor) set by the Authority at 0.5% in real terms.

Resolution ARG/gas 92/2008 also established that the allocation of reference revenues between re-gasification capacity and the commodity component is fixed at 90:10 (compared to 80:20 ratio in the second regulated period).

Re-gasification Code. From 2007 GNL Italia Re-gasification Code is in force, defining rules and regulations for the operation and management of the re-gasification plant of Panigaglia in North-West Italy. The Code, approved with the Resolution VIS 8/2009, is based on the criteria for access to LNG re-gasification services set by the same Regulator with Resolution No. 167/2005 (August 1, 2005) in accordance with Legislative Decree No. 164/2000. The decision also defines criteria for the allocation of re-gasification capacity. In particular it establishes that take-or-pay contracts entered into before 1998, as in the case of Eni, are awarded priority access limited to the minimum amount of volumes that have been re-gasified in the period starting from thermal year 2001-2002. Eni filed a claim against this decision with the Regional Administrative Court of Lombardy that rejected the claim. Subsequently, Eni filed a claim with a higher degree administrative court.

Distribution

Distribution is the activity of delivering natural gas to residential and commercial customers in urban centers through low pressure networks. Distribution is considered a public service operated in concession and is regulated on the basis of Law Decree No. 164/2000.

Distribution tariffs. With Resolution No. 159/2008, the AEEG defined a new methodology for determining revenues for natural gas distribution activity. Starting from January 1, 2009 and for the duration of a four-year regulated period, i.e. until 2012, the resolution provides for the recognition of total revenues for each regulated year amounting to a value that the Authority will set at the time of approving the operators requests for distribution tariffs and defined as Total Revenue Constraint (TRC), representing the maximum remuneration recognized by the AEEG to each operator for covering costs borne.

In previous years, revenues were determined by applying tariffs set by the AEEG to volumes actually distributed to selling companies in the relevant year. The resolution also provides for any positive or negative difference between TRC and revenues resulting from invoices for actually distributed volumes to be regulated through an equalization device making use of credit/debit cards lodged with the Electricity Equalization Exchange.

As a result of the new mechanism, revenues are no longer related to the seasonality of volumes distributed but are constantly apportioned during the year. The introduction of this new mechanism does not cause a decline in total revenues on a yearly basis.

Storage of natural gas

Storage activities in Italy are regulated by Decree No. 164/2000. The most important aspects of Decree No. 164 concerning storage activities are the following: (i) in vertically integrated enterprises, storage is to be carried out by a separate company not operating in other gas activities (such as Eni s subsidiary Stoccaggi Gas Italia SpA) or by companies engaged only in transport and dispatching activities, provided the accounts of these two activities are clearly separated from the accounts of storage; (ii) storage activity is exercised pursuant to concessions granted by the Ministry of Productive Activities. The duration of a concession is 20 years, with the possibility of obtaining at most two ten-year extensions if operators complied with the storage programs and other obligations deriving from applicable laws. Existing storage concessions are subject to the decree. Their original term was confirmed and includes relevant production concessions; (iii) the need for strategic storage in Italy is defined explicitly; the burden of strategic storage is imposed upon companies importing from non-EU countries, which have to provide a strategic storage capacity in Italy corresponding to 10% of the amount of natural gas imported each year; (iv) holders of storage concessions are required to provide storage capacity for domestic production, for strategic use and for modulation to eligible users without discriminations, where technically and economically viable; (v) modulation storage costs are charged to shippers which have to provide modulation services adequate to the requirements of their final customers; (vi) storage tariffs criteria are determined by the AEEG in order to ensure a preset return on capital employed, taking into account the typical risk inherent in this activity, as well as volumes stored for ensuring peak supplies and the need to incentive capital expenditure for upgrading the storage system; and (vii) the AEEG establishes the criteria and priority of access storage operators have to include in their own storage codes.

In compliance with the provisions of Article 21 of Decree No. 164/2000, on October 21, 2001 all storage activities carried out within the Eni Group were conferred to Stoccaggi Gas Italia SpA ("Stogit"), which holds ten storage concessions.

Storage tariffs. On August 3, 2010, the AEEG with Resolution No. 119/2010 published the criteria for determining storage tariffs for the 2011-2014 regulated period.

According to this resolution, the storage company calculates revenues for the determination of unit tariffs for storage services by adding the following cost elements:

(i) a return on the capital employed by the storage company equal to 6.7% (7.1% in the second regulated period);
(ii) depreciation and amortization charges;
(iii) dismantling costs; and
(iv) operating costs.

In the years following the first year of the new regulated period, reference revenues are updated to take account of variations of capital employed and the impact of the indexation of depreciation charges and operating costs to consumer price inflation lowered by a preset rate of productivity recovery.

Applicable regulation provides for incentives to capital expenditures intended to develop and upgrade storage capacity by recognizing an additional rate of return of 4% on the basic rate to capital expenditure projects aiming at developing new storage deposits and increasing existing capacity. Such incentives are applicable for a sixteen-year period and an eight-year period, respectively.

Storage Code. From November 1, 2006 Stoccaggi Gas Italia (Stogit) Storage Code is in force.

This Code regulates access to and provision of storage services during normal operational conditions, regulates procedures for conferring storage capacities, fees to be charged to customers in case they uplift from or input to storage sites volumes in excess or uses higher input/uplift capacity with respect to scheduled and operating programs. On the basis of these provisions, Eni may incur significant charges for storage services should the Company fail to use storage services in accordance with scheduled operating programs.

The storage company offers services according to the access priority established by the AEEG as follows:
(i) mandatory services, including modulation storage, mineral storage, and strategic storage services; and (ii) services for operating needs of transport companies, including hourly modulation.

The modulation storage service is geared towards satisfying modulation needs of natural gas users in terms of peak consumption and daily or seasonal trends in consumption. Final clients consuming less than 200,000 CM on an annual basis are entitled to a priority when satisfying their modulation requirements. To that end, the storage company makes available its capacity for space, injection and off-take on an annual basis in accordance with its storage code.

The mineral storage service aims to allow natural gas producers to perform their activity under optimal operating conditions, according to criteria determined by the Ministry for Economic Development.

The strategic storage service aims to satisfy certain obligations of natural gas importers from countries not belonging to the EU in accordance with Article 3 of Legislative Decree No. 164/2000. The relevant storage capacity dedicated to this service is determined by the Ministry for Economic Development.

Storage capacity is awarded by the storage company for periods no longer than a thermal year by April 1, of each year. The first requests to be met are those for strategic storage and for the operating balancing of the system.

The residual capacity available and the maximum daily uplift capacity is awarded according to the following order of priority to: (i) holders of production concessions requesting mineral storage services; (ii) natural gas selling operators who are held to provide a modulation service of their supply to their customers according to Article 18, paragraphs 2 and 3 of Legislative Decree No. 164/2000, for maximum volumes corresponding to a seasonal demand peak with average temperatures, on the terms and conditions established by a procedure to be issued by the Regulatory Authority for Electricity and Gas; (iii) to the entities mentioned in (ii) above only for those additional maximum volumes related to a seasonal demand peak in case of certain low temperatures measured on a 20-year period, under the terms and conditions of the procedure mentioned in (ii) above; and (iv) the entities requesting access for services different from the ones mentioned above.

From November 2009, according to the Resolution No. 165/2009 set by the Regulator, monthly based storage services are available for gas-network users (Shippers). Storage capacities are sold on auction basis.

Eni held natural gas for strategic reserve purposes in its storage business, as established by Decree No. 164/2000.

The strategic reserves of gas are defined as "stock destined to meet situations of deficit/decrease of supply or crisis of the gas system". The Ministry for Economic Development determines quantities and usage criteria of such reserves. As of December 31, 2010, Eni held approximately 177 BCF of strategic reserves of natural gas (177 BCF at year end 2009).

Refining and Marketing of Petroleum Products

Refining. Under Legislative Decree No. 112 of March 31, 1998, companies that seek to establish refining operations in Italy or to expand the capacity of existing refining operations must obtain an operating concession from the relevant region, while companies that seek to build or operate new plants that do not increase refining capacity must obtain an authorization from the relevant region. Management expects no material delays in obtaining relevant concessions for the upgrading of the Sannazzaro and Taranto refineries as planned in the medium-term.

Service stations. Legislative Decree No. 32 of February 11, 1998, as amended by Legislative Decree No. 346 of September 8, 1999 and Law Decree No. 383 of October 29, 1999, as converted in Law No. 496 of December 28, 1999, significantly changed Italian regulation of service stations. Legislative Decree No. 32 replaces the system of concessions granted by the Ministry of Industry, regional and local authorities with an authorization granted by city authorities while the Decree No. 112 still confirms the system of such concessions for the construction and operation of service stations on highways and confers the power to grant to Regions. Decree No. 32 also requires that contracts between license holders and service station operators have a duration of not less than six years and are drafted in accordance with arrangements agreed by the relevant trade group of license holders and the union representatives for the service station operators. Decree No. 32 also provides for: (i) the testing of compatibility of existing service stations with local planning and environmental regulations and with those concerning traffic safety to be performed by city authorities; (ii) upon the closure of at least 7,000 service stations, the option to extend by 50% the opening hours (currently 52 hours per week) and a generally increased flexibility in scheduling opening hours; (iii) simplification of regulations concerning the sale of non-oil products and the permission to perform simple maintenance and repair operations at service stations; and (iv) the opening up of the logistics segment by permitting third party access to unused storage capacity for petroleum products. With the same goal of renewing the Italian distribution network, Law No. 57 of March 5, 2001 provides that the Ministry of Productive Activities is to prepare guidelines for the modernization of the network, and the Regions shall follow those guidelines in the preparation of regional plans. The subsequent Ministerial Decree of October 31, 2001 establishes the criteria for the closing down of incompatible stations, the approval of the plan, the renewal of the network, the opening up of new stations and the regulations of the operations of service stations on matters such as automation, working hours and non-oil activities.

Law No. 133 of August 6, 2008, by intervening in competition provisions, removes some national and regional regulations which might prejudice the liberty of establishment and introduces new provisions particularly concerning the elimination of restrictions concerning distances between service stations, the obligation to undertake non-oil activities and the liberalization of opening hours. Management believes that those measures will favor competition in the Italian retail market and support efficient operators.

Petroleum product prices. Petroleum product prices were completely deregulated in May 1994 and are now freely established by operators. Oil and gas companies periodically report their recommended prices to the Ministry of

Productive Activities; such recommendations are considered by service station operators in establishing retail prices for petroleum products.

Compulsory stocks. According to Legislative Decree of January 31, 2001, No. 22 ("Decree 22/2001") enacting Directive No. 1993/98/EC (which regulates the obligation of member states to keep a minimum amount of stocks of crude oil and/or petroleum products) compulsory stocks, must be at least equal to the quantities required by 90 days of consumption of the Italian market (net of oil products obtained by domestically produced oil). In order to satisfy the agreement with the International Energy Agency (Law No. 883/1977), Decree 22/2001 increased the level of compulsory stocks to reach at least 90 days of net import, including a 10% deduction for minimum operational requirements. Decree 22/2001 states that compulsory stocks are determined each year by a decree of the Minister for Economic Development based on domestic consumption data of the previous year, defining also the amounts to be held by each oil company on a site-by-site basis.

Law No. 96 of June 4, 2010 requires the government to follow some principles and criteria in drafting the legislative decree that shall implement, by December 31, 2012, Directive No. 2009/119/EC (imposing an obligation

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on member states to maintain minimum stocks of crude oil and/or petroleum products), in particular: (a) keep a high level of oil security of supply through a reliable mechanism to assure the physical access to oil emergency and specific stocks; and (b) provide for the institution of a Central Stockholding Entity under the control of the Ministry for Economic Development with the mandatory participation of entities who have imported oil or petroleum products that should be in charge of: (i) the holding and transport of specific stocks of products, (ii) the stocktaking, (iii) the statistics on emergency, specific and commercial stocks; and, eventually, (iv) the provision of a storage and transportation service of emergency and commercial stocks in favour of sellers of petroleum products to final clients not vertically integrated in the oil chain.

As of December 31, 2010, Eni owned 6.5 mmtonnes of oil products inventories, of which 4.2 mmtonnes as "compulsory stocks", 1.7 mmtonnes related to operating inventories in refineries and depots (including 0.2 mmtonnes of oil products contained in facilities and pipelines) and 0.4 mmtonnes related to specialty products.

Eni s compulsory stocks (as of December 31, 2010) were held in term of crude oil (33%), light and medium distillates (46%), fuel oil (16%) and other products (5%) and they were located throughout the Italian territory both in refineries (78%) and in storage sites (22%).

Competition

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

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

National courts shall have the power to apply Articles 101 and 102 of the Treaty. Where the Commission, acting on a complaint or on its own initiative, finds that there is an infringement of Article 101 or of Article 102 of the Treaty, it may: (i) require the undertakings and associations of undertakings concerned to bring such infringement to an end; (ii) order interim measures; (iii) make commitments offered by undertakings to meet the concerns expressed to them by the Commission binding on the undertakings; and (iv) find that Articles 101 and 102 of the Treaty are not applicable to an agreement for reasons of Community public interest.

Eni is also subject to the competition rules established by the Agreement on the European Economic Area (the "EEA Agreement"), which are analogous to the competition rules of the Lisbon Treaty (ex Treaty of Rome) and apply to competition in the European Economic Area (which consists of the EU and Norway, Iceland and Liechtenstein). These competition rules are enforced by the European Commission and the European Free Trade Area Surveillance Authority.

In addition, Eni s activities are subject to Law No. 287 of October 10, 1990 (the "Italian Antitrust Law"). In accordance with the EU competition rules, the Italian Antitrust Law prohibits collusion among competitors that restricts competition within Italy and prohibits any abuse of a dominant position within the Italian market or a significant part thereof. However, the Italian Antitrust Authority may exempt for a limited period agreements among companies that otherwise would be prohibited by the Italian Antitrust Law if such agreements have the effect of improving market conditions and ultimately result in a benefit for consumers.

Property, Plant and Equipment

Eni has freehold and leasehold interests in real estate in numerous countries throughout the world. Management believes that certain individual petroleum properties are of major significance to Eni as a whole. Management regards an individual petroleum property as material to the Group in case it contains 10 per cent or more of the Company worldwide proved oil and gas reserves and management is committed to invest material amounts of expenditures in developing it in the future. See "Exploration & Production" above for a description of Eni s both material and other properties and reserves and sources of crude oil and natural gas.

Organizational Structure

Eni SpA is the parent company of the Eni Group. As of December 31, 2010, there were 270 fully-consolidated subsidiaries and 76 associates that were accounted for under the equity or cost method. For a list of subsidiaries of the Company, see "Exhibit 8. List of Eni s fully-consolidated subsidiaries for year 2010".

Item 4A. UNRESOLVED STAFF COMMENTS

None.

Item 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

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

This section contains forward-looking statements which are subject to risks and uncertainties. For a list of important factors that could cause actual results to differ materially from those expressed in the forward-looking statements, see the cautionary statement concerning forward-looking statements on page ii and "Item 3 Risk Factors".

Executive Summary

Eni reported net profit of euro 6,318 million for the year ended December 31, 2010, representing an increase of 44.7% from 2009. That amount represented net profit attributable to Eni s shareholders.

The Group operating profit for the year ended December 31, 2010 amounted to euro 16,111 million, up 33.6% from 2009 mainly related to: (i) a positive operating performance reported by the Exploration & Production segment, reflecting higher oil realizations in U.S. dollar terms (up 27.8%), and the depreciation of the euro against the U.S. dollar (down 4.7%); (ii) higher results of the Engineering & Construction Division which were driven by revenue growth and increased profitability of acquired orders; and (iii) improved operating results recorded by both the downstream refining and petrochemical businesses thanks to a more favorable trading environment. In contrast, the Gas & Power Division reported sharply lower results due to lower unit margins on sales outside Italy and volumes losses in the Italian market reflecting increased competitive pressures and oversupply conditions in the gas market. Results of the Gas & Power Division were also hit by an impairment charge amounting to euro 426 million relating to goodwill due to a reduced profitability outlook for the European gas marketing business.

Operating profit benefited from the recognition of an inventory holding gain amounting to euro 881 million (euro 345 million in 2009), reflecting the impact of rising prices of crude oil and products on year end valuation of inventories according to the average cost method of inventory accounting. Those gains were partly offset by higher environmental provisions as the Company recorded a charge amounting to euro 1,109 million to account for a proposal of a global environmental settlement with the Italian Ministry for the Environment. The proposed settlement is intended to define the Company s commitments to perform clean-up and remediation activities at certain Italian sites and settle all pending civil and administrative litigation on the issue of environmental damage. See "Significant Transactions" below for a full description of the proposed transactions.

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Group results for the year also benefited from higher profits reported by non-consolidated entities that are accounted for under the equity or the cost method (up euro 587 million).

Net cash provided by operating activities amounted to euro 14,694 million for the year ended December 31, 2010 and benefited from a cash inflow from transferring certain account receivables without recourse to factoring institutions, amounting to euro 1,279 million due in 2011. These inflows were balanced by outflows for pre-payments to the Company s suppliers of gas under long-term contracts upon triggering the take-or-pay clause (euro 1,238 million). Net cash provided by operating activities, together with cash proceeds from divestments amounting to euro 1,113 million, were used to fund part of the cash outflows relating to capital expenditures totaling euro 13,870 million and dividend payments to Eni s shareholders amounting to euro 3,622 million. Dividends paid to non-controlling interests amounted to euro 514 million, mainly relating to Saipem and Snam Rete Gas.

As of December 31, 2010 net borrowings amounted to euro 26,119 million, an increase of euro 3,064 million from December 31, 2009.

In 2010, oil and natural gas production available for sale averaged 1,757 KBOE/d. Production for the year expressed in barrel-of-oil equivalent was computed assuming a natural gas conversion factor which was updated to 5,550 cubic feet of gas equals 1 barrel of oil. See disclosure in a footnote to the "Conversion Table" on page vi. On a comparable basis, i.e. when excluding the effect of updating the gas conversion factor, production showed an increase of 0.9% for the full year. Production growth was driven by additions from new field start-ups, particularly the Zubair field (Eni s interest 32.8%) in Iraq (for a total increase of 40 KBOE/d). These increases were offset in part by mature field declines.

Worldwide gas sales in 2010 amounted to 97.06 BCM, down 6.4% from 2009 due to lower volumes supplied to the Italian market (down 5.75 BCM, or 14.4%) against the backdrop of stronger competitive pressures and oversupply on the marketplace which also hit sales to importers of natural gas in Italy (down 2.04 BCM or 19.5%). These declines were partly offset by higher volumes achieved in a number of European markets driven by growth in France, Northern Europe (including the UK), Germany/Austria and the Iberian Peninsula, while sales decreased in Turkey, Belgium and Hungary.

In 2010, capital expenditures amounted to euro 13,870 million (euro 13,695 million in 2009) and related mainly to:

- oil and gas development activities (euro 8,578 million) deployed mainly in Egypt, Kazakhstan, Congo, the USA and Algeria;
- exploration projects (euro 1,012 million), of which 97% carried out outside Italy, primarily in Angola, Nigeria, in the USA, Indonesia and Norway;
- upgrading of the fleet used in the Engineering & Construction Division (euro 1,552 million);
- development and upgrading of Eni s natural gas transport network in Italy (euro 842 million) and distribution network (euro 328 million), as well as development and increasing storage capacity (euro 250 million); and
- projects aimed at improving the conversion capacity and flexibility of refineries (euro 446 million), as well as building and upgrading service stations in Italy and outside Italy (euro 246 million).

During the 2010-2014 four-year period, Eni expects to invest approximately euro 53.3 billion in capital expenditures and exploration projects to implement its growth strategy, based on the assumptions discussed below under "Management s Expectation of Operations".

Trading Environment

	2008	2009	2010
Average price of Brent dated crude oil in U.S. dollars (1)	96.99	61.51	79.47
Average price of Brent dated crude oil in euro (2)	65.93	44.16	59.89
Average EUR/USD exchange rate (3)	1.471	1.393	1.327
Average European refining margin in U.S. dollars (4)	6.49	3.13	2.66
Euribor - three month euro rate % (3)	4.6	1.2	0.8

(1) Price per barrel. Source: Platt s Oilgram.
(2) Price per barrel. Source: Eni s calculations based on Platt s Oilgram data for Brent prices and the EUR/USD exchange rate reported by the European Central Bank (ECB).
(3) Source: ECB.
(4) Price per barrel. FOB Mediterranean Brent dated crude oil. Source: Eni calculations based on Platt s Oilgram data.

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When the term margin is used in the following discussion, it refers to 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 petrochemicals products). Margin trends reflect the trading environment and are, to a certain extent, a gauge of industry profitability.

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

In 2010, Eni s results were driven by higher oil realizations driven by rising Brent prices which were up 29.2% from 2009. Results also benefited from the depreciation of the euro versus the U.S. dollar, down by 4.7%, which improved the operating results reported by Eni s subsidiaries whose functional currency is the U.S. dollar. Unit margins in the marketing of gas outside Italy were hit by lower price differentials between spot prices for gas recorded in European continental hubs, as those prices have become the benchmark in contractual selling formulae in Europe, and the Company s purchase costs of gas which have remained mainly indexed to the cost of oil and certain refined products. Eni s realized refining margins in U.S. dollar terms remained at unprofitable levels as the Brent benchmark refining margin for the year was down 0.47 $/BBL, or 15% from 2009. That trend reflected higher oil-feedstock costs which were only partially transferred to prices of refined products at the pump pressured by weak underlying fundamentals (slow demand, excess capacity, high inventory levels). Nonetheless, Eni s realized margins posted a slight improvement from the depressed levels of the year-earlier due to wider price differential between sour and sweet crude qualities and higher relative prices of middle distillates compared to heating oil, which benefited Eni s complex refineries. Petrochemical product margins also improved from the prior year as high oil-based feedstock costs were at least partially offset by higher chemicals commodity prices on the back of a recovery in demand.

Key Consolidated Financial Data

		2008	2009	2010
			(euro million)	
Net sales from operations		108,082	83,227	98,523
Operating profit (1)		18,517	12,055	16,111
Net profit attributable to Eni		8,825	4,367	6,318
Net cash provided by operating activities		21,801	11,136	14,694
Capital expenditures		14,562	13,695	13,870
Acquisitions of investments and businesses (2)		4,305	2,323	443
Shareholders equity including non-controlling interest at year end		48,510	50,051	55,728
Net borrowings at year end (2)		18,376	23,055	26,119
Net profit attributable to Eni basic and diluted	(euro per share)	2.43	1.21	1.74
Dividend per share	(euro per share)	1.30	1.00	1.00
Ratio of net borrowings to total shareholders equity including non-controlling interest (leverage) (3)		0.38	0.46	0.47

(1) From year 2009, the Company accounts for gains and losses on non-hedging commodity derivative instruments, including both fair value remeasurement and settled transactions, as items of operating profit. Prior period results have been restated accordingly.
(2) This item includes acquired net borrowings.
(3) For a discussion of the usefulness of and a reconciliation of these non-GAAP financial measures with the most directly comparable GAAP financial measures see - "Liquidity and Capital Resources - Financial Conditions" below.

Critical Accounting Estimates

The Company s Consolidated Financial Statements are prepared in accordance with IFRS as issued by IASB. These require the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. Estimates made are based on complex or subjective judgments and past experience of other assumptions deemed reasonable in consideration of the information available at the time. The accounting policies and areas that require the most significant judgments and estimates to be used in the preparation of the Consolidated

Financial Statements are in relation to the accounting for oil and natural gas activities, specifically in the determination of proved and proved developed reserves, impairment of fixed assets, intangible assets and goodwill, asset retirement obligations, business combinations, pensions and other post-retirement benefits, recognition of environmental liabilities and recognition of revenues in the oil field services construction and engineering businesses. Although the Company uses its best estimates and judgments, actual results could differ from the estimates and assumptions used. A summary of significant estimates follows.

Oil and gas activities

Engineering estimates of the Company s oil and gas reserves are inherently uncertain. Proved reserves are the estimated volumes of crude oil, natural gas and gas condensates, liquids and associated substances which geological and engineering data demonstrate that can be economically producible with reasonable certainty from known reservoirs under existing economic conditions and operating methods. Although there are authoritative guidelines regarding the engineering criteria that must be met before estimated oil and gas reserves can be designated as "proved", the accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Field reserves will only be categorized as proved when all the criteria for attribution of proved status have been met. At this stage, all booked reserves will be classified as proved undeveloped. Volumes will subsequently be reclassified from proved undeveloped to proved developed as a consequence of development activity. The first proved developed bookings will occur at the point of first oil or gas production.

Major development projects typically take one to four years from the time of initial booking to the start of production. Eni reassesses its estimate of proved reserves periodically. The estimated proved reserves of oil and natural gas may be subject to future revision and upward and downward revision may be made to the initial booking of reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

In particular, changes in oil and natural gas prices could impact the amount of Eni s proved reserves in regards to the initial estimate and, in the case of Production Sharing Agreements and buy-back contracts, the share of production and reserves to which Eni is entitled. Accordingly, the estimated reserves could be materially different from the quantities of oil and natural gas that ultimately will be recovered. Oil and natural gas reserves have a direct impact on certain amounts reported in the Consolidated Financial Statements. Estimated proved reserves are used in determining depreciation and depletion expenses and impairment expense. Depreciation rates on oil and gas assets using the UOP basis are determined from the ratio between the amount of hydrocarbons extracted in the quarter and proved developed reserves existing at the end of the quarter increased by the amounts extracted during the quarter. Assuming all other variables are held constant, an increase in estimated proved developed reserves for each field decreases depreciation, depletion and amortization expense. Conversely, a decrease in estimated proved developed reserves increases depreciation, depletion and amortization expense. In addition, estimated proved reserves are used to calculate future cash flows from oil and gas properties, which serve as an indicator in determining whether or not property impairment is to be carried out. The larger the volume of estimated reserves, the lower the likelihood of asset impairment.

Impairment of assets

Eni assesses its tangible assets and intangible assets, including goodwill, for possible impairment if there are events or changes in circumstances that indicate the carrying values of the assets are not recoverable. Such indicators include changes in the Group s business plans, changes in commodity prices leading to unprofitable performance, a reduced utilization of the plants and, for oil and gas properties, significant downward revisions of estimated proved reserve quantities or significant increase of the estimated development costs. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for global or regional market supply and demand conditions for crude oil, natural gas, commodity chemicals and refined products. Similar remarks are valid for the physical recoverability of assets recognized in the balance sheet (deferred cost see "Item 18 Note 20 to the Consolidated Financial Statements") related to natural gas volumes not collected under long-term purchase contracts with take-or-pay clauses.

The amount of an impairment loss is determined by comparing the book value of an asset with its recoverable amount. The recoverable amount is the greater of fair value net of disposal cost or the value in use. The estimated value in use is based on the present values of expected future cash flows net of disposal costs. The expected future cash flows used for impairment analyses are based on judgmental assessments of future production volumes, prices and costs, considering available information at the date of review and are discounted by using a rate related to the activity involved.

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For oil and natural gas properties, the expected future cash flows are estimated principally based on developed and non-developed proved reserves including, among other elements, production taxes and the costs to be incurred for the reserves yet to be developed. Oil, natural gas and petroleum product prices (and to prices from products which derive there from) used to quantify the expected future cash flows are estimated based on forward prices prevailing in the marketplace for the first four years and management s long-term planning assumptions thereafter. The estimate of the future amount of production is based on assumptions related to the commodity future prices, lifting and development costs, market demand and other factors. The discount rate reflects the current market valuation of the time value of money and of the specific risks of the asset not reflected in the estimate of the future cash flows. Goodwill and other intangible assets with an indefinite useful life are not subject to amortization. The Company tests such assets at the cash generating unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value below its carrying amount. In particular, goodwill impairment is based on the determination of the fair value of each cash generating unit to which goodwill can be attributed on a reasonable and consistent basis. A cash generating unit is the smallest aggregate on which the Company, directly or indirectly, evaluates the return on the capital expenditure. If the recoverable amount of a cash generating unit is lower than the carrying amount, goodwill attributed to that cash generating unit is impaired up to that difference; if the carrying amount of goodwill is less than the amount of impairment, assets of the cash generating unit are impaired on a pro-rata basis for the residual difference.

Asset Retirement Obligations

Obligations to remove tangible equipment and restore land or seabed require significant estimates in calculating the amount of the obligation and determining the amount required to be recorded presently in the Consolidated Financial Statements.

Estimating future asset retirement obligations is complex. It requires management to make estimates and judgments with respect to removal obligations that will come to term many years into the future and contracts and regulations are often unclear as to what constitutes removal. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known as asset removal technologies and costs constantly evolve in the countries where Eni operates, as do political, environmental, safety and public expectations. The subjectivity of these estimates is also increased by the accounting method used that requires entities to record the fair value of a liability for an asset retirement obligation in the period when it is incurred (typically, at the time the asset is installed at the production location). When liabilities are initially recorded, the related fixed assets are increased by an equal corresponding amount. The liabilities are increased with the passage of time (i.e. interest accretion) and any change in the estimates following the modification of future cash flows and discount rate adopted. The recognized asset retirement obligations are based on future retirement cost estimates and incorporate many assumptions such as: expected recoverable quantities of crude oil and natural gas, abandonment time, future inflation rates and the risk-free rate of interest adjusted for the Company s credit costs.

Business Combinations

Accounting for business combinations requires the allocation of the purchase price to the various assets and liabilities of the acquired business at their respective fair values. Any positive residual difference is recognized as "Goodwill". Negative residual differences are credited to the profit and loss account. Management uses all available information to make these fair value determinations and, for major business acquisitions, typically engages an independent appraisal firm to assist in the fair value determination of the acquired assets and liabilities.

Environmental liabilities

Together with other companies in the industries in which it operates, Eni is subject to numerous EU, national, regional and local environmental laws and regulations concerning its oil and gas operations, production and other activities. They include legislations that implement international conventions or protocols. Environmental costs are recognized when it becomes probable that a liability has been incurred and the amount can be reasonably estimated. Management, considering the actions already taken, insurance policies obtained to cover environmental risks and provisions for risks accrued, does not expect any material adverse effect on Eni s consolidated results of operations and financial position as a result of such laws and regulations. However, there can be no assurance that there will not be a material adverse impact on Eni s consolidated results of operations and financial position due to:

(i) the possibility of an unknown contamination;
(ii) the results of the ongoing surveys and other possible effects of statements required by Decree No. 471/1999 of the Ministry for the Environment concerning the remediation of contaminated sites;
(iii) the possible effects of future environmental legislations and rules;

(iv) the effects of possible technological changes relating to future remediation; and
(v) the possibility of litigation and the difficulty of determining Eni s liability, if any, against other potentially responsible parties with respect to such litigations and the possible insurance recoveries.

Employee benefits

Defined benefit plans are evaluated with reference to uncertain events and based upon actuarial assumptions including among others discount rates, expected rates of return on plan assets, expected rates of salary increases, medical cost trends, estimated retirement dates and mortality rates. The significant assumptions used to account for defined benefit plans are determined as follows: (i) discount and inflation rates reflect the rates at which benefits could be effectively settled, taking into account the duration of the obligation. Indicators used in selecting the discount rate include rates of annuity contracts and rates of return on high quality fixed-income investments. The inflation rates reflect market conditions observed country by country; (ii) the future salary levels of the individual employees are determined including an estimate of future changes attributed to general price levels (consistent with inflation rate assumptions), productivity, seniority and promotion; (iii) healthcare cost trend assumptions reflect an estimate of the actual future changes in the cost of the healthcare related benefits provided to the plan participants and are based on past and current healthcare cost trends including healthcare inflation, changes in healthcare utilization and changes in health status of the participants; (iv) demographic assumptions such as mortality, disability and turnover reflect the best estimate of these future events for individual employees involved, based principally on available actuarial data; and (v) determination of the expected rates of return on assets is made through compound averaging. For each plan, the distribution of investments among bonds, equities and cash and their specific average expected rate of return is taken into account. Differences between expected and actual costs and between the expected return and the actual return on plan assets routinely occur and are called actuarial gains and losses.

Eni applies the corridor method to amortize its actuarial losses and gains. This method amortizes on a pro-rata basis the net cumulative unrecognized actuarial gains and losses at the end of the previous reporting period that exceed 10% of the greater of: (i) the present value of the defined benefit obligation; and (ii) the fair value of plan assets, over the average expected remaining working lives of the employees participating in the plan. Additionally, obligations for other long-term benefits are determined by adopting actuarial assumptions. The effect of changes in actuarial assumptions or a change in the characteristics of the benefit are taken to the profit or loss in their entirety.

Contingencies

In addition, to accruing the estimated costs for environmental liabilities, asset retirement obligations and employee benefits, Eni accrues for all contingencies that are both probable and estimable. These other contingencies are primarily related to litigation and tax issues. Determining the appropriate amount to accrue is a complex estimation process that includes subjective judgments.

Revenue recognition in the Engineering & Construction segment

Revenue recognition in the Engineering & Construction segment is based on the stage of completion of a contract as measured on the cost-to-cost basis applied to contractual revenues. Use of the stage of completion method requires estimates of future gross profit on a contract by contract basis. The future gross profit represents the profit remaining after deducting costs attributable to the contract from revenues provided for in the contract. The estimate of future gross profit is based on a complex estimation process that includes identification of risks related to the geographical region, market conditions in that region and any assessment that is necessary to estimate with sufficient precision the total future costs as well as the expected timetable. Requests of additional income, deriving from a change in the scope of work, are included in the total amount of revenues when it is probable that the customer will approve the variation and the related amount. Claims deriving from additional costs incurred for reasons attributable to the client are included in the total amount of revenues when it is probable that the counterparty will accept them.

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2008-2010 Group Results of Operations

Overview of the Profit and Loss Account for Three Years Ended December 31, 2008, 2009 and 2010

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

	Year ended December 31,		
	2008	**2009**	**2010**
		(euro million)	
Net sales from operations	108,082	83,227	98,523
Other income and revenues [(1)]	728	1,118	956
Total revenues	108,810	84,345	99,479
Operating expenses	(80,354)	(62,532)	(73,920)
Other operating (expense) income [(2)]	(124)	55	131
Depreciation, depletion, amortization and impairments	(9,815)	(9,813)	(9,579)
OPERATING PROFIT	**18,517**	**12,055**	**16,111**
Finance income (expense)	(640)	(551)	(727)
Income (expense) from investments	1,373	569	1,156
PROFIT BEFORE INCOME TAXES	**19,250**	**12,073**	**16,540**
Income taxes	(9,692)	(6,756)	(9,157)
NET PROFIT	**9,558**	**5,317**	**7,383**
Attributable to:			
- Eni	**8,825**	**4,367**	**6,318**
- non-controlling interest	733	950	1,065

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

(2) Beginning in 2009, the Company accounts for gains and losses on non-hedging commodity derivative instruments, including both fair value remeasurement and settled transactions, as items of operating profit. Prior period results have been restated accordingly.

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

	Year ended December 31,		
	2008	**2009**	**2010**
		(%)	
Operating expenses	74.3	75.1	75.0
Depreciation, depletion, amortization and impairments	9.1	11.8	9.7
OPERATING PROFIT	**17.1**	**14.5**	**16.4**

2010 compared to 2009. Net profit attributable to Eni s shareholders in 2010 was euro 6,318 million, an increase of euro 1,951 million from 2009, or 44.7%. This increase was driven by:

(i) an improved operating performance (up by 33.6% from 2009) which was mainly reported by the Exploration & Production Division (up by 52%), reflecting a favorable trading environment. Improved operating results were also reported by the Engineering & Construction Division due to strong business trends, while the Petrochemicals and the Refining & Marketing Divisions achieved an improved performance in spite of difficult market conditions. Those gains were partly offset by sharply lower results recorded by the Gas & Power Division which was hit by a weak trading environment, and higher environmental charges up by approximately euro 1.1 billion mainly due to the recognition of a provision to account for the proposed global environmental settlement with the Italian Ministry for the Environment as discussed in the paragraph "Significant Transactions";

(ii) recognition of higher inventory holding gains in particular in the Gas & Power Division. This increase is associated with rising gas prices which resulted in an increased carrying amount of gas inventories recorded under the weighted average cost method; and

(iii) higher profits reported from equity-accounted and cost-accounted entities, including certain gains on divestments of assets (approximately euro 300 million).

These increases were partly offset by higher income taxes (up euro 2,401 million compared to 2009) mainly reflecting higher income taxes currently payable by subsidiaries in the Exploration & Production Division operating outside Italy due to higher taxable profit.

2009 compared to 2008. Net profit pertaining to Eni in 2009 was euro 4,367 million, a decrease of euro 4,458 million from 2008, or 50.5%. This decrease was affected by the following factors:

(i) a decreased operating profit reported by the Exploration & Production and Gas & Power segments due to lower oil and gas prices and a weaker gas demand. The Group results were also affected by higher amortization charges taken in connection with new investments. Those negatives were partly offset by recognition of lower inventory write-downs and impairments of property, plant and equipment particularly in the Refining & Marketing and Petrochemical segments. As a result, the Group consolidated operating profit was down euro 6,462 million, or 34.9%, from a year ago;
(ii) lower profit (down euro 804 million) from non-consolidated entities that are accounted for under the equity or the cost method; and
(iii) a higher consolidated tax rate up from 50.3% to 56% (up 5.7 percentage points), mainly due to new tax rules both in Italy and outside Italy which impacted taxes currently payable, charges accounted in the year which were excluded from tax calculations, and the circumstance that in 2008 the tax rate benefited from certain tax gains associated with an adjustment to deferred taxation amounting to euro 733 million as new tax provisions came into effect pertaining to both Italian and foreign subsidiaries.

Discontinued Operations

Discontinued operations in 2010, 2009 and 2008 were immaterial.

Analysis of the Line Items of the Profit and Loss Account

a) Total Revenues

Eni s total revenues were euro 99,479 million, euro 84,345 million and euro 108,810 million for the year ended December 31, 2010, 2009 and 2008, respectively. Total revenues consist of net sales from operations and other income and revenues. Eni s net sales from operations amounted to euro 98,523 million, euro 83,227 million and euro 108,082 million for the year ended December 31, 2010, 2009 and 2008, respectively, and its other income and revenues totaled euro 956 million, euro 1,118 million and euro 728 million, respectively, in these periods.

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Net sales from operations

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

	Year ended December 31,		
	2008	**2009**	**2010**
	(euro million)		
Exploration & Production [(1)]	33,042	23,801	29,497
Gas & Power [(1)]	37,062	30,447	29,576
Refining & Marketing [(2)]	45,017	31,769	43,190
Petrochemicals	6,303	4,203	6,141
Engineering & Construction	9,176	9,664	10,581
Other activities	185	88	105
Corporate and financial companies	1,331	1,280	1,386
Impact of unrealized intragroup profit elimination	75	(66)	100
Consolidation adjustment [(3)]	(24,109)	(17,959)	(22,053)
NET SALES FROM OPERATIONS	**108,082**	**83,227**	**98,523**

(1) From January 1, 2009, results of the gas storage business, which were previously reported within the Exploration & Production segment, are reported within the Gas & Power segment reporting unit, following restructuring of Eni regulated gas businesses in Italy. As of that date, the results of the regulated businesses in Italy therefore include results of the Transport, Distribution, Re-gasification and Storage activities in Italy. Prior period results have been restated accordingly.

(2) From January 1, 2009 Eni adopted IFRIC 13 "Customer Loyalty Programmes" which requires that the award points granted to clients within the related loyalty program be accounted as a separate component of the basic transaction, evaluated at their fair value and recognized as revenues when effectively used. Prior period results have been restated accordingly.

(3) Intragroup sales are included in net sales from operations in order to give a more meaningful indication as to the volume of the activities to which sales from operations by segment may be related. The most substantial intragroup sales are recorded by the Exploration & Production segment. See Note 35 to the Consolidated Financial Statements for a breakdown of intragroup sales by segment for the reported years.

2010 compared to 2009. Eni s net sales from operations (revenues) for 2010 (euro 98,523 million) increased by euro 15,296 million from 2009, or 18.4% from 2009, primarily reflecting higher realizations on oil, refined products and natural gas in U.S. dollar terms and the positive impact of the depreciation of the euro against the U.S. dollar.

Revenues generated by the Exploration & Production Division (euro 29,497 million) increased by euro 5,696 million, or 23.9%, mainly due to higher realizations in U.S. dollar terms (oil up 27.8%; natural gas up 7.1%) and the depreciation of the euro versus the U.S. dollar. Eni s average liquids realizations decreased by 1.33 $/BBL to 72.76 $/BBL due to the settlement of certain commodity derivatives relating to the sale of 28.5 mmBBL. The latter trend is going to continue in 2011 due to current trends in Brent oil prices.

Revenues generated by the Gas & Power Division (euro 29,576 million) decreased by euro 871 million (or 2.9%) due to lower sales volumes in Italy (down 5.75 BCM, or 14.4%), partly offset by the positive impact of a slight recovery in spot and oil-linked gas prices due to a less unfavorable pricing environment compared to 2009 which are reflected in Eni s revenues. Increased sales volumes were also recorded in key European markets.

Revenues generated by the Refining & Marketing Division (euro 43,190 million) increased by euro 11,421 million (or 36%) reflecting higher selling prices of refined products.

Revenues generated by the Petrochemical Division (euro 6,141 million) increased by euro 1,938 million (up 46.1%) mainly reflecting higher average selling prices (up 35.6%) and a recovery in sales volumes (up 10.9%, mainly in the elastomers business area) following stronger demand on end-markets compared to the particularly weak trading environment of the previous year.

Revenues generated by the Engineering & Construction business (euro 10,581 million) increased by euro 917 million, or 9.5%, from 2009, as a result of increased activities in the onshore and drilling business units.

2009 compared to 2008. Eni s net sales from operations (revenues) for 2009 (euro 83,227 million) were down euro 24,855 million, or 23% from 2008, primarily reflecting lower realizations on oil, refined products and natural gas in U.S. dollar terms and lower sales volumes. These negatives were partly offset by the positive impact of the depreciation of the euro versus the U.S. dollar (down 5.3%).

Revenues generated by the Exploration & Production Division (euro 23,801 million) decreased by euro 9,241 million, or 28% from 2008, mainly due to lower realizations in U.S. dollars (oil down 32.2%; natural gas down 29.8%) reflecting a trading environment that was particularly adverse in the first nine months and the impact of energy parameters on gas prices and a fall in gas spot prices. This decrease reflected also lower sales volumes (down 9.2 million BOE, or 1.5%). These negatives were partly offset by the depreciation of the euro versus the U.S. dollar.

Revenues generated by the Gas & Power Division (euro 30,447 million) decreased by euro 6,615 million, or 17.8% from 2008, mainly due to lower gas prices reflecting trends in energy parameters, as well as lower volumes sold in Italy (down 12.8 BCM, or 24.2%) due to the impact of the economic downturn. These negatives were partly offset by increased sales outside Italy due to contribution of the Distrigas acquisition (up 12.02 BCM).

Revenues generated by the Refining & Marketing Division (euro 31,769 million) decreased by euro 13,248 million, or 29.4% from 2008, reflecting lower product prices and lower sales volumes (down 10%), that were partially offset by the impact of the depreciation of the euro versus the U.S. dollar.

Revenues generated by the Petrochemical Division (euro 4,203 million) decreased by euro 2,100 million, or 33.3% from 2008, mainly reflecting lower sales prices (down 26%) due to lower international prices for crude oil and refined products and a decline in volumes sold due to lower end-markets demand that was driven down by the economic downturn.

Revenues generated by the Engineering & Construction business (euro 9,664 million) increased by euro 488 million, or 5.3% from 2008, as a result of the large number of oil and gas projects that were started during the upward phase of the oil cycle.

b) Operating Expenses

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

	Year ended December 31,		
	2008	**2009**	**2010**
		(euro million)	
Purchases, services and other	76,350	58,351	69,135
Payroll and related costs	4,004	4,181	4,785
Operating expenses	**80,354**	**62,532**	**73,920**

2010 compared to 2009. Operating expenses for the year (euro 73,920 million) increased by euro 11,388 million from 2009, up 18.2%, reflecting primarily higher supply costs of purchased oil, gas and petrochemical feedstocks reflecting trends in the trading environment, the depreciation of the euro against the U.S. dollar, as well as higher operating expenses reported by the upstream activities.

Purchases, services and other costs include environmental and other risk provisions for an overall amount of euro 1,291 million mainly associated with an environmental provision recorded to account for a proposed global settlement on certain environmental issues (euro 1,109 million) filed with the Italian Ministry for the Environment, which is disclosed in the paragraph "Significant Transactions" below.

Payroll and related costs (euro 4,785 million) increased by euro 604 million, or 14.4%, mainly due to higher unit labor cost in Italy and outside Italy, partly due to exchange rate translation differences, the increase in the average number of employees outside Italy (following higher activity levels in the Engineering & Construction business), as well as increased provisions for redundancy incentives (euro 423 million in 2010) including a provision representing the charge to be borne by Eni as part of a personnel mobility program in Italy for the period 2010-2011. These increases were partly offset by a decrease in the average number of employees in Italy.

2009 compared to 2008. Operating expenses for 2009 (euro 62,532 million) were down euro 17,822 million from 2008, or 22.2%, reflecting primarily lower supply costs of purchased oil, gas and petrochemical feedstocks, partially offset by the depreciation of the euro against the U.S. dollar.

Purchases, services and other included environmental and other risk provisions, impairments of certain current and non-current assets, other than tangible and intangible assets, amounting to euro 537 million. They also included a charge amounting to euro 250 million which was estimated on the basis of the possible resolution of an investigation related to the TSKJ Consortium based on the current status of the ongoing discussions with U.S. Authorities.

Payroll and related costs (euro 4,181 million) increased by euro 177 million from 2008 (up 4.4%) mainly due to higher unit labor cost in Italy and outside Italy, partly due to exchange rate translation differences, the increase in the average number of employees outside Italy, following the consolidation of Distrigas in the Gas & Power Division, increased personnel in the Engineering & Construction and Exploration & Production businesses due to higher activity levels, as well as increased provisions for redundancy incentives. These increases were partially offset by a decrease in the average number of employees in Italy.

c) Depreciation, Depletion, Amortization and Impairments

The table below sets forth a breakdown of depreciation, amortization and impairments by business segment for the periods indicated.

	Year ended December 31,		
	2008	2009	2010
	(euro million)		
Exploration & Production [(1)]	6,678	6,789	6,928
Gas & Power	797	981	963
Refining & Marketing	430	408	333
Petrochemicals	116	83	83
Engineering & Construction	335	433	513
Other activities	4	2	2
Corporate and financial companies	76	83	79
Impact of unrealized intragroup profit elimination [(2)]	(14)	(17)	(20)
Total depreciation, depletion and amortization	**8,422**	**8,762**	**8,881**
Impairments	1,393	1,051	698
	9,815	**9,813**	**9,579**

(1) Exploratory expenditures of euro 1,199 million, euro 1,551 million and euro 2,057 million are included in these amounts relative to the years 2010, 2009 and 2008, respectively.

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

2010 compared to 2009. In 2010, depreciation, depletion and amortization charges amounted to euro 8,881 million, representing an increase of euro 119 million from 2009, or 1.4%. The Exploration & Production Division recorded higher charges (up euro 139 million) due to increased development activities as new fields were brought into production and higher expenditures were made in order to support production levels in producing fields. Those were partly offset by lower exploration expenditures. Also the Engineering & Construction business recorded higher charges (up euro 80 million) as new vessels and rigs were brought into operation. The decrease recorded in the Refining & Marketing Division reflected a review of the residual useful lives of refineries and related facilities, with an impact of euro 76 million. In doing so, the Company believes that it aligned with practices prevailing among integrated oil companies, particularly the European companies. In the Gas & Power Division, the impact of new investments entered into operation was offset by the revision of the useful lives of gas pipelines (from 40 to 50 years), as revised by the Authority for Electricity and Gas for tariff purposes, from January 1, 2010, with an impact of euro 31 million.

In 2010, impairment charges of euro 698 million mainly regarded an impairment charge of goodwill allocated to the

European gas marketing cash generating unit in the Gas & Power Division. The impaired goodwill derived from the acquisition of the Belgian company Distrigas that was made in 2009. Management forecasts that weak demand growth and continuing oversupply will continue to weigh on the recovery of the European gas sector in the next few years. Rising competitive pressures will pressure unit margins on gas sales and reduce selling outlets. To factor in those trends, management revised downward with respect to past years, future projections for returns and cash flows of the Company s gas business for the next four years. Particularly, the European market business unit is expected to be negatively affected by lowering marketing margins over the next four years. This reflects ongoing development of highly liquid spot markets for gas and the fact that spot prices have increasingly become the prevailing reference price for contractual formulas in supplies outside Italy whereas Eni s purchase costs for gas are mainly indexed to the price of oil and refined products. Trends in spot prices as compared to those in oil-linked purchase costs have been de-coupling until recently resulting in negative spreads during the course of 2010; management expects that those negative trends will not re-couple until 2014 at the earliest. In the 2010 Consolidated Financial Statements, management recognized an impairment loss amounting to euro 426 million associated with goodwill of the European gas business unit considering weak 2010 results and a reduced outlook for profitability as discussed above. Impairment charges of oil and gas properties in the Exploration & Production Division were recorded for significantly lower amount than in the previous two years. Impairments were triggered by a changed pricing environment and downward reserve revisions which mainly pertained to gas properties in the USA with proved and unproved reserves. Minor impairment losses were recorded on assets impaired in previous reporting periods in the Refining & Marketing and Petrochemical Divisions as capital expenditures made in 2010 were completely written-off as Eni does not expect improving profitability in the underlying business units (For further information see "Item 18 Consolidated Financial Statements Note 14 Tangible and Intangible assets").

2009 compared to 2008. In 2009, depreciation, depletion and amortization charges (euro 8,762 million) increased by euro 340 million, or 4% from 2008, mainly in: (i) the Gas & Power Division (up euro 184 million) reflecting consolidation of assets acquired and entry into service of new investments; and (ii) the Exploration & Production segment (up euro 111 million) where higher charges were associated with the depreciation of the euro against the U.S. dollar, rising development activities reflecting consolidation of acquired oil and gas properties and increased expenditures to develop new complex fields and projects. These negatives were partly offset by lower exploration expenses. The Engineering & Construction segment also increased amortization charges in connection with the entry into service of new assets.

In 2009, impairments (euro 1,051 million) which were down euro 342 million, mainly related to: (i) impairment charges recorded on proved and unproved properties in the Exploration & Production Division due to downward reserve revisions and cost increases mainly recorded in the Gulf of Mexico, Australia, Congo and Egypt; (ii) refinery plants due to expectations of poor refining margins reflecting the industry weak fundamentals and plants specific factors such as low complexity. Also impairments of goodwill were recognized on marketing assets acquired in Central-Eastern Europe and certain other marketing assets in the Refining & Marketing Division, in the light of a downsizing of growth expectations on certain markets; and (iii) a number of plants in the Petrochemical Division due to a weak outlook for pricing/margins as a result of lower petrochemical products demand, excess capacity and higher competitive pressures.

d) Operating Profit by Segment

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

	Year ended December 31,		
	2008	**2009**	**2010**
		(euro million)	
Exploration & Production (1)	16,239	9,120	13,866
Gas & Power (1)	4,030	3,687	2,896
Refining & Marketing	(988)	(102)	149
Petrochemicals	(845)	(675)	(86)
Engineering & Construction	1,045	881	1,302
Other activities (2)	(466)	(436)	(1,384)
Corporate and financial companies (2)	(623)	(420)	(361)
Impact of unrealized intragroup profit elimination	125		(271)
Operating profit (3)	**18,517**	**12,055**	**16,111**

(1)

From January 1, 2009, results of the gas storage business, which were previously reported within the Exploration & Production segment, are reported within the Gas & Power segment reporting unit, following restructuring of Eni regulated gas businesses in Italy. As of that date, the results of the regulated businesses in Italy therefore include results of the Transport, Distribution, Re-gasification and Storage activities in Italy. Prior period results have been restated accordingly.

(2) From 2010 certain environmental provisions incurred by the parent company Eni SpA due to inter-company guarantees on behalf of Syndial have been reported within the segment reporting unit "Other activities" rather than the segment "Corporate and financial companies". Data for the years 2008 and 2009 have been restated accordingly for the following amounts: euro 120 million and euro 54 million, respectively.

(3) From 2009, the Company accounts gains and losses on non-hedging commodity derivatives instruments, including both fair value re-measurement and settled transactions, as items of operating profit. Prior period results have been restated accordingly.

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

	Year ended December 31,		
	2008	2009	2010
		(%)	
Exploration & Production	49.1	38.3	47.0
Gas & Power	10.9	12.1	9.8
Refining & Marketing	(2.2)	(0.3)	0.3
Petrochemicals	(13.4)	(16.1)	(1.4)
Engineering & Construction	11.4	9.1	12.3
Other activities			
Corporate and financial companies	(46.8)	(32.8)	(26.0)
Group	**17.1**	**14.5**	**16.4**

Exploration & Production. Operating profit in 2010 amounted to euro 13,866 million, up euro 4,746 million from 2009, or 52%, due to higher liquids and gas realizations in U.S. dollar terms (up by 27.8% and 7.1%, respectively). The result also reflected: (i) a positive impact associated with the depreciation of the euro against the U.S. dollar, for an estimated amount of euro 400 million; (ii) the recognition of lower asset impairments; and (iii) lower exploration expenditures. These positives were partly offset by increased operating expenses and amortizations charges reflecting new fields entered into operation and activities to improve production rates in existing fields, and higher provisions for redundancy incentives (up euro 66 million).

In 2010, liquids and gas realizations increased on average by 18.6% in U.S. dollar terms, driven by higher oil prices for market benchmarks (Brent crude price increased by 29.2%) and, to a lower extent, higher gas prices which were up by 7.1% on average. Eni s oil realizations increased on average by 27.8% driven by a favorable market environment. Eni s average liquids realizations were negatively impacted for an amount of 1.33 $/BBL on average due to the settlement of certain commodity derivatives relating the sale of 28.5 mmBBL in the year at contractually fixed prices. This was part of a derivative transaction the Company entered into to hedge exposure to volability of future cash flows expected from the sale of a portion of the Company s proved reserves for an original amount of approximately 125.7 mmBBL in the 2008-2011 period. As of December 31, 2010, the residual amount of that hedging transaction was 9 mmBBL.

Liquid realizations and the impact of commodity derivatives were as follows:

		Full Year		
		2008	2009	2010
Sales volumes	(mmBBL)	364.3	373.5	357.1
Sales volumes hedged by derivatives (cash flow hedge)		46.0	42.2	28.5
Total price per barrel, excluding derivatives	($/BBL)	**88.17**	**56.98**	**74.09**
Realized gains (losses) on derivatives		(4.13)	(0.03)	(1.33)
Total average price per barrel		**84.05**	**56.95**	**72.76**

Operating profit in 2009 amounted to euro 9,120 million, down euro 7,119 million from 2008, or 43.8%, reflecting lower realizations in U.S. dollars (oil down 32.2%; natural gas down 29.8%), and reduced production sales volumes (down 9.2 mmBOE, or 1.5%). These negatives were partly offset by: (i) positive currency translation differences which were reported by subsidiaries which adopted the U.S. dollar as functional currency, as the euro depreciated on average by 5.3%. This had an estimated positive impact of euro 500 million; (ii) recognition of lower asset impairments (down euro 234 million); and (iii) gains recorded on the divestment of certain exploration and production assets as part of the agreements signed with Suez.

Liquids and gas realizations for the year decreased on average by 31.2% in U.S. dollar terms driven by lower oil prices for market benchmarks (Brent crude price decreased by 36.6%), partly offset by an improved product mix of Eni s crudes (down 32.2%). Average oil realizations were barely unchanged, due to the settlement of certain non-strategic commodity derivatives relating to the sale of 42.2 mmBBL.

In 2009, the impact of those cash flow hedges was immaterial as the increase in liquids realizations by 0.45 $/BBL as a result of the sale of 31.6 mmBBL at the hedged price recorded in the first nine months was absorbed by a reduction on average by 1.46 $/BBL from the sale of 10.6 mmBBL in the fourth quarter, reflecting the inversion in oil prices trends. The derivatives were entered into to hedge exposure to fluctuations in future cash flows expected from the sale of a portion of the Company s proved reserves, in connection with the acquisition of oil and gas assets in Congo and in the Gulf of Mexico. When entered into, those hedging transactions originally covered an amount of approximately 125.7 mmBBL in the 2008-2011 period, which by the end of 2009 has decreased to approximately 37.5 mmBBL.

In 2009, average gas realizations were down 29.8%, driven by time-lags between movements in oil prices and their effect on gas prices pursuant to pricing formulae and by weak spot prices.

Gas & Power. In 2010, the Gas & Power Division reported operating profit of euro 2,896 million, a decrease of euro 791 million from 2009, down 21.5%, due to a lower performance delivered by the Marketing business which was down by 63.7%. This was partly offset by a better performance achieved by the Italian regulated businesses (up by 12.7%). The negative performance in marketing operations was mainly due to: (i) increasing competitive pressures in Italy, due to oversupply conditions in the marketplace and sluggish demand growth, resulting in both sharply lower gas sales (down by 14.4% and 19.5% to Italian customers and Italian wholesalers importers, respectively) and price reductions to customers during the marketing campaign for the new thermal year beginning on October 1, 2010; (ii) outside Italy, the persistence of unprofitable differentials between oil-linked gas purchase costs provided in Eni s long-term gas supply contracts and spot prices recorded at European hubs which have become a prevailing reference benchmark for selling prices; (iii) the impairment of goodwill attributed to the European marketing cash generating unit (euro 426 million), based on 2010 results and a reduced profitability outlook for this business; (iv) a negative change in mark-to-market evaluation of certain commodity derivatives which are recorded against profit as they lack formal requirements to be designated as hedges under applicable accounting standards; and (v) a reversal in trend of certain energy parameters to which gas purchase and selling prices are indexed, mainly in sales to residential users.

These negatives were partly offset by: (i) the recording of higher inventory holding gains due to the impact of rising gas prices on inventories stated at the weighted average cost of supplies or the net realizable value, whichever is lower; and (ii) a non-recurring gain amounting to euro 270 million related to the favorable settlement of an antitrust proceeding resulting in a provision accrued in previous reporting periods being reversed almost entirely to 2010 profit. The provision was originally accrued to take into account a resolution of the Italian Antitrust Authority, who charged Eni with anti-competitive behavior for having allegedly refused third party access to the pipeline for importing natural gas from Algeria.

Operating profit in 2009 amounted to euro 3,687 million, a decrease of euro 343 million compared with 2008, down by 8.5%. This decrease was principally due to the following factors: (i) lower results from marketing operations in Italy as sales volumes of gas declined by 12.83 BCM, or 24.3%, due to the impact of lower gas demand and competitive pressures, also impacting selling margins. The negative margin/volume performance in marketing operations was incurred notwithstanding a positive impact associated with the renegotiation of certain long-term supply contracts; (ii) a negative impact on gas inventory valuation associated with falling gas prices which resulted in a decreased carrying amount of gas inventories recorded at the weighted average cost or net realizable value, whichever is lower; and (iii) a provision accounted in the LNG business associated with poor market perspectives in the USA. These negatives were partly offset by: (i) the circumstance that sales to residential customers in Italy and other customers consuming less than 200,000 CM/y benefited from the regulatory indexation mechanism whereby the selling price was updated with a certain delay to changed market conditions, resulting in higher margins on those sales. Management believes that this mechanism will have an opposite effect on the Company s results in coming quarters; and (ii) positive mark-to-market evaluation of certain commodity derivatives which are recorded against profit as they lack formal requirements to be designated as hedges under applicable accounting standards. The International Transport business recorded a drop in operating profit; while regulated businesses in Italy increased their result.

The table below sets forth break-down of operating profit by businesses in the Gas & Power Division:

	Year ended December 31,		
	2008	**2009**	**2010**
		(euro million)	
Marketing	1,806	1,530	555
Regulated businesses in Italy	1,701	1,773	1,998
International transport	523	384	343
Operating profit of the Gas & Power Division	**4,030**	**3,687**	**2,896**

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Refining & Marketing. In 2010, the Refining & Marketing segment reported an operating profit of euro 149 million, compared to the prior-year loss of euro 102 million. The improvement reflected a less adverse refining scenario with Eni s complex refineries helped by widening price differentials between sour and sweet crudes and better spreads of middle distillates to heating fuel. Refining margins still remained unprofitable as high oil feedstock prices were only partially transferred to final prices of refined products pressured by weak industry fundamentals. The Eni Refining business also benefited from cost efficiencies and various optimization measures in supply and refining activities, and integration of refinery cycles whereby the Gela refinery have begun processing heavy residues from Taranto throughputs thus enabling to reap cost savings and margins improvements. The Marketing business was affected by rapidly rising supply costs that were only partially transferred to prices at the pump, and lower retail sales in Italy. These negatives were partly offset by higher sales on European networks. Results of Refining & Marketing Division also benefited from the circumstance that in 2009 material impairment charges were recorded to align the carrying amounts of unprofitable refining and marketing assets to their projected recoverable amounts (down by euro 313 million).

In 2009, the Refining & Marketing segment reported an operating loss of euro 102 million, which represented a significant improvement (up euro 886 million) compared to 2008 when a loss of euro 988 million was recorded. The improvement reflected the circumstance that an inventory write-down amounting to euro 1,199 million was recorded in 2008 as year end inventories of oil and products were aligned to net realizable values prevailing on the marketplace at the time of the assessment which coincided with the low of the oil cycle. In 2009, an inventory holding gain amounting to euro 792 million was recognized reflecting the impact of a recovery in prices of crude oil and products on year end valuation of inventories according to the average cost method of inventory accounting. When excluding the inventory impacts, the Refining & Marketing segment reported underlying losses mainly due to sharply lower refining margins. Those were affected by an unfavorable trading environment due to weak end-prices of products depressed by poor demand, excess inventory of finished products on the marketplace, in particular diesel oil, whose spread on raw material reached historical lows in the fourth quarter, and excess capacity. As a result, product price did not absorb the purchase price of oil-based feedstock. Also narrowing price differentials between heavy and light crude qualities negatively affected Eni s complex throughputs by reducing cost-advantages associated to conversion: (i) lower operating performance delivered by the Marketing activities affected by weak demand in wholesale markets in Italy and retail European markets; and (ii) higher asset impairment charges recorded in the light of the negative outlook for the refining industry and a downsizing of growth expectations on certain markets.

Petrochemicals. In 2010, the Petrochemical Division recorded a sharp reduction in its operating loss which was down by 87.3% from the year-earlier (from a loss of euro 675 million in 2009 to a loss of euro 86 million in 2010). This positive result reflected better market conditions and a recovery in demand which drove improved product margins and higher sales (up by 10.9% mainly in the elastomers business area). Profitability was also supported by cost efficiencies. An inventory holding gain amounting to euro 105 million was recognized (compared with a loss of euro 121 million in 2009) reflecting the impact of higher oil-based feedstock and commodity prices on year end valuation of inventories according to the average cost method of inventory accounting, as well as lower asset impairments (down by euro 69 million).

In 2009, the Petrochemical segment reported an operating loss in the amount of euro 675 million, which represented an improvement of euro 170 million compared to 2008 mainly due to lower impairment losses (down euro 157 million from 2008). The segment s results continued to be affected by weak industry fundamentals due to poor demand, excess capacity and competitive pressures. As a result, the segment reported unprofitable margins on products and lower sales volumes (down 8.9%).

Engineering & Construction. Operating profit in 2010 amounted to euro 1,302 million, an increase of euro 421 million, or 47.8% compared to 2009. This increase was driven by a positive operating performance reported by the Onshore Construction and Offshore Drilling business areas reflecting higher activity levels and higher margins on the works performed. The utilization rate of the Perro Negro 6 jack-up and the semisubmersibles Scarabeo 3 and 4 increased. In addition, the comparison with 2009 benefited from the circumstance that in 2009 a charge amounting to euro 250 million was recorded to settle the TSKJ legal proceeding "Item 8 Financial Information Legal Proceedings" for further details.

Operating profit in 2009 amounted to euro 881 million, a decrease of euro 164 million, or 15.7% compared to 2008. This decrease related to a non-recurring item represented by a charge amounting to euro 250 million that was the estimated cost of a possible resolution of the investigation related to the TSKJ Consortium based on the current status of ongoing discussions with U.S. Authorities (See "Item 18 Note 34 of the Financial Statements"). Although the charge was recognized in the segment results of the Engineering & Construction business as it related to a project to build gas liquefaction plants, it will be fully incurred by Eni and Saipem s minorities will be left unaffected due to Eni s contractual obligations to indemnify Saipem undertaken in connection with the divestiture of Snamprogetti SpA, whose subsidiary Snamprogetti Netherlands BV participates to the TSKJ venture. See "Item 8 Financial Information Legal Proceedings" for further details. When excluding the impact of the charge, the segment reported an improved operating performance recorded in all business areas reflecting steady revenue

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growth and stable profitability as a result of the large number of oil and gas projects that were started during the upward phase of the oil cycle.

Other activities. This reporting segment includes the results of operations of Eni s subsidiary Syndial which runs minor petrochemical activities and reclamation and decommissioning activities pertaining to certain businesses which Eni exited in past years.

Other activities reported an operating loss of euro 1,384 million for 2010, representing a sharply higher increase of euro 948 million compared to the loss recorded in 2009 (euro 436 million) mainly due to higher environmental provisions recorded to account for a proposed global transaction on certain environmental issues (euro 1,109 million) filed with the Italian Ministry for the Environment, which is disclosed in the paragraph "Significant Transactions" below.

Other activities reported an operating loss of euro 436 million for 2009, representing an improvement of euro 30 million, or 6.4%, compared to the loss recorded in 2008 (euro 466 million) mainly due to lower environmental charges.

Corporate and financial companies. These activities are mainly cost centers which comprise corporate activities and central treasury departments and financial and other subsidiaries that provide a range of financial and business support services to Group companies, including financing of Eni s projects around the world, information technology, employee selection, training and retention, real estate and other general purposes services.

The aggregate Corporate and financial companies reported an operating loss of euro 361 million for 2010, representing a reduction of euro 59 million, compared to the loss recorded in 2009 (euro 420 million), mainly reflecting the implementation of cost efficiency measures.

The aggregate Corporate and financial companies reported an operating loss of euro 420 million for 2009, representing a reduction of euro 203 million, compared to the loss recorded in 2008 (euro 623 million), mainly reflecting the circumstance that in 2008 a contribution of euro 200 million to the solidarity fund pursuant to Italian Law Decree No. 112/2008 to be used to subsidize the gas bills for residential uses of less affluent citizens and higher environmental provisions were accounted for.

e) Net Finance Expense

The table below sets forth a breakdown of Eni s net finance expense for the periods indicated:

	Year ended December 31,		
	2008	2009	2010
	(euro million)		
Gain (loss) on derivative financial instruments	(427)	(4)	(131)
Exchange differences, net	206	(106)	92
Interest income	87	33	18
Finance expense on short and long-term debt	(993)	(753)	(766)
Finance expense due to the passage of time	(249)	(218)	(251)
Income from equity instruments	241	163	

Other finance income and expense, net