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

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(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.

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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,

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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.

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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 conditio