ENI SPA
Form 20-F
June 21, 2006

SECURITIES AND EXCHANGE COMMISSION

Washington, DC 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, 2005

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)

Piazzale Enrico Mattei 1, 00144 Rome, Italy

(Address of Principal Executive Offices)

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)	

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 each	**4,005,358,876**

Indicate by check mark whether 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 whether the Registrant is nor required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934:

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 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:

Large accelerated filer Accelerated filer Non-accelerated filer

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

* Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission.

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(*) Omitted pursuant to General Instructions for Form 20-F.

(**) The Registrant has responded to Item 18 in lieu of responding to Item 17.

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 Qualitative and Quantitative 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 , 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 Report 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.*

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CERTAIN DEFINED TERMS

In this Form 20-F, the term "Eni" or the "Company" refers to 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 "Certain Oil and Gas Terms" and "Conversion Table".

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PRESENTATION OF FINANCIAL AND OTHER INFORMATION

The Consolidated Financial Statements of Eni, included in this annual report, have been prepared in accordance with IFRS issued by the International Accounting Standards Board (IASB) and adopted by the European Commission following the procedure contained in Article 6 of the EC Regulation No. 1606/2002 of the European Parliament and Council of July 19, 2002. Until December 31, 2004, Eni prepared its Consolidated Financial Statements and other interim financial information (including quarterly and semi-annual data) in accordance with Italian GAAP. IFRS require adopting companies to restate only one year of past financial statements. Pursuant to SEC Release 33-8567, *"First-time Application of International Financial Reporting Standards"*, Eni is not required to include in this annual report financial statements for any earlier periods. Accordingly this annual report includes financial information prepared in accordance with IFRS as of and for the two years ended December 31, 2004 and 2005.

IFRS, under which Eni s Consolidated Financial Statements have been prepared, differ in certain significant respects from U.S. GAAP. For information on the differences between IFRS and U.S. GAAP as they relate to Eni, see Notes 33, 34 and 35 to Eni s Consolidated Financial Statements included herein.

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.

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 — It is a non-GAAP measure of a company s financial condition, calculated as the ratio between net borrowings and shareholders equity, including minority interests. For a discussion of management s view of the usefulness of this measure and its reconciliation with the most directly comparable GAAP measure, 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, see "Item 5 Financial Condition".

Business terms

Associated gas — Natural gas, occurring in the form of a gas cap, overlying an oil zone, contained in the reservoir s crude oil gas.

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 — These are light hydrocarbons produced along with gas that condense to a liquid state at surface temperature and pressure.

Conversion capacity	Maximum amount of heavy fractions that can be processed in certain dedicated facilities of a refinery to obtain finished products.
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.
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 petrochemicals products). Margin trends reflect the trading environment and are, to a certain extent, a gauge of industry profitability.
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.
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 mining concession is assigned 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 the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of the impact of changes on existing prices on existing contractual arrangements, but not on escalations based upon future conditions. Proved reserves include: (i) proved developed reserves: amounts of hydrocarbons that are expected to be retrieved through existing wells, facilities and operating methods; and (ii) non-developed proved reserves: amounts of hydrocarbons that are expected to be retrieved following new drilling, facilities and operating methods. Based on these amounts the company has already defined a clear development expenditure program which is an expression of the company s determination to develop existing reserves.
Reserve life index	Ratio between the amount of 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 property or upstream assets, the revision of previous estimates, enhanced recovery, improvement in recovery rates and changes in the value of reserves in PSAs due to changes in international oil prices.
Ship-or-pay	Clause included in natural gas transportation contracts according to which the customer is requested to pay for the transportation of gas whether or not the gas is actually transported.

Strategic Storage	According to Legislative Decree No. 164/2000, these are volumes required for covering lack or reduction of supplies from extra-European sources or crises in the natural gas system.
Take-or-pay	Clause included in natural gas supply contracts according to which the purchaser is bound to pay the contractual price or a fraction of such price for a minimum quantity of gas set in the contract whether or not the gas is collected by the purchaser. The purchaser has the option of collecting the gas paid for and not delivered at a price equal to the residual fraction of the price set in the contract in subsequent contract years.
Upstream/Downstream	The term upstream refers to all hydrocarbon exploration and production activities. The term downstream includes all activities inherent to the oil sector that are downstream of exploration and production activities.

ABBREVIATIONS

mmCF	=	million cubic feet
BCF	=	billion cubic feet
mmCM	=	million cubic meters
BCM	=	billion cubic meters
BOE	=	barrel of oil equivalent
KBOE	=	thousand barrel of oil equivalent
mmBOE	=	million barrel of oil equivalent
BBOE	=	billion barrel of oil equivalent
BBL	=	barrels
KBBL	=	thousand barrels
mmBBL	=	million barrels
BBBL	=	billion barrels
/d	=	per day
/y	=	per year

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CONVERSION TABLE

1 acre	= 0.405 hectares	
1 barrel	= 42 U.S. gallons	
1 BOE	= 1 barrel of crude oil	= 5,742 cubic feet of natural gas [1]
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]	
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)

(1) From January 1, 2004 in order to conform to the practice of other international oil companies, Eni unified the conversion rate of natural gas from cubic meters to BOE. The new rate adopted is 1 barrel of oil equals 5,742 cubic feet of natural gas. This conversion rate has been determined by management based on a number of factors. Other oil companies may use a different conversion rate. The change introduced had a negligible impact on production expressed in BOE.

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) and adopted by the European Commission following the procedure contained in Article 6 of the EC Regulation No. 1606/2002 of the European Parliament and Council of July 19, 2002. Until December 31, 2004, Eni prepared its Consolidated Financial Statements and other interim financial information (including quarterly and semi-annual data) in accordance with Italian GAAP. IFRS require adopting companies to restate only one year of past financial statements. Pursuant to SEC Release 33-8567, *"First-time Application of International Financial Reporting Standards*", Eni is not required to include in this annual report financial statements for any earlier periods. Accordingly the tables below show Eni selected historical financial data prepared in accordance with IFRS as of and for the years ended December 31, 2004 and 2005 and in accordance with U.S. GAAP for the five year period ended December 31, 2005. The selected historical financial data are derived from Eni s Consolidated Financial Statements included herein. IFRS, under which Eni s Consolidated Financial Statements have been prepared, differ in certain significant respects from U.S. GAAP. For information on the differences between IFRS and U.S. GAAP as they relate to the Eni, see Notes 33, 34 and 35 to the Eni s Consolidated Financial Statements.

	Year ended December 31,				
	2001	**2002**	**2003**	**2004**	**2005**
	(million euro except data per share and per ADS)				
CONSOLIDATED PROFIT STATEMENT DATA					
Amounts in accordance with IFRS (euro):					
Net sales from operations				57,545	73,728
Operating profit					
Exploration & Production				8,185	12,574
Gas & Power				3,428	3,321
Refining & Marketing				1,080	1,857
Petrochemicals				320	202
Oilfield Services Construction and Engineering				203	307
Other activities	-			(395)	(902)
Corporate and financial companies				(363)	(391)
Unrealized profit in inventory [(1)]				(59)	(141)

Operating profit				12,399	16,827
Net profit pertaining to Eni				7,059	8,788
Data per ordinary share (euro) [(2)]:					
Operating profit				3.29	4.48
Net profit: basic and diluted				1.87	2.34
Data per ADS ($) [(2)] [(3)]:					
Operating profit				8.91	10.61
Net profit: basic and diluted				5.06	5.54
Amounts in accordance with U.S. GAAP (euro):					
Net sales from operations	45,848	43,632	48,018	54,698	70,331
Operating profit [(4)]	8,853	7,861	9,215	11,739	15,528
Profit before cumulative effect of change in accounting principle and income taxes	10,330	8,350	9,274	12,324	16,281
Net profit before cumulative effect of change in accounting principle			6,098		
Effect of adoption of SFAS No. 143			198		
Net profit	6,317	5,292	6,296	6,401	7,583
Data per ordinary share (euro) [(2)]:					
Operating profit	2.26	2.05	2.44	3.11	4.13
Net profit: basic and diluted	1.62	1.38	1.67	1.70	2.02
Data per ADS ($) [(2)] [(3)]:					
Operating profit	4.02	4.30	6.15	8.42	9.78
Net profit: basic and diluted	2.88	2.89	4.21	4.60	4.78

	As of December 31,				
	2001	2002	2003	2004	2005
	(million euro except number of shares and dividend information)				
CONSOLIDATED BALANCE SHEET DATA					
Amounts in accordance with IFRS:					
Total assets				72,853	83,850
Short-term and long-term debt				12,684	12,998
Capital stock issued				4,004	4,005
Amounts in accordance with U.S. GAAP:					
Total assets	64,976	66,122	71,995	72,354	82,977
Short-term and long-term debt	12,379	15,320	16,144	12,697	12,954
Capital stock issued	4,001	4,002	4,003	4,004	4,005
Other Financial Information in accordance with IFRS:					
Capital expenditure				7,499	7,414
Weighted average number of ordinary shares outstanding (shares million)	3,912	3,827	3,778	3,772	3,759
Dividend per share (euro)	0.750	0.750	0.750	0.900	1.100
Dividend per ADS ($) (5)	1.48	1.71	1.83	2.17	2.63

(1) Unrealized profit in inventory concerned intragroup sales of goods and services.

(2) Euro per Share or dollars per American Depositary Share (ADS), as the case may be. Starting from December 2005 one ADS represents two Eni shares. Previously one ADS was equivalent to five Eni shares. Data per ADS for prior periods have been recalculated accordingly. Earnings per share is calculated by dividing net profit by the weighted-average number of shares issued and outstanding during the year, excluding treasury shares. The dilutive effect of potential ordinary shares, in terms of the number of ordinary shares underlying outstanding stock grants and stock options on earnings per share or ADS, is immaterial.

(3) The 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 euros 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 ADS, with the exception of dividend per ADS in the years 2001 to 2004, were translated at the Noon Buying Rate of December 31 for each year presented ($0.8901, 1.0485, 1.2597 1.3538 and 1.1842 = euro 1.00 as of December 31, 2001, 2002, 2003, 2004 and 2005, respectively). Dividend per ADS for the years 2001 through 2004 has been translated into U.S. dollars using for each year presented the Noon Buying Rate on the payment date. On June 12, 2006, the Noon Buying Rate was $1.26 per euro 1.00.

(4) See Note 34 to the Consolidated Financial Statements for details of operating profit under U.S. GAAP by business segment for the last two years.

(5) Historic dividends of the four years 2001-2004 were converted at the Noon Buying Rate of the pay-out date. The dividend for 2005 was converted at the Noon Buying Rate of the interim dividend (euro 0.45 per share) pay-out date, occurred on October 27, 2005. The balance of euro 0.65 per share payable on June 22, 2006 was translated at the Noon Buying Rate of December 31, 2005.

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Selected Operating Information

The table below sets 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, 2001, 2002, 2003, 2004, 2005. Data on proved reserves, production of oil and natural gas and hydrocarbon production sold includes Eni s share of reserves and production of affiliates and joint ventures accounted for under the equity or cost method of accounting.

	Year ended December 31,				
	2001	2002	2003	2004	2005
Proved reserves of oil at period end (mmBBL)	3,948	3,783	4,138	4,008	3,773
Proved reserves of natural gas at period end (BCF)	17,072	18,629	18,008	18,435	17,591
Proved reserves of hydrocarbons in mmBOE at period end (1)	6,929	7,030	7,272	7,218	6,837
Reserve replacement ratio (2) (three year average)	226	202	179	117	89
Reserve life index (3)	13.7	13.2	12.7	12.1	10.8
Average daily production of oil (KBBL/d)	857	921	981	1,034	1,111
Average daily production of natural gas available for sale (mmCF/d) (4)	2,827	3,015	3,174	3,171	3,344
Average daily production of hydrocarbons available for sale (KBOE/d) (4)	1,353	1,449	1,536	1,586	1,693
Hydrocarbon production sold (mmBOE)	499.7	523.3	556.2	576.5	614.9
Oil and gas production costs per BOE (5)	3.85	3.83	4.16	4.92	5.59
Profit per barrel of oil equivalent (6)	5.48	5.08	5.95	8.87	12.20
Sales of natural gas to third parties (7)	63.72	64.12	69.49	72.79	77.08
Natural gas consumed by Eni (7)	2.00	2.02	1.90	3.70	5.54
Sales of natural gas of affiliates and relevant companies (Eni s share) (7)	1.38	2.40	6.94	7.32	8.53
Total sales and own consumption of natural gas (7)	67.10	68.54	78.33	83.81	91.15
Transport of natural gas for third parties in Italy (7)	11.41	19.11	24.63	28.26	30.22
Length of natural gas transport network in Italy at period end (8)	29.6	29.8	30.1	30.2	30.7
Electricity production sold (9)	4.99	5.00	5.55	13.85	22.77
Refined products production (10)	37.78	35.55	33.52	35.75	36.68
Balanced capacity of wholly-owned refineries (11)	664	504	504	504	524
Capacity utilization of wholly-owned refineries (12)	97	99	100	100	100
Number of service stations at period end (in Italy and outside Italy)	11,707	10,762	10,647	9,140	6,282
Average throughput per service station (in Italy and outside Italy) (13)	1,685	1,858	2,109	2,488	2,479
Petrochemicals production (10)	7.83	7.12	6.91	7.12	7.28
Oilfield Services Construction and Engineering order backlog at period end (14)	6,937	10,065	9,405	8,521	9,964
Employees at period end (units)	72,405	80,655	75,421	70,348	72,258

(1) Includes approximately 728, 779, 747, 737 and 760 BCF of natural gas held in storage in Italy at December 31, 2001, 2002, 2003, 2004 and 2005, respectively. See "Item 4 Information on the Company Exploration & Production Storage".

(2) Consists of: (i) the increase in proved reserves 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 SFAS 69. See the unaudited supplemental oil and gas information in Note 35 to the Consolidated Financial Statements. Expressed as a percentage.

(3) Consists of proved reserves at year end divided by production during the year as set forth in the reserve tables, in each case presented in accordance with SFAS 69. See the unaudited supplemental oil and gas information in Note 35 to the Consolidated Financial Statements. Expressed on a yearly basis.

(4) Natural gas production volumes exclude gas consumed in operations (94, 132, 151, 220 and 250 mmCF/d in 2001, 2002, 2003, 2004 and 2005, respectively).

(5) Consists of production costs (costs incurred to operate and maintain wells and field equipment including also royalties) prepared under U.S. GAAP divided by actual production net of production volumes of natural gas consumed in operations. See the unaudited supplemental oil and gas information in Note 35 to the Consolidated Financial Statements. Expressed in dollars.

(6) Results of operations from oil and gas producing activities, divided by actual sold production, in each case prepared in accordance with SFAS 69. See the unaudited supplemental oil and gas information in Note 35 to the Consolidated Financial Statements for a calculation of results of operations from oil and gas producing activities. Expressed in dollars.

(7) Expressed in BCM.

(8) Expressed in thousand kilometers.

(9) Expressed in terawatthour.

(10) Expressed in million tonnes.

(11) Expressed in KBBL/d.

(12) Expressed in production as a percentage of capacity taking into account scheduled plant shutdowns.

(13) Expressed in thousand liters per day. Referred to the Agip brandednetwork.

(14) The sum of the order backlog of Saipem SpA and Snamprogetti SpA, expressed in millions of euro.

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Exchange Rates

The following table sets 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,				
2001	0.95	0.84	0.90	0.89
2002	1.05	0.86	0.95	1.05
2003	1.26	1.04	1.13	1.26
2004	1.36	1.18	1.24	1.35
2005	1.35	1.17	1.24	1.18

(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		
December 2005	1.20	1.17	1.18
January 2006	1.23	1.20	1.22
February 2006	1.21	1.19	1.19
March 2006	1.22	1.19	1.21
April 2006	1.26	1.21	1.26
May 2006	1.29	1.26	1.28
June 2006 (through June 12, 2006)	1.30	1.26	1.26

Fluctuations in the exchange rate between the euro and the dollar affect the dollar equivalent of the euro price of the Shares on the Telematico and the dollar price of the ADSs on the NYSE. Exchange rate fluctuations also affect the dollar amounts received by owners of ADSs upon conversion by the Depository of cash dividends paid in euro on the underlying Shares. The Noon Buying Rate on June 12, 2006 was $1.26 per euro 1.00.

Risk Factors

Competition

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

In the Exploration & Production business, Eni encounters competition from other international oil companies for obtaining exploration and development rights, particularly outside Italy. The current trend of the industry towards a reduction of the number of operators via takeovers or mergers might lead to possibly stronger competition from operators with greater financial resources and a wider portfolio of development projects.

In its natural gas business, Eni encounters increasingly strong competition from both national and international natural gas suppliers, also following the impact of the liberalization of the Italian natural gas market introduced by Legislative Decree No. 164/2000 which provides for, among other things, the opening of the Italian market to competition, limitations to the size of gas companies relative to the market and third party access to transport infrastructure. In addition, Legislative Decree No. 164/2000 grants the Italian Authority for Electricity and Gas certain regulatory powers in the matters of natural gas pricing and access to infrastructure, among others. In its electricity business, Eni competes with other producers from Italy or outside Italy which sell electricity on the Italian market.

Eni faces competition from several international oil companies in its refinery and refined product marketing businesses. In retail marketing 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 plans for the upgrading and efficiency improvement of the national service station network can advance only in accordance with the evolution of the regulatory framework, which lags behind that of other major European countries.

Eni also faces significant competition from certain international operators in the oilfield services, construction and engineering industries. Such competition is primarily on the basis of technical expertise, quality and number of services and availability of technologically advanced facilities (for example vessels for offshore construction).

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 expenditure and entails particular economic risks and opportunities. It is subject to natural hazards and other uncertainties including those relating to the physical characteristics of oil or natural gas fields. The production of oil and natural gas is highly regulated and is subject to intervention 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, environmental protection measures, control over the development and abandonment of fields and installations, and restrictions on production. The oil and gas industry is subject to the payment of royalties and excise duties, which tend to be higher than those payable in respect of many other commercial activities.

Exploratory drilling efforts may not be successful

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, among others, 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 other adverse weather conditions and shortages or delays in the delivery of equipment. Exploring or drilling in offshore areas, in particular in deep water, is generally more complex and riskier than in onshore areas; so is exploratory activity in remote areas or in challenging environmental conditions as in the case of the Caspian Region or Alaska.

Failure in the activity of exploration of oil and natural gas could have an adverse impact on Eni s future results of operations and financial condition. Because of the percentage of Eni s capital plans devoted to higher risk exploratory projects, it is likely that Eni will continue to experience significant exploration and dry hole expenses. In particular Eni plans to explore for oil and gas offshore, often in deep water or at deep drilling depths, where operations are more difficult and costly than on land or at shallower depths and in shallower waters. Deep water operations generally require a significant amount of time between a discovery and the time that Eni can produce and market the oil or gas increasing both the operational and financial risks associated with these activities. In addition, lack of necessary equipments such as a shortage of deep water rigs, could further delay operations, thus increasing both operational and financial risks.

In addition, failure in finding additional commercial reserves could dampen future production of oil and natural gas which is highly dependent on the rate of success of exploratory activity.

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

Eni is involved in numerous development projects for the production of hydrocarbon reserves, principally offshore. Eni s future results of operations rely upon its ability to develop and operate major projects as planned. Key factors that may affect the economics of those 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);
- timely issuance of permits and licenses by governmental agencies;
- the occurrence of technical difficulties including delays in manufacturing and delivery of critical equipment, and, risks associated with the use of new technologies;
- changes in operating conditions and costs, including costs of third party equipment or services such as drilling rigs and shipping;
- the actual performance of the reservoir and natural field decline;
- the availability of third party equipment or services; and
- the ability and time necessary to realize suitable transport infrastructures to export production towards final markets.

Furthermore, deep water 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 estimated and actual timing of critical events may adversely affect the completion and start-up of production from such projects and, consequently, the actual returns on such projects.

Inability in replacing oil and natural gas reserves could adversely impact operations and earnings

Eni s operations and earnings are substantially dependent on our ability to develop and sell oil and natural gas. Unless we are able to replace produced oil and natural gas, our reserves will decline. Future oil and gas production are 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 and future results of operations.

Lifting and development costs are increasing and this could reduce profit per BOE for the oil industry

Profit margins in the oil industry are being affected by a steady rising trend in lifting and development costs as a result of the following: (i) the increasingly high percentage of complex development projects (such as those in deep and ultra deep waters and in harsh environments) which bear higher development costs as compared to development projects in traditional environments; (ii) inflationary pressure affecting purchase prices of raw materials and services in connection to the worldwide economic recovery; and (iii) lack of specialized resources (such as engineers and other valuable technicians) especially in remote areas. Eni s management expects this rising trend of lifting and development costs to continue in the medium term and this could lead to a reduction in profit per BOE.

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

Crude oil prices are subject to international supply and demand and other factors that are beyond Eni s control. OPEC member countries control production of a significant portion of the worldwide supply of oil and can exercise substantial influence on its price levels. International geopolitical tensions and political developments, including sanctions imposed on certain oil-producing countries on the basis of resolutions of the United Nations, can also affect world supply and prices of oil. Such factors can also affect the prices of natural gas because natural gas prices are typically tied to the prices of certain crudes and refined petroleum products. Lower crude oil prices could have an adverse impact on Eni s results of operations.

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 judgement;
- 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 production after the date of the estimates may require substantial upward or downward revisions;
- changes in oil and natural gas prices could have an effect on the quantities of Eni s proved reserves because the estimates of reserves are based on prices and costs at the date when such estimates are made. In particular the reserves estimates are subject to revision as prices fluctuate due to the cost recovery feature under certain Production Sharing Agreements (PSAs); and
- the production performance of Eni s reservoirs.

Many of these factors, assumptions and variables involved in estimating proved reserves are beyond Eni s control and may prove to be incorrect over time. Accordingly, the estimated reserves could be materially different from the quantities of oil and natural gas that ultimately will be recovered. Additionally, any downward revision in Eni s estimated quantities of proved reserves could adversely impact Eni s financial results, leading to increased depreciation, depletion and amortization charges and/or impairment charges, which would reduce earnings and shareholders equity.

Political Considerations

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. At December 31, 2005, approximately 73% of Eni s proved hydrocarbon reserves were located in such countries. Similarly, a substantial portion of Eni s natural gas supply comes from countries outside the EU and North America. In 2005, approximately 60% of Eni s supplies of natural gas came from such countries. See "Item 4 Gas & Power Natural Gas Supplies". Adverse political and economic developments in any such producing country may affect Eni s ability to continue operating in that country, either temporarily or permanently, and affect Eni s ability to access oil and gas reserves. In operating in politically unstable countries Eni faces risks in connection with the following: (i) lack of well-established and reliable legal systems; (ii) other political developments and laws and regulations (such as expropriation or forced divestiture of assets and unilateral cancellation or modification of contract terms), for example in April 2006, Eni s titles and mineral assets relating to an important oil field were transferred to the Venezuelan state oil company following its unilateral cancellation of the contract regulating oil activities in the field; (iii) restrictions on exploration, production, imports and exports; (iv) tax or royalty increases (including retroactive claims); and (v) civil unrest, for example in the first quarter of 2006 certain episodes of civil unrest in Nigeria caused disruptions at certain Eni oil producing facilities. See "Item 4 Exploration & Production Oil and Natural Gas Reserves"; and "Item 5 Recent Developments".

In August 1996, the United States adopted the Iran and Libya Sanctions Act (the "Sanctions Act") with the objective of denying Iran and Libya the ability to support acts of international terrorism and fund the development or acquisition of weapons of mass destruction. On April 23, 2004 the President of the United States terminated the application of the Sanctions Act to Libya, with the remaining economic sanctions against Libya lifted on September 23, 2004. The Sanctions Act still applies to Iran and authorizes the President of the United States to impose sanctions from a six-sanction menu under certain circumstances against any person, including any foreign company, making investments in Iran, thus contributing directly and significantly to the enhancement of Iran s ability to develop its hydrocarbons resources. The Sanctions Act is scheduled to expire on August 5, 2006. Eni does not believe that enforcement of the Sanctions Act against it would have a material adverse effect on its financial condition or results of operations. However, a bill to amend and extend the extra-territorial reach of the economic sanctions imposed by the United States with respect to Iran has been passed by the U.S. House of Representatives and may lead to the passage of new laws in this area. Iran continues to be designated by the U.S. State Department as a State sponsoring terrorism. For a description of Eni s operations in Iran and Libya see "Item 4 Information on the Company Exploration and Production North Africa and Rest of World".

Cyclicality of the Petrochemical Industry

The petrochemical industry is subject to cyclical fluctuations in demand, with consequent effects on prices and profitability exacerbated by the highly competitive environment of the industry. Eni s petrochemicals operations, which are located mainly in Italy, have been in the past and may in the future be adversely affected by worldwide excess installed production capacity, as well as by economic slowdowns in many industrialized countries. The dislocation of petrochemical activities to geographic areas like the Far East and oil producing countries which provide long-term competitive advantages has weakened the competitiveness of petrochemicals operations in industrialized countries, including Eni s petrochemical operations. Petrochemical operations in industrialized countries are also less competitive than those located in the above-mentioned areas due to stricter regulatory frameworks and growing environmental concerns which prevail in industrialized countries.

Liberalization of the Italian Natural Gas Market

Legislative Decree No. 164/2000 opened completely the Italian natural gas market starting on January 1, 2003. This means that all customers in Italy are free to choose their supplier of natural gas. The decree, among other things, introduced rules which have a significant impact on Eni s activity, as the company is present in all the phases of the natural gas chain, in particular:

- until December 31, 2010, antitrust thresholds for operators will be calculated as a percentage share of national consumption as follows: (i) effective January 1, 2002, 75% for imported or domestically produced natural gas volumes input into the national transport network and destined to sales; this percentage is to decrease by 2 percentage points per year until it reaches 61% in 2009; and (ii) effective January 1, 2003, 50% for sales to final customers. Compliance with these ceilings is verified annually by comparing the allowed average percentage on a three year basis for volumes input or sold to the average percentage obtained by each operator in the same three year period. Allowed percentages are calculated net of losses (in the case of sales) and volumes of natural gas consumed in own operations. In accordance with Article 19, paragraph 4 of Legislative Decree No. 164/2000 the volumes of natural gas consumed in own operations by a company or its subsidiaries are excluded from the calculation of ceilings for sales to end customers and for volumes input into the Italian network to be sold in Italy; transport of natural gas by means of high pressure trunklines, storage of natural gas, LNG facilities and distribution of natural gas in urban centers by means of low pressure networks are activities of public relevance and criteria for determining tariffs of those activities are set by the Authority for Electricity and Gas; and third parties are allowed to access natural gas infrastructure which comprises, among other things, high pressure trunklines, low pressure networks and storage sites according to certain conditions set by the Authority for Electricity and Gas.

The new regulatory regime has the effect of limiting the size and profitability of Eni s natural gas business in Italy.

Eni s natural gas margin in Italy may decrease permanently compared to historical levels

In order to meet the expected growth of the Italian natural gas market over the medium and long-term, Eni entered into long-term purchase contracts with producing countries that currently have a residual average term of approximately 15 years. Existing contracts, which in general contain take-or-pay clauses, will ensure total delivery of approximately 67.3 BCM/y of natural gas (Russia 28.5, Algeria 21.5, the Netherlands 9.8, Norway 6 and Nigeria 1.5) by 2008. The above quantities are based on the annual contract quantity of the relevant contract. The average annual minimum quantity that Eni is committed to purchase under its take-or-pay obligations is approximately 85% of said quantities. In order to comply with the above mentioned regulatory thresholds relating to volumes input into the national transport network and sales volumes in Italy, Eni signed multi-year contracts with third party importers in Italy and started implementing a strategy of increasing natural gas sales in the rest of Europe in order to sell outside Italy natural gas volumes available under its take-or pay contracts, exceeding mandatory thresholds. In prior years Eni sold the majority of its natural gas availability on the Italian market. This change in the sale mix is structural and is adversely affecting Eni s results of operations. Further, management expects Eni s margins on natural gas in Italy to come under pressure in future years due to the entry into the market of new competitors, including the impact of the build-up of Eni s supplies to the above mentioned Italian importers.

Eni growth prospects in Italy are limited by regulation

Due to the antitrust threshold on direct sales in Italy, management expects Eni s natural gas sales in Italy to increase at a rate that cannot exceed the growth rate of natural gas demand in Italy. Management believes this development might have a material adverse impact on Eni s results of operations.

If Eni fails to grow natural gas sales in Europe as planned, Eni may be unable to fulfill its minimum take obligations under take-or-pay purchase contracts and this could adversely impact results of operations

Over the medium term, Eni plans to increase its natural gas sales in Europe also to absorb its natural gas availability under take-or-pay contracts. Should Eni fail to increase natural gas sales in Europe as planned, Eni may be unable to sell all the volumes of natural gas purchased under take-or-pay contracts, and this could adversely impact results of operations.

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

Over the next few years, Eni plans to import certain volumes of natural gas using the highest purchase flexibility as provided for by its take-or-pay purchase contracts. Eni also assumes that it will be entitled to the necessary transport capacity on the Italian transport infrastructure. However, Eni planning assumptions are inconsistent with current rules regulating the access to Italian transport infrastructure as provided for by the Network Code drafted under Decision No. 137 of July 17, 2002 of the Authority for Electricity and Gas. Such rules established certain priority criteria for the entitlement to transport capacity of natural gas at points where the Italian transport infrastructure connects with international transport networks (the so-called entry points to the Italian transport system). In particular current rules establish that take-or-pay contracts entered into before 1998, as in the case of Eni, have the right to a priority in the entitlement to available transport capacity equal to average daily contractual volumes. There is therefore no guaranteed access priority for Eni s contracted volumes exceeding average daily contractual volumes. In fact, take-or-pay contracts entered into by Eni before 1998 envisage Eni s right to offtake daily volumes larger than the average daily contractual volume; this contractual flexibility provided by the difference between the maximum daily volume Eni is allowed to purchase and the average daily contractual volume is used when demand peaks, usually during the winter. In the event of congestion at entry points, natural gas volumes not receiving priority are entitled to available transport capacity in proportion with requests from operators. Eni considers Decision No. 137/2002 to be inconsistent with the overall rationale of the European natural gas legislative framework, especially with reference to Directive 98/30/CE and Legislative Decree No. 164/2000, and is challenging Decision No. 137/2002 before the competent administrative courts. See "Item 4 Regulation of the Italian Hydrocarbons Industry Gas & Power". However, Eni cannot rule out a negative outcome in this matter. Accordingly, management believes that Eni s results of operations could be adversely affected should market conditions and/or regulatory constraints prevent Eni from selling its whole availability of natural gas purchased to fulfill take-or pay contract obligations (i.e., in case congestion occurs at the entry points of the Italian transport infrastructure which would force Eni to offtake a smaller volume of gas than the minimum contractual off take). See "Item 5 Management Expectations of Operations".

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

Eni cannot predict future developments in the regulation of the Italian natural gas market. Also an institutional debate is ongoing in Italy regarding the liberalization of the natural gas market and this may produce significant developments on this matter. A brief description follows of certain recently enacted laws and certain proceedings before the Authority for Electricity and Gas and the Italian Antitrust Authority in order to allow investors to gain some insight of the complexity of this matter. For a full discussion of laws and procedures described herein see "Item 4 Regulation of the Italian Hydrocarbons Industry Gas & Power ".

In 2003, Law No. 290 was enacted which prohibits Eni from holding an interest higher than 20% in undertakings owning natural gas transport infrastructure in Italy (Eni currently holds a 50.07% interest in Snam Rete Gas, which owns and manages approximately 97% of the Italian natural gas transport infrastructure).

On the basis of the findings of a joint inquiry conducted from 2003 through June 2004 on the Italian natural gas market, the Authority for Electricity and Gas and the Italian Antitrust Authority (the "Antitrust Authority") acknowledged that the overall level of competition of the Italian natural gas market is unsatisfactory due to the dominant position held by Eni in many phases of the natural gas chain. According to both the Authority for Electricity and Gas and the Antitrust Authority, the vertical integration of Eni in the supply, transport and storage of gas has restricted the development of competition in Italy notwithstanding the antitrust ceilings introduced by Legislative Decree 164/2000. It was further stated that the price of natural gas in Italy (in particular for the industrial sector) is higher than in other European countries.

In October 2005, the Authority for Electricity and Gas started an inquiry concerning the competitive behavior of operators selling natural gas to residential and commercial customers with the aim of defining measures to improve competition.

In February 2006, the Antitrust Authority closed an inquiry concerning Eni s competitive behavior concluding that Eni abused its dominant position with regard to its decision to suspend a plan for the upgrading of the import pipeline from Algeria and to unilaterally cancel certain contracts to sell the relevant transport capacity to third parties. Contracts were signed early in 2003 and the relevant upgrade is expected to become effective in 2007. The Antitrust Authority fined Eni by an amount of euro 290 million.

On May 5, 2006, the European Commission started an inquiry in order to verify an alleged abuse of dominant position on the part of Eni in violation of Article 82 of the EEC Treaty and Article 54 of the CES Agreement in the activities of international gas transport and wholesale and retail supply of gas.

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 for management and cannot exclude negative impacts on Eni s financial condition or results of operations in future years deriving from developments on these matters.

Eni believes an oversupply of natural gas is likely to occur in the long-term (beyond 2009)

Eni plans to upgrade its natural gas import infrastructure from Algeria and Russia to Italy, with expected start-up in 2008 and late 2008/2009, respectively. Taking into account the build-up of supplies of natural gas from Libya through the Greeenstream gasline and of Eni s fourth long term take-or-pay purchase contract from Russia, an additional import capacity of 883 BCF/y is expected to be available for the Italian natural gas market starting in 2009. A large portion of this expected import capacity has been or is planned to be awarded to third parties. In addition, certain operators in the Italian natural gas market have publicly announced plans to develop LNG terminals in Italy. Eni expects at least one new LNG terminal with a 283 BCF/y capacity to start operations by 2009 thus adding new import capacity to the Italian market. Management believes the pace of demand growth in the Italian natural gas market may not meet the expected increase in supplies of natural gas market starting in 2009 and beyond. If this projections materialize, a decrease in natural gas margins is likely to occur.

Decisions of the Authority for Electricity and Gas in the matter of natural gas tariffs may diminish Eni s ability to determine the price at which it sells natural gas to customers

On the basis of certain legislative provisions, the Authority for Electricity and Gas holds a general monitoring power on pricing in the natural gas market in Italy and the power to establish selling tariffs in the natural gas residential and commercial segments taking into account, among other things, the public interest goal of containing the inflationary pressure due to a rise in energy costs. The 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 fuels on to the final consumers of natural gas. In particular, with Decision No. 248/2004 the Authority for Electricity and Gas established, among other things: (i) that an increase in the international price of Brent crude oil is only partially transferred on to residential and commercial users of natural gas in case international prices of Brent crude oil exceed the 35 dollars per barrel threshold; and (ii) that Italian natural gas importers including Eni must renegotiate supply contracts to wholesalers in order to take account of the reduction of the price of natural gas sold to residential and commercial users. A proceeding has commenced between the Authority for Electricity and Gas and Eni, which appealed Decision No. 248/2004 to an administrative court.

Eni s management expects a negative outcome of this matter. Eni has accrued a material provision in its 2005 Consolidated Financial Statements in order to reflect the risks associated with this matter. In 2006 management expects Eni s results of operations to be adversely impacted by a material amount in light of the high Brent crude oil prices, in the event Decision 248/2004 is implemented in its original form. See "Item 4 Regulation of the Italian Hydrocarbons Industry Gas & Power" and "Item 5 Financial Review and Prospects".

Environmental Regulation

Eni may incur material operating costs and liabilities in relation to compliance with applicable environmental regulations and future environmental developments

Eni is subject to numerous EU, national, regional and local environmental 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, 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, petrochemicals 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.

Although management, considering the actions already taken with the insurance policies to cover environmental risks and the provision for risks accrued, does not currently expect any material adverse effect on Eni s Consolidated Financial Statements as a result of its compliance with such laws and regulations, there are risks that Eni may incur significant costs and liabilities in future years due to: (i) the chance of as yet unknown contamination; (ii) future developments in environmental regulation; (iii) the results of on-going surveys or surveys to be carried out on the environmental status of Eni s industrial sites and other possible effects deriving from the implementation of Decree No. 471/1999 of the Ministry of Environment; (iv) the possible effects deriving from the implementation of certain enacted regulations such as the ones deriving from Decree No. 367 of the Ministry of Environment published in January 8, 2004, regarding the fixing of new quality standards for aquatic environment in relation to dangerous substances, and those deriving from the application of European directive 2004/35/EC concerning environmental responsibility for prevention and reclamation of environmental damage; and (v) the possibility of litigation and the difficulty of determining Eni s liability, if any, as against other potentially responsible parties with respect to such litigation and the possible insurance recoveries.

Legal Proceedings

Eni is a party to a number of civil actions and administrative proceedings arising in the ordinary course of business. Although Eni s management does not currently expect a material adverse effect on Eni s financial position and results of operations on the basis of information available to date and taking account of existing provisions, Eni s management cannot rule out that in future years Eni may incur material losses in connection with pending legal proceedings due to: (i) uncertainty regarding the 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) errors in the estimate of probable future losses.

Risks deriving from changes in oil prices and in natural gas, refined and petrochemical products prices and margins

Operating results in certain of Eni s businesses, particularly the Exploration & Production, Refining & Marketing, Gas & Power and Petrochemical segments are affected by changes in the price of oil and by their impact on prices and margins of natural gas and 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 of oil prices is generally immediate. However Eni s average realization for oil differs from the price of marker crude Brent due primarily to the circumstance that Eni s production slate, which also includes heavy crudes, has a lower API gravity compared with Brent crude (when processed the latter allows for higher yields of valuable products compared to heavy crudes, hence higher market price).

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

A time lag exists between movements in oil prices and movements in the prices and margins of natural gas and refined and petrochemical products. In particular, trends of natural gas margins in Eni s natural gas business tend to mitigate the impact of changes in oil prices on Eni s operating results due to different movements in prices of certain energy parameters to which natural gas purchase and sale prices are contractually indexed in different proportions and as measured over different reference periods.

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

The results of operations of 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. Generally, a time lag exists between changes in oil prices and movements in refined products prices.

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

Eni s petrochemical products margins are affected by trends in demand and changes in oil prices which influence changes in cost of petroleum-based feedstock. Generally, an increase in oil price determines a decrease in petrochemical products margins in the short-term. Prolonged weakness of the European economy as well as Eni s own structural weaknesses have prevented Eni s Petrochemical segment from returning to profitability in recent years due to the inability to transfer increases of oil-based feedstocks into selling prices. Due to industry conditions and weak economic growth in Europe, management does not expect any significant and durable improvement in Petrochemicals segment profitability over the foreseeable future.

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 euro. Similarly, prices of Eni s petrochemical products are generally denominated in, or linked to, the euro, whereas expenses in the Petrochemicals segment are denominated both in euro and U.S. dollars. Accordingly a depreciation of the U.S. dollar versus the euro generally has an adverse impact on Eni results of operations.

Weather in Italy and Seasonality

Significant changes in weather conditions in Italy from year to year may cause variations in 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, may be affected by such variations in weather conditions. In addition, 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.

Interest Rates

Interest on Eni s financial 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 financial expense in respect to its financial debt.

Critical Accounting Estimates

The preparation of financial statements entails accounting estimates that are characterized by a high degree of uncertainty, complexity and judgment. Although these critical accounting estimates are thoroughly applied and underlying amounts are fairly determined, management cannot rule out that actual outcomes may differ from such estimates, due to, among other things, the following factors: uncertainty, lack or limited availability of information; the availability of new informative elements, variations in economic conditions such as prices, significant factors (e.g., removal technologies and costs) and the final outcome of legal, environmental or regulatory proceedings. See "Item 5 Critical Accounting Estimates".

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, electricity generation, petrochemicals, oilfield services and engineering industries. Eni has operations in about 70 countries and 72,258 employees as of December 31, 2005.

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.it.

The name of the agent of Eni in the United States is Viscusi Enzo, 666 Fifth Ave., New York, NY 10103

Eni s principal segments of operations and subsidiaries are described below.

Eni conducts its exploration and production activities through its Exploration & Production Division and certain operating subsidiaries. Eni s exploration, development and production activities commenced in 1926, when Agip SpA was established by the Italian Government with a mandate to explore for and develop oil and natural gas. Agip SpA was merged into Eni SpA effective as of January 1, 1997 to become Eni s Exploration & Production Division.

Eni is engaged in exploration and production of hydrocarbons in Italy, North Africa, West Africa, the North Sea, the Gulf of Mexico, Australia, South America and areas with great development potential such as the Caspian Sea, the Middle and Far East, India and Alaska. In 2005, Eni s hydrocarbon production available for sale averaged 1,693 KBOE/d and, at December 31, 2005, Eni s estimated proved reserves totalled 6,837 mmBOE with a life index of 10.8 years. In 2005, Eni s Exploration & Production segment had net sales from operations (including intersegment sales) of euro 22,477 million and operating profit of euro 12,574 million.

Eni conducts its natural gas and electricity generation activities through its Gas & Power Division and certain operating subsidiaries. Eni s natural gas supply, transmission and distribution activities commenced in the 1940s with the commercial sale of natural gas to industrial users in Northern Italy. Snam SpA was merged into Eni SpA effective as of February 1, 2002 to become Eni s Gas & Power Division. In 2005, Eni s sales of natural gas to third parties totalled 52.47 BCM in Italy and 23.44 BCM in the rest of Europe; Eni s share of natural gas volumes sold by its affiliates totalled 8.53 BCM (of which 7.85 billion was sold in the rest of Europe). Natural gas volumes consumed in operations by Eni and Eni s subsidiaries mainly in electricity generation, refining and petrochemicals operations totalled 5.54 BCM. Natural gas sales in Italy include: (i) sales to wholesalers, mainly local companies selling natural gas to residential and commercial customers, and to large industrial and thermoelectric customers which are supplied by a high and medium pressure pipeline network; and (ii) sales to residential and commercial customers which are supplied by a low pressure pipeline network. Eni s high and medium pressure gas pipeline network for natural gas transport is about 30,700-kilometer long in Italy, while outside Italy Eni holds transmission rights on approximately 5,000 kilometers of high pressure pipelines. Eni s natural gas transport network in Italy is owned and managed by Snam Rete Gas SpA. Snam Rete Gas is listed on the Italian Stock Exchange, Eni s share being 50.07%. Snam Rete Gas transports natural gas on behalf of Eni and third parties ("shippers"); in 2005 its transported volumes were 85.10 BCM, of which 30.22 billion were on behalf of third parties. Eni, through its 100% subsidiary Italgas and other subsidiaries, is engaged in natural gas distribution activity in Italy serving 1,282 municipalities through a low pressure network consisting of approximately 48,000 kilometers of pipelines as of December 31, 2005.

Eni conducts its electricity generation activities through its wholly-owned subsidiary EniPower SpA, which owns and manages Eni s power stations of Livorno, Taranto, Mantova, Ravenna, Brindisi and Ferrera Erbognone with a total installed capacity of approximately 4.5 gigawatt as of December 31, 2005. In 2005, sold production of electricity totalled 22.77 terawatthours. Eni owns other minor power stations located in Eni s petrochemical plants and refineries whose production is mainly for internal consumption. The accounts of these power stations are reported within Eni s Refining & Marketing and Petrochemicals segments.

In 2005, Eni s Gas & Power segment had net sales from operations (including intersegment sales) of euro 22,969 million and operating profit of euro 3,321 million.

Eni conducts its refining and marketing activities through the Refining & Marketing Division and certain operating subsidiaries. Activities commenced in the 1930s, when Eni initiated the development of the industrial and retail markets for refined products in Italy. AgipPetroli SpA was merged into Eni SpA effective December 31, 2002 to become Eni s Refining & Marketing Division. Eni s refining and marketing activities are located primarily in Italy and in the rest of Europe. In 2005, Eni s retailing market share for refined products in Italy through its Agip-branded network of service stations was 29.7%. In 2005, Eni divested its wholly-owned subsidiary Italiana Petroli which is engaged in the retail marketing of refined products through a network consisting primarily of leased service stations, under the IP brand. In 2005, sales of refined products totalled 51.63 million tonnes, of which 30.29 million were in Italy. The balanced refining capacity of Eni s wholly-owned refineries totalled 524 KBBL/d as of December 31, 2005. In 2005, Eni s Refining & Marketing segment had net sales from operations (including intersegment sales) of euro 33,732 million and operating profit of euro 1,857 million.

Eni s petrochemical activities commenced in the 1950s, when it began production of basic petrochemicals at its Ravenna industrial complex. Through Polimeri Europa SpA and its subsidiaries, Eni operates in olefins and aromatics, basic intermediate products, chlorine derivatives, polyethylene, polystyrenes, and elastomers. Eni s petrochemical operations are concentrated in Italy and in Western Europe. In 2005, Eni sold 5.4 million tonnes of petrochemical products. In 2005, Eni s Petrochemicals segment had net sales from operations (including intersegment sales) of euro 6,255 million and an operating profit of euro 202 million.

Eni s oilfield services, construction and engineering activities commenced in the late 1950s. Through Saipem SpA (a 43% owned subsidiary) and its subsidiaries, Eni operates in offshore construction, in particular fixed platform installation, subsea pipe laying and floating production systems. Through Snamprogetti SpA (a wholly owned subsidiary) and its subsidiaries Eni is a provider of engineering and project management services to the oil and gas, refining and petrochemical industries. In 2005, Eni s Oilfield Services, Construction and Engineering segment had net sales from operations (including intersegment sales) of euro 5,733 million and operating profit of euro 307 million.

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

Strategy

Eni plans to deploy a strategy of organic growth intended to sustain the group s business over the long-term.

In the Exploration & Production activities, Eni plans to grow production of oil and natural gas through organic growth, targeting a production level of more than 2 mmBOE/d in 2009, which corresponds to a compound average growth rate of approximately 4% under certain trading environment assumptions (See "Item 5 Management Expectations of Operations"). Eni plans to reach said production target by leveraging in particular on the contribution of recently completed large development projects and projects in the development phase in Angola, Libya, Nigeria, Egypt, Iran, Algeria and Kazakhstan. Management will continue to evaluate opportunities to increase production through the purchase of corporations or individual assets. Eni intends to pay special attention to reserve replacement in order to ensure the medium to long-term sustainability of its business. Eni intends to optimize its portfolio of development properties by focusing on areas where its presence is established, seeking for new opportunities and divesting marginal assets. Eni intends to develop its LNG business also through the purchase of interests in liquefaction plants in order to better exploit its natural gas reserves in North and West Africa. In exploration activities Eni intends to renew its portfolio of properties focusing on such areas where management believes a high mineral potential exists, on assets in areas where its presence is established (in particular Egypt, Nigeria, the United States, Italy and Norway) and to start exploration in newly acquired areas (in particular Alaska, Libya and India).

In the Gas & Power activities, Eni plans to grow natural gas sales in the rest of Europe and to develop its presence in the LNG business in order to compensate for lower growth opportunities on the domestic market due to the limits imposed on operators by the sector regulation and increasingly intense competition. In Italy, Eni plans to comply with regulatory limits on direct sales and input volumes to the national transport network by optimizing allocation of supplies between direct sales in Italy and in the rest of Europe and by using natural gas at its own electricity generation plants and, at the same time, leveraging on the expected consumption growth. In the medium term, management expects its natural gas sales in Italy to decline from the 58 BCM level recorded in 2005 as a consequence of increasing competition from third parties. Eni plans to implement a more attractive commercial offer than Eni s competitors on the basis of the quality of services, pricing formulas including different indexation schemes to suit various customers purchasing profile and the integration of supply of gas and electricity. Management plans to grow natural gas sales on European markets by leveraging on the availability of Eni s equity gas and on a diversified portfolio of supply contracts, an extensive gas pipeline network, which allows for the supply of natural gas from several sources, and long standing relationships with producing countries. Eni intends to strengthen its presence in markets where its presence is already established such as the Iberian Peninsula, Germany and Turkey and to develop sales in markets with significant growth and profitability prospects (in particular France and the United Kingdom).

In the Refining & Marketing activities, Eni intends to maximize returns from its existing assets. In the refining activity Eni plans to invest in new primary distillation capacity and in new conversion capacity to make its refining system flexible enough to obtain a higher yield of middle distillates and to achieve a greater vertical integration with its upstream activities. In marketing Eni aims to improve its competitive position in Italy and to increase sales in selected neighboring countries in the Rest of Europe.

Eni s oilfield services construction and engineering activities play an essential role in contributing to technological innovations and in the implementation of world-scale projects thus supporting Eni s growth process in the oil & gas business.

In technological research and innovation activities Eni plans to implement a relevant capital expenditure programme to develop such technologies that management believes may ensure competitive advantages in the long-term and promote sustainable growth. Eni plans to continue developing existing programmes on clean fuels, sulphur and greenhouse gas management as well as projects such as the upgrading of heavy crudes (EST), high pressure gas transmission (TAP) and Gas to Liquids (GTL).

In pursuing this strategy Eni plans a capital expenditure programme amounting to euro 35.2 billion over the next four years. Eni plans to finance this capital expenditure programme by using the cash provided by operating activities. Over the next four year period, the Company expects to distribute to its shareholders a flow of dividends in line with the level of 2005 under certain assumptions (See "Item 8 Dividends"). Eni aims to allocate cash flow in excess of capital expenditure and dividend requirements to continue its programme of share buy-back while at the same time maintaining a strong balance sheet. See "Item 5 Management Expectations of Operations".

Key Developments

The most significant events that occurred during 2005 and to date in 2006 were the following:

In 2005, hydrocarbon production available for sale averaged 1,693 mmBOE/d, a 6.7% increase compared to year 2004. Eni s net proved reserves of oil and natural gas were 6.84 BBOE (55% crude and condensates), down 381 mmBOE from 2004 due to an estimated 478 mmBOE adverse impact related to lower entitlements in certain PSAs and buy-back contracts due to higher oil prices (58.21 dollar per barrel at year end 2005 as compared to 40.47 at year end 2004). Eni s reserves replacement ratio was 40%; the average reserve life index was 10.8 years (12.1 in 2004).

In May 2005, the new setup of the consortium operating the North Caspian Sea PSA was defined. As a result of the transaction, Eni s operatorship interest in the Kashagan project increased from 16.67% to 18.52%. Eni plans a capital expenditure programme amounting to $29 billion in order to develop the field reserve. Management is currently reviewing this amount in order to take account of the depreciation of the U.S. dollar versus the euro and rising trends in the cost of certain production factors (such as materials and oilfield services). The development of the project is advancing as planned: first oil is expected by the end of 2008 and the production plateau is targeted at over 1.2 mmBBL/d.

As part of its strategy of expansion in areas with high mineral potential, Eni enhanced its portfolio of mineral rights via acquisition of exploration permits and production licenses located in Libya, India, Alaska, Brazil, Nigeria, Australia, Pakistan and the Gulf of Mexico for a total acreage of 67,000 square kilometers (44,000 net to Eni, of these 93% as operator).

In Angola oil production increased approximately 50% from the level of 2004 reflecting mainly certain significant start-ups: phase B of the development of the fields discovered in the Kizomba offshore area in Block 15 (Eni s interest 20%) and the North Sanha and Bomboco oil, condensate and LPG fields in Block 0 former Cabinda (Eni s interest 9.8%).

As part of the Western Libyan Gas Project (Eni s interest 50%), in August 2005 the offshore Bahr Essalam field was started-up, less than a year after the start-up of the onshore Wafa field. Peak production of the two fields is expected in 2006 at 256,000 BOE/d (128,000 net to Eni). When fully operational in 2006 volumes produced and carried to Italy via the Greenstream pipeline will be 8 BCM/y of natural gas (4 billion net to Eni) already booked under long term supply contracts with operators.

Natural gas sales (91.15 BCM) were up 8.8% due to increased demand for power generation in Italy and the acquisition of new customers combined with growth in markets in the rest of Europe as a result of the expansion strategy pursued by Eni.

The agreement signed by Eni, Amorim Energia and Rede Eléctrica Nacional shareholders of Galp with 33.34, 13.312 and 18.30%, respectively confers stability to the shareholding structure of the Portuguese energy company and sets the stage for future developments aimed at enhancing Eni s investment. The Portuguese Government is expected to sell part of its Galp holding through a public offer before the end of 2006.

As part of its strategy of international expansion in LNG, Eni purchased 6 BCM/y for 20 years of the regasification capacity of the Cameron terminal on the coast of Louisiana in the USA with start-up planned for 2008-2009. This will allow Eni access to markets in the United States for part of its natural gas reserves in North Africa and Nigeria.

Eni continues its development in power generation aimed at reaching 5.5 gigawatt of installed capacity by 2009; at year end 2005 installed capacity was 4.5 gigawatt. The new combined cycle power plants will absorb over 6 BCM/y of natural gas from Eni s portfolio of supplies.

In 2005 Eni divested its total interest in Italiana Petroli SpA, which distributes fuels in Italy through a lease concession network under the IP brand.

On April 1, 2006 the Venezuelan State oil company Petróleos de Venezuela SA (PDVSA) unilaterally cancelled the service contract regulating activities at the Dación oil field where Eni acted as contractor with a 100% working interest. Accordingly, starting on the same day, operations at the Dación oil field have been run by PDVSA which took over Eni Dación BV, Eni s wholly-owned subsidiary that had been operating the field until that date. In 2005 and in the first quarter of 2006, oil production from the Dación field averaged approximately 60 KBBL/d. Management expects Eni s proved reserves of hydrocarbons to be reduced by an amount of approximately 175 mmBBL corresponding to Eni s net proved reserves of the Dación field as of December 31, 2005 as a consequence of the loss of Eni s title to the field.

In 2005, capital expenditure amounted to euro 7.4 billion, of which 91% related to the Exploration & Production, Gas & Power and Refining & Marketing segments, and was primarily related to: (i) the development of oil and gas reserves (euro 3,952 million) in particular in Kazakhstan, Libya, Angola, Italy and Egypt, exploration projects (euro 656 million) and the purchase of proved and unproved property (euro 301 million); (ii) upgrading of Eni s natural gas transport and distribution networks in Italy (euro 825 million); (iii) the continuation of construction of combined cycle power plants (euro 239 million); (iv) actions for improving flexibility and yields of refineries, including the completion of construction of the tar gasification plant at the Sannazzaro refinery, and the upgrade of the refined product distribution network in Italy and in the rest of Europe (overall euro 656 million); and (v) upgrading of vessels and other equipment and facilities in Kazakhstan and West Africa in the Oilfield services and construction business (euro 346 million).

In 2005 capital expenditure decreased by euro 85 billion over 2004, or 1.1%, due to a euro 299 billion reduction, or 20.6%, in the Gas & Power business due principally to the completion of the Greenstream underwater pipeline project and the nearing to completion of the power generation development plan.

In 2004, capital expenditure amounted to euro 7.5 billion (of which 94% related to the Exploration & Production, Gas & Power and Refining & Marketing segments) and concerned: (i) development of hydrocarbon fields (euro 4,369 million) in particular in Libya, Iran, Angola, Italy, Kazakhstan, Egypt, Nigeria and Norway, and exploration (euro 499 million); (ii) upgrading of Eni s natural gas transmission and distribution network in Italy (euro 721 million); (iii) the construction of the tar gasification plant at the Sannazzaro refinery, actions on refineries for the adjustment of automotive fuel characteristics to new European specifications and the upgrade of the refined product distribution network in Italy and in the rest of Europe (for a total of euro 669 million); and (iv) the continuation of construction of electricity generation plants (euro 451 million) and the completion of the Greenstream underwater pipeline project (euro 159 million).

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BUSINESS OVERVIEW

Exploration & Production

Eni operates in the exploration and production of hydrocarbons in Italy, North Africa, West Africa, the North Sea, the Gulf of Mexico, Australia and South America. It also operates in areas such as the Caspian Sea, the Middle and Far East, India and Alaska where management believes a great mineral potential exists. In 2005, Eni produced 1,693 KBOE/d; as of December 31, 2005, Eni s proved reserves totalled 6,837 mmBOE. Eni plans to grow production of oil and natural through organic growth, targeting a production level of more than 2 mmBOE/d in 2009 which corresponds to a compound average growth rate of approximately 4% under certain trading environment assumptions (See "Item 5 Management Expectations of Operations"). Eni plans to reach said production target by leveraging in particular on the contribution of recently completed great development projects and projects in the development phase in Angola, Libya, Nigeria, Egypt, Iran, Algeria and Kazakhstan. Management will continue to evaluate opportunities to increase production through the purchase of corporations or individual assets. Eni intends to pay special attention to reserve replacement in order to guarantee the medium to long-term sustainability of its business. Eni intends to optimize its portfolio of development properties by focusing on areas where its presence is established, seeking for new opportunities and divesting marginal assets. Eni intends to develop its LNG business also through the purchase of interests in liquefaction plants in order to better exploit its natural gas reserves in North and West Africa.

In exploration activities Eni intends to renew its portfolio of properties focusing on such areas where management believes a high mineral potential exists, assets in areas where its presence is already established (in particular Egypt, Nigeria, the United States, Italy and Norway) and to start exploration in newly acquired areas (in particular Alaska, Libya and India).

Eni plans to improve its performance by searching for operating solutions with lower operating costs and synergies.

Oil and Natural Gas Reserves

Eni continues to exercise rigorous control over the booking of proved reserves. The Reserve Department of the Exploration & Production segment, reporting directly to the General Manager, is entrusted with the task of keeping reserve classification criteria ("criteria") constantly updated and of monitoring their periodic process of estimate. The criteria follow Regulation S-X rule 4-10 of the Securities and Exchange Commission (SEC) as well as, on specific issues not regulated by rules, the consolidated practice recognized by qualified reference institutions. The current criteria applied by Eni have been examined by DeGolyer and MacNaughton (D&M), an independent oil engineers company, which confirmed that they are compliant with the SEC rules. D&M also stated that the criteria regulate situations for which the SEC rules are less precise, providing a reasonable interpretation in line with the generally accepted practices in international markets. Eni estimates its proved reserves on the basis of the mentioned criteria also when it participates in exploration and production activities operated by other entities.

Beginning in 1991 Eni has requested qualified independent petroleum engineering companies to carry out an independent evaluation[2] of its proved reserves on a rotation basis. In particular in 2005 a total of 1.64 BBOE of proved reserves, or about 24% of Eni s total proved reserves at December 31, 2005, have been evaluated. The results of this independent evaluation confirmed Eni s evaluations, as they did in past years. In the 2003-2005 three year period independent evaluations concerned 84% of Eni s total proved reserves; in particular evaluations concerned all the new development projects, including Kashagan, and most large-sized mature fields.

Eni s proved reserves of oil and natural gas at December 31, 2005 totalled 6,837 mmBOE (oil and condensates 3,773 mmBBL; natural gas 17,591 BCF) representing a decrease of 381 mmBOE, or 5.3%, from December 31, 2004. The reserve replacement ratio was 40% in 2005; the average reserve replacement ratio for the last three years was 89%.

The average reserve life index is 10.8 years (12.1 at December 31, 2004). The reserve replacement ratio was calculated dividing additions to proved reserves for year 2005 by total production, each as derived from the tables of changes in proved reserves prepared in accordance with SFAS No. 69 presented in Note 35 to the Consolidated Financial Statements. Management considers the reserve replacement ratio to be a key measure of the ability of the company to sustain its growth prospects. However, the ratio measures past performance and cannot be used to forecast the ability of management to replace produced reserve in future years.

Addition to proved reserves booked in 2005 were 253 mmBOE derived from : (i) extensions and discoveries (156 mmBOE), in particular in Nigeria, Norway, Kazakhstan and Algeria; (ii) revisions of previous estimates (down 98 mmBOE) related to lower entitlement in certain Production Sharing Agreements (PSAs)[3] and buy-back contracts due to higher oil prices recorded mainly in Kazakhstan, Angola and Libya; (iii) improved recovery (89 mmBOE), in particular in Algeria, Angola and Kazakhstan; and (iv) purchase of proved property (106 mmBOE) in Kazakhstan, Australia, Italy and Angola. The increase offset in part the decline related to production for the year (634 mmBOE). Due to risks inherent in the exploration and production business, a degree of uncertainty still exists as to whether these additions will actually be produced. See "Item 3 Risks associated with exploration and production of oil and natural gas and Uncertainties in estimates of oil and natural gas reserves.

Proved developed reserves at December 31, 2005 amounted to 4,306 mmBOE (2,350 mmBBL of oil and condensates and 11,229 BCF of natural gas), representing 63% of total estimated proved reserves (60% and 58% at December 31, 2004 and 2003, respectively).

Proved reserves of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator represented approximately 11% of all proved reserves at December 31, 2005 (10% at December 31, 2004; 8% at December 31, 2003).

With effective date April 1, 2006, the Venezuelan State oil company Petróleos de Venezuela SA (PDVSA) unilaterally terminated the service contract governing activities at the Dación oil field where Eni acted as a contractor, holding a 100% working interest. As a consequence, starting on the same day, operations at the Dación oil field are conducted by PDVSA which replaced Eni Dación BV, Eni s wholly-owned subsidiary that had been operating the field until that date.

Eni believes that it is entitled to a market value compensation for the expropriation of the Dación field. On these basis, Eni is available to reach an agreement with the Venezuelan authorities. In case an amicable settlement is not possible, Eni will take any other action in order to protect its interest in Venezuela. Based on internal and external independent evaluation, Eni is confident that a fair market compensation will not be lower than the book value of the Dación related assets. Accordingly, management decided not to impair the book value of Eni s Dación assets. In 2005 and in the first quarter 2006, the Dación field production rate was about 60 KBBL/d. Management expects Eni s proved reserves of hydrocarbons to be reduced by an amount of approximately 175 mmBBL corresponding to Eni s net proved reserves of the Dación field as of December 31, 2005 as a consequence of the loss of Eni s title to the field.

The table below sets forth a geographical breakdown of Eni s proved reserves and proved developed reserves of hydrocarbons, on a barrel of oil equivalent basis, for the periods indicated.

Proved reserves

Eni s proved reserves of hydrocarbons by geographic area

	Year ended December 31,				
	2001	2002	2003	2004	2005

			(mmBOE)		
Italy	1,315	1,199	996	890	868
North Africa	2,122	2,033	2,024	2,117	2,026
West Africa	1,136	1,287	1,324	1,357	1,279
North Sea	879	825	912	807	758
Rest of the World	1,477	1,686	2,016	2,047	1,865
Total consolidated subsidiaries	6,929	7,030	7,272	7,218	6,796
Unconsolidated entities					41
	6,929	**7,030**	**7,272**	**7,218**	**6,837**

Eni s proved reserves of oil by geographic area

	Year ended December 31,				
	2001	**2002**	**2003**	**2004**	**2005**
			(mmBBL)		
Italy	309	255	252	225	228
North Africa	1,171	1,072	1,080	993	961
West Africa	976	1,022	1,038	1,056	936
North Sea	552	498	529	450	433
Rest of the World	940	936	1,239	1,284	1,190
Total consolidated subsidiaries	3,948	3,783	4,138	4,008	3,748
Unconsolidated entities					25
	3,948	**3,783**	**4,138**	**4,008**	**3,773**

Eni s proved reserves of natural gas by geographic area

	Year ended December 31,				
	2001	**2002**	**2003**	**2004**	**2005**
			(BCF)		
Italy	5,640	5,295	4,166	3,818	3,676
North Africa	5,509	5,563	5,467	6,453	6,117
West Africa	925	1,533	1,656	1,729	1,965
North Sea	1,892	1,899	2,223	2,051	1,864
Rest of the World	3,106	4,339	4,496	4,384	3,879
Total consolidated subsidiaries	17,072	18,629	18,008	18,435	17,501
Unconsolidated entities					90
	17,072	**18,629**	**18,008**	**18,435**	**17,591**

Eni s proved developed reserves of hydrocarbons by geographic area

	Year ended December 31,				
	2001	**2002**	**2003**	**2004**	**2005**
			(mmBOE)		
Italy	825	774	702	671	620

North Africa	875	797	806	961	1,230
West Africa	640	703	710	749	793
North Sea	773	724	822	707	611
Rest of the World	654	705	1,190	1,212	1,021
Total consolidated subsidiaries	3,767	3,703	4,230	4,300	4,275
Unconsolidated entities					31
	3,767	**3,703**	**4,230**	**4,300**	**4,306**

Eni s proved developed reserves of oil by geographic area

	Year ended December 31,				
	2001	**2002**	**2003**	**2004**	**2005**
			(mmBBL)		
Italy	171	168	173	174	149
North Africa	685	610	640	655	697
West Africa	539	554	560	588	568
North Sea	476	426	464	386	353
Rest of the World	443	483	610	668	564
Total consolidated subsidiaries	2,314	2,241	2,447	2,471	2,331
Unconsolidated entities					19
	2,314	**2,241**	**2,447**	**2,471**	**2,350**

Eni s proved developed reserves of natural gas by geographic area

	Year ended December 31,				
	2001	**2002**	**2003**	**2004**	**2005**
			(BCF)		
Italy	3,665	3,397	2,966	2,850	2,704
North Africa	1,103	1,084	962	1,760	3,060
West Africa	584	863	866	924	1,289
North Sea	1,721	1,727	2,075	1,845	1,484
Rest of the World	1,221	1,283	3,355	3,122	2,622
Total consolidated subsidiaries	8,294	8,354	10,224	10,501	11,159
Unconsolidated entities					70
	8,294	**8,354**	**10,224**	**10,501**	**11,229**

Mineral Right Portfolio and Exploration Activity

As of December 31, 2005, Eni s portfolio of mineral rights consisted of 1,041[4] exclusive or shared rights for exploration and development in 34 countries on five continents, for a total net acreage of 266,002[5] square kilometers (234,180 at December 31, 2004). Of these, 55,098 square kilometers concerned production and development (41,997 at December 31, 2004). Outside Italy net acreage increased by 41,403 square kilometers due to the acquisition of assets after international bid procedures in Libya, Egypt, India, Pakistan, Angola, Algeria, the United States and Ireland and purchases of mineral assets in Nigeria, Alaska and Australia. These increases were offset in part by releases in Italy, Brazil, Congo, Morocco and Tunisia and divestments of assets in the British section of the North Sea. In Italy net acreage declined by 9,582 square kilometers due to releases.

A total of 52 new exploratory wells were drilled (21.85 of which represented Eni s share on the basis of its working interest in relevant properties), as compared to 66 exploratory wells completed in 2004 (29.5 of which represented Eni s share). Overall success rate was 39.3% in 2005, as compared to 52.1% in 2004; the success rate of Eni s share of exploratory wells was 47.4% in 2005, as compared to 57.3% in 2004.

Production

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 2005 oil and natural gas production available for sale averaged 1,693 KBOE/d (oil and condensates 1,111 KBBL/d; natural gas 3,344 mmCF/d) increasing by 107 KBOE/d compared to 2004, up 6.7%, due to: (i) production increases registered mainly in Libya, Angola, Iran, Algeria, Egypt and Kazakhstan; and (ii) the start-up of fields in Angola and Libya. These increases were partly offset by: (i) an estimated 32 KBOE adverse entitlement impact in PSAs and buy-back contracts related to higher international oil prices; (ii) declines in mature fields mainly in Italy and the United Kingdom; and (iii) the effect of the divestment of proved property carried out in 2004 (16 KBOE) and of hurricanes in the Gulf of Mexico (10 KBOE). The share of production outside Italy was 85% (82.6% in 2004).

Production of oil and condensates (1,111 KBBL/d) increased by 77 KBBL/d compared to 2004, up 7.4%, due to increases registered in: (i) Angola, due to full production of the Hungo and Chocalho fields within phase A of the development of the Kizomba area in Block 15 and the start-up of the Kissanje and Dikanza fields within phase B of the same project in Block 15 (Eni s interest 20%) and the start-up of the Sanha-Bomboco fields in area B of Block 0 (Eni s interest 9.8%); (ii) Libya, due to full production at the Wafa field and the start-up of the Bahr Essalam field (Eni s interest 50%); (iii) Iran, due to full production at the South Pars field Phases 4-5 (Eni operator with a 60% interest) and production increases at the Dorood (Eni s interest 45%) and Darquain fields (Eni operator with a 60% interest); (iv) Algeria, due to full production at the Rod and satellite fields (Eni operator with a 63.96% interest); (v) Kazakhstan, in the Karachaganak field (Eni co-operator with a 32.5% interest) due to increased exports from Novorossiysk terminal on the Russian coast of the Black Sea; and (vi) Italy, due to increased production in Val d Agri resulting from full production of the fourth treatment train of the oil center. These increases were partly offset by declines of mature fields, in particular in the United Kingdom, and by the effect of the divestment of assets carried out in 2004.

Production of natural gas available for sale (3,344 mmCF/d) increased by 173 mmCF/d compared to 2004, up 5.5%, due to increases registered in: (i) Libya, due to full production at the Wafa field and the start-up of the Bahr Essalam field (Eni s interest 50%); (ii) Egypt, due to the start-up of the Barboni field and the Temsah 4 platform in the offshore of the Nile Delta; and (iii) Kazakhstan and Pakistan. These increases were partly offset by declines of mature fields, in particular in Italy, the effect of the divestment of assets effected in 2004 and of the hurricanes in the Gulf of Mexico.

Hydrocarbon production sold totalled 614.9 mmBOE. About 68% of oil and condensate production sold (402.6 mmBBL) was delivered to Eni s Refining & Marketing segment (70% in 2004). About 44% of natural gas production sold (1,219 BCF) was delivered to Eni s Gas & Power segment (40% in 2004).

The tables below set forth Eni s production of oil and condensates and natural gas for the periods indicated.

	Year ended December 31,

	2001	2002	2003	2004	2005
			(KBBL/d)		
Production of oil and condensates (1) (2)					
Italy	69	86	84	80	86
North Africa	228	252	250	261	308
West Africa	219	222	236	285	310
North Sea	204	213	235	203	179
Rest of the World	137	148	176	205	228
Total	857	921	981	1,034	1,111

	Year ended December 31,				
	2001	2002	2003	2004	2005
			(mmCF/d)		
Natural gas production available for sale (1) (2) (3)					
Italy	1,313	1,260	1,181	1,067	972
North Africa	497	560	559	619	900
West Africa	82	87	128	143	151
North Sea	450	516	596	560	563
Rest of the World	485	592	710	782	758
Total	2,827	3,015	3,174	3,171	3,344

(1) Production information set forth above differs from production as reported in the reserve tables in Note 35 to the Consolidated Financial Statements - Supplemental oil and gas information (unaudited), because yearly production presented in such reserve tables is based on estimates made in November of each year and the information above sets forth actual production during the year. Furthermore, Eni s production of natural gas reported in such reserve tables includes, in addition to sold production, production volumes of natural gas consumed in operations. Natural gas produced and reinjected into storage fields in Italy remains part of Eni s proved reserves for each period.

(2) Data includes Eni share of production of affiliates and joint ventures accounted for under the equity or cost method of accounting.

(3) Natural gas production volumes consumed in operations are excluded. The effect was 94, 132, 151, 220 and 250 mmCF/d in 2001, 2002, 2003, 2004 and 2005, respectively.

Volumes of oil and natural gas purchased under long term supply contracts with foreign governments or similar authorities in properties where Eni acts as producer totalled 20.5 KBOE/d and 2.9 KBOE/d in 2005 and 2004, respectively (2003 amounts were immaterial).

The table below sets forth certain information and operating data regarding Eni s principal oil and natural gas interests for the year ended December 31, 2005.

Principal oil and natural gas interests at December 31, 2005

	Commencement of operations	Number of interests	Gross exploration and development acreage (1)	Net exploration and development acreage (1)	Net development acreage (1)	Type of fields	Number of producing fields	Number of other fields
Italy	1926	**180**	**31,048**	**24,053**	**12,700**	Onshore/Offshore	**83**	**79**
North Africa								

Algeria	1981	37	14,352	3,792	860	Onshore/Offshore	23	15
Egypt	1954	56	34,918	22,644	4,180	Onshore/Offshore	35	28
Libya	1959	15	44,955	37,703	15,466	Onshore/Offshore	11	7
Tunisia	1961	11	6,464	2,317	1,601	Onshore/Offshore	9	6
		119	**100,689**	**66,456**	**22,107**		**78**	**56**
West Africa								
Angola	1980	53	15,234	2,310	715	Offshore	36	32
Congo	1968	20	9,855	4,224	880	Offshore	16	8
Nigeria	1962	49	46,075	8,922	6,539	Onshore/Offshore	119	69
		122	**71,164**	**15,456**	**8,134**		**171**	**109**
North Sea								
Norway	1965	51	26,601	8,814	128	Offshore	14	13
The United Kingdom	1964	84	6,504	1,506	652	Offshore	29	15
		135	**33,105**	**10,320**	**780**		**43**	**28**
Rest of World								
Australia	2001	15	31,948	22,349	3,299	Offshore	2	1
Brazil	1999	2	2,203	2,057		Offshore		
China	1983	4	866	181	103	Offshore	8	4
Croatia	1996	3	6,056	3,029	988	Offshore	2	6
Ecuador	1988	1	2,000	2,000	2,000	Onshore	1	1
India	2005	2	14,445	5,698		Onshore/Offshore		
Indonesia	2001	12	31,419	15,859	984	Onshore/Offshore	7	8
Iran	1957	4	1,456	820	820	Onshore/Offshore	4	
Kazakhstan	1995	6	4,934	959	488	Onshore/Offshore	1	5
Pakistan	2000	14	21,876	11,692	615	Onshore/Offshore	6	1
Saudi Arabia	2004	1	51,687	25,844		Onshore		
Trinidad & Tobago	1970	1	382	66	66	Offshore	3	2
The United States	1968	389	7,890	3,569	389	Onshore/Offshore	17	8
Venezuela	1998	4	1,701	867	511	Onshore/Offshore	5	2
		458	**178,863**	**94,990**	**10,263**		**56**	**38**
Other		**9**	**6,276**	**1,279**	**1,114**	Offshore		**1**
Other countries with only exploration activity		**18**	**89,056**	**53,448**		Onshore/Offshore		
Outside Italy		861	479,153	241,949	42,398		348	232
Total		**1,041**	**510,201**	**266,002**	**55,098**		**431**	**311**

(1) Square kilometers.

Eni s principal regions of operations are described below. In the discussion that follows references to hydrocarbon production are to be intended to be hydrocarbon production available for sale.

Italy

In 2005, Eni s hydrocarbon production in Italy totalled 256 KBOE/d and represented 15% of Eni s total production. Eni s exploration and development interests in Italy are concentrated in the Adriatic Sea, the Central Southern Apennines, Sicily and the Sicilian offshore and the Po Valley. Natural gas production available for sale averaged 972 mmCF/d and represented approximately 67% of Eni s hydrocarbon production in Italy. Eni s principal natural gas fields are located in the Adriatic Sea (Barbara, Angela/Angelina, Porto Garibaldi/Agostino, Cervia/Arianna, Porto Corsini, Regina and Bonaccia, which collectively accounted for 50% of Eni s natural gas production in Italy in 2005) and in the Ionian Sea (Luna, which accounted for 9.2%).

Production of oil in Italy averaged 86 KBBL/d. Eni s three major oil fields, Val d Agri in Southern Italy, Villafortuna in the Po Valley and Gela in Sicily, represented 82% of Eni s total oil production in Italy in 2005. Other oil fields are Aquila in the Adriatic offshore of Southern Italy, Rospo in the Adriatic Sea, Prezioso and Vega offshore Southern Sicily, and Giaurone and Ragusa in Sicily.

Exploration activities onshore yielded positive results with the Mezzocolle 1 well (Eni s interest 100%) containing natural gas in the Imola permit in the central Apennines, with the Longanesi 1 well containing natural gas in the Po Plain (Eni s interest 100%) and with Argo-1 well (Eni s interest 60%) testing an offshore gas accumulation in the Sicily Channel.

In the Val d Agri the expected production peak of 73 KBOE/d net to Eni was reached as planned. Oil production derives from the first 19 wells drilled of the 38 foreseen by the development plan.

Production maintenance actions were performed on the offshore Annabella, Armida, Barbara, Garibaldi gas fields and the Rospo oilfield through the drilling of infilling wells and sidetrack activities, increasing production by about 75 mmCF/d.

During 2005 development activities concerned: (i) continuation of the development plan of the onshore Candela and Miglianico fields and the completion of the development of the Naide field; (ii) continuation of drilling and connection of development wells in the Val d Agri; (iii) the optimization of producing fields by means of sidetracking and infilling (the Annabella, Armida, Barbara, Garibaldi gas fields and the Rospo oilfield); (iv) construction of an additional sealine for the optimal management of the fields connected to the Fano terminal; and (v) the beginning of the development phase of the Annamaria field.

As part of the development of onshore gas fields in Sicily the following projects are in an advanced phase: (i) in the Pizzo Tamburino field, the first well is scheduled for the second half of 2006 with expected production of approximately 6 mmCF/d; in 2007 according to the actual production of the first well a second one is expected to be drilled; (ii) in the Fiumetto field, an infilling well is expected to start production in the first half of 2007 with an expected peak flow of approximately 7 mmCF/d; and (iii) in the Samperi field, start-up is expected in the second half of 2006 peaking at approximately 7 mmCF/d.

In December 2005 Eni acquired for euro 90 million (including net financial debt transferred of euro 17 million) a 90% interest in Sarcis SpA holding onshore permits/concessions in Sicily.

North Africa

Eni s operations in North Africa are conducted in Algeria, Egypt, Libya and Tunisia. In 2005, North Africa accounted for 27% of Eni s total worldwide production of hydrocarbons.

Algeria Eni has been present in Algeria since 1981. In 2005, Eni s oil production averaged 86 KBBL/d. The principal oil producing fields operated by Eni are located in the Bir Rebaa area in the South-Eastern desert and include Blocks 401a, 402a, 403, 403a and 403d (Eni s share between 50%-100%), which accounted for approximately 52% of Eni s production in 2005 in Algeria. Other interests held by Eni are HBN, HBNS, HBNSE and satellites (Eni s interest 12.25%) and Ourhoud (Eni s interest 4.59%), which in 2005 accounted for approximately 48% of Eni s production in Algeria.

Exploration activities yielded positive results in permits P 404 in area C (Eni s interest 25%), near the HBNE field, with the SFSW-3 appraisal well on the Sif Fatima discovery and P 403 c/e (Eni s interest 33.33%) with the ZNNW-1 appraisal well. In both permits the presence of hydrocarbons was confirmed at a depth of about 3,000 meters.

In Block P 403a/d (Eni s interest 50%) the NFW ROM-6 discovery well and the ROM North-1 appraisal well were drilled at a depth of about 3,400 meters and confirmed the extension of the new oil levels in the ROM field. The ROM integrated development project entails production from these new levels also through the reinjection of gas produced in the nearby BRN field, reducing gas flaring by nearly 90%. Management expects production of the ROM field to peak at 16 KBOE/d net to Eni in 2009.

The EKT, EMK, EMN and EME fields are in the development phase in block 208 (Eni s interest 12.25%). The development plan provides for the drilling of 142 wells and the construction of a central facility for the production of stabilized oil, condensates and LNG. Management expects production of this field to commence in 2008, peaking at 13 KBOE/d net to Eni in 2010.

Egypt Eni has been present in Egypt since 1954. In 2005, Eni s share of production in this country amounting to 207 KBOE/d accounted for 12% of Eni s total annual hydrocarbon production.

In 2005, oil and condensate production averaged 90 KBBL/d net to Eni and came mainly from the Eni operated Belayim and Ashrafi fields in the Gulf of Suez and Melehia in the Western Desert, which covered 74% of Eni s crude oil production in Egypt.

In 2005, natural gas production available for sale averaged 671 mmCF/d net to Eni. The main natural gas producing interests operated by Eni are concentrated in the Nile Delta: onshore the Abu Madi and el Qar a interests and in the Mediterranean offshore, the North Port Said (former Port Fouad), Baltim, Ras el Barr and el Temsah interests. Production from these concessions covered nearly all of Eni s natural gas production in Egypt.

Exploration yielded positive results in the following concessions: (i) Ashrafi (Eni s interest 50%) in the Gulf of Suez with the drilling of the NFW Ashrafi 1X well that found hydrocarbons at a depth of about 1,700 meters; (ii) Belayim Land (Eni s interest 50%) with the drilling of NFW BLSW-1 well that found gas at a depth of over 3,000 meters; (iii) Belayim Marine (Eni s interest 50%) in the Gulf of Suez with the drilling of the BMNW-4 outpost well which allowed to report mineralized levels at a depth of about 3,000 meters. This well was linked to the existing production facilities; and (iv) North Port Said (Eni operator with a 50% interest) with the drilling of the PFM-D-1 well which found gas and condensates at a depth of about 5,000 meters.

Development activities are underway in concessions in the offshore of the Nile Delta: (i) North Port Said (Eni s interest 50%) where the Barboni gas platform started production in May 2005 at an initial level of about 35 mmCF/d while work continued for the expansion of the el Gamil terminal where in 2005 natural gas production net to Eni increased from 388 to 459 mmCF/d; and (ii) el Temsah (Eni operator with a 25% interest) where in August 2005 gas and liquid production started at the Temsah 4 platform. In the second quarter of 2006 production of gas and condensates is expected to start from platform Temsah NW. Peak production at 41 KBOE/d net to Eni is expected in 2008.

In January 2005 the LNG production plant at Damietta was started-up. The plant (Eni s interest 40%) has a treatment capacity of 247 BCF/y. Eni plans to supply 106 BCF/y of its natural gas production volumes in Egypt to this plant in the next 20 years. A second liquefaction train is planned to be installed at the plant with the same capacity of the first train. Eni plans to supply its production gas to this line as agreed in an intent protocol signed with the Egyptian Government in March 2005.

In January 2005 the NGL plant in Port Said was started-up. The plant (Eni s interest 33%) has a treatment capacity of 1,095 mmCF/d of natural gas and annual production of 330,000 tonnes of propane, 280,000 tonnes of LPG and 1.2 mmBBL of condensates.

In the medium term management plans to increase Eni s hydrocarbon production in Egypt leveraging on the development of natural gas reserves in existing areas. This increase is expected to be offset in part by production decline of certain mature oil fields.

Libya Eni started operations in Libya in 1959. In 2005, Eni s share of production in this country amounting to 158 KBOE/d accounted for approximately 9% of Eni s total annual hydrocarbon production.

In 2005 Eni s hydrocarbon production averaged 158 KBOE/d, of which 76% was oil. The main oil, condensates and gas fields operated by Eni are Wafa onshore in permit NC-169 A and Bahr Essalam located in the NC-41 permit in the Mediterranean offshore north of Tripoli started up in September 2004 and August 2005, respectively, as part of the Western Libyan Gas Project (Eni s interest 50%). Production from the two fields is treated at the Mellitah plant under completion on the Libyan coast. Natural gas is carried to Italy through the underwater Greenstream pipeline. In 2005 the two fields produced 74 KBOE/d. Total peak production at 128 KBOE/d net to Eni is expected in 2006. When fully operational in 2006 the gasline is expected to transport and export to Italy a total volume of 283 BCF/y (141 BCF/y net to Eni). This volume will be entirely sold to third parties on the Italian natural gas market under long term contracts. In addition 71 BCF/y are expected to be sold on the Libyan market. In 2005, volumes transported to Italy through this gasline amounted to approximately to 163 BCF for the year.

Other significant fields are: (i) Bu-Attifel (Eni s interest 50%) onshore in the central-eastern desert and Bouri (Eni s interest 30%) in the Mediterranean offshore facing Tripoli which accounted for 43% of Eni s production in Libya in 2005; and (ii) Elephant in the NC-174 onshore permit in the south-western desert (Eni s interest 23.33%) which in 2005 produced 9 KBBL/d net to Eni.

In October 2005 following an international bid procedure Eni obtained an exploration license as operator of four onshore blocks with a total acreage of 18,220 square kilometers, located in the Murzuk basin (161/1, 161/2&4, 176/3) and in the Kufra area (186/1, 2, 3, 4).

Exploration yielded positive results in offshore block NC-41 (Eni operator with a 50% interest) with the drilling of well NFW T1-NC41 which found oil and gas at a depth of 2,770 meters and yielded 4.6 KBBL/d of crude oil and 13 mmCF/d of gas in test production.

In the NC-174 permit (Eni s interest 23.33%) about 800 kilometers south of Tripoli the development of the Elephant oil field continued. In October 2005 the new 725-kilometer long pipeline linking it to the Mellitah plant started operations. The upgrading of the Mellitah plant will be completed in the first half of 2006. Management expects production of this field to peak at 150 KBBL/d (35 KBBL/d net to Eni) in the second half of 2006.

In the medium term, management expects to increase significantly Eni s production in Libya from the 158 KBOE/d level of 2005 benefiting from the expected achievement of full production at the Western Libya Gas Project and at Elephant fields.

West Africa

Eni s operations in West Africa are conducted in Angola, Congo and Nigeria. In 2005, West Africa accounted for 20% of Eni s total worldwide production of hydrocarbons.

Angola Eni has been present in Angola since 1980. In 2005 Eni s oil production averaged 122 KBBL/d and accounted for 11% of Eni s total annual oil production.

Eni s main oil producing fields are located in Block 0 in Cabinda (Eni s interest 9.8%), Block 14 (Eni s interest 20%) and Block 15 (Eni s interest 20%).

The main oil fields in Block 0 are Takula, Nemba and Malongo. In the first half of 2005 production started at the North Sanha/Bomboco oil, condensate and LPG offshore fields. LPG is produced through an FPSO (Floating Production Storage Offloading) unit, the largest in its class in the world. At Sanha a complex for the reinjection of gas into the fields has been built aiming at reducing gas flaring by 50%. In 2005 production from this block (38 KBBL/d) accounted for approximately 31% of Eni s production in Angola. Peak production of oil, condensate and LPG is expected at 100 KBBL/d (10 KBBL/d net to Eni) in 2007. The main field in the deep waters of Block 14 is Kuito which in 2005 produced approximately 58 KBBL/d (10 KBBL/d net to Eni).

In Block 15 the Hungo and Chocalho fields started-up in August 2004, and the Kissanje and Dikanza fields, started-up in July 2005 within phase A and B of the development of the Kizomba area, are now in production. Both fields are developed by means of an FPSO unit. Peak production of phase B at 250 KBBL/d (47 KBBL/d net to Eni) was reached in late 2005. Peak production of phase A at 250 KBBL/d (43 KBBL/d net to Eni) is expected in 2006 and will be kept at the same level by means of additional production from marginal fields. Another relevant field in Block 15 is Xikomba. In 2005 production from Block 15 (70 KBBL/d) accounted for approximately 56% of Eni s production in Angola. Development is underway at: (i) Mondo field with expected start up in 2007 and expected capital expenditure net to Eni amounting to approximately $360 million; and (ii) at Saxi-Batuque fields with expected start up in 2008 and expected capital expenditure net to Eni amounting to approximately $380 million.

The project is underway for the development of the Benguela, Belize, Lobito and Tomboco oilfields at a depth between 300 and 500 meters in Block 14 (Eni s interest 20%). The project provides for the drilling of 50 wells and the installation of a compliant tower with production facilities for Benguela/Belize. The first oil was produced in January 2006. Lobito and Tomboco are planned to be developed by means of underwater completion and to be connected to the compliant tower of Benguela/Belize with start-up scheduled in the second half of 2006. Management expects production from these four fields to peak at 188 KBBL/d (32 KBBL/d net to Eni) in 2008. Total capital expenditure net to Eni is expected to amount to approximately $460 million.

Offshore exploration activities were successful in the following areas: (i) Block 0, former Cabinda (Eni s interest 9.8%) with the NFW 70-5X well that found hydrocarbons at a depth of 2,335 meters and yielded 2 KBBL/d of crude oil and natural gas in test production; (ii) Block 14K/A-IMI (Eni s share 10%) with the drilling of the Lianzi-2ST and Lianzi-2OH appraisal wells on the Lianzi discovery which showed the presence of natural gas and crude oil layers at a depth of more than 3,000 meters; and (iii) Block 15 (Eni s interest 20%) with the Batuque-3 appraisal well on the Batuque discovery which confirmed the presence of hydrocarbons at a depth of about 2,000 meters.

In May 2006, Eni acquired the operatorship (Eni s interest 35%) of a new exploration area in Block 15.

In the medium term, management expects to increase Eni s production to approximately 200 KBBL/d benefiting from the expected achievement of full production of fields started-up in 2005 and the contribution of new development projects.

Congo Eni has been present in Congo since 1968 and its production in 2005 was 67 KBOE/d.

Eni is the second largest international oil producer, with oil fields operated by Eni accounting for 28% of Congo s total oil production in 2005 (65 KBBL/d net to Eni). Eni s principal oil producing interests operated in Congo are located in the offshore facing Pointe Noire: the Zatchi, Foukanda, Mwafi and Djambala fields (Eni s interest 65%), the Loango field (Eni s interest 50%) and the Kitina field (Eni s interest 35.75%) operated by Eni accounted for approximately 59% of Eni s production in Congo in 2005. Eni holds a 35% interest in the Pointe Noire Grand Fond and Pex permits.

Nigeria Eni has been present in Nigeria since 1962. In 2005, Eni s hydrocarbon production averaged 149 KBOE/d and accounted for 9% of Eni s hydrocarbon production.

Eni s principal producing fields in Nigeria are located in: (i) four onshore blocks (OML 60, 61, 62 and 63) in the Niger Delta (Eni s interest 20%), which in 2005 accounted for 35% of Eni s production in Nigeria; (ii) the offshore OML 125 block (Eni s interest 50.19%), where the Abo field is located which produced over 14 KBBL/d net to Eni in 2005. The development of other levels of the Abo field are expected to reach a production peak of 38 KBBL/d (15 KBBL/d net to Eni) in 2007; and (iii) the offshore OML 119 block, operated through a service contract, where the Okono and Okpoho oil fields are located, which produced 55 KBBL/d (19 KBBL/d net to Eni) in 2005.

Eni also holds a 5% interest in the 31 onshore blocks and a 12.86% interest in the 5 offshore blocks of NASE, the largest oil joint venture in the country. In 2005 production of this joint venture net to Eni accounted for about 34% of Eni s production in Nigeria.

In November 2005 the Bonga oil field (Eni s interest 12.5%), situated in the OML 118 permit offshore Nigeria in waters of a depth between 950 and 1,150 meters, was started up. Development is achieved by means of an FPSO vessel connected to 17 producing wells (9 already drilled). Production is expected to peak at 200 KBBL/d (23 KBBL/d net to Eni) in 2006.

In September 2005 Eni acquired as operator the OML 120 and OML 121 development licenses from Nigerian companies. The concessions, where the Oyo field was discovered, are located approximately 70 kilometers offshore the western coast of the Niger Delta in Nigeria. Two exploration wells are going to be drilled in 2006.

Exploration yielded positive results in the offshore OML 125 block (Eni operator with a 50.2% interest) with the drilling of the Abo 8 appraisal well that found oil layers at a depth of 2,142 meters and in the offshore OPL 219 block (Eni s interest 12.5%) with the drilling of the Bolia 3X appraisal well that found oil levels at a depth of over 3,000 meters.

Eni holds a 10.4% interest in Nigeria LNG Ltd which manages the liquefaction plant located on Bonny Island with a treatment capacity of approximately 812 BCF/y of natural gas corresponding to a production of 17 million tonnes/y of LNG, along with over 2.2 million tonnes/y of LPG and 1.1 million tonnes/y of condensates on five trains. The fourth train was started up in late 2005 and the fifth in January 2006. The fourth train and the fifth train are expected to reach full production in 2007. Nigeria LNG s partners have planned a further capacity expansion to 1,448 BCF/y, corresponding to a production of 30 million tonnes of LNG by means of the installation of two more trains (one already under construction) with start-up expected between 2007 and 2011. Eni expects its share of capital expenditure for the planned capacity expansion to amount to $1.2 billion; this expenditure is expected to be completely financed by cash generated from the plant operations.

Natural gas supplies to the plant (first six trains) will be provided under a gas supply agreement with a 20 year term from production of the NASE joint venture (Eni s interest 5%) and of Blocks OML 60 and 61 (Eni operator with a 20% interest). When fully operational in 2008 they will supply approximately 3.5 BCF/d (0.27 BCF/d net to Eni, corresponding to approximately 47,000 BBL/d). Capital expenditure net to Eni for the development activity is expected to amount to approximately $560 million.

In April 2005, the Okpai power station (independent power plant, Eni s interest 20%) started operations, with a generation capacity of 480 megawatt on two gas and one steam turbines. The power station is fed with gas from the nearby Kwale fields in permit OML 60 (Eni operator with a 20% interest), which will supply 71 mmCF/d of natural gas when the power station is fully operational. The project is part of Eni s and the Nigerian government s plan to reduce CO_2 emissions in the atmosphere.

In the medium term, management expects to increase significantly Eni s production in Nigeria to approximately 200 KBBL/d leveraging on the development of natural gas reserves, in particular in order to ensure supplies to the Bonny plant, and the contribution of fields started-up recently, as in the case of Bonga, and of new development projects.

North Sea

Eni s operations in the North Sea area are conducted in Norway and the United Kingdom. In 2005, the North Sea accounted for 16% of Eni s total worldwide production of hydrocarbons.

Norway Eni has been operating in Norway since 1964. In 2004 Eni s hydrocarbon production averaged 136 KBOE/d. Eni s principal producing interests are the Ekofisk field (Eni s interest 12.39%) in the North Sea, and the Aasgard, Mikkel (both with a 14.9% interest) and Norne (Eni s interest 6.9%) fields in the Norwegian Sea which together accounted for 90% of Eni s production in Norway in 2005.

In November 2005 production started at the Kristin oil and gas field (Eni s interest 8.25%) located in the PL134 permit in the Haltenbanken area about 200 kilometers off the coast in the Norwegian Sea. Oil production is treated on a semi-submersible platform with a capacity of 125 KBBL/d. Production is expected to peak at 218 KBOE/d (18 KBOE/d net to Eni) in 2007. In the same permit the Tofte formation discovered with the first producing well on Kristin will be developed. The synergies with the Kristin production facilities will allow a viable development of the nearby Tyrihans field (Eni s interest 7.9%), expected to start-up in 2009, in coincidence with the expected production decline of Kristin.

In November 2005 the Svale and Stær oil fields in the PL128 permit (Eni s interest 11.5%) were started up, exploiting synergies with the nearby Norne production facilities. Production is expected to peak at 56 KBBL/d (6 KBBL/d net to Eni) in 2006.

The exploration activities yielded positive results in the Barents Sea with the second appraisal Goliath South well on the Goliath oil and gas discovery. Management expects the Goliath South well may results in the discovery of additional hydrocarbon reserves either from the expected reservoir or from deeper layers. Goliath is located in Block PL 229 (Eni s interest 65%).

The United Kingdom Eni has been present in the United Kingdom since 1964. In 2005 Eni s net production of hydrocarbons averaged 141 KBOE/d.

Eni s principal producing interests in the United Kingdom are Elgin/Franklin (Eni s interest 21.87%), MacCulloch (Eni s interest 40%), fields located in the Liverpool Bay (Eni s interest 53.9%) and J-Block (Eni s interest 33%). In 2005 these fields accounted for 77% of Eni s production in the United Kingdom.

Exploration yielded positive results in the P/233 permit in blocks 15/25a (Eni s interest 12%) in the central section of the North Sea with the NWF 15/25°-DD well drilled at a depth of over 2,000 meters and flowed about 4 KBBL/d of high quality oil and natural gas in test production.

Development activities concerned: (i) the start-up of the Farragon field (Eni s interest 30%); and (ii) linkage of the gas and condensate Glenelg (Eni s interest 8%) and West Franklin (Eni s interest 21.87%) fields to the Elgin Franklin production platform.

In July 2005 Eni divested some exploration assets located in the central section of the North Sea as part of its strategy of asset portfolio rationalization.

In November 2005 the British government announced a draft law to increase corporate income taxes by levying a supplementary charge increase of 10 percentage points (from 10 to 20%). In the event this draft law is enacted, management estimates an adverse 1.2 percentage points impact on Eni Group s tax rate in 2006 as compared to 2005. Approximately half of the expected increase will relate to a provision for deferred taxation. Given the expected production decline of the area for the decline of mature fields, the adverse impact of higher rates of taxes in the United Kingdom will diminish with time.

Rest of the World

In 2005, Eni s operations in the rest of the world accounted for 21% of its total worldwide production of hydrocarbons.

In *Brazil* in January 2006 following an international bid procedure held in October 2005 Eni acquired the operatorship of a six year exploration license in Block BM Cal-14, covering an area of about 745 square kilometers in the deep waters of the Camamu-Almada basin, about 1,300 kilometers north of Rio de Janeiro. In March 2005 the exploration license of Block BM-C-3 (Eni s interest 40%) was converted into an evaluation area. The test phase of the Peroba discovery well containing oil is scheduled within 2006. Exploration yielded positive results in Block BM-S-4 (Eni s interest 100%) with the drilling of the NFW Belmonte-1A well which found natural gas at a depth of over 5,000 meters. The relevant authorities allowed a third exploration period for this block which will last two years and provides for the drilling of one well.

In *China* offshore exploration activity yielded positive results in Block 16/19 (Eni s interest 33%) in the South China Sea about 180 kilometers south east of Hong Kong with the drilling of the HZ25-4-1 well (Eni s interest 100%), which found hydrocarbons at a depth between 2,200 and 3,800 meters and flowed about 5 KBBL/d of oil in test production. The HZ25-4 field will be started up by means of the production facilities existing in the area. In Block 16/19 the HZ25-3-2 appraisal well confirmed the extension of the reserves of the HZ25-3 oil field.

In *India* in July 2005, Eni was awarded the right to conduct exploration activities as operator in Blocks 8 and D-6, following an international bid tender. Block 8 (Eni s interest 34%) is located onshore in Rajasthan in the northwest of India, and extends for 1,335 square kilometers. Block D-6 (Eni s interest 40%) is located deep water in the Indian Ocean, some 130 kilometers east of the Andaman Islands, and covers an area of 13,110 square kilometers. This contract marks the beginning of Eni s upstream activities in India. In September 2005 Eni and the Indian Oil & Natural Gas Corporation signed a memorandum of understanding establishing mutual cooperation between the companies aimed at finding new exploration and production opportunities. In particular, the companies will exchange information on a range of deep offshore exploration projects in India and in other countries, with an option to exchange equity interests in selected upstream and midstream projects.

In *Mozambique* in March 2006, following an international bid tender, Eni obtained the exploration license for Area 4, located in the deep offshore of the Rovuma Basin 2,000 kilometers north of Maputo. The block covers an area of 17,646 square kilometers in an unexplored geological basin with great mineral potential according to surveys performed.

In *Turkey* in September 2005 an agreement has been reached with the Turkish Group Calik concerning feasibility study for the realization of a new oil pipeline from the Black Sea Turkish coast east of Samsun (Unye) to Ceyhan, on the Turkish Mediterranean coast. The new oil transportation infrastructure will include: (i) a new loading terminal in Samsun; (ii) a 550-kilometer long pipeline with design capacity of 1.5 million barrels of oil per day; and (iii) oil storage facilities to be built in the existing terminal in Ceyhan. The construction of a pipeline represents a faster, environmentally safer and more economic alternative to the transportation of oil by ship through the Turkish Straits of the Bosphorus and Dardanelles.

Australia Eni has been present in Australia since 2000. In 2005 Eni s hydrocarbon production averaged 21 KBOE/d mainly of oil.

Eni is operator with a 65% interest of the offshore Woollybutt oil field, which in 2005 accounted for 51% of Eni s production in Australia.

Eni holds a 12.04% interest in the liquids and gas Bayu Undan field where liquid production was started-up in 2004. Production of natural gas currently under development will be treated at the Darwin liquefaction plant which has a capacity of 3.5 million tonnes/y. In January 2006 the first shipment of LNG was made to the Japanese market. A production peak of 160 KBOE/d from this field (18 KBOE/d net to Eni) is expected in 2008.

Offshore exploration was successful in: (i) Block AC/P-21 (Eni s interest 40%) with the NFW Vesta-1 well that located oil and gas at a depth of over 3,300 meters; (ii) Block WA-25-L (Eni s interest 65%) with the Woollybutt-4 appraisal well which confirmed the presence of oil in the western extension of Wollybutt-3 at a depth of over 2,000 meters; and (iii) Block WA-208 P (Eni s interest 18.66%) with the NFW Hurricane-1 well that identified natural gas at a depth of over 3,000 meters.

In December 2005 Eni purchased further interests and reached 100% in permits WA 279-P and WA 313-P in the Bonaparte offshore basin off the northern coast of Australia where the Blacktip and Penguin fields are located. Total capital expenditure net to Eni is expected to amount to approximately $325 million. In the same basin Eni purchased a 39% interest in the WA 34-R permit where the Rubicon and Prometeus fields are located.

In December 2005 Eni signed Heads of Agreement with the Darwin Power and Water Utility Company for the supply of a total amount of 20 BCM of natural gas from the Blacktip field for a 25 year period starting in January 2009.

Croatia Eni, through a 50/50 joint venture with INA, the national Croatian company, operates the Ivana natural gas field, located 40 kilometers West of Pola in the Adriatic offshore in approximately 40 meter deep waters. The field is operated through a main production platform, called Ivana A, and three satellite platforms, Ivana B, D and E.

As part of the development plan of the natural gas discoveries in the area between the end of 2005 and the beginning of 2006 the Ika, Ida, Ivana C and K fields were started up. Production from these fields is sent to the Ivana K platform and from this platform through a 57-kilometer long pipeline to the Garibaldi K platform. A 43-kilometer long pipeline is under construction to reach the Croatian coast near Pula. Two fields, Katarina and Annamaria, are under development and are expected to start-up in late 2006 and early 2009, respectively.

In the medium term, management expects to increase Eni s production to approximately 7 KBOE/d benefiting from the full production of the new fields.

Indonesia Eni has been present in Indonesia since 2000. In 2005 hydrocarbon production net to Eni averaged 22 KBOE/d. Eni s producing interests are located in the onshore area in East Kalimantan (Borneo) regulated by the Sanga Sanga PSA (Eni s interest 37.81%) operated by Virginia Indonesia Co, in which Eni holds a 50% interest. This area produces mainly natural gas (about 80%). This gas is treated at the Bontang liquefaction plant, the largest in the world, and is exported to the Japanese, South Korean and Taiwanese markets.

Offshore exploration activity yielded positive results in the Bukat block (Eni operator with a 41.25% interest) in the Tarakan basin offshore Borneo with the drilling of appraisal wells on the Aster oil discovery made in 2004. The Aster 2 and 3 wells confirmed the presence of additional reserves of high quality hydrocarbons and the exploration potential of the basin. In 2006 and 2007 further appraisal activities are scheduled in order to reach a definition of the field s development plan.

Iran Eni has been present in Iran since 1957. In 2005 liquid production net to Eni averaged 35 KBBL/d. The main producing oil fields operated by Eni under buy-back contracts are: (i) South Pars phases 4 and 5 (Eni operator with a 60% interest, the remaining 40% interest being held by Iranian partners) in the offshore of the Persian Gulf. These phases were started up in 2004. At the beginning of 2005 the gas treatment plant as part of the development project of the field was completed. In 2005, production of gas reached a rate equivalent to the 706 BCF/y production plateau; the field produced also one million tonnes/y of propane and butane and 108 KBBL/d of condensates (33 KBBL/d of condensates net to Eni) through separation from natural gas. Eni s share of condensates is destined to cover development costs incurred by Eni and to remunerate capital employed by Eni; and (ii) the Darquain oil field (Eni operator with a 60% interest, the remaining 40% interest being held by Iranian partners) located onshore approximately 50 kilometers north-east of Abadan. On this field the second development phase is underway and aims at increasing production from the present 50 KBBL/d to over 160 KBBL/d (14 KBBL/d net to Eni) through the increase of the existing treatment capacity, the drilling of new producing wells and the injection of gas. These two fields account for 85% of Eni s production in Iran.

Eni also holds interests in the Dorood (45%) and Balal (45%) oil fields in the offshore of the Persian Gulf located respectively near the Kharg island and about 100 kilometers south-west of the Lavan island. The development of Dorood is expected to be completed at the end of 2006 with a peak production of 50 KBBL/d.

Kazakhstan Eni has been present in Kazakhstan since 1992. Eni is co-operator with British Gas with a 32.5% interest of the Karachaganak oil, gas and condensate field. In 2005 production from this field (net to Eni) averaged 64 KBBL/d of liquids and 207 mmCF/d of natural gas. Most of the liquids produced are exported to Western markets through the Caspian Pipeline Consortium pipeline (Eni s interest 2%). This pipeline is connected to the Novorossiysk terminal on the Russian coast of the Black Sea. In 2005 exports amounted to 42.5 KBBL/d net to Eni, corresponding to 41.7% of oil and gas produced by the field net to Eni. The rest of liquid production is exported and sold, as unstabilized condensates, on the Russian and Kazakh markets. The development plan of the field provides for the production of additional liquid and gas reserves by means of a gas treatment plant and the drilling of production wells.

As part of the North Caspian Sea PSA, where the Kashagan field is located, on March 31, 2005 Eni (operator) and the other members of the consortium, except for one, purchased British Gas s interest (16.67%) in proportional shares, according to the option exercised in May 2003, and sold half of this newly acquired interest to the national Kazakh company Kazmunaygaz (KMG), a new partner in the PSA with an 8.335% interest. Following these two transactions (the sale to KMG was closed in May 2005), Eni increased its interest from 16.67% to 18.52% and continues acting as operator. The outlay for this transaction amounted to $200 million. The development plan of the Kashagan field, presented at the end of 2002 and approved in February 2004, mainly foresees: (i) production start-up in 2008 at an initial level of 75 KBBL/d. Management plans production level to increase to 450 KBBL/d at the end of the first phase of development and to reach a plateau of 1.2 mmBBL/d at the end of the field development; (ii) total capital expenditure estimated at $29 billion ($5.4 billion being Eni s share). Such capital expenditure plan is currently under revision in order to take into account depreciation of the U.S. dollar versus the euro and the rising trends in the costs of certain production factors (such as materials and oilfield services). The above mentioned amount does not include the capital expenditure for the construction of the infrastructure for exporting production to international markets, for which various, options are under scrutiny by the consortium. These include: (i) the use of existing infrastructure, such as the Caspian Pipeline Consortium pipeline and the Atyrau-Samara pipeline; and (ii) the laying of a pipeline connecting the Bolashak production center with the Baku-Tbilisi-Cehyan pipeline (BTC, Eni s interest 5%). This new system includes the laying of a 750-kilometer long pipeline with a 42 inch diameter from Bolashak to Kuryk and a reception terminal on the other side of the Caspian Sea near the starting point of the BTC pipeline.

At December 31, 2005, the total amount of contracts awarded for the development of the field was over $8.8 billion for the completion of the first phase of the field s development plan (Tranches 1 and 2) which includes the drilling of development wells, the construction of infrastructure and facilities for offshore production (drilling, treatment and reinjection of sour gas for maximizing the oil yield) and onshore treatment plants. The most advanced techniques are going to be applied in the construction of the planned infrastructure and facilities in order to cope with high pressures in the field and the presence of hydrogen sulphide.

In the medium term, management expects to increase Eni s production in Kazakhstan from the current level of 100 KBOE/d leveraging on the development of natural gas reserves at Karachaganak and the start-up of Kashagan.

Pakistan Eni has been present in Pakistan since 2000. In 2005 production net to Eni averaged 48 KBOE/d, mainly of natural gas. The main natural gas producing fields operated by Eni are Bhit (Eni s interest 40%) and Kadanwari (Eni s interest 18.42%), which in 2005 accounted for 43% of Eni s production in Pakistan. Eni also holds interests in the Sawan (23.68%), Zamzama (17.75%) and Miano (15.16%) fields. In the first quarter of 2005 the Rehmat field (Eni s interest 30%) was started-up.

Eni is operator in the Gorakh permit (Eni s interest 92.5%) in Kirthar Foldbet area and holds an interest in other permits in the Middle Indus Basin.

Eni purchased the Indus M and Indus N exploration permits in the offshore of the Indus Delta with a total area of 5,000 square kilometers. In February 2006 Eni purchased the permits Rajar, Mithi, Thar and Umarkot in the East Sindh area.

United States Eni has been present in the United States since 1966 and holds various mineral interests in the Gulf of Mexico and Alaska. In 2005 Eni s hydrocarbon production averaged 33 KBOE/d and was obtained in the Gulf of Mexico. The main producing fields operated by Eni are Allegheny (Eni s interest 100%) and King Kong (Eni s interest 50%). Another relevant field is Medusa (Eni s interest 25%). These fields accounted for 71% of Eni s production in 2005.

In May 2005 the K2 oil field (Eni operator of the development phase with an 18.17% interest) was started-up. The field s development includes two additional subsea wells linked to the nearby Marco Polo platform, operated by a partner. A peak production of 38 KBOE/d (7 KBOE/d net to Eni) is expected in 2007.

Eni purchased 22 exploration blocks in the Gulf of Mexico following its participation to the 194 (March 2005) and 196 (August 2005) Lease Sale.

In Alaska in August 2005, Eni purchased from the U.S. independent company Armstrong Oil & Gas 104 exploration blocks onshore in the North Slope and offshore in the Beaufort Sea. The blocks, with a total acreage of 1,409 (1,111 net to Eni) square kilometers, include two fields in the pre-development phase holding estimated 170 mmBBL of oil of reserves.

Production for 2005 was adversely impacted by shutdowns of certain facilities as a consequence of the hurricane season. Management expects residual hurricane-related impact in 2006. See the paragraph "Production" above and "Item 5 Recent Developments".

Venezuela Eni has been present in Venezuela since 1998. In 2005 daily production averaged 61 KBBL/d net to Eni and came from the Dación oil field. See the paragraph "Oil and natural gas reserves" above.

The development of the Corocoro oil field (Eni s interest 26%) in the West Paria Gulf is in progress. The plan provides for a phased development depending on the results from wells and reaction of the field to water and gas reinjection. Production is expected to start in 2008 with a peak of about 70 KBBL/d (17 KBBL/d net to Eni) in 2009.

In January 2006, following an international bid, Eni was awarded the Cardon IV Block exploration license in joint venture with another international oil company in the Gulf of Venezuela.

Capital Expenditure

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

Storage

Natural gas storage activities are performed by Stoccaggi Gas Italia SpA (Stogit) to which such activity was conferred on October 31, 2001 by Eni SpA and Snam SpA, in compliance with Article 21 of Legislative Decree No. 164 of May 23, 2000, which provided for the separation of storage from other activities in the field of natural gas.

Storage services are provided by Stogit through eight storage fields located in Italy, based on ten storage concessions[6] vested by the Ministry of Productive Activities.

In 2005 Stogit increased the share of storage capacity used by third parties up to 56% (53% in 2004). From the beginning of its operations Stogit markedly increased the number of customers served and the share of revenues from third parties: from a nearly negligible amount, the latter accounted for 44% of total revenues in 2005.

Storage		**2002**	**2003**	**2004**	**2005**
Available capacity:					
- modulation and mineral	(BCM)	7.1	7.1	7.5	7.5
. share utilized by Eni	(%)	66	53	47	44
- strategic	(BCM)	5.1	5.1	5.1	5.1
Total customers	(No.)	20	30	39	44
. modulation and upstream storage customers	(No.)	14	24	29	35

Gas & Power

Eni is engaged in the business of natural gas supply, transport and sale mainly in Italy and in the rest of Europe. Eni is also engaged in the business of electricity generation, which is conducted in Italy.

Eni plans to grow natural gas sales in the rest of Europe and to develop its presence in the LNG business in order to compensate for lower growth opportunities on the domestic market due to the limits imposed on operators by the sector regulation and increasingly intense competition. In Italy, Eni plans to comply with regulatory limits on direct sales and input volumes to the national transport network through an optimal allocation of supplies between direct sales in Italy and in the rest of Europe and by using natural gas at its own electricity generation plants and, at the same time, leveraging on the expected consumption growth. In the medium term, management expects natural gas sales in Italy to decline from the 58 BCM level recorded in 2005 as a consequence of increasing competition from third parties. Eni plans to implement a more attractive commercial offer than Eni s competitors on the basis of the quality of services, pricing formulas, including different indexation schemes to suit various customer s purchasing profile, and the integration of supply of gas and electricity. Management plans to grow natural gas sales on the European market leveraging on Eni s availability of equity gas and a diversified portfolio of supply contracts, an extensive gas pipeline network, which allows for the supply of natural gas from several sources, and long standing relationships with producing countries. Eni intends to strengthen its presence in markets where its presence is already established such as the Iberian Peninsula, Germany and Turkey and to develop sales in markets with significant growth and profitability prospects (in particular France and the United Kingdom).

Eni also intends to accelerate the development of its LNG business on a global scale through the acquisition of interests in assets covering the whole LNG chain (in particular regasification terminals) and also to monetize its natural gas reserves in West and North Africa, in the Far East.

The matters regarding future natural gas demand and sales target discussed in this section and elsewhere here in 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 for Natural Gas in Italy

In 2005, natural gas demand in Italy totalled 86 BCM (increasing by over 7% over 2004). In 2005, about 18% of natural gas requirements were met through domestic production (including natural gas volumes offtaken from storage), while imports covered 82%. Eni expects natural gas consumption in Italy to reach about 95 BCM in 2010, corresponding to an compound annual growth rate of about 2%.

Most of this increase is expected in electricity generation, because of the significant advantages of the use of natural gas in combined cycle plants, due to its lower investment cost, higher yields and reduced polluting emissions as compared to other fuels. Demand is expected also to increase from residential and commercial users, due to the increased use of natural gas in residential space heating, in households and services, in large tertiary firms and as vehicle fuel.

Natural Gas Purchases

In 2005, Eni s Gas & Power segment purchased 82.56 BCM of natural gas, with a 6.47 BCM increase over 2004, up 8.5%, in line with the increase in sales and related to higher volumes purchased outside Italy (7.04 BCM), offset in part by lower production volumes supplied in Italy (0.57 BCM). Natural gas volumes supplied outside Italy (71.83 BCM) represented 87% of total supplies (85% in 2004).

Outside Italy increases concerned purchases from Libya (3.29 BCM) and from Algeria (0.72 BCM). Imports of LNG destined to Italy increased by 0.18 BCM due to the partial resumption of supplies from Sonatrach after the accident occurred in early 2004 at the Skikda liquefaction plant in Nigeria.

In 2005, a total of 0.84 BCM of natural gas were withdrawn from the storage sites of Stoccaggi Gas Italia SpA (Eni s interest 100%) as compared to 0.93 BCM in 2004.

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

Natural gas supplies	**2001**	**2002**	**2003**	**2004**	**2005**
			(BCM)		
Italy	**14.62**	**12.67**	**12.16**	**11.30**	**10.73**
Russia for Italy	19.51	18.62	18.92	20.62	21.03
Russia for Turkey			0.63	1.60	2.47
Algeria	18.39	16.35	16.53	18.86	19.58
the Netherlands	7.00	7.55	7.41	8.45	8.29
Norway	1.10	4.83	5.44	5.74	5.78
Croatia		0.31	0.65	0.35	0.43
the United Kingdom		1.48	1.98	1.76	2.28
Hungary	3.11	3.05	3.56	3.57	3.63
Libya				0.55	3.84
Algeria (LNG)	1.79	1.92	1.98	1.27	1.45
Others (LNG)		0.30	0.72	0.70	0.69
Other supplies	0.03	0.03	0.04	0.12	1.18
Others outside Europe	0.96	0.96	1.14	1.20	1.18
Outside Italy	**51.89**	**55.40**	**59.00**	**64.79**	**71.83**
Total supplies	**66.51**	**68.07**	**71.16**	**76.09**	**82.56**
Withdrawals from (inputs to) storage	0.13	(1.43)	0.84	0.93	0.84
Network losses and measurement differences	(0.92)	(0.50)	(0.61)	(0.53)	(0.78)
Available for sale	**65.72**	**66.14**	**71.39**	**76.49**	**82.62**

In order to meet the medium and long-term demand for natural gas, in particular of the Italian market, Eni entered into long-term purchase contracts with producing countries that currently have a residual average term of approximately 15 years. Existing contracts, which in general contain take-or-pay clauses, will ensure a total of about 67.3 BCM/y of natural gas (Russia 28.5, Algeria 21.5, the Netherlands 9.8, Norway 6 and Nigeria LNG 1.5) by 2008. The average annual minimum quantity (take-or-pay) is approximately 85% of said quantities. Despite the fact that management plans to sell outside Italy the increasing volumes of natural gas available under Eni s take-or-pay contracts, the expected development of Italian demand and supply of natural gas in the medium and long-term and the evolution of regulations in this segment represent a risk element in the management of take-or-pay contracts. See "Item 5 Contractual Obligations".

In 2005 Eni withdrew about 3.8 BCM more than its minimum offtake obligation. See "Item 5 Recent Developments and Management Expectations of Operations".

In 2003 Eni and Gazexport (Gazprom) signed an agreement under which Eni has the right to sell the gas it purchases from Gazexport (Gazprom) in countries other than Italy. This agreement entails the cancellation of the so called territory destination clause. Gazexport (Gazprom), in turn, can sell its gas to other Italian operators. The European

Commission approved this transaction and requested Eni to assume additional obligations favoring competition, in particular: (i) Eni should make volumes of natural gas purchased from Gazexport (Gazprom) available outside Italy; and (ii) Eni shall promote the upgrading of the TAG gasline (from Austria into Italy) with deadlines consistent with the decision of third parties to build LNG terminals in Italy.

Natural Gas Sales in Italy and Europe

In 2005 natural gas sales (91.15 BCM, including own consumption and Eni s share of sales of affiliates) increased by 7.34 BCM over 2004, up 8.8%, due mainly to higher sales in the rest of Europe (up 3.15 BCM), in the Italian market (up 2.39 BCM, or 4.8%) and natural gas supplies for power generation at EniPower s power stations (up 1.84 BCM, or 49.7%).

In an increasingly competitive market, natural gas sales to third parties in Italy (52.47 BCM) increased by 2.39 BCM over 2004, down 4.8%, reflecting an increase in sales to end users, also due to a cold winter, primarily relating to power generation (up 1.68 BCM or 10.6%), industries (up 0.68 BCM or 5.5%) and the residential and commercial segment (up 0.44 BCM or 6%). These increases were offset in part by lower sales to wholesalers (down 1.82 BCM or 13.1%) related to the so called gas release carried out in accordance with certain decisions of the Antitrust Authority. See "Regulation of the Italian Hydrocarbon Industry Gas & Power Inquiries by Italian and European Antitrust Authorities Sales contracts outside Italy" below.

Natural gas sales in the rest of Europe (23.44 BCM) increased by 1.9 BCM (up 8.8%) due to increases registered in: (i) supplies to the Turkish market via the Blue Stream gasline (up 0.86 BCM); (ii) sales under long-term supply contracts to importers to Italy (up 0.57 BCM), also due to reaching full supplies from Eni s Libyan fields; (iii) France, related to the increase in supplies to industrial customers and to wholesalers (up 0.5 BCM); and (iv) Germany and Austria related to increased supplies (up 0.3 BCM) to Eni s affiliate GVS (Eni s interest 50%) and other operators.

Own consumption[7] was 5.54 BCM, up 1.84 BCM from 2004, or 49.7%, reflecting primarily higher supplies to EniPower due to the coming on stream of new generation capacity, primarily reflecting supplies to EniPower (4.41 BCM), to Polimeri Europa (0.35 BCM) and to Eni s Refining & Marketing segment (0.27 BCM).

Sales of natural gas by Eni s affiliates (net to Eni and net of Eni s supplies) amounted to 8.53 BCM, increasing by 1.21 BCM over 2004, up 16.5%, and concerned: (i) GVS (Eni s interest 50%) with 3.39 BCM; (ii) Galp Energia (Eni s interest 33.34%) with 1.56 BCM; (iii) Unión Fenosa Gas (Eni s interest 50%) with 1.52 BCM; and (iv) volumes of natural gas (1.45 BCM) treated at the Nigeria LNG Ltd liquefaction plant (Eni s interest 10.4%) in Nigeria, sold by Nigeria LNG Ltd to U.S. and European markets.

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

Natural gas sales	**2001**	**2002**	**2003**	**2004**	**2005**
			(BCM)		
Italy	**56.74**	**50.43**	**50.86**	**50.08**	**52.47**
Wholesalers	21.09	17.02	15.36	13.87	12.05
Gas release				0.54	1.95
End customers	35.65	33.41	35.50	35.67	38.47
Industrial users	18.53	14.43	13.17	12.39	13.07
Thermoelectric users	12.21	12.48	15.03	15.92	17.60
Residential	4.91	6.50	7.30	7.36	7.80
Rest of Europe	**6.05**	**12.77**	**17.54**	**21.54**	**23.44**
Outside Europe	**0.93**	**0.92**	**1.09**	**1.17**	**1.17**
Total sales to third parties	**63.72**	**64.12**	**69.49**	**72.79**	**77.08**

Own consumption	2.00	2.02	1.90	3.70	5.54
Total sales to third parties and own consumption	**65.72**	**66.14**	**71.39**	**76.49**	**82.62**
Sales of natural gas of Eni s affiliates (net to Eni)	**1.38**	**2.40**	**6.94**	**7.32**	**8.53**
Europe	0.93	1.93	6.23	6.60	7.85
Outside Europe	0.45	0.47	0.71	0.72	0.68
Total sales of natural gas	**67.10**	**68.54**	**78.33**	**83.81**	**91.15**

The Italian Natural Gas Market

The Italian natural gas market is made up of three main segments: residential and commercial, industrial and thermoelectric. Customers can be divided into three groups: (i) high consumption final users directly linked to the national and regional natural gas high pressure networks (industries and power stations); (ii) customers of the residential and commercial sector such as residential and commercial users, hospitals, schools, public utilities, small enterprises located in urban centers supplied by wholesalers through low pressure networks; and (iii) wholesalers (mainly local selling companies and distributors of natural gas for automotive use) purchasing natural gas to sell it to residential and commercial customers.

In 2005, Eni s natural gas sales to wholesalers amounted to 12.05 BCM (down 13.1% over 2004).

In 2005, natural gas consumption in the Italian industrial segment amounted to approximately 21.8 BCM (approximately 25% of total final consumption), with a 2.3% decrease from 2004. In 2005, Eni s sales of natural gas to industrial users amounted to 13.07 BCM (up 5.5% over 2004).

In 2005, natural gas consumption in the Italian thermoelectric segment amounted to approximately 33 BCM (approximately 38% of total demand), with an approximately 14% increase over 2004. In 2005, Eni s sales of natural gas to thermoelectric users amounted to 17.60 BCM (up 10.6% over 2004).

Natural gas consumption in the residential and commercial segment amounted to over 30 BCM (35% of total demand), with a 6.9% increase from 2004 due to the effect of weather conditions. Eni manages directly over 5 million residential customers and in 2005 Eni s sales to this segment amounted to 7.8 BCM (up 6% from 2004).

Transmission, Dispatching and Regasification Activities

Transmission, dispatching and regasification activities in Italy are carried out by Snam Rete Gas, a company listed on the Italian Stock Exchange (in which Eni holds a 50.07% interest). Eni s primary transmission network was conferred to Snam Rete Gas in July 2001 in implementation of Legislative Decree No. 164/2000 concerning the Italian natural gas market, which provides for the separation of transmission, dispatching and regasification activities from all other activities in the natural gas segment. This Decree also establishes that transport activity qualifies as a public concern activity and consequently is regulated.

The Italian natural gas transmission system is made up of a national pipeline network and a regional pipeline network for a total length of 33,000 kilometers, of which 30,712 kilometers are owned by Eni.

The Italian national transmission network is made up of high pressure trunklines, 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 the regional transmission network. The national network includes also some interregional lines reaching important markets.

The regional transmission network is made up of the remaining lines and allows the transmission of natural gas to industries, power stations and local distribution companies of the various local areas served.

At December 31, 2005 the national pipeline network owned by Eni extended for 8,392 kilometers.

Underground pipelines have a maximum diameter of 48 inches and carry natural gas at pressures of 24 to 75 bars. The underwater pipeline crossing the Messina Strait has a diameter of 20 to 26 inches and carries natural gas at a pressure equal to or higher than 115 bars.

The major pipelines interconnected with import trunklines that are part of Eni s national network are:

for natural gas imported from Algeria:
- two lines with 48/42-inch diameter, each approximately 1,500-kilometer long, including the smaller pipe that crosses underwater the Messina Strait, which links Mazara del Vallo (on the Southern coast of Sicily) to Minerbio (near Bologna). This pipeline is undergoing an upgrade with the laying of a third line with 48 inch diameter that is 290-kilometer long (of these 241 are already operating). Transport capacity at the Mazara del Vallo entry point is approximately 83 mmCM/d;

for natural gas imported from Libya:
- a 36-inch line, 67-kilometer long linking Gela, the entry point of the Greenstream underwater pipeline into the national network near Enna along the import pipeline from Algeria. Transport capacity at the Gela entry point is approximately 26 mmCM/d;

for natural gas imported from Russia:
- two lines with 42/36/34-inch diameters extending for a total length of approximately 900 kilometers that are linked to the Austrian network in Tarvisio and cross the Po Valley reaching Sergnano (near Cremona) and Minerbio. The pipeline is being upgraded by the laying of a third 264-kilometer long line with diameter from 48 to 56 inches; 214 kilometers were already operating at the end of 2005, from Tarvisio to Zimella (Verona). The pipeline transport capacity at the Tarvisio entry point amounts to approximately 99 mmCM/d;

for natural gas imported from the Netherlands and Norway:
- two lines, with a 48/34-inch diameter, 301-kilometer long extending from the Italian border at Passo Gries (Verbania), point of connection with the Swiss network, to the node of Mortara, in the Po Valley. The pipeline transmission capacity amounts to 63 mmCM/d.

In 2005 Eni s national network increased by 196 kilometers due to the upgrade of the trunklines for gas imported from Russia and Algeria.

Eni s regional transmission network is made up of pipes with smaller diameter than the national lines for a total length of 22,320 kilometers. These pipes carry natural gas at pressures between 5 and 12 bars, between 12 and 24 bars and between 24 and 75 bars. In 2005, Eni s regional network decreased by 29 kilometers despite the entry into service of new lines.

Eni s system is completed by: (i) 11 compressor stations with a total power of 683 megawatt; and (ii) 5 marine terminals linking underwater pipelines with the on-land network at Mazara del Vallo, Messina and Gela in Sicily and Favazzina and Palmi in Calabria for the Greenstream pipeline.

The control room of the dispatching system is located in San Donato Milanese and oversees and monitors the whole transmission network in cooperation with peripheral units. In 2005 this system obtained the ISO 9001-2000 certification. Peripheral units are represented by eight districts that monitor the transmission network through 60 centers that guarantee operation, maintenance and control of the whole system. Each unit is responsible for operations in accordance with technical specifications and applicable laws and regulations.

In addition to the international pipeline transmission system, natural gas also enters Eni s system through the Panigaglia (Liguria) LNG terminal, which receives LNG carried by tanker ships. This terminal is currently the only one in Italy and at its maximum capacity can input 3.5 BCM/y into the transmission network. In 2005, volumes of LNG regasified amounted to the equivalent of approximately 2.49 BCM of natural gas.

In 2005 a total of 85.1 BCM of natural gas were input into the national network, of 64% of which was owned by Eni.

In the next four years Eni plans to carry out capital expenditure of approximately euro 3.5 billion aimed at the upgrade of its transport network in view of the expected increase in import capacity (in particular from Russia and Algeria).

Natural gas transported in Italy (1)	**2001**	**2002**	**2003**	**2004**	**2005**
			(BCM)		
Eni	**58.17**	**54.56**	**51.74**	**52.15**	**54.88**
Third parties	**11.41**	**19.11**	**24.63**	**28.26**	**30.22**
Enel	6.28	8.28	9.18	9.25	9.90
Edison Gas	2.98	4.61	7.49	8.00	7.78
Other	2.15	6.22	7.96	11.01	12.54
Total	**69.58**	**74.40**	**76.37**	**80.41**	**85.10**

(1) Include volumes input to domestic storage.

The Italian natural gas system is supplied for about 82% with imported gas, transmitted to Italy through a network of international high pressure pipelines for a total of over 4,300 kilometers; in which Eni owns transportation rights, in particular:

- the TAG pipeline, a 1,018-kilometer long made up of two lines, each about 380-kilometer long and a third line 258-kilometer long, with a transit capacity of 81.3 mmCM/d and three compression stations, which transports natural gas from Russia across Austria from Baumgarten, the delivery point at the border of Austria and Slovakia, to Tarvisio, point of entry in the Italian natural gas transport system. Eni plans to upgrade this pipeline. See "Development Projects" below;
- the Transitgas pipeline, a 291-kilometer long pipeline, with one compression station, which transports natural gas from the Netherlands and from Norway crossing 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 transit capacity of 61 mmCM/d. A new 55-kilometer long line from 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;
- the TTPC pipeline, a 742-kilometer long pipeline, made up of two lines each 371-kilometer long with a transit capacity of 81.2 mmCM/d and three compression stations, which transports natural gas from Algeria across Tunisia from Oued Saf Saf at the Algerian border to Cap Bon on the Mediterranean coast where it links with the TMPC pipeline;
- the TMPC pipeline for the import of Algerian gas, which is 775-kilometer long, made up of five lines, each 155-kilometer long with a transit capacity of 101 mmCM/d, which crosses underwater the Sicily Channel from Cap Bon to Mazara del Vallo in Sicily, the point of entry into the Italian natural gas transport system; and
- the Greenstream pipeline for the import of Libyan gas, a 520-kilometer long, with a transit capacity of 24.4 mmCM/d which crosses underwater the Mediterranean Sea from Mellitah to Gela in Sicily, the point of entry into the Italian natural gas transport system. The pipeline, in which Eni has a 75% interest (the remaining 25% share being held by the National Oil Company), started operations in October 2004 and by 2006 is expected to transport 8 BCM/y already booked under long-term contracts with Italian operators. In the long term, Eni plans to upgrade the transport capacity of this gasline from 8 to 11 BCM/y, starting in 2010 with an expected capital expenditure of euro 80 million.

Eni holds a 50% interest in the Blue Stream underwater pipeline linking the Russian and Turkish coast of the Black Sea. When fully operational, this 774-kilometer long pipeline with a transmission capacity of 49 mmCM/d, is expected to transport 16 BCM/y in 2010 (Eni s share 8 billion) of Russian natural gas to be sold on the Turkish market (see "Development Projects" below). At the end of 2005 the first section of the Dzhubga compression station on the Russian coast of the Black Sea started operations. It is made up of three turbocompressors and three turbogenerators that will allow to increase the volumes of gas transported.

Distribution Activity

Distribution involves the delivery of natural gas to residential and commercial users in urban centers through low pressure networks. Eni, through its 100% subsidiary Italgas and other subsidiaries, is engaged in distribution activity in Italy serving 1,282 municipalities through a low pressure network consisting of over 48,000 kilometers of pipelines, supplying 5.8 million customers at December 31, 2005. Legislative Decree No. 164/2000 concerning the opening up of the natural gas market in Italy defines distribution as a public service which is subject to regulation and its management is entrusted to natural gas companies by local governments exclusively under bid procedures. Concessions existing at the coming into force of the Decree and awarded with a bid procedure expire on December 31, 2012; all other concessions expire on December 31, 2007 (with an optional three year extension in case of public interest). See "Regulation of the Italian Hydrocarbon Industry Gas & Power" below.

Development Projects

Eni is engaged in various development projects concerning the sale of natural gas in European markets and in the LNG business in order to strengthen its market share in area where its presence is already established (Iberian Peninsula, Germany, Turkey) and to develop sales in markets with interesting growth and profitability prospects (in particular France and the United Kingdom). Eni plans to increase the flexibility of its operations by upgrading its logistical assets.

In these European markets Eni can leverage on the availability of equity gas and a diversified portfolio of supply contracts, an extensive gas pipeline network, which allows for the supply of natural gas from several sources, and long standing relationships with producing countries. Eni intends to develop its presence in the LNG business which provides interesting growth prospects, leveraging on the value of its assets, on its participation in liquefaction projects aimed at exploiting its natural gas reserves (mainly in North and West Africa, the Far East and Australia) and on the purchase of interests in regasification terminals located in strategic consumption markets (such as the United States, the United Kingdom and the Far East).

Germany Eni has been present on the German natural gas market since late 2002 through GVS Gasversorgung Süddeutschland GmbH) in which it holds a 50% interest. Through a 1,863-kilometer long gas pipeline network (of these 1,750 are owned and 113 are managed) it transports and markets about 7 BCM/y of gas to local distribution companies serving about 750 municipalities in the South-Western areas of the country.

In January 2005 Eni agreed a 14 year contract, starting in 2006, for the supply of 1.2 BCM/y of natural gas to the German company Wingas. The gas will be delivered at Eynatten at the German-Belgian border. In the medium term, Eni plans to increase its natural gas sales from the 4.2 BCM level recorded in 2005.

Iberian Peninsula

Portugal Eni operates on the Portuguese market through Galp Energia (Eni s interest 33.34%). On December 29, 2005, Eni, Amorim Energia (a privately held Portuguese company in which Sonangol, the national oil company of Angola, holds a minority stake) and Rede Electrica Nacional (REN) entered an eight year long shareholders agreement for the joint management of Galp Energia (Galp). The agreement came in force on March 29, 2006 after the occurrence of all the suspensive conditions, among which: (i) the authorization of the European Commission issued on March 24, 2006;

(ii) the purchase on March 28, 2006 of a 1% stake in Galp by Caixa (a primary Portuguese financial institution) which also entered the shareholder agreement of December 2005; and (iii) the change in the powers of the Portuguese State in Galp (golden share) resulting from the approval by Galp s Shareholders Meeting held on March 29, 2006 of new by-laws consistent with the agreement between Eni, Amorim Energia, REN and Caixa. At the present date shareholders of Galp are: Eni (33.34%), the Portuguese State (17.711%), Parpublica (12.293%), REN (18.30%), Amorim Energia (13.312%), Iberdrola (4%), Caixa Geral de Depositos (1%), Setgas (0.044%).

Key guidelines of the agreement are as follows: (i) the establishment of a new set of corporate governance rules setting, among others, percentages of share capital voting rights necessary to make relevant decisions; (ii) an industrial plan targeting the achievement of a leading market position in natural gas, refining and petroleum products marketing in the Iberian Peninsula, an increase in the weight of upstream activities in Galp s asset portfolio and access to the Portuguese electricity sector; (iii) placement of part of the stake held by the Portuguese State in Galp through an initial public offering by year end of 2006; (iv) spin-off of certain regulated asset of Galp (natural gas transport network, storage sites and the Sines LNG regasification plant) ideally by the end of 2006; those assets are agreed to be sold to REN; (v) transfer of REN s stake in Galp to Amorim Energia within an 18 month period from the effective date of the agreement; and (vi) a five year lock in period.

This agreement replaces the pre-existing agreement between Eni and the Portuguese State.

In 2005 Galp sold about 1.56 BCM of gas to approximately 820,000 customers and managed a high, medium and low pressure network covering about 11,700 kilometers. The assets of Galp include among other things two import infrastructures: the Transmaghreb pipeline and the Sines LNG regasification plant. Following the entry into force of the new agreement, these transport and regasification infrastructures are expected to be spun off.

Spain Eni operates on the Spanish market through the Unión Fenosa Gas group (Eni s interest 50%, the remaining 50% being held by Unión Fenosa SA), which is active in natural gas supply and sales to final users and to power generation companies. In 2005 natural gas sales of Unión Fenosa Gas amounted to 1.52 BCM. Unión Fenosa Gas is active in LNG through an 80% interest in a liquefaction plant with a capacity of over 7 BCM/y, located at Damietta on the Egyptian coast, that started operations in January 2005, and through a 7.36% interest in a liquefaction plant under construction in Oman, completed in 2005. In addition, it holds an 18.9% and a 42.5% interest in the El Ferrol and Sagunto regasification plants under construction, managed by the Reganosa and Saggas companies. The Sagunto plant is expected to start operations between 2006 and 2007.

In the medium term, Eni plans to increase its natural gas sales from the 5.3 BCM level recorded in 2005.

Turkey Blue Stream Eni and Gazprom hold equal shares in Blue Stream Pipeline Company BV, which operates the Blue Stream transport system, that links the Russian (Dzhubga) to the Turkish (Samsun) coast of the Black Sea. In November 2005 the first section of the compressor station at Dzhubga on the Russian coast of the Black Sea started operating. This station is made up of three turbocompressors and three turbogenerators and will allow to increase volumes transported. The gasline transports natural gas produced in Russia which is sold jointly by Eni and Gazprom in Turkey to the Turkish company Botas under a long-term contract. In 2005 volumes transported and sold in Turkey amounted to 5.14 BCM of natural gas (50% of which were Eni s share) corresponding to an 18% market share. Volumes transported and marketed will increase progressively in future years and are targeted to about 16 BCM/y (8 billion net to Eni) in 2010.

France In July 2005 Eni signed a long term agreement with French company EDF for the supply of 860 mmCM/y of natural gas starting in October 2006.

Upgrading of the international transport network Eni has defined a program for the upgrade of transport gaslines from Algeria and Russia. Eni plans to increase the transport capacity of the TTPC gasline from Algeria by 6.5 BCM/y, with a 3.2 BCM starting on April 1, 2008 and an additional 3.3 BCM increase starting on October 1, 2008 with an expected expenditure of euro 345 million. A corresponding capacity on the TMPC downstream gasline is already available. The first section of the upgrade was assigned to third parties in November 2005.

Eni plans to upgrade the transport capacity of the TAG gasline from Russia by 6.5 BCM/y with a 3.2 BCM increase starting on October 1, 2008 and an additional 3.3 BCM increase starting on April 1, 2009 with an expected expenditure of euro 275 million. The first section of the upgrade was assigned to third parties in February 2006. In addition, the upgrade related to the build-up of the fourth import contract from Russia is nearly completed (up 4 BCM from 2007).

Considering also the full capacity from 2006 of the Greenstream gasline from Libya (8 BCM/y) and the upgrade underway of the TAG gasline in the light of the build-up of the fourth import contract from Russia (up 4 BCM/y from 2007), from 2009 a total of about 25 BCM/y of new import capacity are expected be available for the Italian market. Except for the 4 BCM/y of the Russian contract, 14.4 BCM of this new capacity have already been sold to third parties and a further 6.6 BCM/y are expected to be sold under open bidding procedures.

Libya Eni s Gas & Power segment purchase 80% of the natural gas production of the Libyan natural gas producing field of Wafa and Bahr Essalam operated by Eni (with a 50% interest). The share of production belonging to the Libyan partner National Oil Company is purchased under a long term supply contract with a 24 year term. When the two fields achieve full production in 2006, production plateau volume are expected to be 10 BCM/y of which 8 BCM/y will be purchased by Eni s Gas & Power segment and imported to Italy via the Greeenstream gasline. These volumes are sold to Italian third party importers under long term supply contracts with a 24 year term and delivery point at Gela in Sicily. The remaining 2 BCM/y natural gas availability from production is expected to be sold on the Libyan market by the two partners.

LNG

Eni is a party in various initiatives in the area of LNG. What follows is a description of the major initiatives.

United States On August 1, 2005, Eni signed an agreement with the U.S. company Cameron LNG LLC (belonging to the Sempra Energy group) to purchase a share of the regasification capacity of the Cameron liquefied natural gas terminal under construction in Louisiana expected to be completed in 2008-2009. The share of regasification capacity purchased amounts to 6 BCM/y for a period of 20 years, which corresponds to about 40% of the overall initial capacity of the terminal (15.5 BCM/y). This transaction will enable Eni to sell part of its natural gas reserves from North African and Nigerian fields in the United States.

Egypt In January 2005, the first LNG shipment was made from the Damietta liquefaction plant (Eni s interest 40% through its 50% interest in Unión Fenosa Gas) that is targeted to produce about 7 BCM/y. The partners in the project (Unión Fenosa Gas, the Egyptian company EGAS and oil producers Eni and BP) have planned an expansion of the plant consisting in the construction of a second train with the same capacity of the first one with expected capital expenditure amounting to approximately $1.5 billion and start-up in 2009. Eni will supply about 3 BCM/y of natural gas to the first train for twenty years. Further volumes will be supplied to the second train under an intent protocol signed in March 2005 with the Egyptian Government.

Spain Eni holds a 9.5% and a 21.25% interest in the El Ferrol and Sagunto regasification plants under construction and expected to start operations between 2006 and 2007. Eni s share of regasification capacity amounts to 1.8 BCM/y.

Other Developments

Agreement between Eni and Gazprom/Gazexport

In October 2005 Eni and Gazprom agreed to promote a new set of agreements aimed at widening their cooperation agreeing also to cease a previous agreement signed in May 2005. Negotiations are underway.

Sale of the water business

In March 2005, after receiving the authorization of the Italian Antitrust Authority, Italgas divested its majority interest (67.05%) in Società Azionaria per la Condotta di Acque Potabili to Amga SpA and Smat SpA for a cash consideration of euro 85 million (euro 15.57 per share). In May 2005, after receiving the authorization of the Italian Antitrust Authority, Italgas divested its 100% interest in Acquedotto Vesuviano SpA to Gori SpA for a cash consideration of euro 20 million. The above transactions are part of Eni s strategy of concentrating its resources in its core natural gas business.

Purchase of Siciliana Gas

In May 2006 Eni purchased a 50% interest of Siciliana Gas SpA for a cash outlay of euro 98 million. The Italian Antitrust Authority approved the transaction on February 1, 2006. With this purchase Eni becomes the sole owner of Siciliana Gas SpA and through this company also of 100% of Siciliana Gas Vendite SpA. Siciliana Gas SpA has been operating in Sicily since 1979 and holds the rights for the distribution of gas to 76 Sicilian municipalities, including Agrigento, Enna, Trapani and Gela (of these 70 concessions are operating) through a 2,600-kilometer long network and with 186 employees. It owns Siciliana Gas Vendite SpA operating in the sale of natural gas to end users with approximately 215,000 customers and sales volumes of about 190 mmCM/y and 50 employees.

Toscana Energia SpA

On January 24, 2006, Eni, Italgas and the local authorities partners of Fiorentina Gas SpA and Toscana Gas SpA signed a framework agreement for developing an alliance in the area of natural gas distribution and sale. As part of the agreement, the partners incorporated Toscana Energia SpA (Eni s interest 48.7% the remaining 51.3% interest being held by municipalities and local banks) to which they contributed in kind their interests in Fiorentina Gas and Toscana Gas. These two companies operate in natural gas distribution to 97 municipalities through a 7,900-kilometer long network serving 1.6 million customers. They will be merged in Toscana Energia within two years under the framework agreement. The local authority partners will play a role of strategic guidance and control, while Italgas is the industrial partner and has operating and management responsibilities. The agreement provides also for the establishment of a regional sales company (600,000 customers, 1.1 BCM sold in 147 Tuscan municipalities) under Eni s control, through the merger of Toscana Gas Clienti SpA (Eni s interest 46.1% through Italgas) and Fiorentina Gas Clienti SpA (Eni s interest 100%).

Electricity Generation

Eni, through EniPower, is one of the major operators in electricity generation on the Italian market. Operating since 2000, EniPower owns power stations located at Eni s sites in Brindisi, Ferrera Erbognone, Livorno, Mantova, Ravenna, Ferrara and Taranto with installed capacity in operation of approximately 4.5 gigawatt at December 31, 2005 (3.3 gigawatt in 2004).

In 2005, Eni sold 27.56 terawatthours of electricity, of which about 22.77 were produced by EniPower, corresponding to over 5% of the Italian market, and 10.66 million tonnes of steam. Approximately 57% of sales were directed to end users, 28% to the Electricity Exchange, 8% to GRTN/Terna (under CIP 6/92 contracts and imbalances in input) and 7% to wholesalers. All the steam produced was sold to end users.

Eni is completing a plan for expanding its electricity generation capacity targeting in 2009 an installed capacity of 5.5 gigawatt with production amounting to 30 terawatthours from 2008, corresponding to over 10% of electricity generated in Italy at that date. Planned expenditure amounts to euro 2.4 billion, of which euro 1.8 billion is already expensed.

High efficiency, low environmental impact, reduced expenditure and construction times are the main features of these plants, which show interesting profitability prospects due to the expected increase in demand for electricity and the ability to operate in co-generation (combined electricity and steam generation). The co-generation mode has been acknowledged by the Authority for Electricity and Gas as a production mode that entails priority on the national dispatching network and the exemption from the purchase of "green certificates"[8].

Eni estimates that with the same amount of energy (electricity and heat) produced, EniPower power stations will reduce emissions of carbon dioxide by approximately 11 million tonnes, as compared to emissions caused by conventional power stations.

EniPower intends to become a cost leader in the Italian electricity industry thanks to the high technology content and optimal size of the plants it is building. When fully operational in 2008, consumption of natural gas of Eni s plants is expected to reach over 6 BCM/y, supplied by Eni.

Power Generation

		2003	2004	2005
Purchases				
Natural gas	(mmCM)	940	2,617	4,384
Other fuels	(thousand tonnes of oil equivalent)	847	695	563
Sales				
Electricity production sold	(terawatthour)	5.55	13.85	22.77
Electricity trading	(terawatthour)	3.10	3.10	4.79
Steam	(thousand tonnes)	9,303	10,040	10,660

The development plan has been completed at all sites except for Ferrara (Eni s interest 51%), where in partnership with Swiss company EGL AG construction is underway of two new 390 megawatt combined cycle units which will bring installed capacity to 840 megawatt with startup expected in 2007.

Ferrera Erbognone On May 14, 2004 the combined cycle power station was inaugurated, the first one in Italy after the opening up of the electric market. This power station has an installed capacity of approximately 1,030 megawatt articulated in three combined cycle units, two of them with approximately 390 megawatt capacity are fired with natural gas, the third one with approximately 250 megawatt capacity is fired in part with natural gas and complemented with refinery gas obtained from the gasification of tar from visbreaking from Eni s nearby Sannazzaro de Burgondi refinery.

Ravenna Two new combined cycle 390 megawatt units started operations in 2004. Added to the existing 190 megawatt, the power station s installed capacity reached approximately 970 megawatt.

Brindisi Three new combined cycle 390 megawatt units, two of which started operations in 2005, the last is expected to start operation in the second half of 2006. When fully operational the power station will have a total capacity of approximately 1,320 megawatt, including already existing amounts. The completion of the power station is expected between the end of 2005 and the second quarter of 2006.

Mantova Two new combined cycle 390 megawatt units started operations in 2005 with full operation in early 2006. The power station will have a total installed capacity to approximately 840 megawatt. This power station will provide steam for heating purposes delivered to Mantova s urban network through a remote heating system.

Ferrara EniPower owns 51% of the share capital of Società EniPower Ferrara (SEF) in partnership with EGL Swiss. SEF started the construction of two new combined cycle units with a capacity of 390 megawatt each which will bring total installed capacity at Ferrara to 840 megawatt. Operations are expected to start in 2007. In 2004, some 80 megawatt of capacity were purchased.

Capital Expenditure

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

Refining & Marketing

Eni is engaged in refining and the sale of refined products, mainly in Italy and the rest of Europe.

In the refining business, Eni plans to strengthen the competitive positioning of its refining system by increasing the primary refining capacity and conversion capacity and implementing actions to improve flexibility of refineries. Eni s objectives are optimization of processed feedstocks, adjustment of the slate of refined products to the evolution of demand and strengthening of the degree of integration with Eni s upstream activities. Eni s strategy in its refining business is based on the following assumptions regarding trends in demand and the trading environment: (i) an expected worldwide decline in gasoline consumption in favor of diesel fuel, in connection with the expected evolution of the car fleet towards an increasingly high spread of diesel engine cars; (ii) the progressive substitution of fuel oil with natural gas in Italy; (iii) a further increase in worldwide differential between light and heavy crudes that favors high conversion capacity refineries; and (iv) the implementation of European fuel specifications as concerns quality standards of fuels.

In the marketing of refined products, Eni plans to strengthen its competitive positioning in Italy by restructuring and upgrading its distribution network and implementing an innovative marketing strategy, the key elements of which are expected to be an offer of high quality fuels and differentiated promotional initiatives intended to support customer loyalty. In the rest of Europe, Eni intends to develop or strengthen its market share in certain geographic areas where it can obtain logistical and operating synergies and exploit its Agip brand. Eni plans to grow sales volumes buying, leasing and building well equipped and high throughput services stations and by launching marketing campaigns aimed at consolidating the perception of the Agip brand in target markets.

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 2005, a total of 66.48 million tonnes of oil were purchased (67.05 in 2004), of which 37.30 million tonnes were from Eni s Exploration & Production segment[9], 14.85 million tonnes under long-term contracts with producing countries and 14.33 million tonnes on the spot market. Some 24% of oil purchased came from West Africa, 19% from North Africa, 17% from countries of the former Soviet Union, 16% from the Middle East, 14% from the North Sea, 7% from Italy and 3% from other areas. Some 31.07 million tonnes were resold, representing an increase of 1.32 million tonnes over 2004, up 4.1%. In addition, 3.58 million tonnes of intermediate products were purchased (3.10 in 2004) to be used as feedstocks in conversion plants and 16.21 million tonnes of refined products (18.8 in 2004) sold as a complement to own production on the Italian market (4.97 million tonnes) and on markets outside Italy (11.24 million tonnes).

Refining

Eni is engaged in the refining business in Italy and owns interests in refineries in Germany and the Czech Republic with a total refining capacity (balanced with conversion capacity) of approximately 35 million tonnes (equal to 701 KBBL/d) of which 30.2 million tonnes capacity is located in Italy.

Eni s refining system in Italy is made up of five wholly owned refineries and a 50% interest in the Milazzo refinery in Sicily. Eni plans to upgrade its refining system with a capital expenditure for the next four years amounting to approximately euro 2.4 billion (including logistics activities). Main actions planned are: (i) an increase of primary processing and conversion capacity, also in light of an expected increased availability of equity oil in the Mediterranean area; (ii) an improvement of refinery flexibility with the aim of optimizing feedstock processing; and (iii) the production of fuels in line with demand and in compliance with European environmental standards. Eni also aims at achieving a higher degree of vertical integration with Eni s upstream and downstream activities, increasing intake processing of equity crudes and feedstock volumes transferred to petrochemicals activities.

The table below sets forth certain statistics regarding Eni s refineries at December 31, 2005.

	Location	Ownership Interest	Conversion Equivalent (1)	Balanced Primary Distillation Capacity (2)
Wholly-owned refineries:				
Sannazzaro	Lombardy	100.0%	42.5	160,000
Gela	Sicily	100.0%	140.1	100,000
Taranto	Apulia	100.0%	71.6	90,000
Livorno	Tuscany	100.0%	11.4	84,000
Porto Marghera	Veneto	100.0%	22.8	70,000
			59.2	504,000
Partly-owned refineries:				
Milazzo	Sicily	50.0%	69.6	80,000
Ingolstadt/Vohburg/Neustadt	Germany	20.0%	32.6	52,000
Schwedt	Germany	8.0%	41.8	19,000
Kralupy/Litvinov	Czech Rep.	16.3%	28.8	26,000
			49.7	177,000
Total Eni			56.7	681,000

(1) Stated in fluid catalytic cracking equivalent/topping (% by weight), based on 100% of balanced primary distillation capacity.

(2) Barrels per calendar day. Based on percentage equity interest ownership in the refinery, not on actual utilization of balanced primary distillation capacity.

Each of Eni s Italian refineries has an operational and strategic setup adequate to maximizing return on assets and monetizing its geographic location with respect to end markets and integration with other Eni business segments.

Sannazzaro, with a balanced primary refining capacity of 160 KBBL/d and an equivalent conversion index of 42.5% is one of the most efficient refineries in Europe. Located in the South-West of the Po Valley, at the confluence of the rivers Po and Ticino, it supplies mainly markets in north-western Italy and Switzerland. The high degree of flexibility of this refinery allows it to process a wide range of oil from Russia, Africa and Asia, CPC Blend crude oil from the Caspian Sea carried through the CPC pipeline and oil from Eni s nearby Villafortuna field. From a logistical standpoint this refinery is located along the route of the Central Europe Pipeline, which links the Genova terminal with French speaking Switzerland. This refinery contains two primary distillation plants and a vacuum unit.

The conversion plants are: a fluid catalytic cracker (FCC), an HDCK middle distillate conversion, a visbreaking thermal conversion unit, two catalytic reforming plants, an isomerization plant, an alchilation plant, an MTBE plant and three desulphurization plants for middle distillates and one for naphtha from cracking. In 2005 works continued for the completion of the tar (heavy residue from visbreaking) gasification plant that will produce syngas that will be used to fire the nearby EniPower power station at Ferrera Erbognone. In the medium term Eni plans to upgrade the conversion capacity of this refinery; planned actions include: (i) construction of a new hydrocracking unit with a capacity of 28,000 BBL/d which will allow for the production of one million tonnes/y of high quality diesel fuel with low sulphur content; and (ii) construction of a new deasphalting unit with a capacity of 18,000 BBL/d for the separation of vacuum residues of asphaltenes with the aim of obtaining additional feedstocks for the cracking plant. Works are expected to be completed by 2008. Capital expenditure for this project is expected to amount to euro 400 million.

Gela, with a balanced primary refining capacity of 100 KBBL/d and an equivalent conversion index of 140.1% represents an upstream integrated pole with the production of heavy crudes obtained from nearby Eni fields offshore and onshore Sicily, while downstream it is integrated with Eni s nearby petrochemical plants. Located on the Southern coast of Sicily, it manufactures fuels for automotive use and residential heating purposes, as well as petrochemical feedstocks. Its high conversion level allows it to minimize the yield of fuel oil and semi-finished products. Besides its primary distillation plants, this refinery contains the following plants: an FCC unit with advanced technology for the conversion of low grade feedstocks and two coking plants for the vacuum conversion of heavy residues. All these plants are integrated in order to process heavy residues and feedstocks and manufacture valuable products. This refinery also contains two reforming units, an alchilation unit, an MTBE unit and plants for desulphurization of gasoil and naphtha from cracking. The power plant of this refinery also contains modern residue and exhaust fume treatment plants which allow the complex to comply with the most exacting environmental standards.

Taranto, with a balanced primary refining capacity of 110 KBBL/d and an equivalent conversion index of 60.5%, can process a wide range of crudes and semi-finished products with great operational flexibility. It mainly produces fuels for automotive use and residential heating purposes for the South-Eastern Italian markets. Besides its primary distillation plants, this refinery contains a flash vacuum unit, two plants for the desulphurization of middle distillates, a reforming unit, an isomerization unit and conversions plants such as: a two-stage thermal conversion plant (visbreaking/thermal cracking) and an RHU conversion plant, that allows to convert high sulphur content residues into valuable products and 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 2005 a total of 3.1 million tonnes of this oil were processed. In the medium-term Eni plans a relevant upgrade of this refinery by means of two projects for increasing primary refining and conversion capacity with an expected expenditure of euro 800 million. The first project entails construction of a new 17,000 BBL/d capacity hydrocracking plant with a new associated hydrogen unit for the manufacture of approximately 0.6 million tonnes/y of high quality diesel fuel. Works are expected to be completed by 2008. The second project entails the construction of: (i) a new topping plant with a capacity of 4 million tonnes/y with an associated vacuum unit with a capacity of 2.5 million tonnes/y; (ii) a new plant for the desulphurization of middle distillates with a capacity of 2.3 million tonnes/y; and (iii) ancillary units and utilities with other logistical assets. Works are expected to be completed by 2009.

Livorno, with a balanced primary refining capacity of 84 KBBL/d and an equivalent conversion index of 11.4%, manufactures mainly gasolines, fuel oil for bunkering, specialty products and lubricant bases. Besides its primary distillation plants, this refinery contains a vacuum unit, a reformer unit, an isomerization plant, two desulphurization units for middle distillates and two lubricant manufacturing lines. Its pipeline links with the local harbor and with the Florence storage sites allow the Livorno facility to operate with great efficiency as concerns reception, handling and distribution of products.

Porto Marghera, with a balanced primary refining capacity of 70 KBBL/d and an equivalent conversion index of 22.8%, produces mainly gasolines and other light products for the supply of markets in North-Eastern Italy, Austria, Slovenia and Croatia. Besides its primary distillation plants, this refinery contains a reformer plant, an isomerization plant, two gasoil desulphurization units and a two-stage thermal conversion plant (visbreaking/thermal cracking) for increasing yields of valuable products.

In Germany Eni holds an 8.3% interest in the **Schwedt** refinery and a 20% interest in **Bayernoil**, an integrated industrial pole including the Ingolstadt, Vohburg and Neustadt refineries. Eni s refining capacity in Germany amounts to approximately 70 KBBL/d. Eni s share of the production of the three integrated refineries and of the Schwedt refinery is mainly used to supply Eni s distribution network in Bavaria and Eastern Germany.

Eni holds a 16.33% interest in **Ceska Rafinerska** which owns and manages two refineries, Kralupy and Litvinov, in the Czech Republic. Eni s overall balanced conversion capacity from this refinery amounts to 27 KBBL/d.

Eni is evaluating a restructuring of the Bayernoil refinery pole and the purchase of interests in strategically located refineries aimed at supporting growth in its distribution activities in the rest of Europe.

On March 2, 2005 Eni sold to Erg SpA its 28% interest in Erg Raffinerie Mediterranee SpA and Erg Nuove Centrali SpA, anticipating the maturity (November 2006) of Eni s put option, provided for by the agreement for the restructuring of the Priolo site signed on October 1, 2002. In order to guarantee the continuity of existing supply contracts of oil-based feedstocks to Polimeri Europa, Eni s processing contract for about 2 million tonnes/y of crude oil retains validity until December 31, 2006 at the conditions (yields and payments) reflecting the current setup of the refinery.

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

Petroleum products availability	**2001**	**2002**	**2003**	**2004**	**2005**
			(million tonnes)		
Italy					
Products processed in wholly-owned refineries	32.24	30.09	25.09	26.75	27.34
Products processed for third parties	(1.45)	(1.88)	(1.72)	(1.50)	(1.70)
Products processed in non owned refineries	5.92	6.27	8.43	8.10	8.58
Products consumed and lost	(1.95)	(1.91)	(1.64)	(1.64)	(1.87)
Products available	**34.76**	**32.57**	**30.16**	**31.71**	**32.35**
Purchases of finished products and change in inventories	5.19	6.27	5.86	5.07	4.85
Finished products transferred to foreign cycle	(4.96)	(5.56)	(5.19)	(5.03)	(5.82)
Consumption for power production		(1.74)	(1.07)	(1.06)	(1.09)
Sales	**34.99**	**31.54**	**29.76**	**30.69**	**30.29**
Outside Italy					
Products available	3.02	2.98	3.36	4.04	4.33
Purchases and change in inventories	10.27	12.16	12.12	13.78	11.19
Finished products transferred from Italian cycle	4.96	5.56	5.19	5.03	5.82
Sales	**18.25**	**20.70**	**20.67**	**22.85**	**21.34**
Sales in Italy and outside Italy	**53.24**	**52.24**	**50.43**	**53.54**	**51.63**

In 2005 refining throughputs on own account in Italy and outside Italy were 38.79 million tonnes, up 1.10 million tonnes from 2004, or 2.9%, due to higher processing at Eni s wholly-owned refineries of Taranto, Livorno and Sannazzaro also as a result of fewer maintenance standstills. These increases were offset in part by the impact of the maintenance standstill of the Porto Marghera refinery and lower processing at the Gela refinery following the damage caused by a sea storm to the docking infrastructure in December 2004. Processing on third party refineries increased, especially at the Milazzo refinery (Eni s interest 50%). Total throughputs on wholly owned refineries (27.34 million tonnes) increased 0.59 million tonnes from 2004, or 2.2%, with full balanced capacity utilization. About 32.3% of all oil processed came from Eni s Exploration & Production segment (33% in 2004).

Logistics

Eni is engaged in storage and transport of petroleum products in Italy. Its logistical integrated infrastructure consists of 12 directly managed storage sites and a network of petroleum product pipelines.

Eni holds interests in five companies established by the major Italian operators in the oil business in Vado Ligure-Genova (Petrolig), Arquata Scrivia (Sigemi), Venice (Petroven), Ravenna (Petra) and Trieste (DCT) aimed at reducing costs, increasing efficiency and providing integrated services to customers.

For the transport of refined products on land Eni also owns a pipeline network, integrated by leased pipelines extending over 3,210 kilometers, of these 1,513 are wholly owned. Transport by sea of crudes and refined products takes place through spot and long-term lease contracts of tanker ships. For the secondary distribution of refined products to retail markets Eni owns a fleet of tanker trucks and manages third-party owned vehicles.

Eni also holds a 65% interest in Costiero Gas Livorno, a company that operates an underground storage facility in Livorno with the capacity to store 45,000 CM of propane.

In the medium-term Eni intends to upgrade the integration of its logistics system with its refining system. Eni plans to upgrade logistical assets in order to support the development of the Taranto refinery. In particular Eni is evaluating the construction of a new storage site for gasoils and gasolines in Campania and of three pipelines, of which two linking the refinery to the new storage site and one for the transport of virgin naphtha to the Eni s Brindisi petrochemical complex. Eni intends also to optimize its logistics system by rationalizing its structures in Lazio, the Po Valley and the Naples area.

Distribution and Marketing

Eni markets a wide range of refined petroleum products, primarily in Italy, through an extensive direct sales network, franchises and other distribution systems. The table below sets forth Eni s sales of refined products by distribution channel for the periods indicated.

Oil products sales in Italy and outside Italy	**2001**	**2002**	**2003**	**2004**	**2005**
			(million tonnes)		
Italy					
Retail sales	11.64	11.14	10.99	10.93	10.05
Wholesale sales	11.24	10.64	10.35	10.70	10.48
	22.88	**21.78**	**21.34**	**21.63**	**20.53**
Petrochemicals	4.23	3.82	2.79	3.05	3.07
Other sales (1)	7.88	5.94	5.63	6.01	6.69
Sales in Italy	**34.99**	**31.54**	**29.76**	**30.69**	**30.29**
Outside Italy					
Retail sales rest of Europe	2.47	2.57	3.02	3.47	3.67
Retail sales Africa and Brazil	1.71	1.44	1.18	0.57	
	4.18	**4.01**	**4.20**	**4.04**	**3.67**
Wholesale sales	5.55	5.65	6.01	5.30	4.50
	9.73	**9.66**	**10.21**	**9.34**	**8.17**
Other sales (1)	8.52	11.04	10.46	13.51	13.17
Sales outside Italy	**18.25**	**20.70**	**20.67**	**22.85**	**21.34**
	53.24	**52.24**	**50.43**	**53.54**	**51.63**

(1) Includes bunkering, consumption for power production (until 2001) and sales to oil companies. From 2002, includes also sales of MTBE.

In 2005 sales of refined products (51.63 million tonnes) were down 1.91 million tonnes over 2004, or 6.2%, mainly due to the divestment of activities in Brazil carried out in August 2004 (down 1.51 million tonnes), lower sales volumes to oil companies and traders outside Italy (down 305,000 tonnes), declining wholesale sales volumes in Italy

(220,000 tonnes) and lower sales on the Agip branded network (130,000 tonnes) related to lower domestic consumption. These declines were offset in part by higher retail and wholesale sales in the rest of Europe (357,000 tonnes) due to the implementation of Eni s development strategy.

Following the approval of the Italian Antitrust Authority granted on August 25, 2005, on September 6, 2005 Eni divested 100% of the share capital of Italiana Petroli ("IP") to api - anonima petroli italiana SpA for euro 190 million. IP is engaged in the retail marketing of refined products through a lease concession network of approximately 2,900 units, under the IP brand. As part of the sale transaction, the parties signed: (i) a five year fuel supply agreement under which IP will purchase from Eni agreed amounts of fuel each year; and (ii) an 18 month long agreement for the supply of lubricants and fuel transport services from storage sites to service stations. Consequently the impact on sales of the divestment of IP was marginal since the lower volumes sold on the retail market were substantially offset by the volumes supplied to the divested company under the contracts in force.

Retail Marketing

Retail sales in Italy

Sales of refined products on retail markets in Italy in 2005 (10.05 million tonnes) were down 0.88 million tonnes from 2004, or 8.1%, reflecting primarily the divestment of IP. Sales volumes on the Agip branded network (8.76 million tonnes) were down 130,000 tonnes, or 1.5%, due mainly to a decline in domestic consumption (down 1.9%) in particular of gasoline and LPG, whose effects were offset in part by an improved performance. Market share of the Agip network was up 0.2 percentage points from 29.5 to 29.7%. Average throughput of gasoline and diesel fuel of the Agip network was substantially unchanged at 2,509,000 liters (down 0.7% from 2004).

At December 31, 2005, Eni s retail distribution network in Italy consisted of 4,349 service stations, 2,895 less than at December 31, 2004 (7,244 service station), due to the divestment of IP (2,915 service stations). Excluding the effect of IP s sale, the Agip branded network increased by 20 units from December 31, 2004 as a result of the positive balance of acquisitions/releases of lease concessions (27 units), the opening of 12 new service stations and an increase in highway service stations (two service stations) offset in part by the closure of 21 less efficient service stations.

Eni plans to strengthen its competitive positioning in Italy by restructuring and upgrading its distribution network and implementing an innovative marketing, the key elements of which are expected to be an offer of high quality fuels and differentiated promotional initiatives intended to support customer loyalty.

In 2005 sales volumes of BluDiesel a high performance diesel fuel virtually sulphur free that improves engine performance on the Agip branded network amounted to nearly 1 billion liters, a decline of about 13% from 2004 due mainly to the increasingly high sensitivity of consumers to the price of fuels in light of the increase in prices in the year. At 2005 year end service stations selling BluDiesel were over 4,000 (about 3,900 at 2004 year end) corresponding to approximately 92% of Eni s Agip branded network.

In 2004, Eni started to sell the new BluSuper gasoline, which guarantees better engine performance and efficiency and reduces polluting emissions, due to its high antidetonating power resulting from a higher octane number (98 as compared to 95 of ordinary gasolines) and its lack of sulfur. BluSuper complements BluDiesel, sold since 2002, and is part of Eni s strategy to improve the quality of its fuels, anticipating their compliance with EU regulations (mandatory from 2009) and targeting its offer to customers requirements, leveraging on Eni s integrated refining-logistics-distribution system. In 2005 sales volumes of BluSuper amounted to 150 million liters. At 2005 year end Agip branded service stations selling BluSuper were 1,719 (about 1,000 at 2004 year end) corresponding to approximately 39% of Eni s network.

In January 2006 Eni started to sell "Ad-Blue®", a water solution containing urea for technologically advanced heavy duty vehicles. This additive, compatible with the new characteristics of most trucks built in Europe reacts with exhaust gases thus reducing emissions and consumption and improving engine performance.

In 2005, Eni continued its Do-It-Yourself campaign which allowed customers accessing self-service outlets provided with an electronic card to obtain price discounts or gifts in proportion to the total amount of purchased fuel, plus a bonus for the most loyal customers and long-distance drivers. At year end the number of cards distributed exceeded 3.8 million; turnover on cards increased by 9% from 2004. The amount of fuel purchased with these cards was about 37% of all fuel sold on Agip branded service stations.

Eni also continued its AgipMaxi promotional initiative addressed to truck drivers who purchase diesel fuel at the approximately 800 Agip branded service stations participating in the program. Active fidelity cards were over 38,000.

The improvement in the quality of service to customers led to a further expansion of the automation process of the domestic network. At December 31, 2005 nearly all Agip branded service stations were provided with a corporate credit card system.

In 2005, Eni continued the development of the European Multicard Routex paying card addressed to professional transport (transporters and car fleets) with sales of 1.414 billion liters (up 3.4% over 2004), while the number of customers provided with this card increased by about 5,000 to 50,000 users at year end. Multicard is used internationally and is part of the international Routex consortium, made up of four oil companies.

Eni continued the development of its non-oil retail activities aimed at promoting the development of its network in line with European standards, such as the diffusion of self-service facilities, high-tech car care systems, and services to customers in particular 1,000 café and fast food outlets as well as innovative commercial outlets. To this end Eni owns master franchisor rights with exclusive rights for the oil sector for some international brands of the restaurant and catering sector.

In 2005, a total of 80 new affiliates were added to the AgipCafè® branded outlets launched in 2003, and by year end 287 franchises were active, while 10 new convenience stores under the "SpazioAgip" brand name were opened, thus reaching a total of 19 locations. Also 45 new car-wash facilities were opened at Agip branded service stations, thus reaching a total of 685 units. In the next four years Eni intends to continue the development of its non oil activities and expects to provide 70% of its Agip branded network with these structures by 2009 (50% in 2005).

Retail sales outside Italy

At December 31, 2005, Eni s retail distribution network outside Italy was represented by service stations located in the rest of Europe, mainly in South-Central Germany, Spain, South-Western France, Austria, Switzerland, the Czech Republic and Hungary, and consisted of 1,933 service stations, 37 more than at December 31, 2004, due in particular to the acquisition of lease concessions in Spain, France and Germany. Throughput per service station averaged 2,427,000 liters, up 1.4% from 2004. Sales of refined products totalled 3.67 million tonnes, representing an increase of 0.20 million tonnes over 2004, up 5.8%, reflecting higher sales mainly in Germany, Spain and the Czech Republic.

Eni intends to develop or strengthen its market share in certain geographic areas where it can obtain logistical and operating synergies and exploit its Agip brand. Eni plans to grow sales volumes buying, leasing and building well equipped and high throughput services stations and by launching marketing campaigns aimed at consolidating the perception of the Agip brand in target markets.

Non oil activities outside Italy are performed under the "CiaoAgip" brand name in 1,120 service stations, of these 330 are in Germany and 163 in France, representing 58% of the whole Agip branded network outside Italy (97% when calculating the percentage on all owned service stations).

Wholesale Marketing and Other Sales

Eni sells gasolines and fuels for automotive use and for heating purposes, fuels for agricultural vehicles and for vessels, gasolines and fuel oil. Major customers are wholesalers, the agricultural and manufacturing industries, public utilities and transports. Agricultural customers and fishing fleets are supplied directly at 60 agricultural centers and 90 owned or leased marine fuel outlets.

Eni provides its customers with its experience 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 and Biodiesel (with very low content of hydrogen sulfide, particulates and carbon dioxide) especially targeted for heavy duty public and private transports.

Customer care is provided by a very widespread commercial and logistical organization present all over Italy and articulated in local sales offices aided by a network of agents, sales persons and concessionaires.

Eni also sells jet fuel directly at 38 airports, of which 27 are in Italy, and marine fuel (bunkering) directly at 38 ports, of which 23 in Italy.

Sales on wholesale markets in Italy (10.48 million tonnes) were down 0.22 million tonnes from 2004, or 2.1%, mainly due to a decline in domestic consumption and lower sales of fuel oil to the power generation segment, due to the progressive substitution of fuel oil with natural gas as feedstock for power plants.

Sales on wholesale markets outside Italy (4.50 million tonnes) declined by 0.80 million tonnes, or 15.1%, due mainly to lower LPG sales resulting from the divestment of activities in Brazil, offset in part by higher sales in the rest of Europe, in particular in Central-Eastern Europe, while they declined in Germany and Spain.

Other sales (22.93 million tonnes) increased by 0.36 million tonnes, or 1.6%, due mainly to higher sales in Italy related to supplies to IP (up 650,000 tonnes) offset in part by lower sales to oil companies and traders outside Italy (down 305,000 tonnes).

Other Businesses

LPG

In Italy Eni is engaged in the production, distribution and sale of LPG. In 2005 Eni sold 649,000 tonnes of LPG for heating and automotive use (under the Agip brand and wholesale), with a 19% market share. An additional 400,000 tonnes of LPG were sold through other channels mainly to oil companies and traders. LPG activities in Italy derive their products from five Italian refineries and from imports received at the three coastal storage sites located in Livorno, Naples and Ravenna. Product availability and customer requirements are met also with 10 other owned plants/storage sites in Italy and 45 contracts for bottling and storage with third party facilities. Eni s LPG sales network is organized over six sale areas with 3 direct sales offices, 21 agencies and 24 concessionaires. Products are sold also to over 150,000 customers owning small tanks, while the sale network of LPG bottles includes over 11,000 outlets. In the past few years LPG pipelines were developed and over 13,000 customers are served through direct links with 95 storage facilities.

Outside Italy Eni is also present in Ecuador with a 36.4% market share in 2005.

Lubricants

Eni operates eight (owned and co-owned) blending plants, in Italy, Europe, North and South America, Africa and the Far East.

In Italy Eni is a market leader in lubricants with the manufacturing of base oils and with a range of products including 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). Base oils are manufactured primarily at Eni s refinery in Livorno. Eni owns two facilities for the production of additives and solvents. In 2005, retail and wholesale sales in Italy amounted to 133,000 tonnes with a 23.9% market share. Eni also sold approximately 5,000 tonnes of special products (white oils, transformer oil and anti-freeze fluids).

Outside Italy sales amounted to approximately 139,000 tonnes, of these about 50% were registered in Europe (mainly Germany, the Netherlands and Spain).

Oxygenates

Eni, through its subsidiary Ecofuel (Eni s interest 100%), sells about 2 million tonnes/y of oxygenates mainly MTBE (9% of world demand) and methanol. About 67% of products are manufactured in Eni s plants in Ravenna, Venezuela (in joint venture with Pequiven) and Saudi Arabia (in joint venture with Sabic), while the remaining 33% is bought from third parties. In Venezuela Eni plans to convert its MTBE plants to the manufacture of isoethane, due to the environmental problems posed by MTBE.

Capital Expenditure

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

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Petrochemicals

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

In 2005 sales of petrochemical products (5,376,000 tonnes) were up 189,000 tonnes, or 3.6% from 2004, reflecting primarily higher sales of intermediates (up 13%), olefins (up 8.8%) and aromatics (up 6%) related to positive demand, higher product availability and the fact that intermediate sales, in particular acetone and phenol, declined in the first quarter of 2004 following a standstill due to an accident at the Porto Torres dock. These increases were offset in part by a decline in: (i) elastomers (down 4.5%) related mainly to the standstill of the polychloroprene rubber plant in Champagnier, France; (ii) styrene (down 2.6%) related to standstills and shutdowns; and (iii) polyethylenes (down 2.3%) due to weak demand for LDPE and LLDPE.

At December 31, 2005, Eni s sales network covered 17 countries, with Italy accounting for 51% of sales, the rest of Europe for 44% and the rest of the world for 5% (54%, 40% and 6%, respectively in 2004).

Production (7,282,000 tonnes) was up 164,000 tonnes from 2004, or 2.3%, in particular in basic petrochemicals. Nominal production capacity declined 1.8% from 2004 due mainly to revisions of the nominal capacity of the Gela cracker and the shutdown of the DMC and ABS plants in Ravenna. The average plant utilization rate calculated on nominal capacity was up 3 percentage points from 75.2 to 78.4 due mainly to fewer maintenance standstills.

About 35.8% of total production was directed to Eni s own production cycle (36.7% in 2004). Oil-based feedstocks supplied by Eni s Refining & Marketing segment covered 23% of requirements (22% in 2004).

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

	Year ended December 31,				
	2001	**2002** (1)	**2003** (1)	**2004**	**2005**
	(thousand tonnes)				
Basic petrochemicals	6,119	4,304	4,013	4,236	4,450
Styrene and elastomers	1,537	1,538	1,635	1,606	1,523
Polyethylene	84	1,274	1,259	1,276	1,309
Polyurethane	91				
	7,831	7,116	6,907	7,118	7,282
Internal consumption	(3,185)	(2,607)	(2,651)	(2,616)	(2,606)
Purchases and change in inventories	588	984	1,010	685	700
Total products	5,233	5,493	5,266	5,187	5,376

(1) As compared to 2002, in 2003 Eni s activities have been grouped differently: Syndial (former EniChem) was included in the "Other activities" segment, which includes all Eni companies not included in specific segments. Data for years preceding 2002 have not been reclassified.

The table below sets forth Eni s sales of main petrochemical products by volume for the periods indicated.

	Year ended December 31,				
	2001	2002 (1)	2003 (1)	2004	2005
	(thousand tonnes)				
Basic petrochemicals	3,928	2,894	2,704	2,766	3,022
Styrene and elastomers	1,138	1,151	1,171	1,038	1,003
Polyethylene	84	1,448	1,391	1,383	1,351
Polyurethane	83				
Total sales	5,233	5,493	5,266	5,187	5,376

(1) As compared to 2002, in 2003 Eni s activities have been grouped differently: Syndial (former EniChem) was included in the "Other activities" segment, which includes all Eni companies not included in specific segments. Data for years preceding 2002 have not been reclassified.

Basic petrochemicals

Sales of basic petrochemicals (3,022,000 tonnes) increased by 256,000 tonnes from 2004, up 9.3%, due to increases registered in all basic chemicals businesses.

In olefins (up 8.8%) sales of ethylene (up 10.7%), propylene (up 5.8%) and butadiene (up 33.6%) increased due to high demand from the Far East. In aromatics (up 6%) sales of the most remunerative products (paraxylene up 13.5% and metaxylene up 35.1%) increased supported by a particularly lively market. In intermediates (up 13%) phenol sales increased 16.7% and acetone sales increased 11.1% related to a positive trend in demand and the fact that in the first quarter of 2004 sales declined due to a standstill for an accident at the Porto Torres dock.

Basic petrochemical production (4,450,000 tonnes) increased by 214,000 tonnes from 2004 (up 5.1%) due to increases registered in all businesses (olefins up 3.8%, aromatics up 8.4%, intermediates up 7%).

Increased olefin production derived mainly from the Brindisi (up 19.9%), Dunkirk (up 12%) and Priolo (up 8.1%) crackers. Declines concerned Gela (down 26.7%) where only one line was active and Porto Marghera (down 13.2%) due to a planned maintenance standstill.

Styrene and elastomers

Styrene sales (581,000 tonnes) decreased by 16,000 tonnes from 2004, down 2.6%, due mainly to lower ABS/SAN availability (down 23.6%) related to the shutdown of the Ravenna plant in April 2005 and lower availability of products due to technical accidents caused by power cutoffs at the Mantova plant in the last quarter of 2005. This decline was offset in part by the 2.8% increase in expandable polystyrene sales pushed by the strong increase in demand especially in Eastern Europe, in particular for increased consumption in the segment of thermal insulation and industrial packaging.

Elastomer sales (422,000 tonnes) decreased by 19,000 tonnes from 2004, down 4.5%, due mainly to the standstill of the Champagnier plant (polychloroprene rubbers) and the decline in SBR (down 12.7%) and TPR (down 2.5%) rubber due to a decline in demand related to the crisis in the shoe manufacturing industry. These declines were offset in part by an increase in sales of EPR rubber (up 19.6%) and latex (up 7.5%), due to lively demand.

Production of styrene (1,048,000 tonnes) declined by 70,000 tonnes from 2004, due mainly to plant shutdowns and standstills.

Elastomers production (475,000 tonnes) decreased by 13,000 tonnes or 2.5%, due to plant standstills and a declining demand for SBR rubber (down 4.8%) and BR (down 4.2%), while demand for EPR rubber (up 13.7%) and latex (up 11%) increased in line with the increase in demand.

Polyethylene

Sales of polyethylene (1,351,000 tonnes) decreased by 32,000 tonnes from 2004, down 2.3%, due to a decline in demand for all products, in particular LDPE (down 3.4%) and LLDPE (down 1.9%), also due increasing competition from imported products.

Production (1,309,000 tonnes) increased by 33,000 tonnes or 2.6%, due mainly to increases in LLDPE (up 8%), due to the flexibility at the Brindisi plant that produced mainly LLDPE in its high pressure line, while HDPE production declined (down 6%).

Capital Expenditure

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

Oilfield Services Construction and Engineering

Eni operates in oilfield services and construction through Saipem, a company listed on the Italian Stock Exchange (Eni s interest 43%), operating in offshore and onshore drilling and construction and LNG.

Eni, through its subsidiary Snamprogetti (100% Eni), is engaged in engineering and contracting in the area of plants for hydrocarbon production, treatment and transport, for the liquefaction and treatment of natural gas, for the conversion of heavy residues from conventional and non conventional crudes, for the chemical industry, for power generation, infrastructure and environmental protection.

Orders acquired in 2005 amounted to euro 8,188 million. Approximately 89% of new orders acquired were represented by work to be performed outside Italy, and 11% by work originated by Eni companies. Order backlog was euro 9,964 million at December 31, 2005 (euro 8,521 million at December 31, 2004). Projects to be carried out outside Italy represented 88% of the total order backlog, while orders from Eni companies amounted to 7% of the total.

On February 24, 2006, Saipem agreed to purchase the entire share capital of Snamprogetti owned by Eni SpA. The transaction was closed on March 27, 2006. The integration of the companies will boost their role in the development of Eni s oil & gas core business.

Orders acquired and order backlog

		2003	2004	2005
Orders acquired	(million euro)	**5,876**	**5,784**	**8,188**
Oilfield Services Construction		4,298	4,387	4,735
Engineering		1,578	1,397	3,453
Originated by Eni companies	(%)	11	14	11
To be carried out outside Italy	(%)	91	90	89
Order backlog	(million euro)	**9,405**	**8,521**	**9,964**
Oilfield Services Construction		5,225	5,306	5,513
Engineering		4,180	3,215	4,451
Originated by Eni companies	(%)	10	8	7
To be carried out outside Italy	(%)	81	84	88

Oilfield Services and Construction

Saipem intends to consolidate its competitive positioning in the segment of large offshore projects for the development of hydrocarbon fields and the construction of large export infrastructure by leveraging on its technological and operational skills, engineering and project management capabilities and ability to operate in complex environments. Leveraging on these assets, Saipem plans to address key success factors of the market represented by the ability to evaluate risks in the bidding phase, technological innovation, ability to manage efficiently the execution of projects by delocalizing support activities to low cost areas and enhancing local contents by employing local resources and creating decentralized logistical bases.

Saipem intends to develop its presence and enter the strategic segments of monetization of natural gas (GTL, LNG) and upgrading of heavy crudes by developing the required skills and resources mainly in the engineering and project management phases. It also plans to expand in the leased FPSO business and in floating LNG treatment systems for liquefaction and regasification of LNG.

Saipem intends to intensify efficiency improvement actions in all its activities, in particular by reducing supply and execution costs while maintaining a high utilization rate of equipment and improving its flexible structure in order to reduce the impact of possible negative cycles.

The most significant orders won in 2005 in oilfield services and construction were:

In the Offshore construction area: in **West Africa**: two turnkey contracts were awarded: (i) the first one for Total Upstream Nigeria for the installation and operation of underwater, umbilical and riser pipelines; and the construction of an unloading terminal, a mooring system for the FPSO vessel and the laying of a pipeline. Works will be carried out by the Saibos FDS and Saipem 3000 vessels; and (ii) the second one for Esso Exploration Angola Ltd for the engineering, procurement, construction and installation of subsea lines for the Marimba field development in Block 15; in **Indonesia**: two turnkey contracts for BP Berau Ltd for the construction of two platforms and the related underwater pipelines linking the Tangguh field with the gas liquefaction plant onshore; and in **Thailand:** a turn key contract for Thai Oil Public Company Ltd for the construction of unloading facilities to supply oil to a refinery in Sri Racha in the Gulf of Siam. Works will be performed in 2007, and the installation will be carried out by Castoro 8 vessel.

In the Leased FPSO area a contract for Petrobas for the conversion of an oil tanker into the new Vitoria FPSO vessel with a production capacity of 100,000 BBL/d and a storage capacity of 1,600,000 BBL for the development of the Golfinho 2 field offshore Brazil at a depth of 1,400 meters.

In the Offshore drilling area two contracts were acquired. The first one for Total Exploration and Production Angola, involving the deep water drillship Saipem 10000 for activities to be performed on the Rosa field for two years plus the option of a further two years. The second one for Burrullus Gas Company involves the renewal of contract for the semi-submersible Scarabeo 6 for three months in Egypt.

In the Liquefied Natural Gas area two contracts were awarded: (i) the first one, in association with Technip and Zachry, for the engineering and procurement of tanks for an LNG regassification terminal on the Quintana island in Texas; and (ii) the second one, in consortium with the Mexican company Gutsa, for the construction of infrastructure for the mooring and dry-docking of tankers at the Costa Azul in Mexico.

In the Onshore construction area two turnkey contracts were acquired: (i) the first one for Saudi Aramco to convert the existing East-West pipeline from oil to gas transport. It includes also fabrication, construction, installation and commissioning of new sections of East-West line and related facilities. Works will be performed in early 2008; and (ii) the second one for Sonatrach-Sonelgaz for the engineering, procurement and construction of a gas-fired power station.

In the Onshore drilling a contract for the North Caspian Sea consortium for drilling activities in Block D of the Kashagan field utilizing two drillings rigs owned by the client. Activities will be performed for five years.

Business areas

OFFSHORE CONSTRUCTION

Saipem is able to execute large projects for the development of offshore hydrocarbon fields by integrating its technical and operational skills, supported by a technologically advanced fleet and the ability to operate in complex environments, with engineering and project management capabilities acquired on the market (among which Bouygues Offshore, Moss Maritime, Petromarine, Idpe). The services that Saipem can currently provide to its customers can cover the main market segments such as: (i) floating production units (FPU); (ii) underwater developments; (iii) fixed platforms; and (iv) pipelines. Management expects the demand for these services to increase in particular in the FPU and underwater development areas, due to the increased share of deep water development projects. Key areas are West Africa, Asia Pacific, and Latin America.

Saipem operates in the area of deep offshore hydrocarbon field development by means of the construction and installation of FPUs. Among FPUs, FPSO vessels offer the main interesting market prospects due to their storage capacity, which allows to develop fields remote from transport infrastructure, and to their versatility, which allows at the end of the useful life of a field to relocate vessels on other fields thus expanding their useful life.

Saipem is engaged in the segment of underwater development in the deep offshore, which includes laying of small diameter pipes, umbilical lines, risers and other sub sea structures thanks to the design ability of its engineering structures and the installation capacity of its vessels. Saipem is also engaged in the segment of design, procurement and installation of fixed platforms, in particular in the segment of ultra heavy lifting, thanks to the technical features of its vessels. Saipem is able to execute the laying of large diameter long distance subsea pipelines and transport infrastructure both in conventional and deep offshore.

Its offshore construction fleet is made up of 25 vessels and 45 robotized vehicles able to perform advanced subsea operations. Among its major vessels are: (i) Saipem 7000, semi-submersible vessel with dynamic positioning system, with 14,000 tonnes of lift capacity (the highest of this kind in the world), capable to lay pipelines using the J-lay technique to the maximum depth of 3,000 meters. This vessel has been used to lay the Blue Stream pipeline in the waters of the Black Sea at the record depth of 2,150 meters; (ii) the Saibos FDS for the development of underwater fields in dynamic positioning, provided with cranes lifting up to 600 tonnes and a system for j-lay pipe laying to a depth of 2,000 meters; (iii) the Castoro 6 semi-submersible 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, derived from the transformation of the Maxita that can lay rigid and flexible pipes and is provided with cranes capable of lifting over 2,000 tonnes; and (v) the Semac semisubmersible vessel used for large diameter underwater pipe laying. The fleet includes also remotely operated vehicles (ROV), highly sophisticated and advanced underwater robots capable of performing complex interventions in deep waters.

OFFSHORE DRILLING

Saipem provides offshore drilling services to oil companies mainly in key areas such as West Africa, the North Sea and the Mediterranean Sea, it operates in the most complex segments of deep and ultra deep offshore. Management expects demand for offshore drilling services to increase steeply in the short to medium-term according to the exploration plans announced by the major oil companies. Management expects unit tariffs to be supported by a shortage of supply. West Africa is confirmed as one of the most attractive areas. Saipem can seize these market opportunities by leveraging on the technical features of its equipment. Its offshore drilling fleet consists of 10 vessels properly equipped for its primary operations and some drilling plants installed on board of fixed offshore platforms. One of its most important offshore drilling vessels is the Saipem 10000, designed to explore and develop hydrocarbon reservoirs operating in excess of 3,000 meters water depth in full dynamic positioning. The ship has a storage capacity of 140,000 BBL and can maintain a steady operating position without anchor moorings by means of 6 computerized azimuth thrusters, which offset and correct the effect of wind, waves and current in real time. Capital expenditure for building this ship amounted to about $300 million. The vessel is operating in ultra deep waters (over 1,000 meters) in West Africa.

Other relevant vessels are Scarabeo 5 and 7, third and fourth generation semi-submersible rigs able to operate at depths of 1,900 and 1,200 meters of water, respectively.

LEASED/SALE FPSO

Saipem provides to oil companies services for the development of offshore hydrocarbon fields by leasing its FPSO vessels. Following acquisitions carried out in recent years (in particular Moss Maritime and Bouygues Offshore), Saipem significantly strengthened its design skills. The leasing of an FPSO represents an alternative to direct expenditure for oil companies. West Africa and Latin America are the markets with the highest expected growth rates due to the number of development projects announced or started-up by oil companies. Saipem s main vessels are: (i) FPSO Firenze, a tanker ship which, after its conversion into a floating production and storage vessel, has been installed in Eni s Aquila field, in the Adriatic Sea, where it operates at a depth of 850 meters; and (ii) FPSO Mystras that has been installed since January 2004 in the Okono and Okpoho oil fields operated by Eni with a 100% interest in the deep offshore of Nigeria. Saipem intends to expand its market share in this business and plans to upgrade its offer by adopting the new generic FPSO vessels, designed and equipped in direct cooperation with the client in order to identify standard features that make the vessel easily employable in more than one development project according to the client s portfolio of fields. In this light, Saipem is building its new Vitoria unit that will be operating on the Golfinho 2 field in the offshore of Brazil.

ONSHORE CONSTRUCTION

Saipem operates in the construction of plants for hydrocarbon production (separation, stabilization, collection of hydrocarbons, pumping stations, water injection) and treatment (removal and recovery of sulphur dioxide and carbon dioxide, fractioning of gaseous liquids, recovery of condensates) and in the installation of large onshore transport systems (pipelines, compression stations, terminals). The demand for this kind of services from the oil industry is expected to increase in the medium-term, in particular long distance pipelines represent one of the favorite systems for linking production areas with their end markets, despite the increasing competition from other transport modes (LNG, GTL). The main operation areas are Africa and the Middle East. Saipem also boasts a consolidated presence in remote areas such as the Caspian Sea and Far East Russia, leveraging on its ability in operating in hostile environments, managing complex projects and enhancing local content, in addition to providing on land services complementing offshore activities (key factor in projects in areas such as the Caspian Sea). Saipem intends to consolidate its competitive positioning in the strategic segment of monetization of natural gas (GTL, LNG) and upgrading of heavy crudes by upgrading and acquiring the skills and resources necessary in the engineering and project management phases, which are key factors in this segment characterized by large EPC contracts. The acquisition of Snamprogetti is a key step in this direction.

ONSHORE DRILLING

Saipem operates in this area as main contractor for the major international oil companies performing its activity mainly in Saudi Arabia, North Africa and Peru, where it can leverage on its knowledge of markets and integration with other business areas. Saipem also boasts a long standing presence in remote areas (such as the Caspian Sea) based on its operating skills and ability to operate in hostile environments. Onshore drilling is conducted through 23 drilling platforms and 15 workover plants that can drill to 10,000-meter depths in high pressure and high temperature environments.

LNG

Saipem operates in the LNG segment following its purchase of Bouygues Offshore and Moss Maritime which contributed their experience in the LNG chain, complementary to the onshore and offshore transport of natural gas. The markets offering the highest potential are Asia, Europe and the Americas. Services provided by Saipem include: (i) the onshore segment which, according to management, shows interesting growth prospects, where Saipem is engaged in the design and construction of regasification terminals, storage tanks and in the design of gas tanker ships. Saipem also intends to acquire skills and critical mass in liquefaction; and (ii) the offshore segment, that includes FSRU (Floating Storage Regasification Units) and FNLG (Floating Liquefaction plants for Natural Gas) integrated systems which, according to management, show interesting growth prospects in the medium-term due to their lower environmental impact and greater flexibility as compared to other systems. Saipem intends to develop its presence in this segment.

MAINTENANCE, MODIFICATION & OPERATION

Saipem is also present in the MMO business which complements the company s activities and provide interesting growth prospects for the increasing tendency of oil companies to outsource these services (both routine work and upgrading/revamping) and for the development of remote areas for hydrocarbon production. Saipem is capable of seizing the opportunities provided by this segment by leveraging on its specialized know-how also as project manager, on its resources and network of logistical bases.

Engineering

Snamprogetti intends to consolidate its competitive positioning in the market of high complexity onshore projects, mainly in the strategic segments of oil and gas, natural gas monetization (GTL, LNG) and ethylene. In order to attain this objective, Snamprogetti intends to focus on the role of the main contractor, leveraging on its skills in terms of project management capabilities, a wide and integrated array of services provided and availability and continuing development of proprietary technologies.

Snamprogetti intends to expand the supply of qualified services in the phases of front end loading of projects (feasibility studies, conceptual, basic and front end engineering and project management) mainly to major clients and as a support to Eni s investment plans.

It plans also to intensify actions for improving operational efficiency and flexibility also through the rationalization of its operating structure, full utilization rates of low cost engineering and fabrication centers, the optimization of procurement, the adoption of the most stringent international best practices in terms of working tools and methods and the hiring of highly qualified resources.

Snamprogetti intends to continue enhancing its proprietary portfolio of technologies by means of support activities to the development on an industrial scale of technologies in strategic areas, such as the conversion of heavy crudes and high pressure transmission of natural gas, and the development of know-how in the field of the manufacture of high quality fuels and in the area of natural gas monetization (GTL, syngas, methanol, ammonia, urea).

In 2005, the engineering order backlog increased by euro 1,236 million due in particular to the recovery ongoing in reference markets, in particular the following contracts were awarded: (i) an EPIC contract for Abu Dhabi Gas Industries (GASCO) for the construction of a single line plant with a treatment capacity of 24,400 tonnes/y of LNG at the Ruwais complex in the United Arab Emirates. Works include also the construction of storage facilities, new port infrastructure and the provision of ancillary services; (ii) the Escravos GTL project in Nigeria, in joint venture with U.S. company KBR for Chevron for the construction of a 34,000 BBL/d plant for the production of diesel fuel, naphtha and LPG; and (iii) the Hawiyah GTC project in Saudi Arabia for Saudi Aramco for the construction of a natural gas treatment and compression plant with a capacity of 31,000 BBL/d.

Business areas

PLANTS

Oil & Gas Snamprogetti is engaged in the execution of complex and technologically advanced projects in the area of plants for hydrocarbon production, natural gas treatment and monetization (LNG; recovery and fractioning of natural gas liquids). Based on the capital expenditure plans announced by oil companies, Snamprogetti expects a growth in the demand for services in these areas. In particular the segment of transport and treatment of natural gas seems the most dynamic due to the progressive globalization of demand and supply of natural gas. Snamprogetti intends to consolidate its know-how in natural gas treatment by means of acquiring and developing needed competence in particular in the business of liquefaction. Significant capital expenditures for expanding liquefaction and regasification capacity of about 130 million tonnes/y of LNG (equivalent to 180 BCM/y) are expected in the next four years.

Refining Snamprogetti is engaged in the segment of conventional plants (grass root refineries and refining units) and in the segment of plants for the hydroconversion and hydrotreatment of heavy residues and distillates. Snamprogetti intends to seize the growth opportunities of the business of plants for heavy residue conversion and production of clean fuels. Growth in this business is supported by the wider availability of heavy crudes and by the increasingly stringent environmental requirements on emissions established worldwide. At Eni s Taranto refinery the first demonstration plant with 1,200 BBL/d capacity based on the Eni Slurry Technology is nearing completion. This technology has a high strategic value and aims at meeting the increasing demand for upgrading of heavy crudes and non conventional crudes (tar sands) and for conversion of refining residues (see: "Innovative Technologies" below).

Chemical complexes Snamprogetti is engaged in the area of plants for the conversion of natural gas (syngas, GTL, hydrogen, ammonia, methanol and urea) and gas-to-chemicals (ethylene and ethane derivatives). Snamprogetti plans to grow in the strategic segment of conversion of natural gas to liquids (GTL) for the manufacture of high value added products (LPG, diesel fuel and virgin naphtha); in this segment, where syngas is a critical element, Snamprogetti owns a proprietary technology through its subsidiary Haldor Topsøe. Snamprogetti holds a sound position in the design and construction of plants for the production of nitrogen-based fertilizers and high-octane additives for gasoline (MTBE, ETBE, TAME and iso-octene/iso-octane), based on proprietary technologies. Snamprogetti intends to strengthen its competitive position in the segment of world scale plants for ammonia and urea production, demand for which is supported by increasing consumption in Asia, with capital expenditure in new capacity concentrated in areas where gas has a competitive price (Middle East, Africa, Latin America). Snamprogetti intends to seize the opportunities for the construction of plants for the manufacture of world scale ethylene in particular in areas where feedstocks have a low price (especially the Middle East). Snamprogetti intends to seize this opportunity leveraging on its skills.

Energy Snamprogetti is active in the design and construction of combined cycle power stations also fired with refinery residues (IGCC - Integrated Gasification Combined Cycle). Snamprogetti intends to make use of the relevant know-how it acquired in the construction of EniPower power stations searching for new projects in Italy and outside Italy.

FIELD UPSTREAM FACILITIES AND PIPELINES

Snamprogetti is engaged in the design and construction of pipelines for the transport of hydrocarbons, collection networks and upstream plants (construction of primary separation plants, gas and water injection systems, compression and pumping stations), the demand for which is expected to grow. Snamprogetti is developing new advanced technologies for high pressure transport of natural gas aimed at the monetization of reserves located in remote areas (see: "Innovative Technologies" below).

INFRASTRUCTURE

Snamprogetti is active in the field of design and construction of great infrastructure in Italy. In particular it is working at the completion of the high speed/high capacity train tracks from Milan to Bologna.

AQUATER - ENVIRONMENTAL ACTIVITIES

Snamprogetti, through its Aquater - Environmental Activities division, is active in the field of projects for environmental remediation and reclamation, protection of the soil and integrated water systems in the framework of the optimization of compatibility of industrial development and environmental protection. The division provides a wide range of engineering services for the soil, the environment and natural resources and is active both as a consultant and as a main contractor in the area of environmental remediation, reclaiming of plants, waste management, water purification and civil works.

CEPAV UNO AND CEPAV DUE

Snamprogetti holds interests in the CEPAV Uno (50.36%) and CEPAV Due (52%) consortia that in 1991 signed two contracts with TAV SpA for the construction of the tracks for high speed/high capacity trains from Milan to Bologna (under construction) and from Milan to Verona (in the design phase).

As part of the project for the construction of the tracks from Milan to Bologna, an addendum to the contract between CEPAV Uno and TAV SpA was signed on June 27, 2003, redefining certain terms and conditions of the contract. In 2005, the consortium CEPAV Uno requested a time extension for the completion of works and an additional payment amounting to approximately euro 800 million. CEPAV Uno and TAV failed to solve this dispute amicably, and on

April 27, 2006, CEPAV Uno notified TAV of a request for arbitration, as provided under the terms of the contract.

At the end of 2005, CEPAV Uno Consortium had completed works corresponding to 71% of the total contractual price in line with the contractual obligations.

As concerns the Milan-Verona portion, in December 2004 CEPAV Due presented the final project, prepared in accordance with Law No. 443/2001 on the basis of the preliminary project approved by an Italian governmental authority (CIPE).

The final project was due to be examined by TAV for final approval. CEPAV Due started an arbitration procedure against TAV for the recognition of damage related to TAV s belated completion of its tasks. A final decision is expected late in 2006.

Other Activities

Eni s other activities are organized as follows:

- the "Other Activities" aggregate of subsidiaries, including Syndial SpA (former EniChem), which manages certain decommissioning and reclamation activities relating to certain shut down industrial sites of Eni, and certain other Eni subsidiaries (such as, among others, Sieco, Tecnomare, EniTecnologie, Eni Corporate University and AGI) engaged in diversified activities (mainly services to Eni business segments, such as real estate services, general purposes services, corporate research, training); and
- the "Corporate and financial companies", including Eni Corporate and certain of Eni s subsidiaries engaged in treasury services, Eni Corporate is the department of parent company Eni SpA performing Group strategic planning, human resources management, finance, administration, information technology, legal affairs, international affairs and corporate research and development functions. Through Enifin SpA, Società Finanziamenti Idrocarburi-Sofid SpA and Eni International BV, Eni carries out lending, factoring, leasing and insurance activities, principally on an intercompany basis.

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.

Research and Development

In technological research and innovation activities Eni plans to implement a capital expenditure programme in the 2006-2009 four year plan in order to develop such technologies that management believes may ensure competitive advantages in the long-term and promote sustainable growth. Eni plans to continue developing existing programmes on clean fuels, sulphur and greenhouse gas management as well as projects such as the upgrading of heavy crudes (EST), high pressure gas transmission (TAP) and Gas to Liquids (GTL).

In 2005, Eni s costs incurred for research and development amounted to euro 204 million, of these 32% were incurred by Eni s research department, 25% by the Exploration & Production segment, 24% by the Petrochemical segment and 13% by the Refining & Marketing segment. At December 31, 2005, a total of 1,420 persons were employed in research and development activities. In 2004, Eni s costs incurred for research and development amounted to euro 257 million, of which 39% were incurred by Eni s research department, 21% by the Exploration & Production segment, 21% by the Petrochemical segment and 12% by the Refining & Marketing segment. At December 31, 2004, approximately 1,470 persons were employed in research and development activities (1,400 at December 31, 2003).

In the next four years Eni plans to invest approximately euro 1 billion, balancing resources between projects aimed at reaching short-term objectives for business units with group-wide projects aimed at strengthening medium to long-term business sustainability. In particular the main focus of Eni s R&D lines are: (i) reserve replacement and reduction of mineral risk; (ii) production from non conventional hydrocarbon reserves and optimal management of reserves with high hydrogen sulfide and sulfur content; (iii) expansion in the natural gas market and utilization of associated gas and gas located in remote areas; (iv) improvement of quality and performance of fuels in light of the evolution of engines to increasingly perfected and efficient systems with lower impact on air quality; (v) efficient use of fossil fuels through an improvement in refining yields and an optimal use of each fuel with reduced environmental impact; and (vi) mitigation of the greenhouse effect, through the capture and geological sequestration of carbon dioxide.

Follows a description of Eni s key research and development projects.

INNOVATIVE TECHNOLOGIES FOR SUBSOIL SURVEY
In order to prepare a geological model of fields as near as possible to reality aimed at the simulation and monitoring of fields, Eni developed significant industrial applications of highly innovative technologies. The main objective of these technologies is the reduction of mineral risk and the optimization of processes for extracting and recovering hydrocarbons.

In the area of seismic imaging, the further developments of the proprietary "3D Common Reflection Surface (CRS) Stack" technology found various industrial applications with much higher efficiency than conventional techniques. New depth imaging techniques based on proprietary algorithms can generate depth images with such high resolution that they allow a very precise physical characterization of reservoirs. A new 3D resistivity modeling interpretive technique has been developed for the petrophysical measurement of wells (electrical logs), especially suited for the identification of complex mineralization situations, such as thin strata of sand and clay. Initial field applications proved that this new approach contributes to the production of more accurate estimates of reserves in place.

DRILLING OF "ADVANCED WELLS"
Eni developed and applied at industrial level a series of innovative technologies that allow to drill highly complex wells with greater operating efficiency. In particular, lean profile drilling, developed and patented by Eni, is applied in deep vertical and deviated wells especially in high pressure and high temperature environments allowing a reduction in time and costs and in environmental impact as it reduces the use of products for mud and cement and the resulting waste by about 30-40%.

Wells obtained with this technique are high quality and low risk. The technique basically consists in reducing to a minimum the tolerance between the diameter of wells and their lining columns while keeping the production casing unchanged. The application underway in Val d Agri is a record lean drilling in highly deviated wells (a 13"3/8 casing in a 14"3/4 hole with inclination up to 60°).

INNOVATIVE TECHNOLOGIES FOR THE TREATMENT OF LIQUIDS

In the field of transmission and treatment of hydrocarbons Eni developed and applied innovative technologies with particular attention to multi-phase fluids (water, oil and/or gas) in order to optimize production and reduce its environmental impact. In particular, Eni successfully tested at its Cavone oil center a pilot plant for the removal of oils from layer waters which allows to reduce the residual concentration of hydrocarbons in water to less than 10 ppm, starting from an initial content of over 1,000 ppm. The system is based on the use of adsorbing polymers capable first to capture oil particles and then to release them favoring their coalescence and making them easier to separate. The system is currently being engineered in order to make it useable on platforms. Another ongoing project aims at optimizing new design centrifugal systems for the separation of water from oil and for the confirmation of innovative technologies for removing soluble organic compounds.

Also in the field of multiphase pumping Eni is applying innovative technologies as an alternative to traditional production systems in marginal fields, fields located in frontier areas or difficult contexts such as deep waters. The multiphase technology becomes extremely useful, in terms of economic benefits, in offshore applications where the possibility to transport production from the wells over long distances allows to transfer processing activities on existing facilities and infrastructure, thus significantly reducing technical costs for the development of fields. Infield applications of multiphase pumping have been recently installed offshore and onshore in the United Kingdom and Tunisia with other partners in order to obtain a higher recovery of hydrocarbons.

MANAGEMENT OF HYDROGEN SULFIDE AND SULFUR

The Research & Development project for the optimal management of reserves with high content of hydrogen sulfide and sulfur started in 2003 is continuing. The project aimed at developing innovative technologies and/or advanced processes able to manage the disposal and possible exploitation of high amounts of sour gas and sulfur that are co-produced with hydrocarbons, while respecting safety and the environment. In particular innovative processes for the separation of hydrogen sulfide and its conversion into plain sulfur and the storage and/or use of this sulfur are in the development phase. In parallel innovative processes are being studied for the reinjection of hydrogen sulfide into the field and its monitoring.

In 2006 the integrated research program called H_2S and sulphur management in Exploration & Production operations will be completed. The program was aimed at identifying innovative solutions for the treatment of very sour gas. In particular significant progress was achieved in an innovative technology for H_2S bulk removal and in a new system for the massive storage of sulphur.

ENI SLURRY TECHNOLOGY

EST is a process of catalytic hydroconversion in the slurry phase that allows to convert asphaltenes (the hard fraction of heavy crudes) totally, thus reducing to zero the production of solid and fluid residues usually deriving from the refining of non conventional oil.

It is a flexible technology that satisfies the needs of upstream and downstream oil and can be adapted to various kinds of feedstocks to be converted, to different capacities and plants. Among its products are naphtha, kerosene, diesel fuel.

The development of this technology was started at the beginning of the 80s and the decision to test it industrially made possible in 2001 the building of a commercial demonstration plant with a 1,200 BBL/d capacity at Eni s Taranto refinery completed in 2005. It is currently being run for reaching the validation of the technology.

This will provide Eni with an important competitive lever for a more economic use of the full barrel of crude with lower environmental impact.

NATURAL GAS TRANSPORT THE TAP PROJECT

Among the reliable technologies for making the transmission via pipeline of relevant amounts of natural gas from production areas to consuming markets economically viable (gas to market), the TAP (high pressure transport) project will contribute to developing the most advanced long distance, high capacity, high pressure and high grade solutions with relevant targets related to:

(i) distances over 3,000 kilometers;
(ii) natural gas volumes to be transported of about 20-30 BCM/y;
(iii) pressure equal to or higher than 15 Mpa; and
(iv) use of high and very high grade steel (e.g. X100).

The TAP technology is expected to allow a decrease in the consumption of natural gas used in compressor stations from 7.5% to 3% of transported volumes.

The project was started in 2002 with a wide range of design, engineering and construction activities and in 2005 two infrastructures for the validation of its assumptions were completed.

The first one is a 10-kilometer long pilot segment in X 80 steel with 48" diameter from Enna to Montalbano integrated in the Snam Rete Gas network that allowed to test and validate the industrial application of the concepts.

The second infrastructure consists of two pilot pipes, with a 48-inch diameter in high resistance X100 steel installed in Perdasdefogu in Sardinia. It was started up in September 2005 under pressures of 140 bar. Testing is expected to last 20 months and will simulate the actual behavior of an industrial infrastructure for a period equivalent to 20 years.

In 2006 management believes that the first technology manual and FEED developed for a hypothetical trunkline in X100 steel with a 48" diameter linking Central Asia to Europe (for a length of 3,500 kilometers) will be available. A further development of this project will be the construction and operation of a commercial line in X100 steel a few-kilometer long.

CONVERSION OF GAS TO LIQUIDS GTL PROJECT

This is a key technology for the use of natural gas on a large scale for the production of high quality motor fuels, in particular diesel fuel and therefore it receives special attention by all majors due to its primary strategic value.

Eni s R&D activities in 2005 led to the preparation of the first basic design package for an industrial unit.

In 2006 Eni will continue its development activity at the Sannazzaro pilot plant consolidating the Fischer-Tropsch synthesis and optimizing its integration in the first two phases in order to define the optimal size of the GTL module along with its basic design package.

INNOVATIVE FUELS: CLEAN DIESEL FUEL PROGRAM

In its effort to improve the quality of its fuels, in 2002 Eni started to sell new virtually sulphur free (less than 10 ppm) products (first BluDiesel and since 2004 BluSuper) anticipating their compliance with EU regulations mandatory beginning in 2009.

With a longer term objective Eni started a clean diesel fuel program that aims at identifying the optimal formula for a diesel fuel with high performance and low particulate emissions using as benchmark GTL Fischer-Tropsch gasoil.

ENVIRONMENTAL PROTECTION

In the area of environmental protection, with the cooperation of partners from industries and academia, Eni is developing technologies for reducing the environmental impact of offshore and onshore E&P and refining operations.

In this area the following projects are worth mentioning:

- *GHG Program* The integrated Green House Gases (GHG) research program aims at verifying the industrial feasibility of the geological sequestration of carbon dioxide in depleted fields and salty aquifers.
- *The Early Warning Monitoring System (EWMS) project,* for real time recording of the physical and chemical profiles of Eni s productive activities and of their environmental context through a single computerized platform.
- *The Hydrogen Project* aiming at developing a portfolio of technologies for producing hydrogen at competitive costs, also in medium to small sized plants.

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Insurance

Eni constantly assesses its exposure for the Italian and foreign activities that are mainly covered through the Oil Insurance Limited ("OIL"), a mutual insurance and reinsurance company that provides to its members a broad coverage tailored to the specific requirements of oil and energy companies. Eni makes use of a captive insurance company that covers the risks and implements Eni s Worldwide Insurance Program re-insured with high quality securities in order to integrate the terms and conditions of the OIL coverage.

An insurance risk manager works in close contact with managers directly involved in core business activities in order to evaluate potential risks and their financial impact on the Group. This process allows to define a constant level of risk retention and, conversely, the amount of risk to be transferred to the market.

The level of insurance maintained by Eni is generally appropriate for the risks of its businesses.

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Environmental Matters

Environmental Regulation

Eni s operations, products and services are subject to numerous EU, national, regional and local environmental laws and regulations, including legislation that implements international conventions or protocols. In particular, these laws and regulations require that an environmental impact assessment is performed for new operations, restrict the types, quantities and concentration of various substances that can be released into the environment, limit or prohibit activities on certain protected areas, and impose criminal or civil liabilities for pollution resulting from oil, natural gas, refining and petrochemical operations. These laws and regulations also restrict emissions and discharges to surface and subsurface water resulting from the operations and set the rules for the generation, handling, transportation, storage, disposal and treatment of waste materials.

Environmental laws and regulations have a substantial impact on Eni s operations. Some risks of environmental costs and liabilities are inherent in particular operations and products of Eni, as it is with other companies engaged in similar businesses, and there can be no assurance that material costs and liabilities will not be incurred.

Although management, considering the actions already taken with the insurance policies to cover environmental risks and the provision for risks accrued, does not currently expect any material adverse effect upon Eni s Consolidated Financial Statements as a result of its compliance with such laws and regulations, there can be no assurance that there will not be a material adverse impact on Eni s Consolidated Financial Statements due to: (i) the possibility of as yet unknown contamination of industrial sites; (ii) the results of the ongoing surveys and the other possible effects of statements required by Decree No. 471/1999 of the Ministry of Environment concerning the remediation of contaminated sites; (iii) the possible effect of new environmental legislation and rules, such as: (a) the decree of the Ministry of Environment No. 367 published on January 8, 2004, that regards the fixing of new quality standards for aquatic environment and dangerous substances and Legislative Decree No. 59/2005 concerning the integrated environmental authorization (IPPC), (b) the application of European directive 2004/35/EC concerning environmental responsibility for prevention and reclamation of environmental damage, referred to in paragraph 439 of the single Article of Law No. 266/2005 (budget law for 2006), and (c) a legislative decree to be issued in implementation of Law No. 308 of December 15, 2004 that delegated to the Government the restructuring of regulations concerning waste disposal and reclamation of polluted areas, protection of waters from pollution and management of water resources, payment of environmental damage, procedures for the evaluation of environmental impact and for the strategic environmental impact as well as protection from emission into the atmosphere within 18 months. The Decree n. 152/2006 was approved by the Council of Ministers on February 10, 2006 has been in force since April 29, and it is now under examination by the new Government. The decree also implements European directive 2000/60/EC that established a European action framework for the protection of waters; (iv) the effect of possible technological changes relating to future remediation; and (v) the possibility of litigation and the difficulty of determining Eni s liability, if any, as against other potentially responsible parties with respect to such litigation and the possible insurance recoveries.

A brief description of major environmental laws impacting on Eni s activity follows.

Decree No. 471/1999 Management of waste, toxic waste, packaging and packaging waste is regulated by Legislative Decree No. 22 of February 5, 1997 which refers to three European Directives (91/156/CEE, 91/689/CEE and 94/62/CE) and provides incentives to clean technologies and recycling and reuse of waste. This decree prohibits the uncontrolled disposal of waste underground and in the water and obliges polluting entities to remediate polluted areas. Whenever it is not possible to identify one person or entity responsible for existing pollution, the owner of the polluted area is expected to pay for its remediation. This decree became operational with Decree No. 471/1999 of the Ministry of the Environment, which also defined: (i) limits for the contamination of soils and underground waters; (ii) general guidelines for remediation and environmental recovery of polluted areas; and (iii) criteria for the identification of polluted areas of national interest. For the storage of toxic waste, the decree favors techniques avoiding transport of waste and their on-site treatment. Whoever causes, willfully or accidentally, pollution of an area or actual danger of pollution is expected to react within 48 hours according to the procedure set by the decree. At present Eni is not yet able to evaluate the possible future consequences deriving from the completion of on-going surveys and other possible effects of the application of Decree No. 471/1999 of the Ministry of Environment; however there can be no assurance there will not be a material adverse impact on Eni s results of operations and financial position from the application of that decree. Law 388/2000 changed the regulations concerning the remediation of polluted sites, easing the discipline of crimes related to events prior to Legislative Decree No. 22/1997 and imposing the remediation of sites where industrial activity is ongoing. However, the remediation is to be carried out provided that it does not involve a significant disruption in operations; remediation costs can be amortized in ten years.

The new Decree No. 152/2006, concerning the overall revision of previous environmental laws, supercedes Decree 471/1999 and, in particular, it envisages that risk assessment be performed in order to define the extent of the required remediation. At this early stage it is not possible to assess the impact of the new law on Eni s activities, but it is expected that, in general, the introduction of risk assessment could reduce the extent of the remediation projects.

In accordance with European guidelines, the protection from water pollution was strengthened with Legislative Decree No. 152/1999 as completed by Decree No. 258/2000 and by Decree No. 367 of the Ministry of Environment. Decree No. 258/2000 provides for an integrated protection of water resources by extending control from each discharge place to all the effects of accumulation and interactions of various discharges into one single water course and set quality objectives to be reached by 2008. All discharges require preventive authorization, to be renewed every four years, and must lie below the thresholds set by Regions. The Decree No. 152/2006 has also renovated the previous water legislation, by aligning it to the less restrictive EU water directive. To date Eni cannot evaluate the possible impact of the application of the new law. However, there can be no assurance that there will not be a material adverse impact on Eni s operations due to measures adopted by local authorities whenever the quality of a certain water source does not comply with set standards due to the industrial activity of all plants located above that water source.

Law 372/1999 will gradually enter into force. This law, which is related to the European Directive 96/61/CE (IPPC - Integrated Pollution Prevention and Control), envisages that industrial installations will apply for an integrated authorization concerning emissions, wastes and water discharges. The calendar for the request of the integrated authorization has recently been defined. Many of Eni s plants refineries, chemical plants, power stations will have to apply for the authorization by the year end. All the Eni installations are getting ready to request the IPPC authorization, which will have a five year duration, in general, and eight years for installations registered according to EMAS regulation. In order to secure the extended authorization, some Eni installations have obtained or are in the process of obtaining the EMAS registration.

As of the year 2003, according to the IPPC Directive, the Member States of the EU had to communicate their national values of emissions into the atmosphere, wastes produced and managed and, finally, discharges into water of some compounds specified in the annexes of the directive relative to EPER (European Pollutant Emission Register). The Directive applies to several Eni plants, so the Eni divisions and/or companies which own these plants have reported their data to the authority in charge of preparing the Italian national communication.

On January 2006, EU Regulation No. 166 was issued concerning the Pollutant Releases and Transfers Register (PRTR), which are an extensions of the previous EPER registers and deals with all the emissions and transfers of 91 pollutants to air, water and soil. PRTR registers will be operational in the year 2009, with respect to 2007 emissions. To comply with the obligations Eni is considering the use of a group-wide Environmental Information System.

For a description of the impact of Law No. 316 of December 30, 2004 (Emission trading) on Eni s business, see below in "Implementation of the Kyoto Protocol".

HSE Activity for the year

In an operating context requiring companies, in particular those in the energy sector, to meet strict environmental sustainability requirements and to reduce risks, Eni s Health Safety Environment (HSE) activities are increasingly oriented to the application and certification of rigorous HSE management systems, in an effort to constantly improve their performance through specific projects aimed at meeting the main challenges of sustainability of Eni s operating sectors.

At the end of 2003, Eni issued a management system model (MSG) based on a yearly cycle including planning, implementation, control, review of results and definition of new objectives. In 2005 business units continued implementing this management system along with an audit program aiming at checking its functioning in Eni s business segments and at identifying any measures for its improvement.

In 2005, Eni s business units continued to obtain certification of their management systems and operating units according to the most stringent international standards. As of December 31, 2005, the total number of certifications obtained was 155 (133 in 2004), of which 82 certifications met ISO 14001 standard.

Environment In 2005, Eni incurred a total expenditure of euro 1,066 million for the protection of environment, up 33% from 2004. Current environmental expenditure amounted to euro 690 million and related mainly to the intense program of site remediation started in the past few years. Capitalized environmental expenditure amounted to euro 375 million and related mainly to water management and soil and subsoil protection.

Safety Eni is strongly committed to adopting a preventive approach to safety in order to reduce the occurrence of accidents and their consequences. Operations are managed with a special focus on the safety of workers, contractors and local communities. In line with international best practice, safety, prevention and work hygiene include:

(i) identification of dangers, evaluation and reduction of risks related to the deployment of work activities;
(ii) development and implementation of monitoring measures; and
(iii) investigation and analysis of accidents and near misses in order to learn from them and increase the ability to prevent and mitigate risks.

In 2005, expenditure for safety on the workplace amounted to euro 391 million, 57% of which were for current expenditure with the remaining part being capitalized. In 2005, the injury frequency rate measured as the number of injuries per million hours worked by Eni s employees was approximately 3.17, declining from the 2004 level of 4.47.

Health Activities for the protection of health aim at improving general work conditions and are developed according to three main principles: (i) protection of employees health; (ii) prevention of accidents and professional diseases; and (iii) promotion of healthier behaviors and life styles in workplaces.

In 2005 approximately euro 40 million was invested in the protection of health.

In Italy, health surveillance is performed in each operating unit through a network of health centers and by means of medical examinations, controls and monitoring campaigns for the major physical, chemical and biological risk agents. The health of employees outside Italy is protected likewise, in many cases integrating the typical activities of medicine on the workplace and first aid with the activities dedicated to primary health care extended also to family members and in many cases also to local communities.

Eni has a network of 339 own health care centers located in its main operating areas, of these 241 centers are outside Italy and are managed by local staff (322 doctors and 384 nurses). A set of international agreements with the best local and international health centers ensures efficient service and timely reactions to emergencies.

In 2005 Eni boosted its E-medicine program aimed at increasing the quality of health care provided to employees and to health operators in Italy and outside Italy, that integrates computerized technologies and advanced telecommunication systems. The program includes three projects:

(i) health card, on line access to health data of employees by means of an electronic card provided first to groups of employees outside Italy, that will be progressively extended to all employees;
(ii) telemedicine, a project oriented mainly to health care outside Italy, but open also to Italian industrial sites, based on contacts with highly qualified health centers worldwide and capable of providing real time consultation. This project is operating in Congo and Nigeria and in 2005 has been extended to four sites in Libya; and
(iii) e-learning, this project provides access to continuous training programs in the field of health to Eni s health operators in Italy and outside Italy by means of remote learning devices.

In Italy, Eni started a program of prevention, both through information campaigns and by means of screening procedures and direct actions accessed on a voluntary basis. The areas concerned are:

(i) prevention of cancer;
(ii) prevention of cardiovascular diseases; and
(iii) prevention of certain infective diseases.

Outside Italy, Eni promoted specific information campaigns for the protection of its employees, their families and local communities, such as those for the prevention of malaria (in Nigeria and Azerbaijan) and the prevention of HIV transmission (in Nigeria and Congo).

Implementation of the Kyoto Protocol

On February 16, 2005 the Kyoto Protocol entered into force and with it the commitments of the Annex I Parties which have ratified the protocol, including the EU and Italy. According to Law No. 120/2002, Italy committed itself to reduce GHG emissions by 6.5% in the period 2008-2012 as compared to 1990 values. Reductions can be achieved both through internal measures and through a series of instruments supplementary to internal measures. These are the so-called flexible mechanisms, which allow an enterprise 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 emissions credits and to purchase Assigned Amount Units from other Annex I countries, that have a surplus of these Kyoto units (IET - International Emission Trading).

Italy, as an EU Member State, is participating in the EU Emission Trading Scheme, which established, on January 1, 2005 the largest carbon market in the world.

The National Action Plan for the reduction of greenhouse gas emissions 2003-2010, sets out the allowances assigned to each sector and installation. Eni has cooperated with the authorities responsible for the preparation of the National Allocation Plan and it is also active in the utilization of the Kyoto Flexible Mechanisms. In fact, due to its presence in 70 countries, Eni is an elective partner for carrying out CDM and JI projects thus contributing to the Italian program of greenhouse gas reduction. In December 2003 during the Conference of Parties to the Kyoto Protocol COP9 Eni and the Ministry of the Environment signed a Voluntary Agreement for using flexible mechanisms, promoting CDM and JI and contributing to the sustainable development of host countries.

Law No. 316 of December 30, 2004 which converts Law Decree No. 237/2004 has implemented European directive 2003/87/EC which establishes a system for emission trading targeted to industrial installations with high carbon dioxide emissions. From January 1, 2005, this European emission trading scheme has been in force and on this matter on February 24, 2006 the Ministry of the Environment published a decree assigning the EU allowances for the 2005-2007 period to each industrial installation included in the scheme. In the first period of commitment, emissions not covered by corresponding allowances are subject to a fine amounting to euro 40/tonne of carbon dioxide. All companies are expected to identify and carry out projects for emission reduction. Eni participate to the ETS scheme with 61 plants in Italy and two outside Italy, which collectively represent about a third of all greenhouse gas emissions generated by Eni s plants worldwide. Eni was assigned, for the existing installations, allowances equal to 65.2 million tonnes of carbon dioxide (of which 22.4 for 2005, 21.4 for 2006 and 21.4 for 2007). New EU allowances are expected for new entrants, especially in power generation. In 2005, emissions of carbon dioxide from Eni s plants were lower than permits entitled.

In order to play an active role in the ETS Eni:

(i) prepared a methodological and organizational protocol for the accounting of greenhouse gas emissions;
(ii) implemented a database for a precise evaluation of emissions;
(iii) evaluated the compliance of existing monitoring and reporting systems in plants in order to identify improvement requirements; and
(iv) defined a system for balancing emissions from individual plants and business units in order to guarantee the payback of emission rights due.

Eni is also upgrading its ongoing program for the reduction of energy consumption and related CO_2 emissions.

A significant reduction potential can be derived from production activities outside Italy, that in some cases, given the lack of local market outlets, require the flaring of natural gas associated to oil production. The elimination of flaring and the use of associated gas for the development of local economies allow sustainable development while reducing greenhouse gas emissions. The validation of such projects as Clean Development Mechanism and JI will provide emission credits and facilitate the achievement of the Italian reduction target, as set by the Kyoto Protocol. Eni already carried out Zero Gas Flaring projects in Nigeria and Congo while others are underway. In 2004 Eni prepared the documentation required for the Kwale-Okpai combined cycle power station in Nigeria to qualify as a Clean Development Mechanism project, the power station utilizes the associated gas formerly flared. Moreover, Eni endorsed the Global Gas Flaring Reduction Initiative of the World Bank in order to fight for the elimination of obstacles to the completion of gas flaring reduction projects.

The best solutions for compliance with the Kyoto Protocol are the use of low emission energy sources and the adoption of highly efficient technologies. To address the greenhouse gas challenge, Eni completed in 2004 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 reduction from its plants.

To ensure comprehensive, transparent and accurate accounting for GHG emissions, which is consistent over time, Eni introduced a protocol for the accounting and reporting of greenhouse gas emissions (GHG Accounting and Reporting Protocol), which is an essential requirement for emission certification. Indeed, accurate reporting will support the strategic management of risks and opportunities related to greenhouse gases, the definition of objectives and the evaluation of progress.

For safer and more accurate management of GHG emissions and with a view to supporting accounting and certification of these emissions, Eni decided to implement a commercial database to facilitate evaluation of emissions in compliance with the methodologies laid down in its own GHG Accounting and Reporting Protocol.

Eni introduced a complete, accurate and transparent protocol for accounting and reporting of greenhouse gas emissions, which is an essential requirement for emission certification. Indeed, accurate reporting will support the strategic management of risks and opportunities related to greenhouse gases, the definition of objectives and the evaluation of progress.

As a support to its general strategy for a sustainable management of greenhouse gases, Eni continued its programs for the development of natural gas in Italy and outside Italy by means of technologically advanced projects such as the Blue Stream gas pipeline from Russia to Turkey and the Greenstream pipeline from Libya to Sicily. Increased gas availability in Italy will lead to a further expansion of the gas-power integration through high efficiency combined cycles with much lower carbon dioxide emissions than coal and liquid fuels.

In a medium term perspective 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.

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 different 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" for a description of the specific aspects of the Italian regulation and of environmental regulation concerning Eni s exploration and production activities.

Licenses (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a license, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the license holder is entitled to all production minus any royalties that are payable in kind. A license holder is generally required to pay production taxes or royalties, which may be in cash or in kind. Both exploration and production licenses are generally for a specified period of time (except for production licenses in the United States which remain in effect until production ceases). The term of Eni s licenses and the extent to which these licenses may be renewed vary by area.

Production sharing agreements (PSAs) entered into with a government entity or state company generally obligate Eni to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any.

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

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.

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").

In the early 1990s, the Government commenced the gradual liberalization of the Italian hydrocarbons industry by implementing legislation that provided for, among other things: (i) the elimination of price controls on petroleum products, (ii) the abolition of Eni s right of first refusal with respect to the purchase of natural gas produced offshore Italy; (iii) the implementation of a partial third-party access system for the transportation of natural gas; (iv) the establishment of a system for the updating of natural gas retail prices; and (v) the establishment of a royalty reduction program. Law No. 481 of November 14, 1995 (the "Authority Law"), provided for the establishment of a new regulatory body, known as the Autorità per l Energia Elettrica e il Gas (the "Authority for Electricity and Gas"), a public body charged with, among other things, regulatory supervision of electricity activities and natural gas distribution in order to guarantee the promotion of competition and efficiency while providing for an adequate level of service quality. As the latter is concerned, the Authority for Electricity and Gas is mainly responsible for the public service of natural gas distribution through urban networks.

Legislative Decree No. 164/2000 ("Decree No. 164"), which enacted the European Directive on Natural Gas 98/30/CE into Italian legislation, regulates the Italian natural gas market. Prior to the implementation of Decree No. 164, the Italian natural gas market lacked a legislative framework. "See Natural Gas" below.

Legislative Decree No. 32 of February 11, 1998 ("Decree No. 32") as amended by Legislative Decree No. 346 of September 8, 1999 and Law Decree No. 383 of October 29, 1999, significantly changed Italian regulation of service stations. In particular, the Decree replaced the process of concessions granted by the Ministry of Industry, regional and local authorities with a license granted by city authorities. "See Refining and Marketing of Petroleum Products" below.

Legislative Decree No. 443 of October 29, 1999 ("Decree No. 443") modified Legislative Decree No. 112 of March 31, 1998 ("Decree No. 112"), which attributed to Regions many responsibilities in the field of energy and specifically in the sector of hydrocarbons. Decree No. 443 attributes to the State administrative decisions concerning exploration and production of hydrocarbons in the Italian offshore, as well as natural gas storage in fields, while administrative decisions concerning exploration and production of hydrocarbons on the Italian mainland are made by the State in agreement with Regions.

Exploration and Production

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 production concession, in each case granted by the Ministry of Productive Activities (formerly Ministry of Industry). 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 one ten year extension and additional five year extensions until the field depletes.

Royalties The Hydrocarbons Laws require the payment of royalties for hydrocarbon production. Royalties are equal to 7% and 4%, respectively, for onshore and offshore production of oil and 7% for both onshore and offshore production of natural gas.

Preferential Rights Until December 31, 1996, Eni was entitled to a number of preferential rights, including, among other things, the exclusive right to explore for and exploit, without permit or concession, hydrocarbon deposits in the Exclusive Area.

In 1994, the EU enacted a licensing directive (the "Licensing Directive"), which required member states to enact legislation eliminating, by December 31, 1996, all laws that provided exclusive rights to a single entity in a specific geographic area. Legislative Decree No. 625/1996 (Decree No. 625), which was adopted to implement the Licensing Directive, eliminated the exclusivity of Eni s rights in the Exclusive Area. Decree No. 625 allows Eni to obtain upon application exploration permits and production concessions having effect from January 1, 1997 that would preserve such rights as have vested under the regime of exclusivity (based on the activities that have been carried out or are currently underway).

Storage of natural gas

The right to store natural gas in depleted fields in Italy is exercised pursuant to concessions granted by the Ministry of Productive Activities (formerly Ministry of Industry). Before Decree No. 164 came into force, only entities already holding a concession to exploit a hydrocarbon deposit were entitled to receive a concession to store natural gas, which is granted by the Ministry of Productive Activities. The initial duration of a concession is 20 years, with the possibility of obtaining at most two ten year extensions if they complied with the storage programs and other obligations deriving from said concession as per Law No. 239/2004. After the expiration of a concession, new storage or production concessions on the same field may be granted through competitive auctions. Pursuant to Decree No. 625, unused storage capacity can be made available to third parties, subject to the approval of the Ministry, on a negotiated basis. Until December 31, 1996, Eni had the exclusive right to store natural gas in depleted fields in the Exclusive Area. Decree No. 625 eliminated this exclusive right, while granting Eni the right to obtain upon application storage concessions effective from January 1, 1997 that would preserve the rights vested with Eni during the regime of exclusivity (based on current storage activities or certain statutory conditions). Eni obtained the ten storage concessions which it had applied for.

The most important aspects of Decree No. 164 concerning production and storage activities performed by Eni are the following: (i) it favors the development of domestic natural gas reserves; (ii) storage is to be carried out by a separate company not operating in other gas activities (such as Stoccaggi Gas Italia SpA) or by companies which only engage in transmission and dispatching, provided the accounts of these two activities are clearly separated from the accounts of storage. 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 final customers; (vi) storage tariffs criteria are determined by the Authority for Electricity and Gas in order to ensure a proper return on capital employed, taking into account the typical risk inherent in upstream activities, as well as volumes stored for ensuring peak supplies and provides incentives to capital expenditure for the upgrading of the system; (vii) in the transitional period until the publication of the Authority s decision, storage companies determine and publish their own tariffs; and (viii) the Authority for Electricity and Gas has to establish the criteria and priority of access most storage operators have to include in their 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.

In implementation of Decree 164, the Decree of the Minister of Productive Activities of September 26, 2001 defined the criteria for the determination and use of strategic storage. The utilization of natural gas volumes held under strategic storage becomes mandatory in case of interruption or reduction of imports from non-EU countries due to technical and unpredictable causes, in case of emergency on the national gas network, in case of winters colder than those expected by the Authority for Electricity and Gas in its periodic statements concerning the determination of modulation obligations for seasonal consumption peaks.

With Decision No. 26 dated February 27, 2002, the Authority for Electricity and Gas determined tariff criteria for natural gas storage for the first regulated period (from April 1, 2002 to March 31, 2006) on the basis of the costs of the service, plus a weighted average pre-tax rate of return of 8.33%. Tariffs are adjusted through a price cap mechanism that takes into account inflation and a productivity recovery of 2.75% per year. The tariff structure for modulation consists of two fixed elements, one based on the annual capacity used (space occupied in the reservoir) and one based on maximum output capacity demand for one day in the year, as well as a variable element calculated on the basis of the quantities entering and leaving the field. On the basis of these criteria on March 18, 2002, Stoccaggi Gas Italia SpA presented its suggested tariffs for cyclical modulation, upstream and strategic storage services for the first regulatory period. The Authority for Electricity and Gas rejected Stoccaggi Gas Italia proposal and set storage tariffs for the first regulatory period with Decision No. 49 of March 26, 2002. In 2002, Stoccaggi Gas Italia appealed against both decisions to the Regional Administrative Court of Lombardia in order to obtain their cancellation. The Regional Administrative Court of Lombardia repealed Stoccaggi Gas Italia s appeal with decision of September 29, 2003. Stoccaggi Gas Italia appealed to the Council of State against this decision on February 3, 2004. Pending the proceeding, Stoccaggi Gas Italia is currently applying the tariffs set by the Authority for Electricity and Gas.

On March 3, 2006, the Authority for Electricity and Gas with Decision No. 50/2006 published the criteria for determining storage tariffs for the second regulated period. This decision changes the regulation in force in the first regulated period, introducing maximum allowed revenues affecting the capacity component (space and flow) and confirming the price cap mechanism for the commodity component. It also establishes a single national tariff. The decision confirms the mechanisms for the evaluation of net capital employed already defined for the first regulated period; the return on capital employed is reduced from 8.33% to 7.1% (pre-tax). Based on the new tariff regime and keeping into account that all the capacity available in 2006 is considered in the calculation of tariffs, revenues expected in the thermal year from April 1, 2006 to March 31, 2007 amount to about euro 280 million, decreasing 20% from the previous thermal year. The decision contains also incentives to capital expenditure for the development of storage by recognizing an additional rate of return of 4% on the basic rate for 8 years for capital expenditure increasing capacity and for 16 years for the development of new storage sites. Decision No. 56 of March 16, 2006 approved Stogit s tariff proposals for 2006-2007 thermal year.

With Decision No. 119/2005, the Authority for Electricity and Gas regulates ways for the supply of modulation, mineral and strategic storage services on part of storage companies, as well as the service for the operating balancing of transport companies and provides a basic scheme for the preparation of companies storage code.

By February 1 of each year, the storage company is to publish on its internet site: (i) its plant operating and maintenance program for the following thermal year (the thermal year for storage starts on April 1 and ends on March 31 of the following year); (ii) its upgrading and divestment plan as authorized by the Ministry of Productive Activities; and (iii) storage capacity available for each of the services provided.

As concerns the modulation and mineral storage services, in its storage code the company defines a program for the injection phase and the offtake phase, indicating the optimization criteria and flexibility margins provided to users. The offtake phase takes place between November 1 and March 31, the injection phase between April 1 and October 31. The volumes of gas offtaken by the user cannot be higher than the volumes injected or the volumes the customer is entitled to.

The capacity destined to mineral and strategic storage is determined by the Ministry for Productive Activities. As concerns strategic storage, the company makes available the volumes of natural gas in storage it owned resulting from its closing balance at December 31, 2001. For any additional volumes that can contribute to the reaching of the thresholds set by the Ministry, the price is suggested by the storage company and set with a bid procedure. The user can request only storage capacity and inject own natural gas volumes.

Storage capacity is assigned by the storage company for periods no longer than a thermal year by March 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 offtake capacity is assigned according to the following order of priority to: (i) holders of production concessions requesting mineral storage services; (ii) entities deploying natural gas sale activities who are obliged to provide modulation of their supply to their customers according to Article 18, paragraphs 2 and 3 of Legislative Decree 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 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. A procedure to be issued by the Authority for Electricity and Gas will establish the criteria for assigning capacity when the requests mentioned in (iv) above exceed availability.

During the storage thermal year, the company makes new assignations when new capacity becomes available. Users are allowed to sell to each other volumes of gas injected or capacity assigned. Users are requested to transmit to the storage company one week in advance of the next, programs for injection or offtake, within the limit of assigned capacity, confirming each day the bookings for the following day.

The Decision No. 50/2006 also regulates the charges for balancing and replenishing storage for the first regulated period, while for calculating the tariffs related to balancing and replenishing in the second regulated period the Authority is expected to publish a new decision.

If the user offtakes a peak daily amount higher than the assigned amount, without replenishing by purchasing, the storage company applies, for each month to the maximum difference between peak daily capacity actually used and peak daily capacity entitled, a variable charge depending on the volumes of gas in storage on the day of the offtake and the number of days of exceeding use.

If the volumes input to storage are higher than the capacity assigned and the user does not purchase additional capacity or sell excess natural gas volumes within 15 days from receiving information on its position, the storage company will: (i) apply to the maximum exceeding volume in a month a variable balancing charge depending on the month of injection; and (ii) sell, on behalf of the user that has not yet done it, the volume of gas injected exceeding the assigned capacity in the day or days of the thermal year of storage in which working gas reached its maximum amount, if the transport company reduced the volumes planned by users of transport at one or more interconnection points at the border and the same transport users also hold storage capacity.

If the volumes of gas offtaken by a user are higher than those held in storage and the user fails to replenish by means of a purchase, charges are applied that relate to replenishment of offtake from strategic storage, which include: (i) in case of offtakes allowed by the Ministry of Productive Activities, the replenishment of the first volumes input to storage right after the offtake and the payment by the user of a charge applied to the maximum accumulated volume of offtaken gas, net of an income proportional to volumes replenished, as determined by the Authority, as well as the payment of balancing charges without penalty; and (ii) in case of non authorized offtake, the income recognized to the user for replenishment is reduced by a fixed amount. Proceeds from the replenishment of strategic reserves are subdivided proportionally among users in charge of strategic storage services, except for the proceeds from the replenishment of gas offtaken without authorization that are proportionally distributed to all users. Proceeds to the storage company from the application of balancing charges are proportionally distributed to users.

With Decision No. 21 of January 31, 2006, the Authority for Electricity and Gas increased these charges by different amounts with respect to authorized and unauthorized offtakes. On the basis of these provisions, Eni may incur material charges for storage services in case of unauthorized offtakes from the strategic reserve. Eni appealed against this decision.

With Decision No. 266/2005 the Authority for electricity and gas started an inquiry leading to a possible administrative sanction (fine under Law No. 481/1995) alleging that Stogit s behavior does not conform with the discipline contained in Decision No. 119/2005 concerning access to and provision of storage services.

On the use of storage capacity conferred in 2004/2005 and 2005/2006 With Decision No. 37 of February 23, 2006, the Authority for Electricity and Gas started an inquiry on a few natural gas selling companies, among which Eni, with reference to the use of storage capacity in years 2004-2005 and 2005-2006. For the 2004-2005 thermal year and for the period from October 1, 2005 to December 31, 2005 the Authority for Electricity and Gas deemed improper the use of modulation storage capacity. In fact the Authority for Electricity and Gas judged offtakes to be higher than the volumes considered necessary to satisfy the requirements for which the storage company was awarded priority given the weather of the period.

Eni also held natural gas for strategic reserve purposes in its storage business, as established by Decree No. 164. 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 of Productive Activities determines quantities and usage criteria of such reserves. As of December 31, 2005 Eni held approximately 180 BCF of strategic reserves of natural gas (180 BCF at year end 2004).

Gas & Power

Natural gas market in Italy

The European Directive on Natural Gas was implemented into Italian legislation through Legislative Decree No. 164 of May 23, 2000 ("Decree No. 164"), effective from June 21, 2000. As concerns natural gas activities carried out by Eni the most relevant aspects of the decree are as follows: (i) starting in 2003 all customers are eligible customers (with access to the natural gas system and free to choose their supplier of natural gas); (ii) from January 1, 2003 to December 31, 2010 no single operator is allowed to hold a market share higher than 50% of domestic sales to final customers. In addition, no single operator is allowed to supply more than 75% of all natural gas volumes introduced in the domestic transmission network by 2002, decreasing by 2 percentage points per year until it reaches 61%. Compliance with these ceilings is verified annually by comparing the allowed average percentage on a three year basis for volumes input or sold to the average percentage obtained by each operator in the same three year period. Allowed percentages are calculated net of losses (in the case of sales) and volumes of natural gas consumed in own operations. In accordance with Article 19, paragraph 4 of Legislative Decree No. 164/2000 the volumes of natural gas consumed in own operations by a company or its subsidiaries are excluded from the calculation of ceilings for sales to end customers and for volumes input into the Italian network to be sold in Italy; (iii) imports from the European Union are free, while natural gas imported from outside the European Union is subject to an authorization of the Ministry of Productive Activities. Subjects importing from countries outside the EU must secure a certain availability of strategic storage. Such constraints apply also to the import contracts entered into before the coming into effect of Decree No. 164, these contracts are automatically considered authorized since this date; (iv) natural gas transport and dispatching activities have to be carried out by a separate company that is not allowed to carry out any other activity in the natural gas field, with the only exception of storage, for which, however, accounting and operating separation is envisaged. Also distribution, which includes the transport of natural gas by means of local gas pipeline networks for delivery to customers, has to be carried out by a separate company which may not perform other gas related activities. Sale activity to final customers is compatible only with import, export and production activities and is subject to an authorization from the Ministry of Productive Activities. Concessions for the distribution of natural gas will be assigned only through an auction procedure; and (v) tariff criteria and return on capital employed for transport, dispatching, storage, use of LNG terminals and distribution are determined by the Authority for Electricity and Gas. Third parties are allowed to access transport infrastructure, storage sites, LNG terminals and distribution networks on a regulated basis. As provided for by the decree, a Network Code containing norms and regulations for the operation of and access to infrastructure was prepared by operators on the basis of criteria set by the Authority for Electricity and Gas.

In particular 2005 closes the second three year regulated period for natural gas volumes input in the domestic transmission network (for which the allowed average percentage is 71% of domestic consumption of natural gas) and the first three year regulated period for sales volumes (for which the allowed average percentage is 50% of gas sales). Eni s presence on the Italian market complied with said limit.

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 conferral 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.
- Paragraph 34 of the single article prohibits undertakings active in the field of natural gas and electricity with a concession for local public services or for the management of networks (excluding all sale activities) from operating in a competitive market for post-counter services, in the areas where they hold the concession for the duration of the concession, including through subsidiaries or affiliates.
- Paragraph 51 cancels paragraph 5 of Article 16 of Legislative Decree No. 164/2000, which obliged distribution companies to ascertain the safety of plants which do not only supply gas to productive units and safety of post-counter services.
- Paragraph 69 provides the authentic 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 at December 31, 2012.

Law Decree No. 239/2003 Law Decree No. 239/2003, converted with amendments into Law No. 290/2003, prohibits companies operating in the natural gas and electricity 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 electricity from July 1, 2007. Law No. 266/2005 (budget law for 2006) extended this deadline from July 1, 2007 to December 31, 2008. At December 31, 2005 Eni held a 50.05% interest in Snam Rete Gas. Following this provision, Eni will have to sell part of its stake in Snam Rete Gas until it reaches the 20% maximum interest allowed within the end of 2008.

On March 23, 2006 a Law Decree of the President of the Council of Ministers defined criteria and modes 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 this company.

Natural gas emergency procedure On December 12, 2005, the Minister of Productive Activities updated the emergency procedure to cope with a natural gas shortage in the event of unfavorable climatic events. In particular the new established procedure set the following sequence of activities:

- an increase of gas availability (maximization of natural gas importation);
- activation of the interruption of customers with interruptible contracts;
- interruption of supplies to "dual-fuel" plants;
- further actions to reduce natural gas consumption of "dual-fuel" plants; and

further initiatives to reduce natural gas consumption.

In order to manage the natural gas emergency during the 2005-2006 winter opened on December 19, 2005, the following provisions were adopted:

- Resolution No. 10/2006: the Authority introduced an auction mechanism to activate an interruption temporary system of the gas natural supply;
- Ministerial Decree of January 24, 2006: the Ministry of Productive Activities reduced emissions limits to the power generation plant up till March 31, in favor of the use of oil; and
- Ministerial Decree of January 25, 2006: the Ministry of Productive Activities reduced from 1 to 28 of February the allowed limits of temperature in the residential buildings.

The Ministry of Productive Activities declared the end of the emergency procedure on March 22, 2006.

Natural Gas prices

Prices of natural gas sold to industrial and thermoelectric customers as well as to wholesalers are freely established among buyers and sellers following the liberalization of the natural gas sector introduced by Decree No. 164. Eni applies a multi-choice price structure to its individual customers or groups of customers who are able to choose among various forms of price indexation. This price structure aims at reducing the impact of the volatility of raw material prices due to fluctuations in the prices of energy parameters and in exchange rates by introducing mechanisms that minimize commodity risks. The Authority for Electricity and Gas holds a power of surveillance on this matter (see below) under Law No. 481/1995 (establishing the Authority for Electricity and Gas) and Legislative Decree No. 164/2000. See below for a discussion of natural gas prices of sales of natural gas to residential and commercial customers which were not eligible customers until December 31, 2002.

The Decree of the President of the Council of Ministers of October 31, 2002 conferred to the Authority for Electricity and Gas the powers to: (i) define, calculate and update and gas selling prices also after the opening up of markets set at January 1, 2003 for customers who were not-eligible customers until December 31, 2002; (ii) define methods for updating selling prices with reference to variable costs that minimize the impact of inflation; and (iii) define criteria for allocating the costs deriving from social support measures, in order to reduce the aggregate net cost of interventions as much as possible and to ensure neutrality in the application of selling prices to the various groups of users. Consistently with this decree, the Authority for Electricity and Gas: (i) with Decision No. 195 of November 29, 2002 changed the methods for periodically updating selling prices for natural gas in connection with changes in international prices of crude oil and refined products. Such changes concern the schedules update process (from every two months to every three), and the duration of the reference period for the calculation of changes in average international prices as compared to the application quarter (from the preceding six months to the preceding nine months). The invariance threshold, beyond which tariffs are updated, remained at 5%; and (ii) with Decision No. 207 of December 12, 2002, it decided that companies selling natural gas through local networks have to maintain the conditions applied to non-eligible customers until December 31, 2002 until the customer accepts a new contract offer. In addition, the Authority for Electricity and Gas decided that these companies can propose their own new contract offers and the tariffs determined according to the criteria established by the Authority for Electricity and Gas, adequately advertising them before March 31, 2003 (such offers must be published on the companies web page, on at least one newspaper of general circulation and on the Official Gazette of their region or autonomous province).

With Decision No. 248 of December 29, 2004, the Authority for Electricity and Gas changed the indexing mechanism concerning the raw material component in tariffs paid by end customers that were non-eligible customers until December 31, 2002 according to Decision No. 195/2002. The decision introduced the following changes: (i) establishment of a cap set at 75% for the changes in the raw material component if Brent prices fall outside the 20-35 dollar/barrel range; (ii) change of the relative weight of the three products making up the reference index of energy prices whose variations when higher or lower than 5% as compared to the same index in the preceding period determine the adjustment of raw material costs; (iii) substitution of one of the three products included in the index (a pool of crudes) with Brent crude; and (iv) reduction in the value of the variable wholesale component of the selling price by euro 0.26 cents per cubic meter in order to foster the negotiation of prices consistent with average European prices in gas import contracts starting from October 2005. Decision No. 248/2004 obliges Italian suppliers to wholesalers to renegotiate supply contracts in light of the price revision introduced by same decision in supply contracts between wholesalers and end users. This decision also states that the Authority may review these clauses in the light of import contracts. Eni provided the Authority with the terms of its import contracts that may lead the Authority to reconsider its decision, as Eni is one of the largest importers to Italy.

In May-October 2005 the Regional Administrative Court of Lombardy, based on claims of Eni and other operators, annulled Decision No. 248/2004. In March 2006, the Council of State annulled the decision of the Regional Administrative Court of Lombardy in the case of a single operator and, at the same time, postponed to the plenary meeting of the Council of State the case of an association of natural gas wholesalers and local selling companies, taking into account a possible procedural flaw. Furthermore, the Council of State postponed its decision on the appeal proposed by the Authority against the decision of the Regional Administrative Court of Lombardy in favor of Eni after the decision of the plenary meeting of the Council of State on said procedural issues (expected to occur late in 2006).

In December 2005 the Authority for Electricity and Gas implemented Decision No. 248 for the first quarter 2006 through Decision No. 298/2005. The Regional Administrative Court of Lombardia initially suspended Decision No. 298/2005 based on claims of Eni and other operators. Then the same Court cancelled the suspension it had initially granted. Therefore Decision No. 298/2005 is now fully effective. On March 28, 2006, the Authority for Electricity and Gas issued Decision No. 63/2006 which updates tariffs for the April-June 2006 quarter, in application of Decision No. 248/2004. Eni appealed also this decision for the reasons stated above.

Eni s management expects a negative outcome of this matter. In fact Eni accrued a material provision in its 2005 Consolidated Financial Statements in order to reflect the risks associated with this matter. In 2006 management expects Eni s results of operation to be adversely impacted by a material amount in light of the high Brent crude oil prices, in the event Decision 248/2004 is implemented in its original form. Actually Eni s results of operations for the first quarter 2006 were negatively affected by this matter. See "Item 3 Risk Factors" and "Item 5 Results of Operations and Recent Developments".

With Decision No. 65/2006, the Authority started a consultation with operators to redefine mechanisms for the updating of the raw material component in natural gas prices to households and established provisions concerning partial adjustments for final customers related to differences between Decision No. 248/2004 and the previous Decision No. 195/2002. Consistently with the appeal against Decision No. 248/2004, Eni appealed also against Decision No. 65/2006 with the Regional Administrative Court of Lombardia. The Authority, in the consultation document published on May 17, 2006, proposed the followings: (i) while confirming a quarterly basis mechanism for the updating of the raw material component in natural gas price formulas, with a five percentage points of invariance threshold as provided for by Decision No. 195/2002, a monthly updating mechanism is proposed for the recognition of purchase costs borne by operators with an half percentage point invariance threshold; (ii) the establishment of a compensatory fund which will redistribute among operators the differences between natural gas prices recognized to end customers and the raw material costs incurred by operators; and (iii) the fixation of a range of $35-60 per barrel of Brent crude oil to which selling companies apply the 75% cap, limiting the ability to pass increases in the purchase cost onto final customers. Beyond $60, increases in the purchase cost are proposed to be transferred to end customers with a 90-95% cap for a maximum two year transition period. In addition the Authority confirmed the obligation of suppliers to wholesalers to renegotiate supply contracts taking account of the new price mechanism introduced by Decision No. 248/2004. Management expects the proposed changes to partially mitigate the impact of Decision No. 248/2004, as they do not enable Eni to fully recover the purchase cost of natural gas in selling prices.

Inquiry of the Authority for Electricity and Gas on import purchase prices With Decision No. 107/2005 the Authority for Electricity and Gas started a formal inquiry under Law No. 481/1995 against Eni and other gas importers alleging their failure to comply with the Authority information requirements contained in its Decision No. 188/2004 of October

27, 2004, by which it required natural gas importers, among which Eni, to give information concerning: (i) dates and supplier for each supply contract for the import of natural gas; (ii) FOB purchase prices; (iii) price updating formulas; and (iv) volumes supplied and FOB purchase average prices on a monthly basis for each supplying contract relating to the period October 2002-September 2004. Under Law 481/1995, the Authority for Electricity and Gas can impose a fine on Eni. Eni appealed this decision with the Regional Administrative Court of Lombardia that on March 22, 2005 cancelled the obligation for Eni to communicate dates and supplier for each contract and FOB purchase prices. Accordingly, Eni initially gave the Authority for Electricity and Gas only part of the information required. On April 6, 2006 a final hearing was held in front of the Authority Eni confirmed its position that it has provided adequate information, but with the intention of full collaboration it provided the data concerning average monthly fob prices for the October 2002-September 2004 period.

Inquiry of the Authority for Electricity and Gas on behaviors of operators selling natural gas to end customers With Decision No. 225 of October 28, 2005, the Authority for Electricity and Gas started an inquiry on the behaviors of companies selling natural gas to end customers aimed at acquiring new customers or re-acquiring customers transferred to other sellers, with particular reference to hurdles posed by companies to customers wishing to leave one distributor or to the entry of competitors on the market. The inquiry aims at identifying any measure the Authority should take in this area and is expected to close before July 31, 2006.

Inquiries by the Italian and European Antitrust Authorities

Sale contracts outside Italy With a decision of November 21, 2002, the Antitrust Authority judged that Eni had violated competition rules by entering in 2001 into contracts outside Italy with other operators importing into Italy the supplied volumes and thus limiting third party access to natural gas transport infrastructure. The Antitrust Authority considered that these contracts infringe the rationale of Article 19 of Legislative Decree No. 164/2000 which defines the limits for volumes to be input by single operators into the national network. With the same decision and taken into account the lack of clarity of Italian regulations and Eni s availability to increase the transmission capacity of gaslines outside Italy, the Antitrust Authority imposed on Eni a symbolic fine amounting to euro 1,000 and requested Eni to submit "implement measures to eliminate infringing behaviors with specific attention to the upgrading of the transmission network or equivalent actions".

On June 18, 2004, Eni submitted to the Antitrust Authority a proposal entailing the sale to third parties of a total of 9.2 BCM of natural gas in the four-thermal year period starting in October 1, 2004 through September 30, 2008, corresponding to 2.3 BCM for each thermal year, before such natural gas enters the national transmission network at Tarvisio. With a decision of June 24, 2004, the Antitrust Authority judged this proposal adequate to end the effects of the violation of competition rules highlighted in the November 21, 2002 decision. With the decision of October 7, 2004 that closed the above mentioned procedure, the Antitrust Authority acknowledged that Eni had taken proper measures for executing the decision of November 21, 2002 by signing gas release contracts. However, it fined Eni euro 4.5 million alleging that Eni had complied belatedly with the Antitrust Authority s indications. On December 6, 2004, Eni filed a claim with the Regional Administrative Court of Lazio against this decision requesting the annulment of the fine that was however recorded in Eni s accounts. In May 2005 the Regional Administrative Court repealed this claim. Eni paid the fine imposed on it by the Antitrust Authority. In June 2006, the appeal proposed by Eni before the Council of State against the decision of the Regional Administrative Court was rejected. A claim filed by Eni with the Regional Administrative Court of Lazio against the decision of November 21, 2002 is still pending.

Inquiry of the Authority on the upgrade of the TTPC Pipeline - Appeal to the Regional Administrative Court for Lazio On February 15, 2006, the Antitrust Authority informed Eni of the closing of an inquiry started in February 2005 to ascertain an alleged abuse of dominant position. The events leading to the opening of the procedure relate to behaviors of Trans Tunisian Pipeline Co Ltd (TTPC), wholly owned by Eni, concerning its decision to consider expired certain ship-or-pay contracts signed on March 31, 2003 by TTPC with four shippers, who had been assigned new transport capacity on TTPC s pipeline, due to the non occurrence of certain suspensive clauses. Therefore TTPC decided to not proceed to the planned upgrade of the pipeline by 2007.

In January 2006 Eni submitted to the Antitrust Authority a proposal containing the actions it intends to perform in order to favor competition on the Italian natural gas market and mitigate the effects if its alleged abuse of dominant position, concerning in particular the upgrade of the TTPC pipeline in Tunisia for the import of natural gas to Italy from Algeria: 3.2 BCM/y from April 1, 2008 and further 3.3 BCM/y from October 1, 2008.

With a decision notified on February 15, 2006 the Antitrust Authority stated that Eni s behavior through its subsidiary TTPC represented an abuse of dominant position under Article 82 of the European Treaty. It therefore fined Eni. The original fine amounted to euro 390 million and was reduced to euro 290 million in consideration of Eni s commitment to perform actions favoring competition as mentioned above. Eni appealed against this decision with the Regional Administrative Court of Lazio. The hearing is scheduled on July 12, 2006. See above "Gas & Power Development Projects".

Eni SpA - GNL Italia SpA On November 18, 2005 the Antitrust Authority notified Eni and its subsidiary GNL Italia the opening of an inquiry, in accordance with Article 14 of Law No. 287/1990, concerning an alleged abuse of dominant position in the assignment and use of the total continuous regasification capacity of the Panigaglia terminal (owned by GNL Italia) in thermal years 2002-2003 and 2003-2004, as evidenced by an inquiry of the Authority for Electricity and Gas which referred Eni to the Antitrust Authority. In a later communication the company was informed that the inquiry has been extended also to thermal year 2004-2005 and to Snam Rete Gas which is the parent company of GNL Italia SpA. The inquiry is due to be closed on October 31, 2006.

Inquiry of the European Commission On May 5, 2006 the European Commission started an inquiry in order to verify an alleged abuse of dominant position on the part of Eni in violation of Article 82 of the EEC Treaty and Article 54 of the CES Agreement in the activities of international gas transport and wholesale and retail supply of gas.

According to the European Commission Eni might have adopted commercial practices that constitute barriers to access to the Italian market for the wholesale supply of natural gas, in particular taking account Eni long-term purchase contracts. In addition Eni also entered long-term transport contracts which award Eni a majority share of transport capacity of the certain international gaslines and, as a consequence, Eni might have prevented others to access infrastructure.

In addition according to the European Commission, Eni might have delayed or annulled certain plans for the upgrading international transport infrastructure, despite the significant demand for access by third parties. This behavior would have favored natural gas commercial supplies downstream of transport activities thus allowing Eni to keep its dominant position in the market of wholesale sales.

Lastly, based on information held by the Commission, Eni might have subdivided the market with other companies operating in the supply and/or transport of natural gas, in particular by limiting the use of rights of access to entry and exit points of gas pipelines, in particular TENP and TAG.

Officials from the European Commission conducted inspections at headquarters of Eni and of certain Eni s subsidiaries and collected documents.

If the existence of the alleged anti-competitive practices is confirmed, the European Commission could fine Eni.

Transport

Transport tariffs With Decision No. 120 of May 30, 2001, the Authority for Electricity and Gas published the criteria which transport companies have to apply in determining natural gas transport and dispatching tariffs on national and regional transportation networks, for the first regulatory period made up of four thermal year (each thermal year begins on October 1 of each calendar year and ends on September 30), as provided for by Decree No. 164/2000. Tariffs are subject to approval by the same Authority, which ensures their compliance with preset criteria. This tariff system substituted preceding agreements between Eni and customers of any category. Within the first quarter of each calendar year, transport companies submit the tariff proposal to the Authority for Electricity and Gas which in turn approves or rejects the proposal of transport companies.

Criteria established by the Authority for Electricity and Gas provide for a cap on revenues from transport and dispatching activity ("allowed revenues") which is adjusted annually; those criteria also provide for a separate treatment of revenues on existing assets and on new capital expenditure on expansions and extension of infrastructure. In the first thermal year allowed revenues 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. Net capital employed is calculated by revaluating historic costs of transport infrastructure (pipelines, compressor stations and other support equipment) on the basis of certain inflationary indexes; resulting amounts are adjusted to take into account the residual useful life of assets (pipelines are estimated to have a useful life of 40 years) and also subtracting State grants. The application of this methodology implies an estimated value of Eni s transport assets of approximately euro 9.6 billion. This, however, is a valuation for regulatory purposes and should not be read as an indication of the market value of Snam Rete Gas. The rate of return on capital employed set by the Authority for Electricity and Gas was 7.94% (pre-tax), for the first regulatory period. Once established, allowed revenues for the first year are divided into two components: (i) capacity revenues equal to 70% of allowed revenues which are the maximum amount of revenues collectable from the sale of transport capacity to customers; and (ii) commodity revenues equal to 30% of allowed revenues which are the maximum amount of revenues collectable from transported volumes. Starting from the second year these two components are adjusted on a yearly basis to take into account inflation and certain reduction factors (set at 2% and 4.5% for capacity revenues and commodity revenues, respectively); commodity revenues are also adjusted to transported volumes of the current regulatory period. The 2% reduction factor on capacity revenues provides scope for improving results of operations of the transport company if cost reductions exceed the set amount, whereas the 4.5% reduction factor on commodity revenues provides scope for improving results of operations of the transport company if transported volumes grow more than the reduction factor. New capital expenditure in extension and expansion enable transport companies to increase the capacity revenue by a stated percentage in the regulatory period following the period in which new capital expenditure is incurred. In addition, those capital expenditures give rise to a six year fixed increase in allowed commodity revenues. At the end of the first regulatory period, all transport cost components were recalculated and 50% of higher cost reductions with respect to established efficiency improvements were recognized to transport companies and 50% were transferred to customers. Once the allowed revenues are established, transport companies define individual tariffs to clients which are based on a charge for the capacity used at the entry location (border, fields, storage sites) and the capacity used at interconnection nodes with regional networks (divided into 17 zones) and on a charge for the capacity used at regional level, providing for discounts to those outgoing the network at less than 15 kilometers from the interconnection point between regional and national networks. A further charge (commodity charge) is related to the amounts of gas transported plus an annual fixed charge varying according to the delivery points. This tariff system regulated the four-thermal year period starting October 1, 2001 and ending on September 30, 2005.

With the Decision No. 166/2005, the Authority for Electricity and Gas revised the outlined tariff regime for the second regulatory period (October 1, 2005-September 30, 2008). The new tariff structure confirms the breakdown of the tariff into two components: capacity and commodity in a ratio of 70 to 30 and the entry-exit model for the determination of the capacity component on the national pipeline network, already present in the previous tariff regime established by Decision No. 120/2001. The major new elements of the new regime are the following: (i) a reduction of the rate of return of capital employed in transport activities from 7.94% to 6.7% (pre-tax); (ii) a new set of incentives for new capital expenditure. In the previous regime, the return on upgrade and capacity expansion expenditure was 7.47% for one year only included in the calculation of the capacity component of the transport tariff and 4.98% for 6 years in the calculation of the commodity component. The new tariff structure provides an additional rate of return depending on the type of expenditure on the return rate recognized for capital employed: from a minimum of 1% for safety measures that do not increase transport capacity, applied for 5 years, to a maximum of 3% for expenditure that increases capacity at entry points into the national network, applied for 15 years. The additional return is part of the determination of the maximum allowed revenues in the calculation of the capacity component of the tariff and therefore is not influenced by changes in volumes transported; (iii) the updating by means of a price cap mechanism of the allowed revenues the transport undertaking is entitled to and the annual recalculation of the portion of allowed revenues relating to costs incurred for capital expenditure. This price cap mechanism applies to operating costs and amortization charges (previously it applied to all the allowed revenues). The annual rate of recovery of productivity was confirmed at 2%; this is used to reduce the effect of changes in the consumer price index on the updating of the preceding year s allowed revenues; instead the preset annual rate of change of productivity recovery for the updating of the commodity component of the tariff was reduced from 4.5% to 3.5% of; and (iv) confirmation of the tariff reduction for start-ups (construction/upgrade of combined cycle plants for electricity generation) and for off take in low season periods (from May 1, to October 31) already contained in Decisions No. 5/2005 and 6/2005 which updated the previous tariff regime. The companies active in the field of gas transport submit their tariff proposals to the Authority who grants approval, within the first quarter of each calendar year.

Network code With Decision No. 75 of July 1, 2003, the Authority for Electricity and Gas approved Snam Rete Gas Network Code, which defines rules and regulations for the operation and management of the transmission network. The Network Code, in accordance with Legislative Decree No. 164/2000, is based on the criteria set by the Authority for Electricity and Gas with Decision No. 137/2002, aimed at guaranteeing equal access to all customers, maximum impartiality and neutrality in transport and dispatching activities. The Network Code regulates entitlement of transport capacity, obligations of transporter and customer and the procedures through which customers can sell capacity to other users. Transport capacity at entry points in the national gasline network (point of interconnection with import gaslines) is assigned on an annual basis and can last up to five thermal years. Entities eligible to be assigned transport capacity on a multi-year basis are those having multi-year import contracts within the limit of their daily average contract volumes. Priority criteria envisage that available capacity is assigned first to parties in multi-year import contracts containing take-or-pay clauses signed before August 10, 1998 (date of coming in force of European Directive 98/30/CE). It requests for capacity in a given thermal year are higher than available capacity, a pro-rata mechanism is applied in compliance with the aforementioned priority.

Parties in annual or shorter import contracts and parties in multi-year import contracts are entitled to annual capacity conferrals corresponding to maximum daily contract volumes and the difference between maximum daily contract volumes and average daily contract volumes, respectively. Available transport capacity is assigned first to parties in annual import contracts and parties in multi-year import contracts. If requests for capacity in a given thermal are higher than available capacity, a pro-rata mechanism is applied in compliance with the aforementioned priority.

Eni filed a claim against this decision with the Regional Administrative Court of Lombardia, that was partially accepted with a decision of December 2004. The Authority filed a claim against this decision with the Council of State and informed Eni on February 19, 2005. This proceeding is still pending.

New tax criteria for the determination of amortizations for companies operating in transport and distribution of natural gas The criteria for the determination of the annual share of amortizations of natural gas transport and distribution assets deductible in the determination of income taxes have been changed starting in 2005 onwards by Law Decree No. 203 of September 30, 2005, converted into Law No. 248 of December 2, 2005 and Law No. 266 of December 23, 2005 (budget law for 2006). Due to these changes, the share of amortizations that was previously calculated based on rates set by a decree of the Minister of Finance of December 31, 1988, is now determined by dividing the relevant asset gross book value in accordance with the useful lives determined by the Authority for Electricity and Gas and reducing the amount obtained after tax by 20%. The alignment of the fiscal lives of natural gas transport and distribution assets to their useful lives entails the anticipation of the payment of income taxes given the postponement of the deductibility of amortization without impacting on net profit of companies involved (mainly Snam Rete Gas and Italgas), except for the financial charges related to this cash anticipation.

Regulation (EC) No. 1775/2005 On November 3, 2005 Regulation (EC) No. 1775/2005 concerning conditions for accessing international natural gas transport networks was published. The Regulation establishes non discriminatory access rules and will be effective starting on July 1, 2006. The Regulation will be directly applicable in each Member

State and national regulatory authorities will be responsible for its enactment.

Preliminary investigation on the management and operation of the Panigaglia LNG regasification terminal The Authority for Electricity and Gas with Decision No. 204 of November 18, 2004, started a preliminary investigation on the management and operation of Eni s Panigaglia LNG regasification terminal and on LNG supplies to the Italian market in the thermal years from 2001 to 2004 in order to ascertain any behavior infringing the rules of equal access and equal conditions and neutrality in providing the regasification services.

Adoption of guarantees for free access to LNG regasification services and rules for the regasification code With Decision No. 167 of August 1, 2005, the Authority for Electricity and Gas published the criteria for access to LNG regasification services. The Decision also defines criteria for the allocation of regasification capacity. In particular it establishes that take-or-pay contracts entered into before 1998, as in the case of Eni, are assigned a priority access limited to the minimum amount of volumes that have been regasified in the period starting from thermal year 2001-2002. Eni filed a claim against this decision with the Regional Administrative Court of Lombardia.

Regasification tariffs Tariffs for both the continuous and spot regasification services are based on treated volumes of LNG, number of discharges carried out and energy associated to volumes input in the national transport network. Tariffs for the spot service are 30% lower than those for continuous service.

Distribution

Distribution is the activity of delivering natural gas to residential and commercial customers of 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 Decision No. 237 dated December 28, 2000 as amended, the Authority for Electricity and Gas determined tariff criteria for natural gas distribution activity for the first regulated period ending on September 30, 2004. Tariffs are determined so that annual revenues from natural gas distribution activity cover operating costs and the remuneration of capital employed and are adjusted yearly according to the price cap method based on parameters and formulas determined by the Authority for Electricity and Gas. Capital employed is determined by applying a parameter-based method or, alternatively, a method of revalued historical cost for those companies that published audited financial statements starting with the fiscal year ended before January 1, 1991 (which include Italgas). With Decision No. 170 of September 29, 2004 the Authority for Electricity and Gas defined gas distribution tariffs for the second regulated period from October 1, 2004 to September 20, 2008, setting at 7.5% the rate of return on capital employed of distribution companies, as compared to the 8.8% rate set for the preceding regulated period. The rate of productivity recovery one of the components of the annual adjustment mechanism of tariffs was set at 5% of operating expenses and amortization charges (as compared to the 3% rate applied to total expenses and charges in the preceding regulated period). With Decision No. 122 of June 21, 2005, the Authority integrated and changed Decision No. 170/2004 defining a new determination mechanism for distribution tariffs that takes account of capital expenditure incurred by distributing companies.

Distribution network code With Decision No. 138/2004 the Authority for Electricity and Gas defined a set of rules to ensure free access to the distribution networks and neutrality of the distribution service, as well as criteria for the definition of distribution network codes.

With Decision No. 108/2006 the Authority for Electricity and Gas approved the Gas Distribution Master Code which will be used as a standard contract between distribution companies and shippers (natural gas selling companies). Within three months from its publication, distribution companies are due to issue their own gas distribution code adopting either the Gas Distribution Master Code or the scheme provided for by the Decision No. 138/2004.

Refining and Marketing of Petroleum Products

Refining Under Decree No. 112, 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 Decree No. 32 of February 11, 1998, as amended by Legislative Decree No. 348 of September 8, 1999 and Law Decree No. 383 of October 29, 1999, significantly changed Italian regulation of service stations. The Decree replaces the system of concessions granted by the Ministry of Industry, regional and local authorities with an authorization granted by city authorities. Legislative Decree No. 112/1998 confers the power to grant concessions for the construction and operation of service stations on highways 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 be 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; (iv) establishment of a fund for the restructuring of the sales network, in part financed through a contribution, in the 1998-2000 period. In 2002 the fund received new financings: the decree of the Minister of Productive Activities of August 7, 2003, implementing Law No. 237 of December 12, 2002, defined the amount of euro 0.0003 and euro 0.0001 for each liter of automotive fuel (gasoline, diesel fuel and LPG) sold in 2002 in the ordinary distribution network to be paid by authorization holders and service station managers, respectively. The latest payment date was set at December 31, 2003; (v) the opening up of the logistics segment by permitting third party access to unused storage capacity for petroleum products; and (vi) measures designed to increase competition on the market for LPG for residential, industrial and agricultural users. With the goal of renewing the Italian distribution network, Law No. 57/2001 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 Decree was issued on October 31, 2001 and established 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.

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 and service station operators, and such recommendations are considered by service station operators in establishing retail prices for petroleum products. With Ministerial Decree dated February 16, 2000, an entity was established that supports the Ministry of Productive Activities in monitoring trends in domestic and international prices of oil and oil products. Furthermore, in order to avoid initiatives inhibiting competition, Law No. 57/2001 provides the compliance with EU Regulation No. 2790/1999 concerning "vertical agreements" on economic relations between operators in this area. To date, this regulation has had no significant impact on Eni s operations.

Compulsory Stocks According to Legislative Decree of January 31, 2001, No. 22 ("Decree 22/2001") enacting European Directive No. 98/1993 (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 of Productive Activities 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.

Decree No. 32 of February 11, 1998 established an entity responsible for the maintenance and management of this compulsory stock whose main tasks are to: (i) distribute stocks on the national territory according to available storage sites and consumption levels; (ii) meet the demand for refined products in case of crisis; (iii) guarantee storage volumes to operators; and (iv) record demand for refined products in the various areas of Italy. The Agency has been created on June 14, 2001; its by-laws had been approved with a Ministerial Decree of January 29, 2001 and its operating regulation has been approved on May 20, 2003 by the general meeting of the Agency s members.

At December 31, 2005 Eni owned 7.2 million tonnes of oil products inventories, of which 4.8 million tonnes as "compulsory stocks", 1.0 million tonnes related to operating inventories in refineries and depots (including 0.2 million tonnes of oil products contained in facilities and pipelines), 1.1 million tonnes related to oil products contained in ships and 0.3 million tonnes related to specialty products.

Eni s compulsory stocks (at December 31, 2005) were held in term of crude oil (27%), light and medium distillates (44%), fuel oil (22%) and other products (7%) and they were located throughout the Italian territory both in refineries (75%) and in storage sites (25%).

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Property, Plant and Equipment

Eni has freehold and leasehold interests in real estate in numerous countries throughout the world, but no one individual property is material to Eni as a whole. See "Exploration & Production" above for a description of Eni s reserves and sources of crude oil and natural gas.

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Organizational Structure

Eni SpA is the parent company of the Eni group companies. As of December 31, 2005, there were 257 fully consolidated subsidiaries, 94 subsidiaries accounted for under either the equity method or the cost method and 176 affiliates accounted for under either the equity method or the cost method. The significant subsidiaries, associated undertakings and joint ventures of the Eni Group controlled directly or indirectly by Eni at December 31, 2005 and included in the scope of consolidation, as well as Eni s percentage of equity capital or joint venture interest (rounded to the nearest whole number) are set forth in the table below. The principal country of operation is generally indicated by the company s country of incorporation or by its name.

Company/Undertaking	Country of Incorporation	%
Exploration & Production		
Stoccaggi Gas Italia SpA	Italy	100
Eni Oil Algeria Ltd	the Netherlands	100
Eni Angola Exploration BV	the Netherlands	100
Agip Caspian Sea BV	the Netherlands	100
Eni Congo SA	the Netherlands	100
Eni Dación BV	the Netherlands	100
Lasmo Sanga Sanga Ltd	Bermuda	100
Eni Iran BV	the Netherlands	100
Agip Karachaganak BV	the Netherlands	100
Eni Lasmo Plc	the United Kingdom	100
Eni LNS Ltd	the United Kingdom	100
Eni North Africa BV	the Netherlands	100
Agip Oil Ecuador BV	the Netherlands	100
Eni Petroleum Co Inc	USA	100
Eni UK Ltd	the United Kingdom	100
Ieoc Production BV	the Netherlands	100
NAOC Nigerian Agip Oil Co Ltd	Nigeria	100
Eni Norge A/S	Norway	100
Gas & Power		
Snam Rete Gas SpA	Italy	50
Società Italiana per il Gas pA	Italy	100
Distribuidora de Gas Cuyana SA	Argentina	46
Gas Brasiliano Distribuidora SA	Brazil	100
Greenstream BV	the Netherlands	75
Inversora de Gas Cuyana SA	Argentina	76
Tigáz Rt Tiszántúli Gázszolgáltató Részvénytársaság	Hungary	50

EniPower SpA	Italy	100
Refining & Marketing		
AgipFuel SpA	Italy	100
Ecofuel SpA	Italy	100
Eni Portugal Investment SpA	Italy	100
Agip Deutschland GmbH	Germany	100
Agip España SA	Spain	100
Agip Française SA	France	100
American Agip Co Inc	USA	100
Petrochemicals		
Polimeri Europa SpA	Italy	100
Dunastyr Polystyrene Manufacturing Co Ltd	Hungary	100
Polimeri Europa Benelux SA	Belgium	100
Polimeri Europa Elastomères France SA	France	100
Polimeri Europa UK Ltd	the United Kingdom	100
Oilfield Services Construction and Engineering		
Saipem SpA	Italy	43
Snamprogetti SpA	Italy	100
CEPAV (Consorzio Eni per l Alta Velocità) Uno	Italy	50
Saipem SA	France	43
Other Activities		
Syndial SpA - Attività Diversificate	Italy	100
EniTecnologie SpA	Italy	100
Sieco SpA	Italy	100
Tecnomare - Società per lo Sviluppo delle Tecnologie Marine SpA	Italy	57
Corporate and financial companies		
Eni International BV	the Netherlands	100
Eni Coordination Center SA	Belgium	100
Società Finanziaria Eni SpA - Enifin	Italy	100
Società Finanziamenti Idrocarburi - Sofid-SpA	Italy	100

Item 4A. UNRESOLVED STAFF COMMENTS

None.

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Item 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

The information in this item should be read together with the Key Information presented in Item 3 and the Consolidated Financial Statements and related Notes thereto included in Item 18.

Executive Summary

Eni recorded a net profit of euro 8.8 billion in 2005, an increase of 24.5% over 2004. Operating profit in 2005 amounted to euro 16.8 billion, up 35.7% from 2004 reflecting volume growth and performance improvements in Eni s main businesses combined with a favorable trading environment characterized by strong gains both in crude oil prices and in refining margins.

On the basis of the results achieved, Eni s management proposed at the Annual General Shareholder Meeting a dividend of euro 1.1 per share, of which euro 0.45 was already paid as an interim dividend in October 2005. This dividend is 22% higher than in 2004 (euro 0.90 per share) and was approved by the Annual General Shareholder Meeting on May 25, 2006.

In Exploration & Production, Eni continued to build on its established position in some of the world s fastest-growing producing nations of oil and natural gas. Eni s daily production of oil and natural gas available for sale increased by 6.7% over 2004 to 1,693 KBOE. Net proved reserves of oil and natural gas were 6,837 mmBOE at year end 2005 (55% crude and condensates), down 381 mmBOE from 2004 due principally to an adverse entitlement impact in certain production sharing agreements and buy-back contracts as a result of higher oil prices which reduced Eni s entitlement to volumes of oil and natural gas to recover costs incurred by Eni for the development of certain oil fields. The reserve replacement ratio was 40%. The reserves life index at year end 2005 was 10.8 years (12.1 years at December 31, 2004).

Eni increased its interest in the Kashagan project (Kazakhstan) from 16.67% to 18.52%. Management believes Kashagan to be a very important project for the future growth of Eni s production of oil and natural gas. The development of the project, of which Eni is the sole operator, is on track, with 40% of work completed, and management plans to achieve first oil production by end-2008. Management is currently reviewing the planned $29 billion capital expenditure for the development of this large field in order to take account of changing market conditions.

Eni added to its exploration portfolio with the acquisition of assets in areas such as Libya, Nigeria and Angola where Eni s presence is already established, and in new basins such as Alaska and India.

In Gas & Power, Eni continued to leverage on its assets consisting of access to infrastructure, availability of gas both from owned facilities and from long term purchase contracts and large customer base, to increase natural gas sales in European gas markets.

Overall gas sales in 2005 totalled 91.15 BCM, up 8.8% from 2004. This growth has been driven by European gas sales and by larger volumes sold in Italy:

- gas sales across Europe (31.29 BCM) rose 11.2% as compared to 2004, driven also by the build up of the Greenstream project; and
- Italian gas sales (58.01 BCM, including own consumption) increased by 8% from 2004, mainly driven by gas consumption in our power business, and gas sales in South America were stable at 2 BCM.

Electricity sales (22.8 TWh) increased by 64% in volume terms from 2004 as a result of the start-up of two power units at the Mantova power plant and the first unit of the Brindisi plant, as well as full commercial operation at the

Ravenna and Ferrera Erbognone plants.

In Refining & Marketing, Eni is seeking to increase return from assets by upgrading its refining system, increasing integration with Exploration & Production activities and strengthening its competitive position in marketing.

In 2005, Eni completed the construction of the Sannazzaro gasification plant and the disposal of its wholly-owned subsidiary Italiana Petroli which operates in the retail market in Italy. Overall retail sales in Europe under the Agip brand in 2005 amounted to 16 billion liters, of which 11.3 billion liters were in Italy. Retail sales increased 0.6% from 2004 reflecting higher sales in certain markets of Central Europe and in Spain.

In Engineering & Construction, Saipem was awarded important contracts in complex environments such as Kashagan in Kazakhstan and Sakhalin in Russia. Snamprogetti significantly increased its backlog, closing 2005 with strong financial results.

Capital expenditure totalled 7.4 billion in 2005, in line with 2004; 91% of capital expenditure was carried out in oil and gas activities. The principal projects for the year were:

- development of oil and natural gas reserves (euro 3.95 billion), mainly in Kazakhstan, Libya, Angola, Egypt and Italy, as well as exploration (euro 656 million) and the acquisition of proved and unproved property reserves (euro 301 million, of which euro 161 million was for the acquisition of an additional 1.85% share in the consortium developing Kashagan);
- expansion and improvements of the natural gas transportation and distribution network in Italy (euro 825 million);
- ongoing power generation construction programme (euro 239 million); and
- upgrading of our Italian refining and logistics system to enhance flexibility and increase the yields of light products and middle distillates, including completion of the heavy residue gasification plant at the Sannazzaro refinery and improvement of the retail distribution network both in Italy and in the rest of Europe (euro 656 million).

Margin[10]

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 petrochemicals products). Margin trends reflect the trading environment and are, to a certain extent, a gauge of industry profitability.

Trading Environment

	2003	2004	2005
Average price of Brent dated crude oil (1)	28.84	38.22	54.38
Average price in euro of Brent dated crude oil (2)	25.50	30.72	43.71
Average EUR/USD exchange rate (3)	1.131	1.244	1.244
Average European refining margin (4)	2.65	4.35	5.78
EURIBOR three month euro rate % (3)	2.3	2.1	2.2

(1) In U.S. dollars per barrel. Source: Platt s Oilgram.

(2) Source: Eni s calculations.

(3) Source: European Central Bank.

(4) In U.S. dollars per barrel. FOB Mediterranean Brent dated crude oil. Source: Eni calculations based on Platt s Oilgram data.

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". The trading environment was generally favorable in 2005 with prices of Brent crude oil increasing by approximately 42% compared to 2004. Natural gas demand in Italy increased by approximately seven percentage points over 2004 driven by strong growth in the electricity generation. Natural gas margins in Italy decreased in 2005 as compared to 2004 due to competitive pressure in the domestic natural gas market, offset in part by favorable trends in prices of certain refined products to which natural gas sale and purchase prices are contractually indexed resulting in a higher increase of selling prices as compared to supply costs when comparing 2005 to 2004. In 2005, refining margins increased sharply due to strong demand for refined products, especially in Asia, a shortage of fuels meeting required European specifications due to lags in the upgrading certain refineries and imbalances in the availability of products in different areas of the world. Petrochemical product margins declined in 2005 as compared to 2004, essentially due to the higher cost of oil-based feedstocks not being completely reflected in to selling prices.

Key consolidated financial data

(million euro)		2004	2005
Net sales from operations		57,545	73,728
Operating profit		12,399	16,827
Net profit		7,059	8,788
Net cash provided by operating activities		12,500	14,936
Capital expenditure		7,499	7,414
Investments		316	146
Shareholders equity including minority interest		35,540	39,217
Net borrowings [1]		10,443	10,475
Net profit per share	(euro per share)	1.87	2.34
Dividend per share	(euro per share)	0.90	1.10
Net borrowings to total shareholders equity ratio including minority interests (leverage) [1]		0.36	0.33

(1) 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.

The adoption of IFRS

The Consolidated Financial Statements of Eni have been prepared in accordance with IFRS issued by the International Accounting Standards Board (IASB) and adopted by the European Commission following the procedure contained in Article 6 of the EC Regulation No. 1606/2002 of the European Parliament and Council of July 19, 2002. The IFRS adopted by Eni differ in certain limited respects from the IFRS sanctioned by the IASB. Until December 31, 2004, Eni prepared its Consolidated Financial Statements and other interim financial information (including quarterly and semi-annual data) in accordance with Italian GAAP. IFRS require adopting companies to restate only one year of past financial statements. Pursuant to SEC Release 33-8567, "First-time Application of International Financial Reporting Standards", Eni is not required to include in this annual report financial statements for any earlier periods. Accordingly this annual report includes financial information prepared in accordance with IFRS as of and for the two years ended December 31, 2004 and 2005. For hydrocarbon exploration and production, accounting policies generally applied by the oil industry have been adopted, with particular reference to amortization according to the

Unit-Of-Production (UOP) method, buy-back contracts and Production Sharing Agreements. The Consolidated Financial Statements have been prepared by applying the cost method except for items that under IFRS must be recognized at fair value as described in the Notes to the Consolidated Financial Statements under the heading "Evaluation Criteria".

The general principle that should be applied on first-time adoption of IFRS is that standards in force at the transition date (January 1, 2004) should be applied retrospectively. However, IFRS 1 "First-time Adoption of International Financial Reporting Standards" (IFRS 1) contains a number of exemptions that companies are permitted to apply. Eni has taken the following main exemptions:

- no retroactive restatement of business combinations that occurred before January 1, 2004. As a result of this exemption, goodwill was not restated to take into account amortization charges recorded in previous periods before the adoption of IFRS; and
- the election of January 1, 2005 as the transition date for the first application of IAS 32 and IAS 39, related to the evaluation of financial instruments, including derivatives. As permitted under IFRS 1, Eni has not restated comparative information. In the Consolidated Financial Statements for the year ended December 31, 2005 the impact of recording certain derivative financial instruments at fair value, as is required by IAS 39, was a euro 386 million charge in the profit and loss account. For further information see "Consolidated Financial Statements Effects of the adoption of IFRS and Evaluation Criteria".

The IFRS under which Eni s Consolidated Financial Statements have been prepared differ in certain limited respects from the IFRS adopted by the IASB, the effect of such differences on the Consolidated Financial Statements is not material.

Critical Accounting Estimates

The preparation of these consolidated financial statements requires Management to apply accounting methods and policies that are based on difficult or subjective judgments, estimates based on past experience and assumptions determined to be reasonable and realistic based on the related circumstances. The application of these estimates and assumptions affects the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of income and expenses during the reporting period. Key areas where estimates are applied include the determination of oil and gas proved reserves and proved developed reserves, accounting for exploratory drilling costs under U.S. GAAP, impairment of fixed assets, intangible assets and goodwill, asset retirement obligations, business combinations, recognition of environmental liabilities and recognition of revenues in the oilfield services construction and engineering businesses. Actual results may differ from these estimates given the uncertainty surrounding the assumptions and conditions upon which the estimates are based. Summarized below are the accounting estimates that require the more subjective judgment of our management. Such assumptions or estimates regard the effects of matters that are inherently uncertain and for which changes in conditions may significantly affect future results.

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 with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Although there are authoritative guidelines regarding the 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 judgment.

Reserves in a field will only be categorized as proved when all the criteria for attribution of proved status have been met, including an internally imposed requirement for project sanction that occurs when a final investment decision is made. At the point of sanction, all booked reserves will be categorized as proved undeveloped. Volumes will subsequently be recategorized 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. Adjustments may be made to booked reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

Eni reassesses its estimate of proved reserves on an annual basis. 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 as regards the initial estimate and, in the case of Production Sharing Agreements and buy-back contracts, the share of production and reserves Eni is entitled to. 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 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 year and proved developed reserves existing at the year end increased by the amounts extracted during the year. Assuming all other variables are held constant, an increase in estimated proved reserves decreases depreciation, depletion and amortization expense. On the contrary, a decrease in estimated proved reserves increases depreciation, depletion and amortization expense. Also, estimated proved reserves are used to calculate future cash flows from oil and gas properties, which serve as an indicator in determining whether a property impairment is to be carried out or not. The larger the volumes of estimated reserves, the less likely the property is impaired. See "Item 3 Risk Factors Uncertainties in Estimates of Oil and Natural Gas Reserves".

Accounting for Suspended Well Costs under U.S. GAAP

Under U.S. GAAP costs for exploratory wells are initially capitalized pending the determination of whether the well has found proved reserves. If proved reserves are found, the capitalized costs of drilling the well are reclassified to tangible assets and amortized on a UOP basis. If proved reserves are not found, the capitalized costs of drilling the well are charged to expense. However, successful exploratory efforts are, in many cases, not declared to be proved until after an extensive and lengthy evaluation period has been completed. These issues were addressed by the FASB staff in its FSP FAS 19-1, published in April 2005, amending FAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies". Under the provisions of FSP FAS 19-1, companies in the oil and gas industry are allowed to continue capitalization of an exploratory well after the completion of drilling when: (a) the well has found a sufficient quantity of reserves to justify completion as a producing well; and (b) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. Determination of whether an exploratory well should remain capitalized after completion of drilling requires a high degree of judgment on the part of management in assessing whether the Company is making sufficient progress assessing the reserves and the economic and operating viability of a given project. The company evaluates the progress made on the basis of regular project reviews which take account of the following factors: (i) costs are being incurred to assess the reserves and their potential development; (ii) existence (or active negotiations) of sales contracts with customers for oil and natural gas; and (iii) existence of firm plans, established timetables or contractual commitments, which may include seismic testing and drilling of additional exploratory wells. As of December 31, 2005, an amount of euro 403 million remain capitalized relating to approximately 30 exploratory wells for which drilling activities have been completed for more than one year, of this capitalized amount euro 59 million (or 8 wells) relates to projects progressing towards completion of development activities, and the remaining euro 344 million (or 22 wells) relates to projects for which additional exploratory activity is underway or firmly planned. See Note 35 to the Consolidated Financial Statements.

Impairment of Assets

Eni assesses its fixed 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 and, for oil and gas properties, significant downward revisions of estimated proved reserve quantities. 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.

Technically, the amount of an impairment charge 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 costs and value in use. The estimated value in use is usually based on the present values of expected future cash flows using assumptions commensurate with the risks involved in the asset group. The expected future cash flows used for impairment reviews 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.

For oil and natural gas properties, the expected future cash flows are estimated 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. The estimated future level of production is based on assumptions about future commodity prices, lifting and development costs, field decline rates, market demand and supply, economic regulatory climates and other factors.

Under both IFRS and U.S. GAAP, goodwill is not amortized but, like indefinitive lived intangible assets, is tested for impairment at least annually. Under IFRS the assessment of goodwill impairment is based on the determination of the fair value of each cash generating units to which goodwill can be attributed on a reasonable and consistent basis. A cash generating unit is a group of assets that generates cash inflows that are largely independent of the cash inflows from other groups of assets. If the fair value 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 generating unit are impaired on a pro-rata basis for the residual difference.

Asset Retirement Obligations

Obligations related to the removal of tangible equipment and to the restoration of land or seabeds require significant estimates in calculating the amount of the obligation and determining the amount required to be recorded in the Consolidated Financial Statements. Estimating the future asset removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years into the future and contracts and regulations are often unclear as to what constitutes removal. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public relations considerations. 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 obligations in the period when it is incurred (typically at the time the asset is installed at the productions 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 (interest accretion) and any change of the estimates following the modification of the future cash flows and the discount rate adopted. The recognized asset retirement obligations are based upon future retirement cost estimates and incorporate many assumptions such as expected recoverable quantities of crude oil and natural gas, time to abandonment, future inflation rates and the risk-free rate of interest adjusted for the Company s credit costs.

Business Combinations

Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business at fair value. Any positive residual difference is recognized as "Goodwill". Negative residual differences are charged against profit and loss account. Management uses all available information to make these fair value determinations and, for major business acquisitions, typically engages an outside appraisal firm to assist in the fair value determination of the acquired long-lived assets.

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, productions and other activities, including legislation that implements 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.

Although management, considering the actions already taken, the insurance policies to cover environmental risks and provision for risks accrued, does not expect any material adverse effect on Eni s consolidated results of operations and financial position as a result of such laws and regulations, 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 as yet unknown contamination; (ii) the results of the on-going surveys and the other possible effects of statements required by Decree No. 471/1999 of the Ministry of Environment concerning the remediation of contaminated sites; (iii) the possible effect of future environmental legislation and rules, like the Decree No. 367 of the Ministry of Environment, published on January 8, 2004, that introduces new quality standards for aquatic environment and dangerous substances and those that may derive from the legislative decree that the Italian Government will have to enact in order to implement Directive 2000/60/EC creating a framework for joint European action in the area of water; (iv) the effect of possible technological changes relating to future remediation; and (v) the possibility of litigation and the difficulty of determining Eni s liability, if any, as against other potentially responsible parties with respect to such litigation and the possible insurance recoveries.

Employees post-retirement benefits

Employees benefits (such as pension payments, life insurance payments, medical assistance after retirement, etc.) are evaluated with reference to uncertain events and based upon actuarial assumptions including among others discount rates, expected rates of return on any plan assets, expected rates of salary increases, medical cost trend rates, estimated retirement dates, mortality rates. These assumptions are reviewed annually and may change from year to year impacting future results of operations.

The significant assumptions used to account for pensions and other post-retirement benefits are determined as follows:

- discount and inflation rates reflect the rates at which the benefits could be effectively settled, taking into account the duration o f the obligation. Indications used in selecting the discount rate include rates of annuity contracts and rates of return on high-quality fixed-income investments (such as government bonds). The inflation rates reflect market conditions observed country by country;
- salary increase assumptions (when relevant) are determined by each entity. They reflect an estimate of the actual future salary levels of the individual employees involved, including future changes attributed to general price levels (consistent with inflation rate assumptions), productivity, seniority, promotion and other factors;
- healthcare cost trend assumptions (when relevant) 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;
- demographic assumptions such as mortality, disability and turnover reflect the best estimate of these future events for the individual employees involved, based principally on available actuarial data; and
- determination of expected rates of return on assets is made through compound averaging. For each plan, there are taken into account the distribution of investments among bonds, equities and cash and the expected rates of return on bonds, equities and cash. A weighted-average rate is then calculated.

Differences between projected and actual costs and between the projected return and the actual return on plan assets routinely occur and are called actuarial gains and losses.

The unrecognized actuarial losses of pension benefits as at December 31, 2005 were euro 144 million compared to euro 41 million in 2004. The euro 103 million increase from 2004 reflected primarily changes in assumptions used to account for pensions and other post-retirement benefits mainly related to the decrease in discount rates (4.0% in 2005 compared with 4.5% in 2004). Pension accounting principles require that such actuarial losses be deferred and amortized over future periods. Eni applies the corridor method to amortize its actuarial losses and gains. This method amortizes the net cumulative actuarial gains and losses 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.

In 2005, Eni recognized a charge of euro 126 million (euro 118 million in 2004) in the profit and loss account in connection with its obligations for employee post-retirement benefits.

See Note 20 of the Consolidated Financial Statements for further information about employees post-retirement benefits.

Contingencies

In addition to accruing the estimated costs for asset retirement obligation and environmental liabilities, Eni accrues for all contingencies that are both probable and estimable. These other contingencies are primarily related to employee benefits, litigation and tax issues. Determining appropriate amounts for accrual is a complex estimation process that includes subjective judgments.

Revenue recognition in the Oilfield Services, Construction and Engineering segment

Revenue recognition in the Oilfield Services, Construction and Engineering business 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 deducing 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 condition in that region and any assessment that it is necessary to estimate with sufficient precision the total future costs as well as the expected timetable. Variation in the scope of the work, are included in the total amount of revenues when it is probable that the customer will approve the variation and claims deriving for additional costs are included in the total amount of revenues when it is probable that they will result in additional revenue.

Results of Operations

Profit and loss Account for Two Years ended December 31, 2005

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,	
	2004	**2005**
	(million euro)	
Net sales from operations	57,545	73,728
Other income and revenues [1]	1,377	798
Total revenues	58,922	74,526
Operating expenses	(41,592)	(51,918)
Depreciation, amortization and writedowns	(4,931)	(5,781)
Operating profit	12,399	16,827