Autorità per l'energia elettrica e il gas

ANNUAL REPORT
TO THE EUROPEAN COMMISSION
ON THE STATE OF THE SERVICES AND ON THE REGULATION
OF THE ELECTRICITY AND GAS SECTORS

31 July 2005

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1 FOREWORD

This document contains the Authority for Electricity and Gas (AEEG) report to the Commission on the state of the Italian electricity and gas markets in accordance with the provisions contained in articles 3, 4, 23(1) and 23(8) of Directive 2003/54/EC for the electricity sector and articles 3, 5 and 25(1) of Directive 2003/55/EC for the natural gas sector.

The structure of the report follows the guidelines provided by the European Commission's Directorate-General for Energy and Transport. After a brief description of the AEEG's institutional role and recent regulatory developments in the energy market, the report analyses the main structural development taking place in the two markets of electricity and gas.

In the electricity sector, 2004 was a particularly significant year since it saw the start of operations on the Italian Power Exchange (IPEX), with the launch of the electricity market in April 2004 opening a new stage in the liberalisation process. The new framework of reference should provide market operators with efficient price signals that encourage the reconversion of existing plants and provide a decisive impetus for the many anticipated new plant construction projects. The need to provide a stable economic framework was a key priority, especially following the "scheduled disconnections" and widespread blackouts that characterised much of 2003.

A series of structural problems still remain in the market, however – as evidenced by the investigation carried out by the AEEG in conjunction with the Antitrust Authority (AGCM) – connected with the influence of the dominant operator, which continues to weigh heavily in many of the geographical areas into which the Italian electricity market is divided. The transition period leading to full liberalisation will therefore need to be monitored carefully to avoid abuses of dominant position and commercial strategies on the part of the incumbent that might create barriers to the entry of new operators.

It should also be noted that in 2004 the process of drawing up provisions to transpose EC regulation 1228/2003 was begun and completed. These provisions envisage market mechanisms to regulate our country's interconnections with abroad and the resolution of congestions, in accordance with the provisions of articles 5 and 6 of the Regulation. More specifically, it is now envisaged that congestions on the interconnection network should be resolved by a market method based on the implicit auction system. This solution makes it possible to select offers and bids from foreign operators on the basis of criteria of economic efficiency.

With respect to the gas market, the liberalisation process is struggling to get fully under way. This can mainly be explained by the high degree of market concentration and the marked rigidities in access to the international networks transporting natural gas to Italy. The vertical integration of the incumbent's foreign activities severely limits the scope for competition of the Italian natural gas market. As evidenced in the investigations carried out, significant difficulties are emerging for new operators seeking to enter the market as a result of the low availability of import capacity, with what there is largely occupied by long-term contracts concluded by the incumbent prior to Directive 98/30/EC. Access to transnational gas pipelines is for Italy, and more in general for the European market, a decisive factor in achieving an acceptable minimum level of competition.

In the Italian markets for both electricity and gas the principles governing the unbundling of significant infrastructure activities have been adopted in advance with respect to the objectives set by the new directives. From the point of view of quality, the new regulatory framework of the electricity and gas market has enabled a considerable improvement in service quality throughout the country and provided all Italian consumers with greater continuity of supply and the application of improved commercial standards.

As a more stable regulatory and market framework is progressively achieved it will be possible to strengthen the investment policies adopted by market operators, to the benefit of a sustainable competition model for users of the service.

2 SUMMARY / MAJOR DEVELOPMENTS OVER THE LAST YEAR

Organisational structure of the regulatory body

Composition of the board and staffing structure of the AEEG

The AEEG's organisational structure was initially established by its founding law, Law 481 of 14 November 1995. Under this law the board was composed of a president and two members and the payroll was to consist of 80 permanent full-time staff and 40 set-term employees. Law 239 of 23 August 2004 altered the organisational structure: the board was increased by two members and as a result will now be composed of the president and four members[1]. With the new provisions the number of full-time staff on the AEEG's payroll also increased, to 120, while the number of staff on set-term contracts has risen to 60[2].

The AEEG's mandate

The AEEG's mandate was established in Article 1 of 481/1995, whereby the AEEG is required to ensure that competition and efficiency are promoted in public utility services, under economically viable conditions, by guaranteeing their uniform availability and distribution throughout the country, through a transparent and reliable system of tariffs based on set criteria designed to promote the protection of users' and consumers' interests. The tariff system should also reconcile the economic and financial objectives of operators with general objectives of a social nature, and of environmental protection and the efficient use of resources. The AEEG operates with due consideration for the EU regulations governing these matters and the general policies laid down by the Government.

Powers

Law 481/1995 provides that the AEEG should:

- set and up-date tariffs for non-eligible consumers;
- define the conditions for the use of network services and ensure non-discriminatory access by users;
- issue directives for the accounting and administrative unbundling of the activities carried out by regulated parties;
- establish minimum service quality levels and monitor compliance with obligations;
- monitor the operation of public utility services by operators;
- settle disputes between users and regulated parties;
- apply penalties to regulated parties if they fail to comply with its provisions.

[1] Following the resignation of one member (Fabio Pistella) in July 2004, and pending the appointment of the two additional members envisaged by Law 239/2005, the board of the AEEG is at present composed of the president Alessandro Ortis and member Tullio Maria Fanelli.

[2] Article 1.118.

Independence and responsibilities

The AEEG operates with full autonomy and independence of judgement in its sectors of competence, subject only to EU legislation and the general policies laid down by the Government.

The AEEG reports each year to the Parliament and to the Prime Minister through the presentation of an annual report on the state of the services and the activity carried out. The latest report was presented on 23 June 2005.

Law 239/2004 introduced some new features and defined more precisely some elements of the AEEG's activity and operations. More specifically, it envisages that the state can make use of the AEEG's consultative and advisory role and specifies that if the AEEG does not express its opinion within 60 days of receiving such requests, the provisions in question may be adopted by the Government. Similarly, Law 239 establishes that if the AEEG does not adopt acts or provisions for which it is competent pursuant to the current legislation, the Government should adopt the provisions in question.

With respect to the AEEG's tasks the law provides that the Government should inform it of the development needs of the public utility services provided by the electricity and gas sectors in the general national interest. It also provides that the Council of Ministers can establish general policies for the performance of the functions attributed to the AEEG. And finally, it brings forward the deadline for the presentation of the annual report to the end of June (rather than the end of July).

Overlaps with the role of other public bodies

The legal framework is fairly clear and there is no duplication of responsibility with other public bodies, such as might arise in the event of ambiguity in the definition of institutional functions. Nevertheless, in some exceptional cases the situation has arisen where decisions taken by other institutions have affected the AEEG's regulatory activity. For example, with the recent decision to modulate the payment in the electricity tariff of general costs relating to electricity companies' stranded costs, the action of the Government to some extent overlapped with that of the AEEG. Similarly, Law 80 of 14 May 2005, concerning competition, envisaged special tariff conditions for the supply of high-voltage electricity for the production of aluminium, lead, silver and zinc and for the electro-chemical chlorine cycle in Sardinia.

Evolution of the electricity and gas markets

Demand and supply of electricity and gas

In 2004 demand for electricity grew by just 0.4% on 2003, an anomalous year from the climatic point of view. Compared with previous years, demand continued to grow without diverging notably from the long-term historic trend, of 2.5% per year on average. The problems of scarce supply that had emerged in the summer of 2003 were not repeated, even though electricity imports were lower. Installed capacity in fact increased significantly and the management of the country's electricity generating plants improved (especially with respect to power station maintenance programmes), with the aim of increasing reserves near to peaks in demand.

Electricity generation increased by 2.2%, partly as a result of the higher contribution from hydro-electric production after two years of severe water shortages. Following the entry of new plants into service and the completion of conversion works on existing ones, the contribution made by gas to electricity generation increased, reaching 43% of gross production (compared with 24% in 1997). Coal generation also increased (by 16.5% on 2003), as an effect of the greater use of solid fuels in multi-fuel thermoelectric power plants. Electricity generation from fuel oil, on the other hand, declined sharply and indeed for the first time was overtaken even by coal.

The market for electricity production shows a fairly high degree of concentration, with the first 6 national groups covering 80% of thermoelectric generation. The wholesale market is also relatively concentrated, with 6 operators covering nearly 60% of sales. Merger and acquisition operations currently under way could also lead to a further increase in concentration.

Demand for natural gas grew by 3.8%, essentially in relation to the increase in electricity production from natural gas, to over 80 G(m^3) in 2004. The continuous fall in domestic production (13 G(m^3) had to be met by an increase in imports to 67 G(m^3)), which translates into 84% of total demand.

The wholesale market for gas is highly concentrated, with 6 operators covering 92% of sales. Eni provided the market with 66% of the national requirement (including consumption by related companies), a figure that rises to nearly 80% if sales abroad to competitors who subsequently imported and re-sold the gas in Italy are included. The retail market is, by contrast, much more fragmented, with 353 operators. 46% of final sales are covered by the first 4 operators, and 84% by the first 41. However, a process of concentration is under way, which produced a fall of 14% in the number of vendors in 2003 and of 18% in 2004.

Legislative developments

The most significant legislative developments in the period 1 January 2004–30 June 2005 include the law concerning the "Reorganisation of the energy sector, and enabling authority to the Government to review the provisions currently in force in energy matters" (Law 239/2004). This law, which had a parliamentary gestation period of over two years, was issued in August 2004 and addresses the energy sector as a whole. Its main objective is to clarify the framework of laws governing relations between the various institutions and between them and energy sector operators, with the aim of simplifying and streamlining authorisation processes and driving forward the on-going liberalisation process with due respect for the principles designed to ensure the protection of competition, essential levels of service and public safety.

One of the key aims of the law concerns coordination between central government and regional and local government. Pending the definitive structure of relations between the different levels of government, the law gives the state the task of establishing the general objectives and energy policies that should inspire the action of central government and the Regions. It also establishes the general criteria for the implementation of this action at the local level, distinguishing between the tasks assigned to the state and those delegated to the regional authorities, as well as mechanisms for liaison with and between the regions. On the demand side, the law extends the rules on the opening of the electricity market to all consumers with effect from July 2007, as envisaged by EU Directive 2003/54/EC, and provides for measures to support efficiency in final uses of energy. On the supply side, it contains clearly defined provisions designed to:

- foster access by new entrants to the gas market, by promoting investment in new supply infrastructure and introducing a special system for access to new regasification terminals and interconnection pipelines;
- facilitate the construction of new electricity and interconnection lines through simplified procedures;
- strengthen the rules for dealing with electricity emergencies;
- intensify actions to diversify energy sources, including through exploration for and exploitation of hydrocarbons;
- foster the increased use of renewable sources, distributed electricity production and the clean use of coal.

In 2004 two ministerial decrees concerning the promotion of savings and efficiency in the final uses of electricity and natural gas were issued, the implementation of which is delegated to the AEEG. The aim of these decrees is to achieve, by the end of 2009, an energy saving equivalent to the annual increase in total national consumption from 1999 to 2001. The decrees impose quantitative requirements for primary energy savings by electricity and natural gas distributors, to be achieved by developing projects in favour of energy consumers or by purchasing energy efficiency certificates from third parties attesting to the achievement of energy savings by such parties.

Legislative actions in the course of the year also include the Ministry for Productive Activities decree of 6 August 2004 concerning stranded costs in the electricity sector.

Developments in the electricity market

In April 2004, after a delay of three years with respect to the provisions of Legislative Decree 79 of 16 March 1999 transposing European Directive 96/92/EC in Italy, the Power Exchange was finally opened. In 2004 participation by operators in trading on the Exchange was limited on a transitional basis solely to sales bids/offers and with reference to dispatch points for production units with a generating capacity of over 10 MVA. Participation by the demand side, with the negotiation of purchase bids by consumers or their intermediaries, began in January 2005, with 40 operators actively taking part. As envisaged by Legislative Decree 79/1999, the Single Buyer (SB) also began operating contemporaneously with the launch of the Power Exchange, for the supply of electricity to the non-eligible market. With the aim of protecting the most vulnerable categories of customers from the risk of price volatility on the Exchange, the SB has differentiated its electricity procurement activities through a range of contract types (physical, bilateral, for differences, CIP6 and import). From April to December 2004, these reduced uncovered purchases in the exchange to less than 20%.

On the electricity generation side, 2004 saw an increase in capacity as a result of the completion of reconversion work on existing power stations and the entry of new plants into service. The current structure of production sees the incumbent with over 50% of the country’s efficient generating power plants and with nearly all of its peak plants as well as a significant share of mid-merit plants. A supply structure of this type provides the incumbent with a considerable competitive advantage in covering the lion's share of hourly demand in nearly all areas of the country.

As regards transmission, in 2004 the legislative framework for the ownership and management "rebundling" of the national transmission system under a single operator was finalised. The Prime Minister's Decree of 11 May 2004 established that the unification should be completed by 31 October 2005 and introduced a 5% ceiling on ownership for electricity companies (raised to 20% for the former monopolist, Enel) and a limit, again of 5%, for operators in the sector (therefore applying also to Enel) in exercising the right to vote for appointments to the Board of Directors. The reason for this operation was the expectation of greater effectiveness in planning the development of the network and in financing new infrastructure facilities and then carrying out the works required. For 2005, in accordance with the provisions of articles 5 and 6 of EC Regulation 1228/2003 of the European Parliament and Council of 26 June 2003, it was established that Italy's share of transmission capacity on interconnection networks should be allocated through an implicit auction mechanism. This method was already in use in 2004 to resolve congestions in the day-ahead market in the Power Exchange. In this respect, it should be noted that the operators of grids sharing borders with Italy have adopted a number of different approaches in allocating interconnection capacity.

Since 1 July 2004, in accordance with Directive 2003/54/EC, all non-household consumers have been eligible to buy electricity on the free market. However, only a very small percentage of new eligible customers (those with annual consumption lower than the previous threshold of 0.1 GWh) looked to the free market in 2004. More specifically, the electricity purchased on this market in 2004 amounted to about 60% of the potential (129 compared with 215 TWh), with only 3% of the electricity consumed by new eligible customers with consumption of less than 0.1 GWh being bought on this market.

Developments in the gas market

No significant changes took place in the gas market in 2004. Legislative Decree 164/2000 had already adopted most of the provisions on the organisation and operation of the market contained in European Directive 2003/55/EC, including the complete opening of the market,which has already under way in Italy with effect from 1 January 2003.

Following the inquiry opened in 2001 and its subsequent 2002 ruling on the abuse of dominant position[3], the AGCM instructed Eni to upgrade its facilities in order to remove bottlenecks to imports. However, Eni decided to delay these upgrades, in the light of new entrants' investment programmes in regasification terminals, to avoid the situation arising where upgrades to the international network and the construction of new terminals might produce such sizeable gas flows as to cause supply surpluses that would be incompatible with the take or pay obligations in its long-term import contracts. Eni's failure to comply with the requirement to upgrade its facilities led the AGCM to impose a fine of €4.5 million and a parallel obligation to release gas to competitors under conditions laid down by the same AGCM. Eni met this requirement in October 2004.

The system for daily trading/releases of gas and capacity on the national network, known as the Virtual Trading Point (VTP), has been operating since the beginning of thermal year

[3] Provision 11421/02 on the ENI – Blugas case.

2003-2004. Situated in conceptual terms between the entry and exit points of the national gas pipeline network, the VTP facilitates bilateral transactions by users and enables them to trade, release and purchase gas on a daily basis, including in the course of any given day, for balancing purposes. Bilateral transactions were previously carried out solely at entry points to the national network. In the first few months of 2005 the number of operators involved in VTP transactions reached a total of 23. Such transactions increased rapidly, to 20% of transactions on the secondary market, which amounts to about 10% of total procurement. The remaining 80% of transactions continue to take place at network entry points. After the peak of 270 M(m^3) reached in October 2004 at the time of the gas release operation carried out by Eni, the VTP seems to have stabilised pending further regulatory initiatives that the AEEG is implementing.

Main problems addressed by the regulator

Over the 12-month period from the start of July 2004 to the end of June 2005, the AEEG issued about 240 regulatory provisions concerning the electricity and gas sectors[4]. Of these, 53% concerned the electricity sector and 47% the gas sector. Their regulatory content can be broken down as shown in Table 1.

Table 1 Regulatory content of the AEEG's Resolutions

Content	% share
Network access conditions	28
Non-eligible market tariffs	21
Investigations, inquiries and inspections	13
Organisation of the free market	11
Appeals and disputes	10
Service quality	9
Warnings and penalties	5
Other provisions[5]	3
TOTAL	100

With the progressive restructuring of the regulated markets, the AEEG's regulatory activity has changed. The following sections provide a brief overview of just some of the activities that characterised the past year.

Joint investigations with the AGCM

Over the last year investigations on the state of liberalisation of the electricity and gas sectors conducted jointly by the AEEG and the AGCM were completed.

In the electricity sector, the investigation focused on the wholesale market, where the considerable problems caused by the presence of an incumbent that is able to exercise a high degree of market power and so exert a strong influence on price-setting more or less

[4] This does not include the approximately 40 provisions concerning the organisation and operation of the AEEG.

[5] Includes Resolutions concerning general electricity costs, CIP6 incentives, stranded costs, energy efficiency, etc.

countrywide, emerged once again. The main lines of intervention proposed in the conclusions to the investigation were of two types: regulatory and structural. The regulatory measures are designed to restore competitive market conditions and discourage strategies to remove production capacity from the market with a view to influencing prices. Alongside these regulatory solutions, actions designed to install new generating plant by parties other than Enel were called for, especially in areas thus far experiencing a shortfall in supply. These new plants would contribute to the development of the national transmission system by reducing as far as possible the risks of inter-zonal congestion and encouraging the development of interconnection lines with abroad, including through the construction of direct lines.

In the gas sector the investigation led to the conclusion that the incumbent continues to exercise a strong degree of market power, expressed primarily through control of raw material procurement. Eni practically holds a monopoly in national production and directly or indirectly continues to control the market for gas imports to Italy. Indeed, if the company managed to comply with the antitrust ceiling envisaged by Legislative Decree 164/2000 (about 62% of gas injected to the system in 2004), this was partly through the sale of Norwegian gas abroad to competitor companies Plurigas, Dalmine Energie S.p.A., Energia and Edison (so-called "innovative sales"). The investigation highlights the difficulties experienced by new entrants in importing gas, since Eni has exploited its rights on transport facilities located abroad to saturate import capacity by selling gas to selected competitors, to which it also made available the necessary transport capacity abroad. The informational imbalance, the lack of transparent and non-discriminatory regulations for access to international pipelines and the fact that capacity is limited all make access by third parties to facilities difficult and costly. This also applies to the use of any marginal capacity freed up by the flexibility of the take or pay contracts previously concluded by Eni. The market control power exerted by Eni also applies to imports travelling through the regasification terminal at Panigaglia, currently the only such terminal in Italy.

Activity in the electricity sector

By virtue of the supervisory powers conferred by Law 481/1995 and in observance of the provisions of the Ministry of Productive Activities Decree of 19 December 2003, the AEEG has begun to monitor trading in the Power Exchange on the basis of a series of indices designed to detect the exercise of market power by the incumbent[6]. In 2004 and early 2005, anomalous trends were noted in prices in the Exchange. These called for timely changes to the monitoring arrangements, including to take into account the start of active participation by demand in trading[7].

The start of merit order dispatching brought out marked price differentials caused by the cost of congestions on the national grid and, by virtue of the new mechanism for the management of congestions on interconnections, on transmission capacity with foreign zones. These problems led the AEEG to develop future instruments that make it possible to hedge temporal and spatial price risk caused by congestions between catchment areas and on interconnections, including with a view to encouraging the entry of new operators and more efficient functioning of the organised market. In this regard, the AEEG has

[6] Resolutions 21/2004 and 49/2004.

[7] Resolutions 254/2004 and 50/2005.

issued provisions regulating the allocation of instruments[8] to hedge the risk associated with price differentials between Italian electricity market zones and between these and foreign zones at different electricity borders. These are based on criteria of profitability, proportionality in the quantities applied for, security of the national electricity system, and gradual application of the regulations with respect to those adopted in previous years. Firm transmission rights for international transactions were allocated free of charge, with the aim of transferring congestion revenue on interconnections to consumers entitled to take part in the allocation procedure. With effect from 2005, firm transmission rights for transactions carried out in Italy have been allocated through competitive procedures managed by the GRTN, with clearly defined constraints designed to avoid speculation or the exercise of market power.

In the course of 2003 the first period of tariff regulation for the use of the electricity transmission and distribution system came to an end. After the usual consultation procedure, which opened in July 2003, at the start of 2004 the AEEG set rates of return on invested capital of 6.7% per annum in real terms before tax for transmission, and 6.8% for distribution. These values should be compared with the 5.6% and 7.4% applied for the previous period. Annual productivity gain targets of 3.5% for distribution and 2.5% for transmission have also been set. These take into account efficiency gains achieved by operators in the first period of regulation. Finally, in the second regulatory period a rate of return on invested capital has also been set for electricity metering and sales activities, at 8.4% per annum.

Activity in the gas sector

The first period of tariff regulation for the use of local gas distribution networks came to an end in 2004 and in 2005 the corresponding regulatory period for the transport service will also end. After the usual consultation procedure, the AEEG set a real pre-tax rate of return on invested capital of 7.5% per annum for distribution. This compares with 8.8% for the previous period. A return of between 6.2% and 7.1% has been proposed for pipeline transport in the second period of regulation, compared with the 7.9% currently in force.

With Resolution 22/2004, issued in February 2004, the AEEG provided for the establishment of the VTP under operating conditions that comply with the balancing criteria established in the network code, the registration of transactions with advance notice ranging from short periods of less than a day to one month, and the reduction of the minimum duration of trading at entry points from one month to one day. Operations envisaged by Resolution 22/2004 and currently at the preparatory stage concern: the definition of a standard contract; a system of direct transactions between operators and network operator (Snam Rete Gas); and a system to determine marginal prices from the balance between demand and supply.

With respect to imports through the Panigaglia regasification terminal and following the dispute between Gas Natural and GNL Italia S.p.A. (the Eni Group company that operates the terminal), AEEG established conditions for the use of the terminal that enabled access to a higher number of users in the 2004-05 thermal year. At the end of 2004 the AEEG also opened a fact-finding investigation into the way the terminal was operated in previous thermal years.

[8] Known as congestion cover charges (CCCs), or Firm Transmission Rights.

3 REGULATION AND PERFORMANCE OF THE ELECTRICITY MARKET

3.1 Regulatory Issues

3.1.1 General

Over the last five years the electricity sector has experienced rapid organisational development driven by the deverticalisation and unbundling process set in motion in Italy, partly as a result of Directive 96/92/EC.

In 2004 the AEEG proposed a new tariff regulation system for the period 2004-2007. In keeping with the provisions applied in the previous regulatory period, this is based on a vertical breakdown of activities and is intended to encourage the development of competition in all stages of the supply chain not subject under current legislation to exclusivity constraints.

Electricity production is a free activity, albeit one that is subject to obligations deriving from its public service nature. For the years prior to 2003, taking into account the failure at that time to set up the bidding system (power exchange), it was envisaged that the AEEG should set the price of wholesale electricity intended for customers in the captive market. Now that the bidding system has begun operating, the price obtained by electricity producers, regardless of whether consumption is by free market or captive market customers, is set by market mechanisms or bilateral negotiation.

Electricity transmission and dispatching activities are reserved for the state and assigned to the *Gestore della rete di trasmissione nazionale* (the Italian Transmission System Operator, GRTN). Since they are conducted on an exclusive basis, they require regulatory measures guaranteeing non-discriminatory access to grid infrastructure, along with incentives to improve efficiency and cost-reflective price-setting arrangements. In seeking to achieve these objectives, and efficiency improvement incentives in particular, the organisational and ownership structure of the infrastructure must also be taken into account. For the new regulatory period solutions concerning the regulation of fees have been identified that take the planned reunification of the ownership and operation of the grid infrastructure into account.

Distribution activity is carried out on an exclusive basis, with concessions granted by the Ministry of Productive Activities. The monopolistic nature of distribution activity under the current regulatory framework requires regulatory measures to guarantee non-discriminatory access to grid infrastructure, as well as the introduction of incentivising tariff regulation mechanisms that ensure that prices are truly cost-reflective. For the new regulatory period the previous system based on the tariff options offered by distributors has been confirmed.

Electricity sales activity is free. The need to ensure that customers on the captive market are adequately protected and the single countrywide tariff is observed, means that tariff regulation by the AEEG is necessary for the sale of electricity to customers on that market. On the basis of the provisions envisaged for the new regulatory period, as part of the sales tariff, non-eligible consumers will pay the electricity procurement cost borne by the Single

Buyer, which since 1 January 2004 has acted as guarantor for the supply of electricity to these customers. This cost, which is then transferred to consumers, is determined as an estimate of the price of electricity released to distribution companies, taking into account all the procurement arrangements used by the Single Buyer itself (power exchange, bilateral contracts, contracts for differences, etc). Sales tariffs include the remuneration of the energy sales marketing service which, with respect to the previous regulatory period, has now been distinguished from the distribution marketing service.

In the case of electricity metering, although this is a potentially free activity, in the light of the current organisational and regulatory framework it requires tariff regulation mechanisms to be introduced to protect users. Only once the metering service begins to be opened up to competition will it be possible to gradually phase out metering tariff regulation.

Since 1 July 2004 all non-household consumers have been free to choose their own supplier. With effect from July 2007, as an effect of the European legislation the opening of the market in the sales sector will also apply to household customers.

In the presence of potential demand in the eligible sector of 215 TWh (about 80% of national consumption net of auto-consumption), at 31 December 2004 eligible customers corresponding to 60% of potential demand, or 129 TWh, had exerted the right to eligibility and obtained their supplies on the free market.

Table 2 Opening of the electricity market

Year	Consumption threshold GWh/year	% Market opening (excluding auto-consumption)
1999	30 *(from Jan 1999)*	33
2001	20 *(from Jan 2000)*	47
2003	9 *(from Jan 2002)* 0.1 *(from May 2003)*	70
2005	All non-household customers *(from July 2004)*	80
2007	*(from July 2007)*	100

3.1.2 Management and Allocation of Interconnection Capacity and Mechanisms to Deal with Congestion

On the supply side, the wholesale electricity market has been designed as a zonal market to take network congestions into account. This means that the presence of constraints on electricity transmission over the network could give rise to a division of the market, in which producers compete in zones smaller than the national market. Sales bids/offers in the centralised market (day-ahead and adjustment markets) are valued at the equilibrium price for the zone in which the electricity in question is injected to the grid. Accepted purchase bids/offers, on the other hand, are calculated independently of the zone in which the withdrawals take place, at a *Prezzo Unico Nazionale* (National Single Price, PUN), which is the average zonal price weighted on the basis of consumption. In this way the reconciliation of electricity flows with constraints on the relevant network takes place partly in electricity sub-markets (day-ahead and adjustment), thus reducing the economic impact on the dispatching services market, where the physical balance between electricity demanded and supplied is achieved in reliable conditions.

Operators taking part in the day-ahead market and parties to bilateral contracts are both exposed to the risk arising from the variability of PUN and zonal sales price differentials, or in other words to variations in the transmission capacity usage charge determined by the emergence of congestions on the national grid. To hedge the risks connected with this variability, for 2005 the AEEG has provided for the introduction of Firm Transmission Rights (known in Italy as *copertura dai costi di congestione* or CCCs), which have been allocated by the GRTN through competitive procedures. These CCCs have an explicit value referred to the difference between the price for the zone indicated in the CCC and the PUN, i.e., the value of the charge for the allocation of transmission capacity usage rights.

In order to allocate the share of transmission capacity on the interconnection network of pertinence to Italy, for 2005 the Minister for Productive Activities and the AEEG have selected the implicit auction method among the various methods that are compatible with the regulations for the management of cross-border congestions. More specifically, it is envisaged that congestions on the interconnection network should be resolved by means of a market method based on the implicit auction system already used in 2004 to resolve congestions on the day-ahead market.

In this context, congestions on the interconnection network are managed by establishing virtual zones representing the foreign market zone connected with the Italian network, with respect to which transmission limits corresponding to capacity at each electricity border are defined.

In keeping with the provisions of the regulation, the implicit auction method for the allocation of transmission capacity usage rights on the interconnection, as envisaged by the AEEG, enables congestions on the interconnection network to be managed using non-discriminatory solutions based on market rather than transaction-related criteria. It also provides economic signals to parties taking part in the market and to transmission system operators.

With this method, in which congestions are managed hourly over a daily time-horizon, the charge envisaged by the dispatching conditions established by the AEEG for the allocation of transmission capacity usage rights is also applied to electricity imported through cross-border exchanges. This is an hourly charge which corresponds to the difference between the value of electricity purchased at the PUN and the value of electricity at the zonal price applied in the market zone where it is injected. In the case of imports, the fee for the allocation of transmission capacity usage rights corresponds to the difference between the prices applied in the foreign electricity injection zone and the PUN.

To enable importers to hedge the risk of volatility in the price differential between the virtual foreign zones located at electricity borders and the Italian zones adjoining them, the AEEG has provided for the allocation of hedging instruments specifically designed for interconnections. These are known as Interconnection Firm Transmission Rights (*Corrispettivi di copertura delle congestioni sull'interconnessione*, or CCCIs). These instruments have been allocated free to applicants on a pro-quota basis in order to transfer the congestion revenue on interconnections directly to Italian consumers entitled to take part in the allocation procedure. In this way, importers can use interconnection lines without paying any congestion charges, up to the end of the Italian in-put zone.

3.1.3 The Regulation of the Tasks of Transmission and Distribution Companies

Following the Independent System Operator (ISO) model, Legislative Decree 79/1999 transposing Directive 96/92/EC envisaged the separation of the activity of operating the national transmission grid, which is entrusted to a public operator controlled by the Ministry of Finance, and activities connected with ownership of network infrastructure, which remains in the hands of operators. Terna, a company 29.99% controlled by incumbent Enel, currently owns over 90% of the assets relating to the national transmission grid, while the remaining facilities are owned by a total of 12 municipally owned companies and electricity producers. In the model adopted in Italy, inefficiencies and difficulties have however emerged in coordination between the operator and owners of the grid. This has led the Government to propose that transmission system ownership and operation be "rebundled" (see section on Unbundling).

With respect to distribution networks, Decree 79/1999 gave rise to a process of gradual rationalisation of distribution activity, both through the aggregation of distribution companies – the decree envisaged the issue of just one concession for each municipal catchment area – and by giving companies part-owned by local authorities the option of asking the incumbent, Enel, to dispose of business units engaged in distribution activity in the municipal area where these same companies serve at least 20% of users, or in neighbouring catchment areas with the requirement, in this case, that they serve at least 100000 customers. At present there are 173 local transmission network operators.

Transmission and distribution tariffs

Since the AEEG began operating, the Italian tariff system has been designed on the basis of the price cap incentivising model, as expressly envisaged by the law establishing the AEEG (Law 481/1995). The regulatory period is four years. Law 290/2003 subsequently added to the criteria the AEEG is required to observe in setting tariffs for the remuneration of transmission and distribution networks, including with a view to ensuring that the development needs of the electricity sector are met. At the beginning of the second period of regulation (2004-2007), initial tariff levels for the transmission and distribution services were based on allowed costs (operating costs, mainly of external resources, including personnel, material procurement and depreciation of fixed assets, calculated on the basis of economic-technical criteria; and an adequate return on invested capital).

For the purpose of recognising operating costs, the AEEG refers to the costs incurred by operators as recorded in 2001 and carried forward to 2004, taking inflation and the required efficiency gains into account. To these costs were added 50% of any productivity gains achieved by operators over and above the target (4% per year) envisaged in the first period of regulation, calculated with reference to the difference between actual and allowed unit costs at 2001. These higher productivity gains were then weighted by the amounts estimated for 2004.

The rate of return on invested capital allowed for regulatory purposes for the period 2004-2007 has been designed to ensure those providing capital (risk and debt) with pay-back prospects in line with the return they could have obtained on the market by investing in activities with a similar risk profile. For the rate of return on risk capital the AEEG has used the *Capital Asset Pricing Model* (CAPM), the method commonly used in financial markets to determine the rate required by investors for activities with a given level of risk. To determine the rate for risk-free activities, it was decided to use the 12-month average (1 January 2003 to 31 December 2003) of gross returns on the 10-year Treasury bond (BTP) benchmark taken by Bank of Italy. The levels of β parameters, which measure the degree of systematic, and therefore not diversifiable, risk of an activity, were set by the AEEG taking into account the values recognised in European best regulatory practice and the characteristics of the Italian electricity market.

Table 3 Parameters to determine the allowed rate of return on invested capital

Parameter	Description	Transmission	Distribution
r_f	Nominal rate for risk-free activities (%)	4.25	
B levered	Systematic risk for the activity	0.55	0.6
Pr	Market premium (%)	4	
Kd (nominal)	Return on debt capital (%)	4.7	
T	Tax rate (%)	40	
Tc	Tax shield (%)	33	
Rpi	Average inflation rate (%)	1.7	
WACC	**Weighted average cost of capital (%)**	**6.7**	**6.8**

From 2005 and until 2007, the AEEG adjusts tariffs and tariff parameters annually for transmission and distribution services by applying the price cap mechanism to that part of the parameters intended to remunerate operating costs (including depreciation), according to the provisions of Law 290/2003. In the first regulatory period the price cap was also applied to the return on capital. A target productivity gain (X-factor) of 2.5% for transmission and 3.5% for distribution has been set. The tariff components covering the allowed costs for the return on invested capital are adjusted annually by reviewing the capital itself using the average annual change in the gross fixed investment deflator measured by the National Statistics Office, and taking into account any net investments carried out by companies the previous year. With the aim of supporting investment for the development of the national transmission network (also in the light of the problems that emerged following the countrywide blackout on 28 September 2003), the AEEG has provided for a rate of return 2 percentage points higher than the rate generally allowed for the transmission service. This will be applied at the time of the annual tariff review, for network development initiatives completed by 30 June of the year preceding the one to which the tariff levels refer.

While for the transmission service the tariff is set directly by the AEEG, for the distribution service companies can offer their customers a range of tariff options with due respect for certain constraints defined by the AEEG itself.

Regulation of the quality of the electricity distribution service

Law 481/1995 outlines the general framework and functions assigned to the AEEG for the development of its actions with respect to service quality:

a) definition of guaranteed and overall service quality levels;

b) imposition of automatic compensation/refunds to users in the event of the service levels established by the AEEG not being respected;

c) evaluation, for the purposes of setting the price-cap, of service quality improvements with respect to pre-established standards.

With respect to service continuity, the regulation envisaging incentives to reduce the duration of outages, introduced in 2000, was reiterated by the AEEG for the second regulatory period (2004-2007).

Regulation of the duration of outages is based on annual improvement targets set in advance by the AEEG and on the *ex post* verification of the results. By comparing these with the improvement targets, the AEEG is able to establish incentives and financial penalties to apply to distribution companies. A specific tariff component is envisaged to cover the net annual balance of incentives and penalties which, for 2003, amounted to €202 million.

The improvement targets refer to the benchmark indicator (overall duration of long – over three minutes – outages without notice per low-voltage customer), calculated over two years and excluding outages caused by *force majeure* or damage caused by third parties, or originating on high-voltage networks or on the national transmission grid. The overall duration of outages per customer, taking all long outages without notice into consideration, fell from 192 minutes lost in 1999 to 91 minutes in 2004. The number of outages per customer fell from 3.9 in 1999 to 2.5 in 2004, a 35% improvement on 1999.

The overall improvement at the national level was accompanied by a progressive convergence of the service continuity values in the regions of central and southern Italy with those in the north of the country, with respect to both the duration and the number of outages. More specifically, the regions of Southern Italy saw an average improvement of 64% in the duration of outages compared with 1999 and those of the Centre an improvement of 58%, compared with 31% for northern Italy. Similarly, the gap between Northern and Central-Southern Italy with respect to the average number of outages per customer has also been reduced.

Table 4 Electricity service continuity

Indicators	1999	2000	2001	2002	2003[(A)]	2004
Duration of outages per low-voltage customer *(minutes lost per customer)*	192	187	149	115	104	91
Number of outages per year per low-voltage customer	3.8	3.6	3.1	2.8	2.6	2.5

(A) Excluding scheduled disconnections and blackouts.

Table 5 Regulation of transmission system operators

	Number of companies regulated	Estimated transmission tariff (€/MWh)		
		Ig	Ib	Dc
Transmission	13 (owner companies)	3.27	3.50	67.23[(A)]
Distribution	173	5.83	37.61	

(A) This value also includes the recovery of energy sales marketing costs.

Balancing

The conditions for the delivery of the dispatching service and the procurement of related resources on a merit order basis were issued by the AEEG in Resolution 168/2003 as amended. The GRTN then drew up the rules for dispatching, subject to AEEG approval.

The market for the dispatching service provides reliable conditions to achieve a "physical" balance between electricity supply and demand by addressing imbalances between programmed and actual flows and then calculating the relevant electricity levels in real time. In the Italian electricity system this is the only organised market for spot trading.

The GRTN selects the production and consumption units entitled to supply the necessary resources to resolve congestions and for reserve and balancing purposes, on a merit order basis and also on the basis of:

a) the technical characteristics of the production and consumption units in question;

b) the location of the units on the network concerned.

These are therefore the two variables that identify, for the most part, the switchability nexus of production and consumption units in the supply of the various dispatching services, which correspond technically to the secondary reserve, tertiary reserve, balancing services and congestion solving.

The technical requirements that must be met by production and consumption units for eligibility to supply dispatching services are not uniform. More specifically:

a) the technical requirements for production and consumption units to be considered eligible to supply the resources needed to resolve scheduled congestions are a sub-set of those required for eligibility to supply the resources needed for the tertiary reserve and balancing;

b) the technical requirements for eligibility to supply the resources needed for the tertiary reserve and balancing are in turn a sub-set of the eligibility requirements to supply the resources needed for the secondary reserve.

A "qualitative" hierarchy therefore exists that makes the above-mentioned resources technically switchable in one direction only; we speak, in fact, of "one-way switchability":

secondary reserve $\Rightarrow$ *tertiary reserve and balancing* $\Rightarrow$ *congestion solving resources*

The balancing period is 60 minutes for consumers and small producers who do not submit balancing resource bids/offers, and 15 minutes for all other producers.

The resources for the reserve are supplied on a national scale with due respect for reserve constraints of a zonal nature (mainland, islands) as well as transmission constraints between macro-areas. Interaction is possible at the zonal aggregate level but not with respect to neighbouring countries. The GRTN provides notification of the inter-zonal transmission constraints at hourly intervals over a daily time horizon.

The market for the dispatching service closes at 15:00 hours. In the Italian market the possibility of intra-day adjustments is not envisaged.

On average, the imbalance charge has been €100/MWh

Balancing payments are settled in the second month following the month to which they refer.

With respect to the conditions under which the GRTN provides the balancing service, the AEEG has established methods to calculate:

- imbalance charges, which evaluate the electricity injected/withdrawn at a dispatching point in excess of/less then the injection/withdrawal schedule;
- charges for failure to observe dispatching orders, which punish the operators selected in dispatching service markets who fail to follow the GRTN's orders.
- non-arbitrage charges, which provides for penalties to operators who, when withdrawing electricity, exploit the differential between the zonal price and the PUN (national single price) by engaging in arbitrage between the day-ahead and adjustment markets.

With a view to facilitating small producers, the AEEG has introduced a series of simplifications and exemptions, especially for micro-generating plants and those supplied by renewable sources. More specifically:

- for plants with nominal power of up to 1 MW exemption from entering into dispatching contracts is envisaged;
- for plants supplied by renewable sources and with power of less than 10 MVA and for plants of any power level supplied by renewable wind, solar, geothermal, wave, tidal and run-of-river hydro plants, imbalance charges are not applied. Those plants enjoying additional incentives pursuant to the legislation currently in force are excluded from this exemption.

3.1.4 Effective Unbundling

As noted earlier, in the first instance the Italian legislation established that the ownership and operation of the Italian transmission system should be unbundled. This separation is currently being superseded with the planned "rebundling" of the GRTN unit dedicated to transmission and dispatching and Terna, the company that owns over 90% of the national transmission grid, and the subsequent privatisation of the new operator thus established.

This operation envisages the entry of the Cassa Depositi e Prestiti S.p.A. (a public body with its own legal personality and management, organisational, corporate property and budgetary autonomy which carries out activities and services in the general economic interest) in Terna's share capital, currently held by incumbent Enel, by taking out a stake of 29.99%, and the acquisition of the GRTN unit engaged in electricity transmission and dispatching. As a result of this operation Enel's holding in the new operator will amount to about 5% of the share capital. It should be noted that Cassa Depositi e Prestiti also owns 10.25% of Enel's share capital, while about 22% is owned directly by the Ministry of Finance[9]. The operation is subject to approval by the AGCM which, on 22 June 2005, opened an inquiry in which it expressed the opinion that "…this operation is liable to give

[9] On 7 July 2005 the placement of the fourth ENEL tranche was completed, thus reducing the Finance Ministry's direct holding in the company from 31% to 22%.

rise to the creation or reinforcement of a dominant position on the electricity transmission and dispatching market, such as to eliminate or reduce substantially and on a long-term basis competition in the wholesale electricity market and in dispatching services".

With respect to distribution activity, the decree implementing Directive 96/92/EC envisaged the corporate unbundling of dispatching companies with more than 300000 customers in respect of the activities of electricity distribution and sales to non-eligible consumers. As they were vertically integrated companies in the period preceding the start of the liberalisation process, both the incumbent and the main municipally owned companies have therefore created separate companies for sales to eligible customers and for distribution and sales to customers in the captive market.

Table 6 Current state of regulation of unbundling in Italy for the electricity sector

	Accounting unbundling	Management/administrative unbundling	Corporate unbundling	Ownership unbundling
DSO < 300000 customers	Obligatory	Partly regulated	Optional	Optional
DSO > 300000 customers	Obligatory	Partly regulated	Obligatory for distribution and sales to non-eligible consumers	Optional
GRTN	Obligatory	Non-applicable	Obligatory	Obligatory but currently being superseded

In 1999 the AEEG introduced a directive, simplified and up-dated in 2001, concerning administrative and accounting unbundling with the aim of standardising and increasing the transparency of the financial statements of operators in the electricity sector, and of making it possible to identify the costs of individual services and ensure *inter alia* that they were being correctly disaggregated and attributed by function, geographical area and user category. The activities covered by the provision are:

- electricity production;
- electricity transmission;
- electricity dispatching;
- electricity distribution;
- electricity metering;
- electricity sales;
- electricity activities abroad;
- gas activities;
- other activities.

For the purposes of administrative unbundling the management structures dealing with the activities listed above must be considered autonomous, as though the activities were each carried out by a different company; the management control procedures adopted must also make it possible to identify events and situations that might affect the balance sheet and income statement of each activity.

For accounting unbundling purposes the operators to which the directive applies are required to draw up separate annual accounts (balance sheet and income statement) for each activity. These accounts are for the sole use of the AEEG and are audited for certification purposes. The certification report attests to the correct application of the directive and notes any reservations and exceptions. The AEEG has established criteria to define *common services*, that is, balance sheet and income statement items that operators cannot attribute to individual activities (e.g.: management control and planning, engineering and construction services, real estate services, personnel services, etc) and shared operational functions, that is, balance sheet and income statement items shared by at least two activities (e.g.: commercial and sales, technical and maintenance, shared metering functions, etc). The directive provides instructions for the attribution to individual activities of the costs and revenues deriving from common services, shared operational functions, financial income and costs, and direct taxes. Simplifications and exemptions from administrative and accounting unbundling obligations are envisaged for smaller companies and companies operating for the most part in just one activity of the electricity supply chain.

To date, the Italian legislation does not envisage a requirement for the distribution system operator to draw up a programme setting out the procedures and measures adopted to prevent discriminatory conduct with respect to customers. It follows that there is no body with responsibility for monitoring such a programme (compliance officer). Neither are there any obligations concerning the choice of business name for sales companies linked to distribution companies: the two companies may share the same brand name (e.g. Enel Distribuzione and Enel Energia, Aem Elettricità and Aem Energia, Asmea and Asm Energy). They often also share the same headquarters and website.

3.2 Competition Issues

3.2.1 Description of the Wholesale Market

The demand for electricity on the Italian network in 2004 reached 322 TWh, 85.8% of which was met by national production and the remaining 14.2% by net imports. Consumption amounted to 301 TWh, a modest 0.5% increase on 2003, compared with the strong growth rates recorded in the period 1997-2004 (of 2.5% per year on average) as a result of the continuous increase in electricity intensity. The marked slowdown recorded in 2004 can be attributed to the re-absorption of the steep rise recorded the previous year as a result of the high summer temperatures. Indeed it is the summer period, as a result of the growing use of air conditioning systems, that is showing the strongest rises in demand, with peaks that in 2005 might even exceed those of the winter months.

Electricity imports declined by 9.8% in 2004 with respect to 2003, a reversal of the trend of recent years (which saw an average annual growth rate of 2.2% from 1997 to 2004). The fall in 2004 can be explained essentially by provisions adopted following the blackout of 28 September 2003 to reduce maximum transmission capacity on the interconnection network. This reduction was agreed by the GRTN with neighbouring system operators.

With effect from 1 January 2004, the value set for Net Transmission Capacity (NTC) (winter-day) at the northern border was 6050 MW, to which should be added 300 MW in imports from Greece. Following the entry into operation of the new S. Fiorano – Robbia interconnection line on 23 January 2005, new NTC levels were set for each border. As a result, the maximum transmission capacity on the northern border rose to 7150 MW (winter-day).

Italy's generating plants are undergoing an intense modernisation process. In 2002-2004 the Ministry of Productive Activities issued authorisations for the construction of new plants with a total capacity of about 20000 MW. 40% of the new authorisations are concentrated in the north of the country, where about 53% of existing net efficient power is already concentrated. If we examine the data for 2001-2004 we note that installed capacity grew more than peak demand, and that Italy's production plants underwent a process of progressive technological change as a result of the decommissioning of fuel oil plants in response to a substantial increase in the number of natural gas combined cycle plants.

With respect to the load-coverage difficulties encountered during the summer of 2003, the entry into operation of new plants, the greater deliverability capacity of thermoelectric plants and the more favourable hydropower supplies meant that it was possible to meet electricity demand in 2004 while maintaining adequate reserve margins, even in the presence of lower import capacity and a higher load.

In terms of ownership structure, the Italian generating system is highly concentrated, with Enel still retaining more than 50% of national generating capacity in 2004, even at the end of the divestment process. Italy performs particularly poorly in comparison with major competitors in terms of the deliverability capacity of its hydroelectric plants.

The proportion of electricity generated by the Enel Group shows a reduction (from 49.2% to 43.9% of national production) in the presence of a generalised increase in generation by the other main producers, both in absolute and percentage terms. The changes in electricity output by company in 2004 compared with the previous year can be attributed to a series of factors. Of these, the following are worthy of note: the completion of renovation and conversion work on former Enel plants, which had limited their generating output in 2003; the construction of new plants and their merit order positioning in the electricity market; and a possible strategy by Enel to reduce volumes in order to increase prices following the start of operations on the Power Exchange.

With particular respect to the companies established as a result of the divestment of Enel plants, the increased share of Italian production represented by Edipower S.p.A. (9% of national production) and Endesa Italia S.p.A. (7.4%), whose thermoelectric plants have been almost completely renewed, should be noted.

The Eni Group has also grown considerably (6.0% of national production) thanks to the construction of new cogeneration electricity power stations by Eni Power S.p.A. The Edison Group's share has remained unchanged, at 12.1% of national production.

Table 7 Development of the wholesale market

	Total demand (TWh)	Peak demand (GW)	Installed capacity (GW)	No. of companies with a > 5% share of generation	% share of generation held by three main companies
2001	304.8	52.0	76.2	4	70.7
2002	310.7	52.6	76.6	3	66.7
2003	320.7	53.4	78.2	4	65.9
2004	322.0	53.6	79.5	5	65.0

With respect to the conditions under which the electricity market operates, the most significant feature in 2004 was the entry into operation, with effect from 1 April, of the bidding system (which, however, at this initial stage did not envisage the active participation of demand; this was postponed until 2005). The Exchange is composed of a day-ahead market (MGP), an adjustment market (MA) and a dispatching services market (MSD). On the MSD, the GRTN obtains the ancillary services needed to ensure the equilibrium of the system. Offers/Bids are submitted by users of the dispatching service the day before transactions are physically carried out. The counterparty to these users is the GRTN, which acts as the sole buyer/vendor with respect to the bids/offers presented.

The bid acceptance process is divided into two stages:

- the day before, when bids/offers are accepted to change the in-put and off-take programmes resulting from the MGP and MA, so as to resolve any residual congestions not solved on those markets, build up the reserve margins needed for the security of the system and balance the scheduled flows
- in real time, when bids/offers are accepted to balance the system in real time (i.e., the same day as the physical exchanges).

Unlike the situation on the MGP and MA, bid/offers on the MSD are not remunerated at the equilibrium price, but at the individual bid/offer-price (discriminatory or pay as bid auction).

On this market, unlike its competitors, Enel is the only company with transactions spread over several of the segments making up the MSD; a factor that further testifies to the structural imbalance characterising the Italian generating system.

With respect to the MSD as a whole, one possible structural indicator is a breakdown over the period 1 April–30 September 2004 of the market share built up on bids/offers accepted over the entire scheduled MSD. In the Northern, Centre-North, Centre-South and Southern zones, Enel's dominant position can be observed both for step-up and step-down bids/offers and for peak and off-peak hours. With the exception of the North, in all peak hours Enel holds a share of between 48% and 94% of accepted step-up and step-down bids/offers, while in the North it has a share of 30-44% of step-down bids/offers and 63-78% of step-up bids/offers.

With respect to the real time MSD, and in particular to the cover of secondary reserve margins, it should be noted that Enel (again in the period 1 April–30 September 2004) was the dominant operator in the supply of secondary reserve services on the mainland (with shares of 71% in peak hours and 68% in off-peak hours). Endesa is the dominant operator in Sardinia (with 69% and 75% respectively), while in the case of Sicily EdiPower covers just under 80% of the secondary reserve requirement.

With respect to the tertiary reserve, Enel acts as dominant operator on the mainland, although it is exposed to a degree of competition from Edison and Endesa in the Northern and Centre-North zones. Enel's market share in the North, Centre-North, Centre-South and South of Italy rarely falls below 65%.

If we move on from this analysis of the ancillary services to a more general overview of energy trading arrangements, it should be noted that the power exchange (IPEX) only started operating on 1 April 2004. In previous years trading should be considered as entirely bilateral, albeit operating under different arrangements on both the free and captive markets.

Table 8 Electricity market (TWh)

	Total consumption	Trading on organised spot market	Trading on forward market	Bilateral trading OTC[(A)]
2002	310.7	0	0	310.7
2003	320.7	0	0	320.7
2004	322.0	67.3	0	254.7

(A) OTC includes: bilateral contracts with Italian producers, imports, supported electricity (CIP6), TEM[10], and STOVE.

A complete picture of the arrangements for electricity procurement in Italy in 2004 is provided in Table 9. This shows the transactions carried out in the bidding system, bilateral transactions relating to imports, CIP6 electricity allocations (supported generation from renewable and assimilated sources) by the GRTN, electricity traded on the STOVE (procurement system operated by the GRTN for scheduled balancing of demand and supply prior to the launch of the bidding system) and physical bilateral trading by operators possessing electricity from national production plants with other free market operators and with the Single Buyer. All of these forms of procurement involve contracts through which operators equipped with generating sources (Italian and foreign producers, production company tollers/agents, GRTN) release electricity physically to other operators (typically, wholesalers or consumers). At this level of trading, total volumes for sale through the various channels correspond to generation destined for national consumption net of quantities auto-consumed.

[10] TEM (Team Energy Management) was the structure created by ENEL in which ENEL Produzione, ENEL GreenPower and the three Gencos (Elettrogen, Interpower and Eurogen) took part, for the transmission to the GRTN of the information it needed to define and ensure priority dispatching of the electricity required to cover demand on the captive market before the launch of the bidding system.

Table 9 Structure of electricity procurement for 2004 (TWh)

Requirement (including pumping)	**332.3**
Auto-consumption	21.0
Net electricity sold on the bidding system	67.3
Imports	45.6
CIP6 and other obligatory GRTN withdrawals	56.7
STOVE	50.4
Physical bilateral	91.3

With respect to the integration of the Italian market with the markets of neighbouring countries, it should be noted that the marked price differential between the former and the latter results in the saturation of interconnection lines for imports to Italy. The high levels of electricity trading with neighbouring countries do not therefore give rise to true market integration as a result of the persisting congestion and transmission constraints, which prevent the Italian price from being aligned with prices in the other markets. This is reflected by the limited correlation between the price on the Italian exchange and prices on the other European exchanges in the period April 2004–June 2005, as shown in Table 10.

Table 10 Price correlation indices for European day-ahead markets (1 April 2004-30 June 2005)

	EXAA	APX	EEX	PowerNext	OMEL	IPEX
EXAA	100%					
APX	59%	100%				
EEX	93%	57%	100%			
PowerNext	94%	57%	92%	100%		
OMEL	61%	35%	61%	67%	100%	
IPEX	69%	43%	66%	68%	52%	100%

As regards mergers and acquisitions, the acquisition of Edison by an alliance of Edf and Aem Milano is of particular significance. Over time this could lead to a new scenario on the Italian energy market, with the consolidation of a new operator in contraposition to Enel. Aem Milano owns installed capacity and a 20% stake in the capacity of Edipower, in which Edison in turn holds 50% of capacity on the basis of the tolling contract concluded by the former Genco's industrial partners. The new group that would come into being would therefore reinforce the oligopolistic structure on the supply side, where Edison is the second operator at the national level. Moreover, the incentive for Edf-Aem to keep prices high on the Exchange to recoup the considerable expense incurred in the operation could lead to a risk of collusion with the dominant operator.

3.2.2 Description of the Retail Market

The sale of electricity to consumers needs to be broken down into sales on the captive market (which includes all household customers and eligible non-household customers who have opted to continue buying electricity at regulated tariffs) and sales on the free market (which includes non-household customers who have chosen to change their supplier).

The operators selling electricity on the captive market are distribution companies; Enel Distribuzione is the only one with an extremely high market share (of about 85%). Together with Acea Distribuzione and Aem Elettricità in 2004, Enel covered 93.4% of captive demand.

In the case of the free final market, the operators selling electricity are wholesalers and producers. Since the start of the liberalisation process the number of operators selling electricity on the final market has grown from 58 wholesalers in 2001 to over 150 wholesalers and producers in 2004 (direct sales by producers to consumers account for about 4% of total sales to the final market).

The number of companies with a market share of over 5% doubled between 2001 and 2004, from 3 to 6; in 2004 Enel Trade, Egl Italia, Edison Energia, Eni Power Trading, Energia and Enel Energia covered nearly 45% of free demand. The first named provided 33.2% of supplies of over 5000 MWh and 11.9% of supplies up to 5000 MWh. In 2003 the three biggest companies (Edison Energia, EGL Italia and Energia) supplied a slightly lower share of supply (32.6%) to customers consuming over 5 GWh, but covered more than a third of supply below this threshold.

As regards electricity generating companies, of 118 different legal persons in 2003, foreign companies had minority shareholdings in 27, and majority (controlling) holdings in 15. Of the over 280183 GWh produced in 2003, 8% and 27% respectively were generated by companies in which foreign operators or bodies held majority or minority stakes.

Of the 295 wholesalers who at 31 December 2003 had obtained the status of eligible wholesale customer, 24 were companies with headquarters abroad (9 in Switzerland, 4 in the United Kingdom, 4 in Germany, 3 in Spain, 2 in Austria, 1 in Belgium and 1 in Holland), while 28 were majority shareholdings of foreign companies and 24 were minority shareholdings. In 2003, companies based abroad and their subsidiaries covered about 24% of sales to the final market for a total of about 22 TWh.

In 2003, about 82% of all companies selling electricity on the free market resulted as being independent of distribution and transmission companies. In 2004 this figure fell to 78%, indicating that with the opening of the market to all non-household customers distribution companies have set up *ad hoc* companies for sales to free customers.

The proportion of trading companies integrated with production companies is, by contrast, relatively high: about 62% are connected with generating companies.

Table 11 Development of retail market

	Total consumption (TWh)	No. of companies with >5% share of final market		No. of independent companies(A)	Market share of the first three undertakings (%)			Cumulative % of customers who have changed supplier (by volume)(E)		
					Large industrial undertakings (B)	Small-medium sized industrial and commercial undertakings (C)	Very small undertakings and household sector (D)	Large industrial undertakings	Small-medium industrial and commercial undertakings	Very small undertakings and household sector
		Free	Captive/Non-eligible							
2001	263.2	3	1	48	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
2002	268.8	4	1	60	n.a.	n.a.	n.a.	22.2 of the free market (21.8 TWh)		
2003	278.7	4	1	103	32.6	32.7	n.a.	n.a.	n.a.	n.a.
2004	280.4	6	1	119	33.2	11.9	93.4	n.a.	n.a.	n.a.

(A) Fully independent of grid operators
(B) With consumption of over 5000 MWh/year
(C) With consumption of up to 5000 MWh/year
(D) Non-eligible customers
(E) Fact-finding investigation opened (July 2005)

Final electricity tariffs

The Single Buyer (SB) began operating in January 2004. The SB is the company assigned by law to act as guarantor of supply to customers on the captive market, a function previously carried out by incumbent Enel. The SB is wholly controlled by GRTN.

Before the Power Exchange began operating, and so right up to the end of March 2004, fees charged to customers in the captive market to cover purchasing and dispatching costs were based on the price of wholesale electricity, an administered price set by the AEEG. This was divided into a component covering fixed costs, set in advance for each year on the basis of fixed generating costs at the national level, and a component covering variable costs, adjusted quarterly on the basis of a predetermined mechanism.

With effect from April 2004, the costs borne by the SB for electricity purchases and as a user of the dispatching service have been transferred to final non-eligible customers through the administered tariffs applied by distribution companies and adjusted quarterly by the AEEG.

In terms of application, since April 2004 the tariff charges to cover purchase and dispatching costs have been set by the AEEG with the aim of covering the costs incurred by distribution companies to supply electricity to their own customers on the captive market. The price paid by distributors to supply electricity corresponds to the release price which, in turn, reflects the purchasing and dispatching costs borne by the SB.

Consequently, for the purpose of setting tariff charges to cover purchasing and dispatching costs, the AEEG refers to the price level of electricity released by the SB to distribution companies.

Table 12 Breakdown by component of electricity tariffs set by the AEEG

July 2004

<table>
<tr><th>Standard customer (Eurostat definition)</th><th>Dc</th><th>Ib</th><th>Ig</th></tr>
<tr><td>Wholesale price of electricity or cost of generation</td><td>66.19</td><td>69.18</td><td>62.22</td></tr>
<tr><td>Transmission tariff (excluding regulatory costs)</td><td rowspan="3">67.35</td><td>3.50</td><td>3.26</td></tr>
<tr><td>Distribution tariff (excluding regulatory costs)</td><td>45.00</td><td>4.34</td></tr>
<tr><td>Estimated energy sales marketing margin</td><td>1.23</td><td>0.003</td></tr>
<tr><td>Grid losses</td><td>8.01</td><td>3.72</td><td>3.34</td></tr>
<tr><td>Regulatory costs</td><td>10.30</td><td>11.69</td><td>10.80</td></tr>
<tr><td>TOTAL (€/MWh)</td><td>151.85</td><td>134.32</td><td>83.97</td></tr>
</table>

July 2005

<table>
<tr><th>Standard customer (Eurostat definition)</th><th>Dc</th><th>Ib</th><th>Ig</th></tr>
<tr><td>Wholesale price of electricity or cost of generation</td><td>75.78</td><td>76.51</td><td>69.49</td></tr>
<tr><td>Transmission tariff (excluding regulatory costs)</td><td rowspan="3">67.23</td><td>3.50</td><td>3.27</td></tr>
<tr><td>Distribution tariff (excluding regulatory costs)</td><td>37.61</td><td>5.83</td></tr>
<tr><td>Estimated energy sales marketing margin</td><td>1.23</td><td>0.003</td></tr>
<tr><td>Grid losses</td><td>9.12</td><td>4.09</td><td>3.71</td></tr>
<tr><td>Regulatory costs</td><td>7.30</td><td>9.22</td><td>8.40</td></tr>
<tr><td>TOTAL (€/MWh)</td><td>159.43</td><td>132.16</td><td>90.70</td></tr>
</table>

Notes:

- The distribution tariff also includes a component to cover the costs of metering and transmission cost equalisation, and a component to cover service quality improvement costs.
- Costs for ancillary generating services and generation cost equalisation are included in the wholesale price.
- Regulatory costs include: stranded costs, incentives for renewable sources and other residual costs not connected to production and network services.

3.2.3 Measures to Avoid Abuses of Dominance

The Ministry of Productive Activities decree of 19 December 2003 approving the regulations governing the electricity market envisaged that the AEEG should establish a mechanism to control market power and arrangements to monitor price trends.

The regulations to control market power, as set forth for 2005 by Resolution 254/2004, were the subject of an appeal to the Lombardy Regional Administrative Court (TAR) by Enel and Endesa. With the TAR's provisional rulings 382/2005 and 383/2005, the Resolution in question was suspended. This was confirmed by order 1532/2005 of the Council of State, Section VI, pending the definitive decision on the matter.

Resolution 254/2004 provides that the *Gestore del Mercato Elettrico* (Electricity Market Operator, GME) should establish, for each operator concerned and in each month, a number of indices designed to detect, firstly, the potential existence of market power exerted by that operator, and secondly, whether or not that power has in fact been exercised.

In order to establish if an operator is able to exert market power, or "set the market price", an index is calculated that ascertains whether:

- the electricity offered by the operator, at a given time and in a given macro-zone, results as being "indispensable" to the market;
- whether the average electricity price is lower or higher than a given threshold.

If this index does not correspond to a pre-established threshold, subsequent indices are then calculated which are designed to determine whether or not market power has in effect been exerted. The first index measures, with reference to a given operator, at a given time and in a given macro-zone, the quantity of electricity in relation to which the market operator resulted as being "indispensable".

Using the second index, it is possible to ascertain the proportion of the total hours of the month under consideration for which a given operator was a "marginal operator" and the proportion for which the average price set in those hours diverges from the overall monthly average, as well as the degree to which the price set in that macro-zone diverges from the price recorded in macro-zones resulting as being more competitive.

Behavioural measures to promote competition are applied to operators when one of the following circumstances is shown by the two indices to exist:

- the market operator has released a lower quantity of electricity than the minimum quantity for which it resulted as being indispensable;
- a considerable price divergence emerges between the macro-zone under consideration and the most "competitive" macro-zone.

These behavioural measures consist, briefly, of the imposition of an obligation on the operator to offer all its available production in the day-ahead market at a fixed price freely determined by the operator, for the thirty days following the period during which the checks are carried out. They also include a requirement on the operator to offer a fixed sales price on the dispatching services market for all hours of the 30 days following the period in which the checks were carried out. This price must not be higher than the average sales offer price accepted for the same dispatching point in the dispatching services market in the month preceding the one to which the inspection refers.

With respect to monitoring activity, Resolution 50/2005 drew up a system of indices supplementing the one envisaged in 2004. These indices are built up with the technical support of the GME and the GRTN and concern all sensitive aspects of the wholesale market, including:

- monitoring of the structure and behaviour of demand;
- the geographical dimension of the relevant markets with respect to both the wholesale electricity market and the procurement of resources for dispatching services;
- the degree of concentration of supply;
- the degree of "indispensability" of the different operators for the purpose of satisfying hourly demand in each market;
- an evaluation of the conduct of operators in relation to possible cost scenarios and different bidding strategies;
- the frequency with which the main operators set prices in relevant markets;

- the relation between producers' revenues and the prices recorded in the day-ahead market, including as relating to the volumes of electricity subject to trading contracts concluded outside the bidding system;
- the conduct of users of the dispatching service.

The electricity market supervisory activity carried out by the AEEG also led to the opening of two fact-finding investigations into price formation processes in the bidding system for the periods of June 2004 and January 2005. These concluded with Resolution 25 of 18 February 2005. Both enquiries were opened following the detection on the days under analysis of anomalies in prices in the day-ahead market and in transmission capacity usage charges.

The findings of the investigations show that the exceptionally high prices levels were not caused by specific circumstances affecting the economy as a whole, such as demand or cost shocks, but by bidding conduct by operators, and by Enel in particular. At the zonal level considerable differences were discovered between events in the two periods. The high purchase price in June was the result of a wide divergence in zonal sales prices, while in January all the zonal prices were essentially in line with the PUN (national single price). It emerged in this respect that Enel was in a position to influence not just its own revenues but also those of competitors, since it was able to favour some operators to the detriment of others.

As regards June 2004, it can be seen that the price divergence between the different market zones affected net revenue from the release of electricity obtained from other operators. These could have been harmed by the increase in transmission capacity usage charges, which was not covered in the bilateral contracts concluded by these operators on the basis of quite different price expectations. In the case of January, the alignment of zonal prices with the PUN favoured operators in the northern zone to whom import capacity was allocated, by cancelling the Fee for Assignment of Rights of Use of Transmission Capacity (known in Italy as the *Corrispettivo per l'assegnazione dei diritti di utilizzo della capacità di trasporto*, or CCT), usually positive, which they would otherwise have had to pay. In this respect two significant pieces of evidence emerged. Firstly, in the month of January the competitive procedure for the allocation of import capacity between Italy and France may indicate an exchange of information between Enel and Endesa. The latter was in fact awarded nearly all of the import capacity by offering a much higher price than the expected market value. This price proved, however, to be congruent with subsequent prices obtained on the day-ahead market for purchases and with respect to the northern zone. To this should be added the fact that an analysis of Enel's bidding behaviour shows that, in the light of the composition of its portfolio and in particular the contracts for differences concluded with the Single Buyer, the company could have increased its profits by reducing the northern zone price with respect to the values actually recorded. This conduct would only be rational in a wider context than that of a single company, and over a longer time horizon.

In view of the emergence of factors that might constitute an abuse of dominant position by the companies under investigation, the results of the two inquiries have been sent to the AGCM which, in provision 14174 of 6 April 2005, has opened a formal inquiry into Enel and Enel Produzione for abuse of dominant position in setting prices in the power exchange.

4 REGULATION AND PERFORMANCE OF THE NATURAL GAS MARKET

4.1 Regulatory Issues

4.1.1 General

In the natural gas sector, Italy can be distinguished at the European level by the implementation of a more advanced framework of rules than those adopted in other countries. The transposition of Directive 98/30/EC, through Legislative Decree 164 of 23 May 2000, gave rise to a configuration of the sector that anticipated the new liberalisation principles contained in Directive 2003/55/EC. This is particularly true with respect to the degree of market opening, the principles inspiring the unbundling of monopoly activities and those potentially open to competition, and third party access to network infrastructure. It should be noted that Italy decided to open its market completely with effect from 2003 (since 1 January of that year all customers have been free to choose their supplier) and that since 2000 it has provided for the corporate unbundling of gas transport and sales activities, and regulated network access. In the case of gas storage too, the solutions adopted by Italy are particularly advanced, translating as they do into the corporate unbundling from sale and transport activities and the application of tariffs and access conditions that are again regulated by AEEG.

The adoption of an advanced regulatory framework is however a necessary but not sufficient condition to inject true and full competition to the market. Indeed, with respect to the opening of competition and the consequent expected reduction in final prices, the balance sheet for the first four years of liberalisation is most certainly disappointing. The structure of the market still shows a high degree of concentration under a single operator in all segments of the supply chain. The economies of scale arising from the considerable vertical integration of the dominant operator make it difficult for new operators to compete in the market.

Table 13 Market opening

Year	Consumption threshold GWh/year	% Market opening
1995		
1997		
1999		
2001	2.12	65
2003	No threshold	100

4.1.2 Management and Allocation of Interconnection Capacity and Mechanisms to Deal with Congestion

As in previous years, at the time when allocations were made for the new thermal year (October 2004), no instances of congestion were recorded at national network entry points interconnected with foreign transport infrastructure, even in the presence of a high level of continuous transport capacity use. At the beginning of the thermal year, 26 operators applied for and obtained access to interconnection points. The results of the allocation for thermal year 2004-2005 show that continuous capacity[11] was nearly all allocated for all entry points interconnected with abroad. The only exception was the entry point at Gela, where 54% of capacity still results as being available since contracts for the supply of gas arriving at this import point are at the build-up stage and the demand for capacity was consequently lower than that technically available for allocation. Transport infrastructure capacity in Italy is essentially gauged to satisfy commitments connected with import contracts concluded by Eni, the dominant operator, before Directive 98/30/EC came into force.

In Italy, in fact, new entrants experience real difficulties in arranging gas imports independently, since Eni controls transport rights in import facilities located abroad, to the construction of which it contributed during the monopoly era. To comply with the AGCM ceilings, Eni has exploited these rights by releasing gas to selected competitors, to which it has granted the necessary access to transport facilities abroad, thus saturating the capacity of the pipelines.

For these reasons, transport capacity is used to the full, both at interconnection points between the Italian network and Northern and Eastern Europe, and in the import pipelines located in Switzerland, Germany and Austria, all controlled by Eni in one way or another. In a short-term perspective too, the use of marginal transport capacity made available by the flexibility of import contracts previously concluded by Eni, appears difficult since the arrangements for allocating capacity for the use of international pipelines, established by Eni, makes access by third parties to these facilities both difficult and costly. Problem areas include informational imbalances with respect to the capacity actually available, and infrastructure usage tariffs (which are excluded from the regulatory framework that governs the tariffs applied by Snam Rete Gas S.p.A.).

The situation of imports from Africa is also critical to the development of competition. At the import point located in Sicily, where gas from Algeria arrives, unused capacity is still available. However, bottlenecks persist in Tunisian territory, where the absence of projects to up-grade the infrastructure, again controlled by the dominant operator, prevents Eni's competitors from organising their own independent supplies. This failure to up-grade the Tunisian network, even in the presence of import contracts concluded by Eni's competitors, constitutes a further obstacle to increased gas imports in Italy and Europe. Again with reference to import infrastructure, the only LNG regasification plant in Italy, at Panigaglia, also belongs to Eni. Since this involves imports of gas by sea, unlike the situation with pipelines Eni has less potential to exert its power to control operators who, having freely purchased LNG consignments from different countries, apply for access to the terminal. However, strict access conditions, which are not compatible with the timescales required for the purchase and transport of LNG, in actual fact restrict the use of the terminal by other operators.

[11] In addition to continuous capacity, at import points from Northern and Eastern Europe interruptible capacity (annual or seasonal-winter) is also allocated with a view to satisfying demand and optimising system use.

Rules for the allocation and management of interconnection capacity

For the continuous transport service on the national network allocations are made on an annual basis (Resolution 137/2002). In the case of entry points interconnected with abroad, allocations are again annual, but are made two years in advance and with the possibility for parties to long-term import contracts to extend their duration to five years (with sole regard to the average daily contracted quantity). The two-year advance period responds to the need to leave sufficient time to take steps to address any congestions in incoming flows. Such steps may be taken either by the transport company, by speeding up any up-grade projects, or by users, by offering to bear the cost of up-grades or by renegotiating their contracts for procurement and transport from other countries to Italy.

The amount of capacity that can be allocated for long-term periods is however limited to the average daily quantity envisaged in import contracts, since this is the factor to which the continuous use of capacity logically corresponds and which typically enables operators to comply with the take or pay restrictions that are a feature of such contracts. In compliance with the provisions of Directive 98/30/EC, parties to take or pay import contracts concluded before the directive came into force enjoy priority access in cases where serious economic and financial difficulties would arise if it were not possible to access the network. All parties to long-term import contracts have access to the annual allocation of capacity, where capacity remains from the long-term allocation, and compete for it with parties to import contracts of no more than one year in duration.

To discourage operators from booking more capacity than they require, a financial guarantee to cover obligations resulting from the allocation in question is envisaged (this is different from the guarantee covering obligations deriving from the consequent delivery of the service). The AEEG has also envisaged a use it or lose it mechanism for holders of priority access rights.

In the event of capacity applications exceeding the transport capacity actually available for allocation, the transport company divides this capacity *pro quota*. At entry points interconnected with abroad, this *pro quota* distribution is made with due respect for the above-mentioned priority access rights.

In cases where consumers switch their natural gas supplier, the transport capacity allocated at the redelivery point is transferred by the old supplier to the new supplier (the proportion of capacity being indicated by the latter).

In order to ensure the utmost impartiality and transparency in access to transport services, the AEEG has established information obligations on the part of transport companies. These are divided into obligations to the benefit of the AEEG and obligations to the benefit of users of the service.

Transport companies are required to send the AEEG monthly data and information (including "commercially sensitive" information that cannot be disclosed) concerning capacity applied for, allocated and used by users, as well as any releases and trading of capacity by users and any allocations in the course of the year, to enable the AEEG to perform its monitoring and supervisory duties. Transport companies are also required to submit annual reports on agreements and coordination with storage companies and reports on network conditions and services, as well as reports containing:

- data and information on the services the transport system is able to provide and the methods and instruments with which these services were established;

- the arrangements for verification by the dispatching service of the transport schedules requested by users, with a particular focus on the method used to limit the requested programmes in cases where technical or operational constraints exist.

To enable the AEEG to exercise its regulatory and supervisory power effectively, information and data are also required from actors other than transport companies, such as import companies, for example.

The informational obligations to the benefit of users are intended to lessen the informational imbalance that puts new entrants at a disadvantage. On the basis of the rules laid down by the AEEG, transport companies are required to publish a very wide range of information on their Internet sites to enable access to the service. Essentially, this information includes:

- information on the transport network (a detailed representation of the network of gas pipelines, location and technical features of the main plants, delivery and redelivery points and interconnection points with other networks, connections to storage facilities and production fields, connections to import pipelines and LNG regasification plants, annual and biannual plans for the operation of the transport network, five- and ten-year plans for the construction of new, and the up-grading of existing, capacity, and lists of new and decommissioned installations); and

- information on transport capacity (publication on an annual basis of the ten-year allocation plan for transport capacity at entry points interconnected with abroad, monthly publication of allocated and available transport capacity at entry, exit and redelivery points – with relative guaranteed pressures – for the continuous and interruptible transport services, and changes in transport capacity arising from maintenance, extension or up-grade initiatives).

Secondary capacity and gas market

With Resolution 22/2002, the AEEG drew up a series of regulatory initiatives designed to gradually establish a centralised gas and capacity market.

The first of these initiatives envisaged the introduction of procedures using an IT platform, to enable the release and trading of transport capacity and natural gas entering the national pipeline network on the basis of bilateral agreements between users in accordance with the transport service balancing criteria established by Resolution 137/2002. The IT platform used for this purpose is the one set up by Snam Rete Gas for transactions in capacity (electronic notice board for capacity transactions between users of the transport system) and in gas (Virtual Trading Point, VTP). Originally a technical support provided by Snam Rete Gas for releases and trading by operators of gas entering the network, since 1 October 2003 the VTP – a point virtually located within the transport system, between the entry and exit points of the national network – has enabled users of the transport network to engage in bilateral transactions on a daily basis for system balancing purposes.

Under the terms of Resolution 22/2004, the AEEG approved and published on its Internet site a user-manual and the contract drawn up by Snam Rete Gas for VTP users.

In recognition also of the need to develop additional functionalities with respect to those initially envisaged by the system put together by Snam Rete Gas, with a view to providing additional flexibility to users of the transport system to optimise the balancing process the AEEG, through Resolution 180/2004, has envisaged and implemented:

- the possibility of conducting and registering natural gas transactions thirty days in advance of the date on which they are entered in accounts for balancing purposes, as well as the possibility of concluding and registering natural gas transactions on the same day as they are entered in accounts, to enable users to correct any unexpected imbalances on the day in question;
- the possibility of releasing and trading transport capacity, for minimum periods of one day, at entry points to the national network of pipelines interconnected with abroad or with LNG regasification terminals (previously, the network code envisaged the possibility of releasing gas on a monthly basis only).

These new provisions have been in force since October 2004. The structure envisaged by the AEEG enables capacity release times to be brought into line with the timescales envisaged for the trading of gas entering the network. Resolution 180/2004 also provided for changes to Snam Rete Gas's network code to coincide with and implement the new provisions.

Another two developments envisaged by Resolution 22/2004, and for which the AEEG has opened a consultation process, are still under study. These are:

- the definition of standard contracts for bilateral trading of gas and capacity (such contracts would be useful in promoting market liquidity by facilitating the completion of transactions by operators, who are given the possibility of setting only the price and volume of the transaction);
- the introduction of a balancing system based on a daily market, in which the transport company buys from (or sells to) system operators any surplus or shortfall of natural gas in the transport network.

Specific tariffs for transit contracts are not envisaged in the regulations on transport tariffs.

4.1.3 The Regulation of the Tasks of Transmission and Distribution Companies

The gas transport network, divided into the national and regional transport networks, is operated by a small number of companies. The main transport operator, Snam Rete Gas, is 50% controlled by Eni, the dominant operator in the sector. This situation is set to change since, in accordance with the provisions of Law 290/2003, with effect from 1 July 2007 no one company operating in the natural gas sector will be able to hold stakes of over 20% in companies owning transport networks.

Snam Rete Gas's transport system is composed of about 30545 km of gas pipelines (about 96% of the entire transport system), of which 8196 km in the national network (which is in any case entirely operated from the commercial point of view by Snam Rete Gas) and the remaining 22349 km in the regional network. The second transport operator is Società Gasdotti Italia S.p.A., which operates a number of regional networks [12] (Table 14).

Transport activity is regulated by network codes drawn up by transport companies and approved by the regulator. These codes have been in force since 1 October 2003.

In spite of the considerable concentration process that has taken place in the last few years, ownership of the distribution network remains fragmented, with about 480 distributors. Through Italgas the Eni Group controls about 30% of the total.

A "standard distribution" network code is currently being drawn up (with rules issued by the AEEG in July 2004 through Resolution 138/2004), on which individual distribution companies will base their own codes. The standard network code came into being as a result of the need to create a benchmark to standardise distribution network use contracts as fully as possible, in view of the high number of operators of these networks.

Transport tariffs

The criteria governing the tariff system for the first four-year period of regulation (from 1 October 2001 to 30 September 2005) were established by Resolution 120/2001, according to the provisions of the liberalisation decree (Legislative Decree 164/2000) and Law 481/1995 establishing the AEEG (see chapter on the electricity sector).

The transport tariff structure is based on the entry-exit model, which envisages the application of a fixed fee for each entry and exit point in the network.

The tariff mechanism for the national network envisages a basic tariff made up of three elements:

- a capacity component, the fee due for committed capacity at entry and exit points on the national transport network;
- a commodity component, the variable fee connected with the energy associated with the volumes of gas transported;
- a fixed component for each redelivery point.

In the case of transport tariffs for the regional network, a uniform tariff is applied countrywide, with proportionate distance-based reductions for redelivery points located in municipal districts less than 15 km from the national pipeline network. The unit redelivery fee approved by the AEEG is multiplied by the daily capacity committed.

Under the current regulations, the commodity component calculation is based on 30% of allowed costs, while the capacity and fixed component calculations are based on 67% and 3% respectively of allowed costs. The AEEG has recently published a consultation document to select the tariff definition criteria for the next regulatory period (starting on 1 October 2005), in which it recommends the abolition of the fixed fee and a 70:30 capacity/commodity ratio.

[12] At present there are two small operators (Retragas Srl and Valtellina di Sondrio Mountain Community) owning small stretches of regional network.

Transport tariffs are set annually by companies on the basis of the tariff criteria established by the AEEG at the start of the regulatory period. The tariffs come into force after approval by the regulator, which verifies whether they satisfy the current criteria.

Tariffs are monitored against reference revenues set for each company engaged in transport activities. The definition of these reference revenues presupposes the identification of cost components for transport activity that cover operating costs (personnel, materials, compression, network losses, external services, and provisions), depreciation and an adequate return on invested capital.

To determine allowed costs, the AEEG has used data from the financial statements of transport companies for 2000 and determined the net invested capital of each company on a Current Cost Accounting basis.

The return on invested capital reflects the Weighted Average Cost of Capital (WACC) for third party risk and debt capital. This return is set in such a way as to provide investors with a return that is equal to the return they could obtain on the market by investing in activities with a similar risk profile. The real pre-tax WACC for transport activities for the first regulatory period was 7.94%.

For the new regulatory period, the AEEG has suggested a real pre-tax WACC of between 6.2% and 7.1% and a two percentage point higher return for new investments.

Allowed returns are adjusted annually using a mechanism that envisages an increase corresponding to the inflation rate of the previous calendar year and a reduction corresponding to a productivity rate set for the entire regulatory period, which reflects a productivity target for transport companies. This adjustment mechanism is hybrid in nature:

- it acts as a revenue cap since it determines the overall amount of revenue independently of the volumes transported. The X-factor for this component is 2%;
- it acts as a ceiling on the energy unit charge (price cap). The X-factor for this component is 4.5%.

The average productivity gain set taking the capacity-commodity ratio into account is 2.75%.

Finally, in the course of the annual adjustment exercise, transport tariffs are adjusted using a revenue variation parameter that takes into account any costs arising from unforeseeable and exceptional events, actions to control demand and service quality improvements as measured against pre-determined standards.

With respect to the new regulatory period, in accordance with the provisions of Law 290/2003 (see the chapter on the electricity sector) the AEEG has provided that the price cap should be applied to the operating cost and depreciation components of the constraint and not to the constraint as a whole, as was the case in the first regulatory period.

Distribution tariffs

As with transport tariffs, distribution tariffs are determined by companies following the criteria established by the AEEG at the beginning of each four-year regulatory period.

With Resolution 170/2004, the AEEG selected the criteria for the new regulatory period for distribution, which runs from 1 October 2004 to 30 September 2008.

Each year, the AEEG checks and approves the tariffs set by distribution companies on the basis of their respective allowed revenue.

At the start of the first regulatory period (2000-2004), the initial tariff levels set for the distribution service were based on allowed costs (operating costs, mainly for external resources, which include personnel and material procurement costs), the depreciation of fixed assets, calculated using economic-technical criteria and an adequate return on invested capital.

In order to compare the performance of the many distribution companies, in the first regulatory period the AEEG had envisaged a tariff system based on the allowance of standard service costs. More specifically, the method adopted envisaged a parametric calculation of invested capital and operating costs with a view to stimulating competition between companies and incentivising efficiency. This method has been reviewed for the second regulatory period (2004-2008) following appeals by operators to the administrative courts. With Resolution 170/2004 the AEEG gave companies the possibility of using an alternative calculation method based on certified financial statement data.

The AEEG has set a rate of return on invested capital corresponding to the weighted average of the rates of return on risk and debt capital (WACC). With respect to risk capital, the regulator has determined the rate of return using the Capital Asset Pricing Model (CAPM). The real pre-tax WACC for the current regulatory period is 7.5%.

The tariff is adjusted annually using the price cap mechanism to take into account changes in consumer prices, the productivity gain (of 5% for the second period of regulation) and a revenue variation parameter that takes into consideration any costs arising from unforeseeable and exceptional events, actions to control demand and service quality improvements as measured against pre-determined standards. In accordance with the provisions of Law 290/2003, the price cap is applied to the operating cost and depreciation components of the constraint and not to the constraint as a whole, as was the case in the first regulatory period.

Table 14 Regulation of transport and distribution companies

	Number of regulated companies	Estimated network tariff €/m^3		
		I4	I1	D3
Transmission	2	0.0207(*)	0.0292	0.0292
Distribution	480	-	0.0723	0.0954

(*) With reference to a consignment of gas with load factor of 0.9 at entry point and 0.45 at exit/redelivery point, and distance of 12 km travelled on the regional network.

To reduce tariff variability, with Resolution 170/2004 the AEEG introduced a uniform countrywide tariff structure for the second regulatory period. The tariff is composed of a single fixed portion of €30/customer/year and a variable portion to be applied over seven consumption bands. The distribution tariff for each catchment area (the zones into which the country is divided) is obtained by applying an area coefficient to the variable elements of the national benchmark tariff. This coefficient is calculated in such a way as to ensure revenues equal to the recognised revenue constraint for the area in question and is obtained by applying the national tariff to the number of customers and to the volumes of gas sold in the catchment area.

In regulating transport and distribution tariffs, the regulator incentivises operators' efficiency by providing in the tariff for operating costs incurred and managed efficiently and reducing them annually on the basis of the price cap.

The regulation of transmission and distribution service quality

The regulator, in exercising the powers attributed by Law 481/1995 (see chapter 3), has defined the regulation of the safety, continuity and commercial quality of the gas distribution service by establishing national basic and reference levels for certain indicators as well as requirements to record and transmit data to the AEEG itself.

With respect to safety, the AEEG has introduced a series of service obligations. More specifically, these concern the minimum annual percentage of network that needs to be inspected for gas leaks and the minimum annual number of gas odourisation measurements that distributors have to carry out.

The regulation of the safety and continuity of the gas distribution service introduced a requirement for each distributor to draw up operating procedures for the management of emergencies and incidents arising from the use of the gas distributed.

The AEEG has also regulated several aspects of the commercial quality of the distribution service, most notably:

- the definition of guaranteed and overall standards;
- the introduction of automatic compensation/refunds in the event of the operator being responsible for failure to meet the commercial standards;
- the definition of differentiated registration requirements depending on the size of operator.

The regulatory provisions were applied gradually. The AEEG currently publishes data on the regulation of commercial quality, although it does not hold data on service continuity on distribution and transport networks.

In 2002 the AEEG introduced provisions regulating the quality of gas in the transport service. More specifically, it provided that the network codes of transport companies should include sections concerning the technical and commercial quality of the service and of the gas transported. Since 2004 transporters have been required to submit data to the AEEG each year measuring performance against the standards set forth in the chapters on service quality, and information on any emergencies occurring on the network.

Balancing

In 2002 the AEEG established general criteria and fees for the balancing of the national and regional transport networks. The regulator also established tolerance thresholds and imbalance penalties (charges). The rules were drawn up following intensive consultation with network users. Subsequently, transport companies introduced balancing rules to their own network codes, that complied with the criteria laid down by the regulator. However, the AEEG has not established criteria for the balancing of the distribution network, which is carried out autonomously by distributors.

With respect to the transport network, companies are required to ensure physical and commercial network balancing. Physical balancing activity is intended to compensate for any daily divergences that may occur, including as an effect of unexpected meteorological conditions, between actual withdrawals and the withdrawals concluded by users on gas day G-1 for day G. To ensure the operational balancing of the network and provide hourly modulation, transport companies enter into contracts with storage companies for the use of the storage service. The amounts billed by the storage companies (tariffs, in the case of transporters purchasing basic services, and market prices, in the case of special services) determine the cost allowed in the transport tariff (balancing revenue). During the first period of regulation, revenues from imbalance penalties (charges) were deducted from allowed balancing revenues. Alternatively, to ensure balancing, transport companies may use the line pack system, the withdrawal from import sources of quantities other than those booked by users or, on delegation by the user who has created the imbalance, the user's own storage capacity.

Users of the transport network are required to ensure a daily balance between energy injected and energy withdrawn. Charges (penalties) are applied to encourage users to ensure this balance.

To help new entrants and small operators, the regulator has established that no charges are due for imbalances of less than 6000 GJ; where charges are applicable, they increase with the size of the imbalance. Two types of imbalance are envisaged: energy imbalances and capacity imbalances.

With respect to the first type of imbalance, the AEEG envisages a charge that increases with the size of the imbalance and, in the event that in the course of the month the user does not compensate in energy for the overall imbalance, a further penalty based on committed capacity. With respect to capacity deviation, the AEEG has established the tolerance thresholds and charges shown in Table 15.

Table 15 Tolerance thresholds and imbalance charges

	Tolerance threshold	Inbalance charge
Entry points interconnected with abroad	$SC_K > 2\%$	$1.125 \cdot \max SC_K(M) \cdot CP_e$
Entry points – national production	$SC_K > 4\%$	$1.125 \cdot \max SC_K(M) \cdot CP_e$
Exit points	$SC_k \leq 5\%$ $5\% < SC_K \leq 15\%$ $SC_K > 15\%$	*Not applicable* $1.125 \cdot \max SC_K(M) \cdot CP_u$ $1.5 \cdot \max SC_K(M) \cdot CP_u$
Redelivery points	$SC_k \leq 10\%$ $SC_K > 10\%$	*Not applicable* $1.1 \cdot \max SC_K(M) \cdot CR_r$

- SC_K is the difference, on a daily basis, between the capacity used by the kth user and capacity allocated at the point under consideration;
- *max* $SC_K(M)$ is the maximum divergence by the kth user recorded in month M at the point under consideration (higher than the tolerance thresholds in the case of exit and redelivery points);
- *Cpe and CPu* are the annual unit capacity charges for capacity allocations at the entry and exit points of the national gas pipeline network;
- *CRr* is the annual capacity unit charge for capacity allocation at the redelivery point of the regional network.

The gas transport system is monitored and continually adapted by the main transport operator's dispatching centre in order to ensure that the necessary quantities of gas are made available at any time and at any point of the network. Through a remote network control system and specific forecasting, optimisation and simulation programmes, transport companies carry out the necessary actions to satisfy users' transport programmes and ensure that the network is balanced correctly.

The balancing area consists of the entire transmission and distribution network. In the case of the transmission network, smaller operators see to the balancing of their own networks; however, the overall gas balance is completed by the principal operator.

Shippers can use their contracts to compensate reciprocally *ex post* for imbalances. This is done through storage.

The quantities of energy subject to balancing are determined in the course of each gas day and transporters make each user's estimated balance available to them by the end of the following day. The accounts for the gas transported are made available by the 15th of the month following the one to which the balancing refers. At the same time as the definitive balance is notified, the transport company sends users the daily temperature series and volume corresponding to basic consumption, as required to calculate the balance itself. Any measurement/allocation corrections noted after the definitive balance is established are taken into consideration by the transporter when the scheduled adjustment exercise is carried out within the following three months.

In the case of distribution, distributors only carry out the physical balancing of their network. No commercial balancing system is currently in place.

4.1.4 Access to Storage, Linepack and Other Ancillary Services

The Italian storage system, composed of depleted reservoirs operated by Stoccaggi Gas Italia Spa (Stogit) and Edison Stoccaggio Spa, are an essential complement to the transport and supply system, in consideration of the incidence of residential consumption on Italy's total demand for gas and the country's strong dependency on gas produced outside the European Union.

Stogit, an unbundled Eni Group company (100% owned by Eni S.p.A.), operates eight storage facilities, of which seven are located in the Po Valley (Brugherio, Cortemaggiore, Ripalta, Sergnano, Settala, Minerbio and Sabbioncello) and one in central Italy (San Salvo). The total active reserve, made up of gas that can be extracted and re-injected seasonally (working gas), amounts to about 17.5 G(m^3), of which 7.5 G(m^3) for seasonal modulation, 5.4 G(m^3) for strategic storage and 4.6 G(m^3) for pseudo working gas, while daily production potential under maximum replenishment conditions is about 280 M(m^3)/day.

Edison Stoccaggio, an unbundled Edison Group company (100% owned by Edison S.p.A.), has two small storage facilities (Cellino in Abruzzo and Collalto in the Veneto region), with an active reserve of about 120 M(m^3) and daily production capacity in conditions of maximum replenishment of about 2 M(m^3)/day, currently being increased. The Ministry of Productive Activities has issued Stogit with authorisations (currently suspended, however) to convert the reservoirs at Alfonsine and Bordolano to storage, which could increase the total active reserve by another 3 G(m^3). Authorisation procedures are also under way for five new reservoir storage sites and one aquifer facility, for a total nominal capacity of about 5 G(m^3). These are assigned to three companies: Edison Stoccaggio, Independent Gas Management and Geogas.

The basic services provided by the two Italian storage companies are seasonal modulation storage, “minerario” (operational) storage and strategic storage. These are accompanied by special services that can be flexibly adapted to operators’ needs. At present the special services offered by Stogit are a-seasonal modulation, counterflow service, additional peak deliverability capacity, incremental space (accessed on a competitive basis), pooling (continuous and interruptible capacity release) and daily releases of stored gas. The special services offered by Edison Stoccaggio are a-seasonal modulation and parking, including in counterflow.

In June 2005 the AEEG established the system of guarantees for access to the national storage system and for the supply of related services. The provision, which was approved at the end of a three-year provisional system, contains rules for immediate application and regulations for the drafting of storage codes by storage companies. The protections envisaged for storage users are intended to limit as far as possible, in this segment also, the exercise of market power by the Eni Group, which is already the dominant operator in all other stages in the supply chain. In the AEEG’s opinion the best solution for the development of competition in the operation of storage facilities is, once again, full independent third party access.

In addition to regulating the basic services, the provision also makes it possible to negotiate any required customised services directly, with due respect for the general criteria and the principle of non-discrimination. Other measures include: the offer of interruptible services; the possibility of transferring storage capacity from one user to another when switching takes place; and the possibility of trading capacity and storage gas, including to compensate for system imbalances for which the operator concerned is responsible. To address the problem of scarce storage resources, which was again demonstrated at the end of last winter, further measures include: a mechanism for storage capacity allocation following a precise order of priority; balancing charges to ensure the prompt replenishment of storage in the event of more capacity being used than that committed to (and strict provisions for unauthorised use of the strategic reserve); more detailed provisions for coordination by storage companies and transport companies (with a view also to finding out the real potential of the system); and constant monitoring of the performance of the system in the course of the year.

4.1.5 Effective Unbundling

With effect from 1 January 2002, transport activity has been subject to separation from all other gas sector activities, with the exception of storage, which must however be unbundled from transport activity in accounting and administrative terms. Storage is therefore subject to corporate unbundling from all other gas sector activities, with the exception of transport. Distribution is subject to corporate unbundling from all other gas sector activities (Table 16).

Table 16 Current rules governing gas sector unbundling in Italy

	Accounting unbundling	Administrative unbundling	Corporate unbundling	Ownership unbundling
DSO < 100000 customers	Obligatory	Partly regulated	Obligatory (derogation until 1 January 2003)	Optional
DSO > 100000 customers	Obligatory	Partly regulated	Obligatory	Optional
TSO	Obligatory	Partly regulated	Obligatory	Optional

In Italy the main transport operator, Snam Rete Gas, is controlled by the incumbent. The second transport company, Società Gasdotti Italia S.p.A., is owned by the private equity fund Clessidra Capital Partners.

Retragas S.p.A., a transport company established to operate interconnected regional transport networks with Snam Rete Gas, was established and is controlled by distribution company Asm Brescia S.p.A.

With respect to the legal form of distribution companies as shown in Table 17, at 1 October 2004 most were joint stock companies or limited liability companies (42.7% and 38.4% respectively).

Table 17 Legal form of gas distribution operators

TYPE	NUMBER	PERCENTAGE SHARE
Municipally operated	61	12.66
Joint stock company (S.p.A.)	206	42.74
Limited liability company (S.r.L.)	185	38.38
Unlimited partnership (S.n.C.)	2	0.41
Limited partnership (S.a.S.)	2	0.41
Joint-stock consortium	2	0.41
Limited liability consortium	5	1.04
Limited cooperative society	4	0.83
Special undertaking	6	1.24
Special consortium undertaking	5	1.03
Consortia	4	0.83
Total	**482**	**100.00**

According to the provisions of Resolution 311/2001, transport and distribution companies are required to provide the AEEG with data and information on their ownership structure (list of shareholders and respective ownership quotas and information concerning mergers, acquisitions and separations).

In some cases there are corporate links between TSOs and DSOs; however, transport companies present themselves to customers as separate companies with their own name, logo and Internet site. In most cases, although they are unbundled in corporate terms, distribution and transport companies occupy the same premises as sales companies (the connection occurring most frequently is actually between distribution and sales companies).

In compliance with the law liberalising the gas sector, since 2001 (Resolution 311/2001) the Italian regulator has laid down rules for the accounting and administrative unbundling of companies operating in the sector. These provisions have been in force since 1 July 2003. As a consequence, transport and distribution companies draw up their balance sheets and income statements divided by activity, as well as separate annual accounts providing a more detailed breakdown, for the sole use of the AEEG. These accounts are drawn up along guidelines provided by the AEEG itself, which has clearly identified the sections into which each activity should be divided, the criteria for allocating common costs and revenues, and the criteria for the sharing of financial income and direct taxes. Finally, the resolution governing unbundling provides that the separate accounts should show transactions between legal persons belonging to the same group and also envisages the unbundling of the consolidated financial statements. In cases where the parties concerned do not comply with the regulatory provisions, the AEEG may impose fines.

The separate annual accounts, both public and those reserved for the AEEG, are subject to auditing by a qualified auditor, who is required to certify to their compliance with civil and commercial law and with the regulatory provisions, as shown in Table 18.

The Italian legislation does not envisage the role of compliance officer.

After the first period of application of Resolution 311/2001, with Resolution 127/2005 the AEEG has initiated a review of the directives governing accounting unbundling, with a view to bringing them more fully into line with its requirements.

In view of the high number of distribution companies, the AEEG has not yet drawn up detailed information on costs, whether concerning the allocation of common costs among companies belonging to the same ownership group or costs incurred for external services.

Table 18 Summary information on Gas unbundling

	Transmission	Distribution
Separate premises (Y/N)	Y	N
Separate corporate identity (Y/N)	Y	N
Unbundling of accounts and guidelines (Y/N)	Y	Y
Audit of unbundled accounts (Y/N)	Y	Y
Publication of unbundled accounts (Y/N)	N	N
Separate board of directors (with some members also sitting on the board of related companies) (Y/N)	Y	N

4.2 Competition Issues

4.2.1 Description of the Wholesale Market

In 2004, national production experienced a further decline, of 6.5% compared with 2003, bringing it to 13 G(m^3) (Table 19). Over the last three years, national gas production as a proportion of total consumption diminished on average by two percentage points each year, to just over 16% of total consumption in 2004, compared with 18% in 2003: a rapid fall if we consider that in 2000 national production still covered 24% of consumption in Italy.

Table 19 Development of wholesale market

	Total demand (1) (G(m^3))	Peak demand(2) (M(m^3)/day)	Production (G(m^3))	Import capacity (G(m^3)/year)				No. of companies with >5% of production and import capacity	No. of companies with >5% of available gas	Share occupied by three main wholesale companies
				total	Priority access for transit	Priority access for LT contracts	Non-reserved access			
2001	125.1	n.a.	15.5	n.a.	n.a.	n.a.	n.a.	n.a.	2	68.2%
2002	111.8	n.a.	14.3	84.0	0.4	77.3	4.2	3	3	67.4%
2003	123.6	n.a.	13.9	84.8	0.4	78.8	3.1	3	3	63.8%
2004	127.3	379.7	13.0	88.7	0.4	84.6	2.1	3	3	62.4%

(1) Volumes of gas sold on national wholesale and retail markets; includes resales.

(2) In-put peak in calendar year 2004, reached on 26 January; the volume shown here includes injections, deliveries from storage, losses and consumption within networks.

The reduction in gas production, partly as a result of the depletion of reserves and partly of the optimisation decisions taken by the dominant operator, is not being made up by the exploitation of new fields, which do however exist in Italy. This can mainly be explained by the red tape that needs to be tackled to obtain authorisations to exploit new fields, the authorisation process being long and complex. These complexities are further increased by the on-going process of decentralising powers from central to regional government, with a consequent increase in time to market – the time between the start of exploration and, in the event of commercially viable findings, the start of production.

Law 239/2004 may bring about a reversal of trend. With respect to exploration and production (E&P), this law envisages:

- the inclusion of the exploitation of national hydrocarbon resources in the country's energy policy objectives;
- the introduction of new simplified procedures for applications for exploration permits and hydrocarbon exploitation concessions;
- the opening of a procedure, through enabling authority to the Government, for the adoption of a consolidated text on hydrocarbons, a document that would make it possible to rationalise and simplify a legislative framework that is still over-fragmented.

Italy therefore remains a net importer of gas. In 2004, imports increased by 8% on the previous year, to cover nearly 84% of consumption.

A breakdown of imports by origin shows that the lion's share of imported gas, about 36.5% of the total, arrives in Italy through the national network entry points located at Tarvisio, at the junction with the Austrian TAG pipeline, and Gorizia; the gas in question comes mainly from Russia. Next, with 35.4%, come imports by pipeline from Algeria, which enter Italy at Mazara del Vallo in Sicily and until a few years ago were the main source of supply for the national gas system. The gas transported as LNG by sea to the regasification terminal at Panigaglia in Liguria, where it is regasified and injected to the network, also comes mainly from Algeria.

In 2004 this gas accounted for just over 3% of total imports, compared with 5.6% the previous year. The decrease can be explained essentially by an incident at the Skikda terminal in Algeria in early 2004, after which the quantities of contracted gas arriving at Panigaglia were reduced. The Panigaglia plants were also closed down for maintenance from September to October 2004. Imports arriving in the national network through Passo Gries, at the Swiss-Italian border, were unchanged on the previous year, at 24%. Gas arriving at this point comes mainly from the Netherlands, with a smaller proportion from other EU producers and Norway (from offshore production in the North Sea). Finally, since the third quarter of 2004 Italy has also been importing gas from Libya. This gas, which at this early stage accounts for less than 1% of total imports, reaches Italy through the Greenstream system linking Libyan production with the national network at the entry point at Gela, in Sicily.

A breakdown by entire duration of the import contracts in force during the thermal year running from October 2004 to September 2005[13] (Fig. 1), shows that the preponderance of long-term contracts with a duration equal to or greater than 25 years (over 39% of contracted volumes for the current thermal year) is confirmed once again this year. The contracts in question are some of those concluded by ENI before European Directive 98/30/EC was issued. Next come contracts of up to 20 years duration (again, nearly all pre-Directive) followed by contracts of 21-24 years. This last category increased this year, including contracts relating to the newly activated imports from Libya, currently at the build-up stage: contracts for Libyan gas are of over 20-year duration. Eni does not appear as a purchaser of Libyan production or indeed as a party to any of the new contracts concluded this year. It should in fact be noted that until 2010 Eni is required to respect the antitrust ceilings established by Legislative Decree 164/2000, which means that it must constantly reduce, by two percentage points each year, its input of domestically produced and imported gas with respect to total input to the system. In actual fact, by employing the "innovative sales" method, Eni has succeeded in eluding the antitrust ceilings.

If we analyse these contracts by residual duration (Fig. 2), the high proportion of contracts of over ten years is confirmed with respect to contracted gas volumes for the current thermal year (about 75% have up to 20 years residual duration). The pre-Directive contracts referred to above are also represented in these categories. Annual and intra-annual (spot) contracts increased notably on the previous year, accounting for about 4%

[13] This breakdown does not include the agreements for new imports from Algeria, which envisage their build-up in 2006-07 as the Tunisian stretch of the Transmed system is up-graded.

and 1% respectively of the total. This increase is the result not just of the higher number and size of annual contracts, but also of the fact that long-term contracts nearing expiry are also included in this category this year (the data considered in the figure do not include spot loads of LNG regasified and injected into the network at Panigaglia).

Fig.1 Breakdown by duration of import contracts in force in thermal year 2004-2005

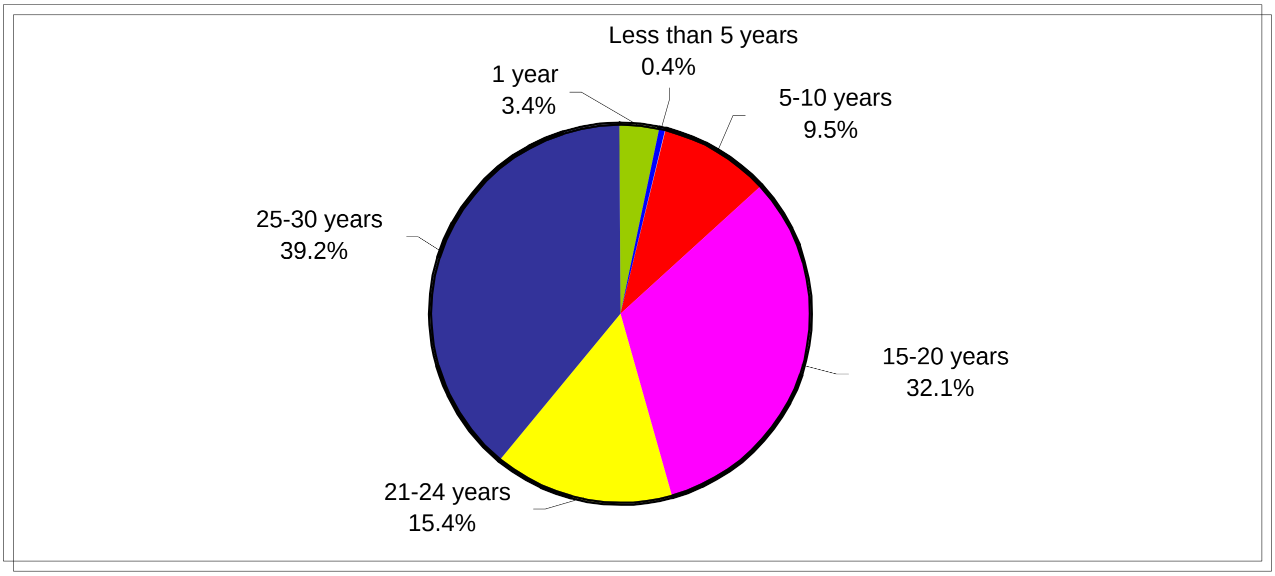
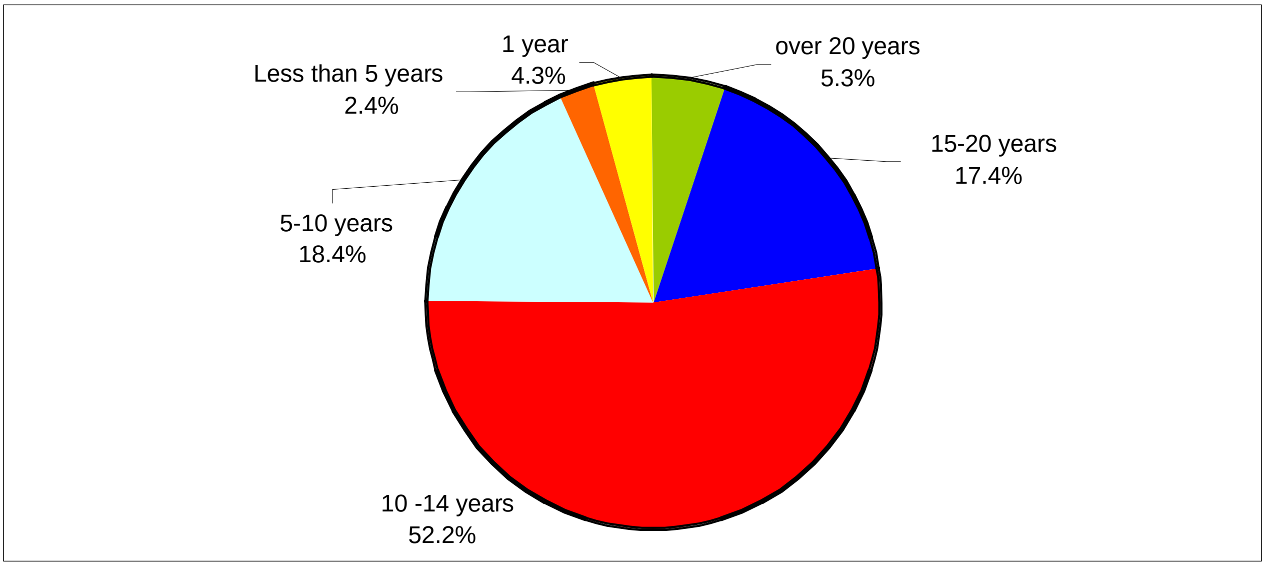


Fig. 2 Breakdown by residual duration of import contracts in force in thermal year 2004-2005



At March 2005, with reference to the 2004-2005 thermal year, the national system counted 26 gas importers (where "importer" means an operator who for customs purposes is the owner of the gas at the Italian border). Part of the gas imported by all 26 operators will enter Italy at Passo Grief; 13 operators will import through Tarvisio and Gorizia, 4 through Mazara del Vallo, 3 through Gela and 4 through Panigaglia. The number of importers is slightly up on the last thermal year (24 importers).

The development of the gas sector in 2004 is reflected concisely in the breakdown of operators shown in Table 20, into "vendors", who re-sell most of the gas purchased on the final market, and "wholesalers", who sell both to other operators and directly on the final market. To establish the share represented by the two categories of operators, a ceiling of 95% of sales on the final market, which reflects normal recourse to balancing and trading activity, has been set.

Table 20 Gas balance sheet in 2004 G(m³)

	Wholesalers	Vendors	Total
Net national production	**12.6**	**0.3**	**13.0**
Net imports(A)	**66.1**	**1.1**	**67.2**
Of which Eni sales at the border	6.5	0.2	6.7
Net withdrawals from storage	**0.1**	**0.0**	**0.1**
- storage at 31 December 2003	4.7	0.1	4.7
- storage at 31 December 2004	4.6	0.0	4.6
Net transfers (purchases – releases to other operators)	**-30.7**	**30.7**	**0.0**
Consumption and losses (B)	**0.8**	**0.3**	**1.0**
Sales to consumers	**47.4**	**31.9**	**79.3**
Electricity generation	31.1	1.0	32.1
Household, commerce and industry	16.3	30.9	47.2

(A) Imports are net of transits (Geoplin).
(B) Estimated consumption and losses on the basis of production, imports, storage and internal purchases.

Source: AEEG, based on operators' declarations

In 2004, apart from Eni Divisione Gas & Power only Enel Trade had total sales of over 10 G(m³). The Edison Group's sales exceeded this threshold only if sales by Edison Energia S.p.A. on the final market were included. Other operators with sales of from 1 to 10 G(m³) were Plurigas S.p.A., Energia S.p.A., Blumet S.p.A., Aem Trading S.r.l. and Blu Gas S.p.A. All the other wholesalers had overall sales of less than 1 G(m³). Only four operators classified as vendors (Italgas Più, Enel Gas, Hera Comm and Aem Energia S.p.A.) had sales on the final market in excess of this level.

The marked increase in national gas demand in 2004 and of auto-consumption in electricity generation, together with the further fall in production, enabled Eni to respect the ceilings on input without any need for recourse to increased gas sales at borders with respect to 2003. The picture shown in Table 20 highlights the marginal role played by vendors in the supply of gas and in seasonal modulation, which these operators delegate almost entirely to wholesalers, from whom they purchase the raw material. In line with the classification set out above, the quantities of gas which these operators release to other operators is also marginal, while purchases from wholesalers, of which the lion's share (nearly 60%) is provided by Eni, are clearly important. It did not seem useful in the context of purchases and sales to highlight the role played by the VTP which, in the absence of the anonymity provided by an actual exchange, continues to act as a bilateral trading market, albeit with the significant advantage of greater flexibility than that envisaged by normal bilateral contracts. The volumes traded at the VTP are shown in any case in Table 21, which shows how the secondary market is growing rapidly in importance over time. The volumes of gas traded at the VTP have tripled over the last three years, to 5.4 G(m^3) in 2004.

Table 21 Gas market (G(m^3))

	Total consumption(1)	Trading organised spot market	Trading forward hub market	Bilateral trading OTC(2)
2002	71.0	not applicable	not applicable	1.7
2003	77.4	not applicable	not applicable	2.7
2004	80.3	not applicable	not applicable	5.4

(1) Gas availability gross of consumption and losses.
(2) Volumes of gas purchased at VTPs or entry points. More precisely, gas purchased on the secondary market; the rest of the gas is purchased on the primary market (i.e. it originates directly from domestic production, imports or storage).

The gas "balance sheet" (Table 20) shows that most of the gas supplied by wholesalers is destined for the electricity generation market. The only exception is small wholesalers, who in practice do not supply this consumption sector. Similarly, supplies by vendors to electricity generators are limited to just 3% of total sales. Overall, about 60% of sales on the final market are made by wholesalers. Only a marginal part of these sales is intended for small consumers with consumption of less than 200000 m^3/year. The degree of specialisation of vendors (and also of small wholesalers) is clear in supplies to customers in the protected market who have opted for the reference tariffs approved by the AEEG. Nearly all wholesalers made use of storage services and provided most of the modulation activities for vendors.

Measures to counter abuse of dominant position

The entry of new operators to the Italian gas market is severely hindered by the control of upstream infrastructure (domestic and international transport networks and LNG terminals) exerted by the incumbent (see section 4.1.2.). For this reason the AEEG has intervened on more than one occasion to ensure access for new entrants and avoid discriminatory conduct by the incumbent or its subsidiaries.

More specifically, following the dispute between the Spanish Gas Natural and GNL Italia S.p.A. (the Eni Group company which operates the Panigaglia terminal), in which the AEEG intervened by ordering GNL Italia to grant access to Gas Natural for the 2004-2005 thermal year, conditions laid down for the use of the terminal have allowed access for a larger number of users. At the end of 2004 the AEEG also opened a fact-finding investigation into the conditions under which GNL Italia managed the Panigaglia terminal in the thermal years from 2001 to 2004, and on the question of LNG procurement for the national market.

Difficulties for new customers in obtaining access to international infrastructure connected to the Italian market have been identified by the AGCM which, in November 2002, ascertained the abuse of dominant position by Eni, originating in the strategic conduct emerging from “innovative sales”. Subsequent to its ruling of abuse of dominant position, the AGCM instructed Eni to up-grade the infrastructure interconnecting the Italian network with abroad with a view to removing the bottlenecks to imports by pipeline, at least in the long term. Eni chose to postpone these up-grades, in the light of the decision by a number of new entrants to invest in the construction of new terminals for the regasification of liquefied gas imported by sea, to overcome (through a bypass operation) the structural barriers to such imports. According to the dominant operator the execution of up-grades on the international network and the construction of new LNG terminals would have enabled such large flows of gas to be imported to Italy as to cause supply surpluses incompatible with the observance of take or pay obligations. Eni’s failure to comply with the infrastructure up-grade requirements translated into a fine of €4.5 million issued by AGCM and in a requirement to release gas to competitors under conditions agreed by the AGCM. Moreover, in January 2005 the AGCM opened a further fact-finding investigation for abuse of dominant position (in the form of exclusion) by Eni, which was accused of strategic conduct tending to monopolise the market for imports of Algerian gas.

Gas release operations

In September 2004 Eni, at the close of the investigation conducted by AGCM into the Blugas case, released gas to competitors for sale on the Italian market, under conditions proposed by Eni itself and approved by the AGCM.

The conditions established for the gas release operation concern access rules and volumes. Batches of gas totalling 2.3 G(m^3) annually are released over a period of four years, making a total of 9.2 G(m^3). The gas is released by Eni on the Italian side of the Tarvisio entry point to the national network (with Eni clearing the gas through customs). Each applicant has access to one or more batches (lower and upper limits are placed on the number of batches) on presentation of exclusive mandates from its customer/s for the corresponding volumes of gas. No more than one company from each group may apply. The gas release price is set by Eni; at the same time as they obtain the gas, applicants present bank guarantees (probably covering the whole four-year period, in the event that long-term allocation has been retained as a condition of the allocation procedure).

The Eni gas released at Tarvisio, amounting therefore to 2.3 G(m^3) for this year, was divided into 37 batches of about 179000 m3/day, allocated to a total of 23 operators. Contemporaneously with the allocation Eni released the corresponding transport capacity it held at Tarvisio to these operators. Only five of the purchasing companies obtained more than one batch.

4.2.2 Description of the Retail Market

At the end of 2004 the companies authorised by the Ministry of Productive Activities to engage in gas sales numbered 389. Most of these companies came into being as a result of the separation of the sales division of former integrated distribution companies. The restructuring of the natural gas trading sector, with the merger of these companies or their incorporation in other larger companies, is an on-going and very dynamic process, and the list of vendors authorised by the Ministry of Productive Activities does not provide a true real-time "snapshot" of operators at any given time. Moreover, a number of wholesalers do not engage in sales activity on the final market and so are not obliged to apply to the Ministry for authorisation to sell pursuant to Art. 17 of Legislative Decree 164/2000.

The classification criterion described earlier identifies 41 "wholesale" operators who sell gas both to other operators and directly to the final market and about 350 "vendors" who engage almost exclusively in re-sales to final customers, using other operators only in the event of surpluses and balancing operations.

An intense concentration process in currently under way in the sales sector. In many cases, the sales strategies adopted by companies are still evolving: the biggest companies in terms of quantities sold have set up companies specialising in specific sales activities and market segments; other operators have opted to operate through the same company on both the retail and markets, with no marked preference for either. As the liberalisation process advances, the experience gained has led to a redefinition of roles with the establishment, and subsequent disappearance, downsizing or expansion of wholesalers and vendors within the same Group. This also explains the variations in volumes sold and numbers of operators in recent years, caused by the fact that sales on the final market by some major companies were carried out by operators classified as wholesalers one year and vendors the next.

Table 22 Development of the retail market

	Total consumption ($G(m^3)$)	No. of companies with >5% of final market	No. independent companies (A)	Market share of the first three companies (%)				Cumulative % customers who have changed supplier (by volume)			
				Thermoelectric uses	Large industrial companies (B)	Small-medium sized industrial and commercial companies (C)	Very small firms and household sector (D)	Thermoelectric uses	Large industrial companies (B)	Small-medium sized industrial and commercial companies (C)	Very small firms and domestic sector (D)
2001	70.1	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
2002	70.0	4	n.a.	85.71		54.31		n.a.	n.a.	n.a.	n.a.
2003	76.4	5	n.a.	74.43		45.60		n.a.	n.a.	n.a.	n.a.
2004	79.3	5	110	80.33	54.14	n.a.	33.27	53(E)		6(F)	1(G)

(A) Completely independent of grid operators
(B) Industrial undertakings
(C) Commercial and service undertakings
(D) Household customers
(E) Standard consumers with annual consumption > 200000 m^3/year
(F) Standard consumers with annual consumption 5000-200000 m^3/year
(G) Standard consumers with annual consumption < 5000 m^3/year

Table 22 contains the main data relating to the retail market. Gas consumption has shown a marked rise, from 70 $G(m^3)$ in 2001 to 79 $G(m^3)$ in 2004. This notwithstanding, the number of operators owning more than 5% of the market remains essentially unchanged, at 5 (Eni Gas & Power, Enel Trade, Italgas Più, Edison Gas and Enel Gas). In 2004 the first three operators covered 80% of sales to electricity generating companies, 54% of sales to industrial customers and 33% of sales to households (equally detailed data for the different market segments for previous years are not available).

Switching

Since 1 January 2003 customers on the natural gas market have been free to continue applying contracts concluded in the past, with the addition of minimum conditions laid down by the AEEG, and to continue to buy gas from their old vendor or else choose:

– a different contract from the range offered by their old vendor;

– a different contract from the range offered by another vendor authorised by the Ministry of Productive Activities.

To switch vendor in the free market customers are required to withdraw from their existing contract under the conditions laid down therein, and to conclude a new contract with another vendor. Subject to a period of advance notice (which for customers with the typical consumption levels of household, craft and commercial users may not exceed 30 days, unless the customer and vendor have agreed on another term that must be set out clearly in the contract), customers may withdraw at any time from their supply contract. The cost of this operation is set individually by vendors; there is no "one-size-fits-all" cost. However, vendors are required to inform their customers of any costs connected with the opening and closure of the contractual relationship. The AEEG plays a supervisory role in ensuring that the costs proposed by vendors are not liable to hinder customers from changing supplier when they so wish.

The percentage of customers to have switched supplier is estimated at around:

- 23% for large consumers (with consumption of over 200000 m^3/year);
- 3% for medium consumers (with consumption of between 5000 and 200000 m^3/year);
- 1% for small consumers (with consumption of less than 5000 m^3/year).

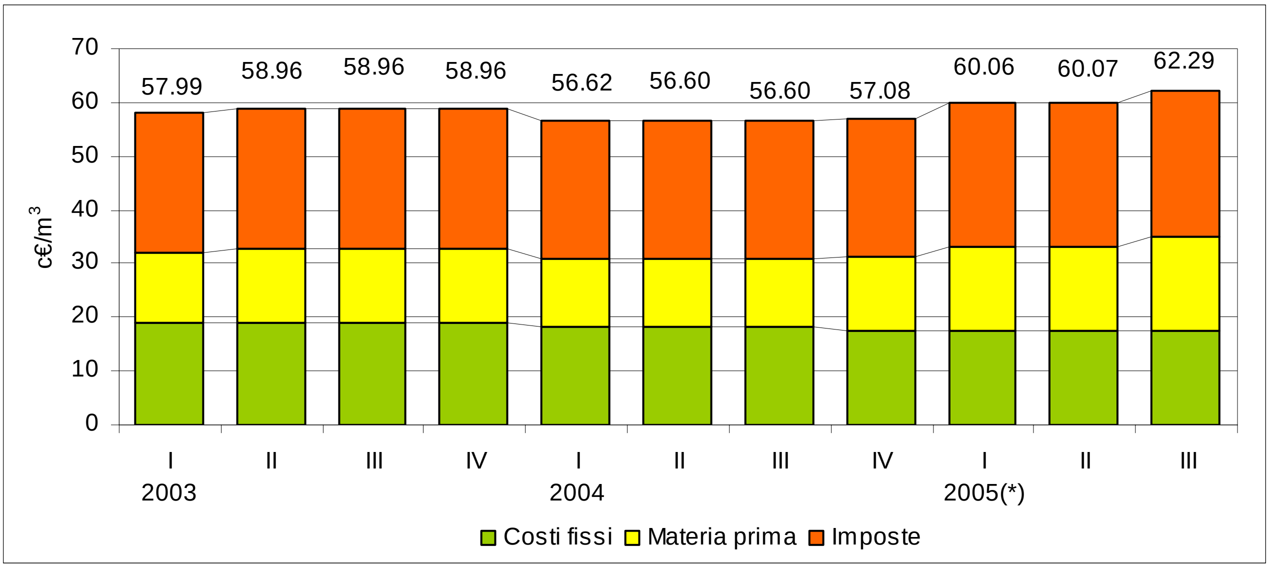
It should also be noted that the percentages rise considerably when the relative quantities of gas are taken into consideration, as shown in Table 22.

Average sale prices

The trend in international prices for oil products, which have risen substantially and continuously since spring 2003, produced a marked acceleration in gas tariffs for Italian households in 2003, while in 2004 the indexation mechanisms established by the AEEG succeeded in calming prices considerably. The trend in the average national benchmark tariff published by the AEEG with reference to small consumers using less than 200000 m^3 per year is shown in Figure 3. This is the average national value under the economic supply conditions defined by Resolution 138/2003 and which sales companies have been required to offer since 1 January 2004, alongside any other specific conditions selected by each vendor, to households and small consumers in the commercial and craft sectors (i.e., customers from the old captive market).

In 2003 the impact of the oil price rises was lessened by the indexation mechanism, thanks to which the value of the raw material component (QE) rose just once, from c€13.21 to c€14.02/m^3 in the second half of the year, to then remain stable for the following two quarters. In 2004, the reduction to c€12.83/m^3 recorded in the first quarter was followed by two quarters in which the price remained stable and then by a final hike to c€13.68/m^3. The impact on the total tariff was of this increase in the raw material component, however, partly attenuated by the contemporaneous reduction in the component covering the costs of distribution on local and urban networks (included under fixed costs) in the last quarter. The AEEG's provision establishing the criteria for the formulation of gas distribution tariffs for the second regulatory period, 1 October 2004-30 September 2008 (as seen in an earlier section of this chapter) dates from that time. As an effect of these provisions, the distribution component in the average national reference tariff fell from c€8.04/m^3 to c€7.53 m^3, reducing its incidence on the final gas tariff to 13.2%.

Fig. 3 Trend in the average national reference tariff for natural gas



2005 opened with a new, marked tariff increase, the causes of which lie once again in the continuing upwards trend in international oil prices, as well as the effect of the tax burden on gas.

With a view to easing the pressures on the overall tariff, the AEEG intervened at the end of 2004 with a new indexation mechanism for the raw material component (Resolution 248/2004). This was intended to make it possible to keep the rise in the QE component in the first quarter of the year to no more than c€14.63/m^3, bringing the total tariff to c€59.0911/m^3. Following the suspension by the Italian administrative courts of Resolution 284/2004 (against which the sales companies appealed), in the second quarter of 2005 the value of the raw material component was re-calculated (with retroactive effect to the first quarter of the year) using the old adjustment method envisaged by Resolution 195/2002, after which it rose to c€15.44/m^3. The overall tariff consequently rose to c€60.06/m^3, where it remained during the second quarter, to then rise to c€62.29/m^3 in the third, once again as a result of the long upwards trend in the prices of oil and the other fuels to which the gas raw material tariff is currently indexed.

Thus, 56% of the average national reference tariff at 1 June 2005 was made up of cost-cover components and the remaining 44% of taxes applicable to natural gas for civil and commercial uses (consumption tax, regional surtax and VAT).

The raw material cost accounts for nearly one third (28%) of the total cost component, marketing costs for 10% and the cost of infrastructure use and maintenance for the remaining 18%. In the context of infrastructure costs the most significant component is distribution, which accounts for 12% of the total tariff; the transport cost component amounts to nearly 5%, and the storage component to 1.5%.

The average prices levels by component in the various market segments are shown in Table 23.

Table 23 Breakdown of final price components (€/m^3)

	I4(A)	I1(B)	D3(C)
Network tariffs (excluding general costs)	0.0207 (*)	0.1015	0.1246(**)
General costs included in network tariffs	0	0	0
Raw material and marketing costs	0.164742	0.193614	0.211510
Taxes	0.019501	0.191143	0.220796
Total (including taxes)	0.204943	0.486257	0.556906

Values for the following standard customers (m^3/year):
(A) 2000001 - 20000000
(B) 5001 - 200000
(C) 500 - 5000
(*) With reference to a supply of gas with load factor of 0.9 at entry point and 0.45 at exit/redelivery point, and distance of 12 km travelled on the regional network.
(**) Includes storage tariff

5 SECURITY OF SUPPLY

5.1 Electricity

Current peak demand and projections for 2006-2008

The power required by the national electricity system reached a historic peak of 53606 MW in December 2004, an increase of 0.4% on peak winter demand recorded in 2003 (53403 MW)[14]. Average summer weather conditions were favourable, and electricity consumption lower than in 2003. However, the month of July saw brief periods of torrid heat which led to record consumption levels, with a historic summer maximum of 53507 MW[15], 0.8% higher than the previous year's peak for the season (53105 MW).

The gap between peak summer and winter levels once again narrowed in 2004, to just 99 MW. This compares with a difference of about 300 MW in 2003, notwithstanding the torrid summer temperatures that year. On 28 June 2005 the power demand on the network reached a new summer high of 54.1 GW. It appears certain that in coming years the winter peak value will be overtaken by the summer peak.

From the growth projections formulated by the GRTN for 2010 and 2015, summer peak power demand on the network over the next few years can be estimated to increase as follows:

- 2006 56.6 GW
- 2007 58.1 GW
- 2008 59.7 GW

with a margin of uncertainty of about 0.5 GW.

Existing generating capacity

Overall generating capacity in 2004, considerably higher than the previous year in both the summer and winter periods, was sufficient to meet demand comfortably while still maintaining sufficient margins of operational reserves to cope with any network congestions or stoppages at generating plants. With an increase of about 1200 MW in net generating power (up 1.5% on 2003), the increase in the available reserve amounted to 5265 MW at the summer peak and 2364 MW at the winter peak.

These results can be attributed to a number of factors: the more favourable climatic conditions in the summer months; strong hydro-electric producibility, which reached a historic maximum after two years of scarcity; the lower rate of thermoelectric plant failures, largely as a result of the milder summer temperatures; better planning of maintenance operations carried out by the GRTN; and the alignment of generating plants

[14] These figures were recorded at 17:00 hours of Thursday 16 December 2004 and 17:00 hours of Wednesday 10 December 2003 respectively.

[15] At 11:00 hours of Friday 23 July 2004.

remuneration mechanisms with the periods considered to be critical for the electricity system.

Investment in generating capacity in 2006-2007

Available power is expected to increase from 69.5 GW at the end of 2004 to 83.2 GW at the end of 2007. The growth in generating capacity over the period is shown in more detail in Table 24.

Table 24 Increase in generating plant capacity in 2004-2007 (MW)

Year	Installed power	Power available at year-end	Capacity entering system during year		Capacity leaving system for decommissioning or reconversion	Net new plant capacity
			New plants	Reconversion of existing plants		
2003	78250	68456				
2004	79314	69520	1390	2556	2882	1064
2005	83516	73722	4921	2680	3399	4202
2006	89360	79566	2430	3700	286	5844
2007	92989	83195	1135	2724	230	3629

Over the 2002-2004 period the Ministry of Productive Activities (MAP) issued authorisations for the construction of new plants for a total capacity of about 20000 MW, with the following geographical distribution:

- North 7957 MW
- Centre North 790 MW
- Centre South 1580 MW
- South 5430 MW
- Calabria 4000 MW

40% of the new authorisations applied to northern Italy, where about 53% of the country's available installed power is already concentrated.

Capacity under construction in 2005 amounted to about 9 GW.

Composition of current and future thermoelectric generation

Thermoelectric production by type of fuel in 2004 is shown in Table 25. The composition of electricity generation changed greatly from 2000 to 2004: the period saw a strong increase in generation based on natural gas; an equally strong increase in the contribution made by coal; a collapse, especially in 2003-04, in fuel oil, which has been overtaken even by coal; and a significant increase in generation from renewable sources, and biomass in particular. This trend is expected to continue into the future.

Table 25 also shows the estimates for 2007 and 2010 based on GRTN and MAP projections. These forecasts are clearly subject to uncertainty with respect to the time required for the siting of new power stations and the conversion of existing ones.

Table 25 Electricity production by source in 2000-04 and projections to 2010 (TWh)

	2000	2001	2002	2003	2004	2007	2010
Gross production	276.6	279.0	284.4	293.9	300.4	325.0	351.7
hydroelectric, geothermal and renewable	51.4	55.1	49.0	48.0	53.7	56.8	68.3
hydroelectric from pumping	6.7	7.1	7.7	7.6	7.5	7.5	7.5
thermoelectric	218.5	216.8	227.6	238.3	239.2	260.7	275.9
- coal	*26.3*	*31.7*	*35.4*	*38.8*	*45.2*	57.6	67.8
- oil products	*85.9*	*75.0*	*77.0*	*65.8*	*44.9*	28.1	11.2
- natural gas	*97.6*	*95.9*	*99.4*	*117.3*	*129.3*	160.3	183.4
- other	*8.8*	*14.1*	*15.8*	*16.4*	*19.7*	14.8	13.6

Plants coming into or ceasing operation in 2004

New plants with a capacity of 1390 MW came on line in 2004. Further increases in capacity, on completion of repowering, reconversion and environmental adaptation initiatives, amount to 2556 MW. Considering that in 2004 capacity amounting to 606 MW was decommissioned and 2276 MW withdrawn for scheduled repowering, reconversion and environmental measures, net new capacity amounted to 1064 MW.

In 2005, new plants with capacity totalling 4921 MW are expected to begin operating, with increases on completion of work on existing plants amounting to 2680 MW. Capacity totalling 601 MW is expected to be decommissioned and 2798 MW to be withdrawn for plant modernisation. Net new capacity therefore amounts to 4202 MW.

Overall, year-end installed capacity increased from 78250 MW in 2003 to 79314 MW in 2004, with a further increase, to 83516 MW, anticipated in 2005. The amount of power actually available is, however, much lower: 68456 MW in 2003, 69520 MW in 2004 and 73722 MW at the end of 2005.

Criteria for the authorisation of new generating investment and the role of long-term planning

At present, no long-term planning function exists for electricity generating capacity. However, Legislative Decree 79/1999 requires the GRTN to draw up expansion plans for the electricity network and these are in effect based on GRTN’s demand and capacity forecasts.

With the aim of averting the danger of interruptions to the electricity supply and ensuring that the country’s requirement is met, Law 55 of 9 April 2002, known in Italy as the “power station go-ahead law”,[16] provides that the construction and operation of electricity plants with over 300 MW thermal power capacity, as well as adaptation or repowering initiatives, and the related works and infrastructure projects required for their operation, are to be considered as public utility works subject to a single authorisation issued by the MAP. This authorisation replaces the authorisations, concessions and any other permits envisaged by law.

The new unified authorisation is issued following a single procedure in which the central and local government bodies concerned take part. It includes the integrated environmental

[16] Confirming, with amendments, decree-law 7 of 7 February 2002 containing urgent measures to ensure the security of the national electricity system.

authorisation, which replaces the individual environmental authorisations previously issued by government departments and local public authorities. The application procedure is considered to be complete once the environmental authorisation has been issued, and in any case no more than 180 days from submission of the original application, including the outline project design and the environmental impact assessment (VIA).

The law envisages that, if the works involve changes to town planning instruments or zoning schemes, the authorisation will have the effect of implementing such changes. The competent regional authority may promote agreements between proponents and the local authorities affected by the projects to identify compensatory measures that respect environmental protection.

Implicit and explicit incentives for the construction of generating capacity

Legislative Decree 397 of 19 December 2003 introduced a generating capacity remuneration system designed to ensure that national demand was covered, with the necessary reserve margins. The Decree provided that during the transitional period all dispatchable production units should be eligible for remuneration, with the exclusion of those subject to CIP6 provisions and those supplied by wind, solar, geothermal, wave and run-of-river sources. Since 29 July 2004 the remuneration system has been extended to include production plants party to bilateral contracts. The Decree also established that, until a competitive mechanism was put in place for the remuneration of capacity, a regulated transitional system should be adopted from March 2004.

The remuneration fee and the arrangements for calculating available capacity for 2004 were established by the AEEG through Resolution 48/2004. The GRTN has selected 63 highly critical and 65 average-critical days on which capacity remuneration is envisaged.

New transmission infrastructure in Italy

Over the last year 5 new 380 kV lines for a total length of 197 km have been added to the national transmission network. By the end of 2006 another three lines are scheduled to come into service, making it possible to increase network reliability in Calabria and reduce some of the congestion in Lombardy and Puglia. In the years following, important connections on Italian territory are planned with a view to achieving more efficient use of energy production in Lombardy and Piedmont, increasing security in north-eastern Italy, up-grading the interconnection between the Centre-North and Centre-South, and enabling fuller use of power stations located in Calabria and Puglia.

New infrastructure for interconnection with member states and regulatory framework

The interconnection with Greece has been operating since 2003. In 2004 the available capacity was set at 300 MW for imports to Italy from Greece, and 500 MW for exports from Italy to Greece.

The 380 kV S. Fiorano–Robbia line, which was completed in January 2004, is the first new interconnection line crossing the Alps to be constructed in nearly 20 years: the last line to come into service on the northern border dates from 1986 (the Rondissone-Albertville line linking Italy and France). The S. Fiorano–Robbia line, built by Terna in just 7 months, is 46 km long and increases import capacity by 1100 MW (15%).

In 2006 the new undersea connection between Sardinia and Corsica is scheduled to begin operating, with the connection with Slovenia, running from Udine to Okroglo, scheduled for 2006 or shortly afterwards.

The GRTN has reached agreements with neighbouring grid operators on Net Transmission Capacity (NTC) on interconnection lines from 1 January 2004 until the completion of initiatives to improve network security. Capacity is divided for each neighbouring country into day and night periods and summer and winter periods. The GRTN has reduced NTC levels as part of a new calculation approach adopted in agreement with the other European grid operators. The new method evaluates a wider range of possible grid configurations and electricity flows to ensure secure operation in all circumstances.

Grid planning procedures with respect to congestions and wholesale markets

In recent years the level of use of the transmission grid has grown considerably as a result of increased demand and delays in investment in new infrastructure. In 2004 the most congested zones were the North-East, the Milan area and Campania. Inter-zonal connections used for electricity transfers from northern Italy to the centre-south of the country, or from the north-west to the north-east of the country, as well as those in areas with limited production centres, were also heavily used.

As new power stations, often located in already congested areas, come into service, this situation could worsen if the transmission grid is not up-graded accordingly. In this light, great importance is given to the coordinated planning and management of network and generating plant downtime, as necessary tools to ensure that dispatching resources are used efficiently to cover requirements.

Legislative Decree 79/1999 and subsequent provisions to regulate electricity transmission activity envisage that the GRTN, in deciding on national transmission grid (RTN) development initiatives, should pursue the objectives of increasing security and guaranteeing continuity of supply, reducing potential constraints caused by network congestions, and increasing the reliability and quality of the transmission service and the efficiency and cost-effectiveness of electricity transmission, while ensuring that environmental and landscape constraints are respected. The main factors of uncertainty are local distribution and the power of new generating plants, as well as the timescales for the construction of the planned new infrastructure.

The start of operations on the electricity exchange on 1 April 2004 made it possible to obtain direct economic signals, based on zonal prices, of the true extent and degree of congestion between the main areas of the Italian electricity system. The results of the day-ahead market in particular point to a considerable degree of market splitting affecting the North and the Centre-North zones, which considerably limits the flow of electricity from the north to the south of the country, as noted earlier.

National grid component downtime connected with development and maintenance works on the grid itself and on production plants is planned at an annual, quarterly and monthly level with a moveable weekly window. The annual plan is drawn up through a cycle of activities which envisages:

- identifying for the year in question works of strategic value to the RTN, in terms of the development of new components and essential maintenance for the operation of the electricity system;
- establishing which constraints these works will cause to the country's generating plant capacity, with a view to harmonising grid downtime plans with the downtime envisaged for individual production units;
- calculating, for each week of the year, secure power margins in the light of production plant maintenance planning, and notifying dispatching of these and of any grid constraints relevant to them that will be caused by strategic works to be carried out on the RTN;
- coordination by the GRTN of the annual plans for the grid and for plants operated by interested parties so that the criteria described above can be met.

Management of emergencies

After the blackout of 28 September 2003, the GRTN developed a plan to increase the security of the electricity system. This is based on several lines of defence, designed both to avoid the separation of the Italian system from the European system, and to manage the consequences of any separations that do take place. The lines of defence involve: the scheduling of operations; online monitoring and control; voltage regulation and system protection; frequency transient monitoring; black start in the event of faults; and checks on production plant structures and operating arrangements.

For example, a system has been set up for the controlled separation of the Sicilian grid and part of the Calabrian grid in the event of a serious emergency affecting mainland Italy's electricity system. To speed up the resumption of the electricity service after a blackout, a standard procedure has been developed that enables thermoelectric power stations to continue to feed their auxiliary services while awaiting reconnection with the electricity system once it is restarted. The possibility of using gas turbine units intended for peak production to boost the electricity system black start service has also been examined. On a transitional basis, remuneration mechanisms providing incentives to producers and eligible customers to offer GRTN an interruptibility service for a total of about 3000 MW, either with or without advance notice, have been developed.

As regards imports, the GRTN and foreign grid operators have equipped themselves with an operating procedure that makes it possible to reduce imports in real time if necessary to enable secure conditions to be restored. In spite of this, interconnection lines continued throughout 2004 to be amongst those most heavily involved in electricity transmission activity.

5.2 Gas

Gas consumption in 2004 and projections for 2005-08

The natural gas "balance sheet" for 2003-04 is shown in Table 26, together with estimates to 2008 based on MAP projections.

Table 26 Natural gas "balance sheet" in 2003-04 and projections to 2008 (G(m^3))

	2003	2004	2008
Production	13.9	13.0	8.4
Imports	62.1	67.3	81.7
Exports	0.1	0.1	0.1
Changes in stockpiles	-1.4	-0.1	0.0
Available for domestic consumption	77.4	80.2	89.9
Energy sector consumption and losses	-0.8	-0.9	-1.0
Electricity transformation	-25.7	-28.0	-32.8
Total final uses	50.8	51.3	56.2
- industry	*20.6*	*21.3*	*23.6*
- transport	*0.4*	*0.5*	*0.6*
- residential and commercial uses	*28.5*	*28.2*	*30.7*
- agriculture	*0.2*	*0.2*	*0.2*
- non-energy uses	*1.1*	*1.1*	*1.1*

Demand for gas increased by 3.7% in 2004, to exceed 80 G(m^3)for the first time. This increase can be explained mainly by the marked increase in consumption for electricity generation, which rose by 8.9%. Consumption by industry also grew considerably, by 3.5%, while the fall in consumption by the civil sector (of 0.9%) is not surprising in the light of the meteorological conditions in 2003, with a cold winter and very hot summer pushing gas consumption above normal levels.

The MAP forecasts suggest an average annual increase in total demand of about 2.9% from 2004 to 2008. This continuing, vigorous trend is related mainly to the growth of consumption in the electricity generating sector (4.0%), but strong growth is also expected in final uses, especially in the industrial and civil sectors, with increases of 2.6% and 2.1% respectively.

Domestic production and import capacity

2004 saw a continuation of the fall in national gas production which had characterised previous years, to 13.0 G(m^3). This compares with 13.9 G(m^3) in 2003 and 16.9 G(m^3) in 2000. As in the case of oil, the decline was caused more by the long-term lack of investment in exploration and development than by the depletion of resources. Additions to reserves have fallen dramatically since 2000 in parallel with the collapse in investment in exploration and development. The technical timescales involved mean that even an immediate return of investment to the levels of the 1990s (nearly five times higher than at present) would not impact on production levels until the last few years of the decade.

At 1 January 2005 continuous nominal import capacity amounted to 260 million m^3/day, which corresponds to about 95 G(m^3)/year. The breakdown of import capacity by entry point to Italy is shown in Table 27. The Greenstream pipeline for imports from Libya entered into service in October 2004 and it is expected to be fully up and running by early 2006. Actual available capacity in 2005 is therefore nearer to 90 G(m^3). Maintenance work and outages could also reduce the capacity actually available by a few percentage points.

Table 27 Continuous transport capacity at 1 January 2005

	M(m³)/day	G(m³)/year
Passo Gries	57.5	21.0
Tarvisio	88.2	32.2
Panigaglia	11.4	4.2
Mazara del Vallo	80.5	29.4
Gorizia	1.0	0.4
Gela	21.5	7.8
Total	**260.1**	**94.9**

Production and import capacity forecasts for the next three years

MAP forecasts indicate that domestic production will fall from 13.0 G(m³)/year in 2004 to 8-9 G(m³)/year in 2008.

Following the AGCM's ruling on abuse of dominant position, Eni plans to up-grade the TAG and TTPC (Tunisian stretch) pipelines, for gas imports from Russia and Algeria respectively, by 6.5-7 G(m³)/year by 2007. Further up-grades to the TAG and TTPC pipelines, again totalling 6.5-7 G(m³)/year, are planned for 2011-2012. Although some uncertainty remains, it seems probable that at least one of the LNG regasification terminals envisaged at Brindisi and Rovigo will be built by 2007-08, bringing import capacity for this period to 110 G(m³)/year.

Role of the regulator and other authorities

Supplier of last resort

The role of supplier of last resort in the gas sector was introduced through Ministry of Productive Activities decree of 12 February 2004, with the double aim of eliminating the distortion of competition created by the failure by many distributors to unbundle their distribution and sales activities and providing a high degree of protection to consumers and more vulnerable customers.

The decree envisaged the presence of a supplier of last resort for each of the 17 catchment areas connected with exit points from the national gas pipeline network and applies solely to the supply of natural gas to customers consuming 200000 m³ or less who, for reasons outside their will, are without a gas vendor authorised by the MAP. The decree also envisaged that suppliers of last resort should be selected through a public procedure. The selection was made on 19 May 2004.

Incentives to increase production and import capacity

Since 2002 the AEEG has introduced provisions to exempt operators who sponsor new infrastructure or up-grades to existing facilities from application of the third party access rules in respect of 80% of the new capacity for a period of 20 years[17]. These provisions were overtaken by similar measures envisaged by European Directive 2003/55/EC and transposed by the Government through Law 239/2004.

[17] Resolution 137/2002 for new gas pipelines and Resolution 91/2002 for LNG terminals.

This law contains provisions for new interconnection infrastructure or up-grades to existing interconnections between the Italian transport network and the networks of both EU member states and non-EU countries, as well as for new LNG regasification terminals and underground gas storage facilities.

With particular reference to the construction of new LNG regasification terminals and interconnectors between the networks of EU member states and the Italian network, Law 239/2004 establishes that:

- exemption from the third party access system (for a minimum of 80% of capacity for a minimum of 20 years) shall be granted by the MAP, subject to the AEEG's opinion; the MAP shall also establishes the principles governing the issue of these exemptions and access to new capacity created in the national pipeline system;
- the remaining capacity of the new interconnection infrastructure or of LNG terminals, as well as the remaining portion of the new transport capacity at entry points to the national pipeline network, are to be allocated to applicants in accordance with procedures established by the AEEG and based on criteria of efficiency, cost-effectiveness and security of the system established in Ministry of Productive Activities decrees;
- provisions applying to operators who fail to observe the criteria on which they have been allocated transport capacity shall be adopted by the AGCM, including through notification by the AEEG.

Law 239/2004 contains a number of provisions to promote the production of natural gas (and other hydrocarbons). These concern:

- the procedures to obtain authorisations, permits, concessions and other forms of assent for hydrocarbon exploration and exploitation;
- the rules governing payments to local authorities as compensation for the prevention of other alternative uses for the territory in question;
- tax incentives for operators;
- the rationalisation of the current fragmented legislative framework through the adoption of a Consolidated Text.

Storage availability for the public service

99% of underground gas storage facilities in Italy are owned by Eni and the sector is therefore regulated as a *de facto* monopoly. With respect to new storage facilities, as with new pipelines and regasification terminals, the law envisages exemption from third party access for 80% of the new capacity for a period of 20 years. In the regulation of storage the dominant role is played by the state. The AEEG establishes the rules for access to storage as well as the criteria and parameters for establishing access tariffs, and verifies that they are being applied correctly.

Concessions are issued by the MAP, which also establishes the technical and construction criteria and essential technical rules governing plants and lays down the efficiency, cost-effectiveness and security criteria for their use. Under the terms of Law 239/2004 the MAP also performs the following main tasks and functions, with the cooperation of the AEEG where appropriate:

- it determines the rules governing natural gas storage in reservoirs;
- it adopts guidelines to ensure the coordinated operation of the storage system, including the provisions for the use of strategic storage when necessary, with the aim of reducing the vulnerability of Italy's natural gas system;
- it grants exemption from the third party access rules, subject to the AEEG's opinion;
- it establishes the general criteria on which the procedural provisions laid down by the AEEG for the distribution of the residual capacity of new and up-graded storage facilities will be based;
- it distributes the residual capacity.

The critical situation of gas storage in Italy was highlighted in spring 2005, towards the end of the cold season (with heating systems still in operation), when the supply of working gas for modulation purposes was insufficient to cover demand and the MAP was obliged to authorise the use of gas intended for strategic storage. Given that in recent years demand for modulation has increased more than storage deliverability, one short-term solution under consideration is to reduce strategic storage.

Infrastructure projects and regulatory framework

In recent years interest in the installation of regasification terminals in Italy has increased. To date, authorisation has been granted for two terminals (Brindisi and Rovigo), for a total import capacity of 16 G(m^3)/year. A further nine terminals are also at various stages of the authorisation process, for a total capacity of between 55 and 75 G(m^3)/year. It seems unlikely that all of these terminals will in fact be built. If even just half were constructed, however, overall import capacity would increase to 140-150 G(m^3)/year by 2015. This quantity is far higher than the national requirement for gas but would be consistent with transit to other EU countries. Two projects to up-grade import pipelines are also under consideration. These would increase import capacity by at least 15 G(m^3)/year. The feasibility study for the Greece-Italy pipeline project, 50% funded by the European Commission under the Trans European Network regulations, was completed recently. This interconnector, which should enter into service in 2008, is linked to the Greece-Turkey system and, through Turkey, with the Blue Stream system transporting gas from the Caspian Sea area. The Galsi project, to transport gas from Algeria through Sardinia to the Tuscan coast, is also at an advanced stage.

Authorisation for new imports is issued by the MAP. Access to national infrastructure is regulated by the AEEG, with reference both to network use tariffs and network codes. As regards access to import infrastructure outside Italy's borders, over which ENI holds transport and control rights, no form of regulation is either envisaged or, under the current legislation, possible. However, in 2003 the AGCM ascertained the abuse of dominant position by Eni, in the form of restricting or refusing access to operators for imports to Italy of gas originating from sources other than Eni[18]. At the end of the investigation, the AGCM ruled that Eni should perform a series of corrective actions. These included making transport capacity on international pipelines available to the

[18] ENI – Blugas investigation.

secondary market, up-grading import pipeline capacity and releasing a congruent volume of gas (2.3 G(m^3)/year) to third parties for 4 years. The first gas was released in October 2004.

Table 28 New Liquefied natural gas regasification terminals

Terminal	Capacity (G(m^3)/year)	Proposing company	State of authorisation
Brindisi	8	BG Group	Authorised
Rovigo	8	Edison - ExxonMobil - Qatar Petroleum	Authorised
Rosignano	3	Edison - BP - Solvay	Modification requested
Toscana offshore	3 - 4	Olt Lng Terminal	At approval stage
Trieste Zaule	8	Gas Natural	Procedure not yet started
Trieste offshore	8 - 12	Endesa	Preliminary stage
Gioia Tauro	4 - 8	Società Petrolifera Gioia Tauro	Modifications requested
San Ferdinando	6 - 12	Lng Med Gas Terminal	Modifications requested
Taranto	8	Gas Natural	Procedure started
Porto Empedocle	8	Nuove Energie	Procedure started
Priolo - Augusta - Melilli	8 - 12	Erg Power & Gas - Shell Energy Europe	Procedure starting
Total	**72 - 91**		

6 PUBLIC SERVICE ISSUES

Supply to the final market

As far as the natural gas sector is concerned, since 1 January 2003 all consumers have been free to choose their supplier. Since that date, the operator providing the sales service to final customers must be different from the one distributing the gas. Companies selling natural gas must be authorised to do so by the MAP. To obtain authorisation sales companies must:

- have a modulation service that is adequate to supply needs, including storage capacity located on Italian territory;
- demonstrate the origin of the natural gas and be in possession of Italian and international transport contracts;
- have adequate technical and financial capacity.

The presence of a supplier of last resort is envisaged to ensure continuity of supply for customers with consumption of 200000 m^3 or less who, for reasons outwith their control, do not have access to a vendor authorised by the MAP. In May 2004 the Ministry selected suppliers of last resort for each of the 17 catchment areas, through public procedures.

In the electricity sector, no form of authorisation to engage in the sale of electricity on the final market currently exists. On the captive market the sales service is generally carried out by distribution companies (with the exception of some operators that have set up separate companies from the distribution company, specifically to carry out sales activities, in both the free and the captive markets). With respect to the free market Legislative Decree 79/1999, which transposes Directive 96/92/EC, does not provide a definition of vendor but identifies wholesalers as the natural or legal persons buying or selling electricity without engaging in any production, transmission or distribution activity in any country of the European Union. If customers were not able to find a supplier on the market, the Single Buyer would guarantee their electricity supply.

Conditions of supply and consumer protection

With respect to the degree of implementation of the measures envisaged by the EU Directives concerning consumer protection matters, the following should be noted.

Italy has not yet implemented Directive 2003/54/EC, according to which electricity suppliers must specify in bills and in promotional material made available to consumers the contribution of each energy source to the overall fuel mix of the supplier over the preceding year.

The contractual conditions of supply included in both electricity and natural gas contracts are binding and intended as minimum standards. They concern meter readings, billing frequency, the method for calculating consumption, the timing and arrangements for paying bills, the arrangements governing late or non-payment, the arrangements and timescales for suspension of supply, payment by instalments, the guarantee deposit, the arrangements for submitting complaints, and the arrangements for reconstructing consumption in the event of meter faults (only for the electricity sector).

In the electricity sector these conditions concern all non-eligible customers (with the exception of high-voltage customers and public lighting systems); under the bilateral contractual system, however, the only regulated aspect is withdrawal from the contract.

In the natural gas sector the above conditions must necessarily be proposed as minimum contractual "benchmark" conditions to all customers in the natural gas market; alternatively, customers may choose other conditions proposed by operators. All vendors on the liberalised gas market who intend to present commercial offers to small consumers (households, condominiums, operators with annual consumption of up to 200000 m^3), who have less negotiating power than companies, may however draw on the Commercial Code of Conduct approved by the AEEG. This Code of Conduct has retroactive effect since for contracts concluded since 1 January 2003, which did not meet the conditions set forth in the Code, sales companies were able to send their customers (no later than 31 January 2005) an information document describing any obligatory contractual clauses not set out explicitly in their contracts.

The uniform rules of conduct established by the Code apply throughout Italy and are intended as an instrument to ensure the play of competition between vendors under equal conditions. The rules with which vendors must comply concern both the promotion of contractual offers and the drawing up of contracts. More specifically, both the information that needs to be made available to customers before the contract is signed, and the main clauses that need to be contained in the contract, are set out.

Contracts must contain at least:

- the identity and addresses of the parties and the supply address;
- an indication of the services covered by the contract (the following must be specified: the technical conditions for the supply of the service, the date the contract becomes effective, the duration of the contract and where applicable the arrangements for renewal, and any additional services);
- the economic terms for the supply of the service and the arrangements to determine any changes and/or automatic adjustments to fees and charges as well as the economic terms for additional services;
- any forms of guarantee required of the customer and any other demand on the customer relating to the completion or performance of the contract;
- the method and frequency of consumption readings for billing purposes; where the contract envisages periodic meter readings, the maximum interval between readings and the arrangements for informing customers in the event of failed attempts to read their meter and the consequences of this should be specified;
- the guarantees available to customers to check the accuracy of consumption metering; billing arrangements and arrangements for payment (the following must be specified: billing frequency; where bills based on estimated consumption are envisaged, the criterion adopted to estimate consumption; and the terms and arrangements for paying bills);
- the consequences of any delay in payment of bills (specifying the penalties or interest due from customers, as well as the minimum time interval between dispatch of the payment reminder and the suspension of supply for non-payment);

- the automatic compensation envisaged for failure to meet any guaranteed commercial quality standards that are additional to those already envisaged by the current regulations;
- the arrangements with which customers formulate requests for information or complaints to the operator, as well as the arrangements for initiating out-of-court procedures to settle disputes.

The Commercial Code of Conduct protects consumers in the event of changes even where these are included in the unilateral clauses of the contract. When, with just cause, operators need to resort to this option, they are required to inform each customer concerned in writing with notice of at least 60 days prior to the changes taking effect. This notification is not required in the event of changes to fees arising from the application of contractual clauses concerning indexation or automatic adjustments; in such cases customers are informed of the change in the first bill in which it is applied. Finally, operators are required to specify in the notification in question the terms and conditions under which customers may express their intention to withdraw from the contract without incurring any cost.

The AEEG has established that all gas sales companies must provide a set of economic conditions calculated on the basis of criteria drawn up and approved by the AEEG, alongside their own economic conditions. These benchmark conditions are published on the AEEG's Internet site. Gas vendors are required to ensure that their own conditions of supply are adequately publicised by publishing them on their Internet site, in a high circulation daily newspaper in the area in question and in the Official Bulletin of the relevant Region or Autonomous Province.

In the electricity sector tariffs for non-eligible customers are published in the AEEG's Internet site while on the free market suppliers inform eligible customers directly of supply options and prices.

Although there are no regulations governing payment arrangements, it is in fact possible to pay bills in a several ways. Operators are always required to offer customers at least one free method (i.e. free of collection charges) of payment within each province served; the choice of method is left to operators. The AEEG's intention with this provision was to ensure that customers would continue to have access to a service provided prior to liberalisation since the decision to reorganise commercial services by progressively reducing the number of branch offices physically present at the local level should in no way preclude the continuing existence of at least one free payment method.

No costs are envisaged for switching supplier in either of the sectors.

When customers feel that the service does not comply with the regulations or with their contract, or that their rights have been violated, they may submit a complaint to the operator, who is required to provide a response, giving the reasons for its conduct, within 20 days. The response must contain precise information (the customer's request, the cause of the fault or poor service giving rise to the complaint and any corrective measures being undertaken to remedy it, etc). More specifically, operators must provide a pre-printed form illustrating the arrangements and procedures for complaints. This form must be delivered to customers whenever a new contract is concluded and/or at customers' request. The procedures for submitting complaints must take the particular needs of elderly and disabled customers into consideration. Complaints may be submitted using any means of communication with the operator that enables the date of receipt to be recorded.

Although the supply of electricity is in effect guaranteed as a universal service, no explanatory statement exists informing customers of their rights in this respect. Similarly, it is not set out in any document that consumers connected to the gas system should be informed of their right to be supplied with gas of a clearly defined quality at reasonable prices.

With a view to protecting consumers who use gas for household purposes, the insurance policy provided for injury, fire and third party liability, which protects consumers from damages deriving from incidents connected with the use of gas, is of particular importance. The AEEG has made a minimum policy, against injury and fire connected with the use of gas, obligatory. This insurance had already been in force, on a voluntary basis, since 1991 and was due to expire on 31 December 2003. The AEEG's provision defined the content of the insurance cover and also extended it to customers using gas other than methane, such as Liquefied Petroleum Gas (LPG), as long as it is distributed over a network. The insurance covers all residential and commercial customers of gas supplied over a distribution network (therefore excluding gas supplied in cylinders), in installations for household and other use. The cost to consumers is included in bills and has remained at €0.40 per year per customer. The provisions envisage minimum cover, leaving customers free to take out additional insurance (for example, to increase their cover ceilings). This minimum insurance cover, applied countrywide, responds to an important social protection and equity criterion, since it covers not just the households responsible for any incident that may take place but also any neighbouring ones affected. The importance of this cover is clear if we consider just how dangerous the incidents recorded each year actually are.

Treatment of vulnerable consumers

The national legislation governing energy matters includes just one general provision for vulnerable consumers, without however providing any definition in this regard. The AEEG itself has not introduced any form of regulation in this respect, but has merely prohibited electricity sector distributors from disconnecting consumers who need electricity to operate vital medical equipment.

The gas sector tariff reform, however, envisages the possibility for local government to set up funds financed by a surcharge not exceeding 1% of gas distribution tariffs net of tax, to cover costs connected with the supply of gas to economically disadvantaged, elderly or disabled customers in accordance with criteria established by municipal councils.

In the electricity sector the AEEG plans to introduce a special tariff solely for economically disadvantaged customers. This tariff will be made available to a limited range of customers identified through the ISEE (an indicator of economic circumstances). Customers eligible for the special conditions will be able to use a certain amount of low cost electricity. The new tariff will be structured in a targeted fashion and applied only to truly disadvantaged customers, who will be given discounts proportionate to the number of people in their household.

Disconnections for non-payment

In cases where customers do not pay their bills by the deadline indicated, operators may disconnect only if the customer has been given advance notice by registered mail.

However, the AEEG does not monitor the number of disconnections for non-payment, but rather the number of reconnections following such disconnections. In the electricity sector these amounted to 311117 in 2004 (for low- and medium-voltage customers), while in the natural gas sector they numbered 42641 (low-pressure customers). The service benchmark is the “maximum time taken to reactivate supply following suspension for non-payment”. This is defined as one week-day for electricity and two week-days for gas; if companies take longer to reactivate the supply they are required to make a compensatory payment.

Regulation of final prices

Tariff regulation mainly concerns activities conducted through networks.

In the electricity sector a tariff component is also applied for the supply of electricity to all household customers, and to non-household customers who have opted not to obtain their supply on the free market. The final prices paid by customers on the captive market are therefore tariffs rather than market prices.

In the natural gas sector, in view of the fact that all customers have been eligible since 1 January 2003, all gas vendors are obliged to offer, alongside their own conditions, the benchmark economic conditions of supply calculated following criteria established by the AEEG, primarily for customers with consumption of less than 200000 m^3 per year. The AEEG’s aim in this respect is to ensure that any choice of new contractual offers on the free market can be made in an appropriate time period and without breaking with the system of guarantees currently in place, and to protect costumers in those areas still supplied by just one operator, who would be able to change prices in the absence of competition by other operators. On the basis of the control and monitoring responsibilities attributed to it by Law 481/1995 , the AEEG verifies whether sales companies are applying the economic conditions of supply in a proper fashion.

Again under the terms of Law 481/1995, tariff movements in the public utilities are regulated by the price cap mechanism, the channel through which the regulator’s efficiency objectives are implemented.

The price cap coefficients in the two sectors are shown in Table 29.

Table 29 Price cap coefficients in the two sectors

<table>
<tr><th colspan="2">ELECTRICITY SECTOR</th><th colspan="2">NATURAL GAS SECTOR</th></tr>
<tr><td rowspan="2">Transmission</td><td rowspan="2">2.5%</td><td>Transmission</td><td>2% (capacity)
4.5% (commodity)</td></tr>
<tr><td>Distribution</td><td>5% (only on 58.16% of the revenue constraint)</td></tr>
<tr><td rowspan="2">Distribution</td><td rowspan="2">3.5%</td><td>Regasification GNL</td><td>1% (capacity)
2% (commodity)</td></tr>
<tr><td>Storage</td><td>2.75%</td></tr>
</table>

The regulatory period is four years, at the end of which the parameters are reviewed.

In electricity transmission and distribution and in gas distribution, when the annual review of tariffs and tariff parameters takes place the price cap is applied only to the parameters intended to remunerate operating costs, including depreciation. In gas transport, regasification and storage the price cap is applied to the parameters as a whole; in future the application of the mechanism will be brought into line with that of gas distribution. During the annual review the AEEG also takes into account the factors indicated in Law 481/1995. These are:

a) the average rate of change in consumer prices for the households of blue and white-collar workers as surveyed by Istat;

b) the annual productivity gain target;

c) improvements in service quality with respect to pre-set standards;

d) costs arising from unpredictable and exceptional events, changes in the legislative framework or changes in obligations concerning the universal service;

e) costs arising from the adoption of actions to control and manage demand through the efficient use of resources.

In conjunction with the annual review of the tariff components covering operating costs and depreciation, the part relating to the return on invested capital is also adjusted. This review is carried out by adjusting the invested capital eligible for remuneration in the sector concerned, taking factors such as inflation and capital deterioration into account, as well as net investments carried out by operators in the preceding year.

The tariff mechanisms designed by the AEEG envisage a national equalisation system through which distributors/suppliers are compensated for the higher costs they have to bear to supply certain classes of customers; no specific remuneration is however envisaged for the supply of last resort service.

In the natural gas sector 90% of the gas consumed by household customers is supplied under the economic conditions laid down by the AEEG; in the commerce and service, industry and electricity generating sectors, 82.1%, 5.1 % and 0.03 % respectively of gas is supplied at prices other than market prices.

In the electricity sector, all household users are supplied on the captive market (such customers will only become eligible with effect from July 2007), while 41.3% of the electricity withdrawn from the network by non-household customers is also purchased on the captive market.

Table 30 Regulation of final prices

	Electricity			Gas			
	Large industrial undertakings	Small-medium industrial and commercial undertakings	Household sector	Thermoelectric uses	Industrial undertakings	Commercial and service firms	Very small firms and household sector
Existence of regulated tariff (Y/N)	Y(A)	Y(A)	Y(A)	N	N	N	Y(B)
% customers with regulated tariffs	41.3		100	0.03	5.1	82.1(C)	90(D)
Possibility of returning to regulated tariff(Y/N)	Y	Y	n.a.	Y	Y	Y	Y
No. of suppliers with tariff proposal obligation (may also apply to all suppliers)	173(E)			353			

(A) Only household customers are obliged to buy electricity at regulated tariffs are they are not eligible customers. Non-household customers may opt to obtain their supply on either the free or captive market.
(B) These are benchmark economic conditions of supply for consumption of less than 200000 m^3/year.
(C) With reference to commercial and service firms of any size.
(D) With sole reference to the household sector.
(E) Distributors.