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 2006

INDEX

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 issued 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 developments in the electricity and gas markets in relation to regulatory activity and the state of competition. Also included is updated information on security of supply and public service obligations.

1 January 2005 saw the completion of the initial stage of the entry into operation of the electricity market, with the introduction of active participation by the demand side, albeit through the mediation of the Single Buyer (SB) for the non-eligible or captive market. This introductory stage, although lengthy, has however produced significant results in terms of greater efficiency, new investments in production activities, new operators entering the market, and a stronger focus on customers' and consumers' rights. However, these results have largely been overshadowed by the concurrent large increases in fuel costs, while their effect on prices has been limited in extent as competition has still not gained a strong enough foothold. The wholesale electricity market still shows a high degree of market power in the hands of dominant operators, led by Enel, who are capable of controlling prices in certain periods, areas of the country and stages of the market.

The gas emergency of the winter of 2005-06 highlighted the structural changes affecting the country's electricity generating plants over the last few years. These changes have led to increased efficiency in electricity generation, while at the same time increasing the proportion of *base load* plants and uncovering problems with the security of the gas supply, which in turn highlighted the increased interdependence between the electricity and gas sectors. As envisaged by Directive 2003/54/EC, in July 2007 all customers, including residential customers, will be free to choose their own supplier. This will be a fundamental step in completing the liberalisation process in the sector, but new measures will be required to safeguard customers. Universal service obligations will need to be defined, as will the economic conditions of supply (similar to those already defined for the gas sector) for those consumers – especially households – who will not immediately be able to exercise their right to choose their supplier. A supplier of last resort will also need to be established.

The development of these new services and the full participation of demand in the electricity market mean that further development of the wholesale markets will be needed, with the definition of forward products or derivatives that provide suitable instruments to hedge price-related risk and manage the procurement portfolio.

In the gas market, in spite of the advances made in the regulatory and legislative framework, the competition situation is progressively worsening as a result of insufficient infrastructure development, which has not kept up with demand, and of Eni's dominant position with respect to the market as a whole. The country's requirements have increased, mainly as a result of increased demand for electricity production, but, as in previous years, national production has continued to fall and Italy's reliance on imports is increasing noticeably from one year to the next.

Given this national situation, with acute problems in the sphere of competition, the AEEG has on several occasions pointed out the need to take prompt action in the gas sector, as has already been done in the electricity sector, to initiate a process of ownership unbundling by companies operating technical monopolies and those operating freely in a competitive environment, regardless of their position in the supply chain. Experience drawn from the specific nature of the Italian market and from the solutions adopted in other countries shows that corporate unbundling is not enough in itself to ensure full neutrality and transparency in transportation and storage activities – services to which all competitors must have access and which should not be concentrated in the hands of any one operator, far less the dominant one. Alongside its recommendations and proposals and its commitment to play a part in the development of international collaboration, in all its work over the years and all its tariff regulation or network access provisions, the AEEG has introduced clear procedures to promote efficient operation and new infrastructure investments. But all these measures taken together will not deliver the expected returns as long as the acute imbalances between operators on the national market and the asymmetries between the frameworks and regulatory systems of the energy systems of individual countries, the EU and supplier countries remain in place.

In both the electricity and gas markets, the principle of unbundling important infrastructure activities has been adopted in advance of the objectives set by the new directives. The regulation of the electricity and natural gas markets has also made it possible to achieve significant improvements in service quality throughout the country, providing all Italian consumers with greater continuity of supply and higher commercial standards.

2 SUMMARY/MAJOR DEVELOPMENTS OVER THE LAST YEAR

Electricity and gas – demand and supply

The collapse of the growth of the Italian economy to almost zero in 2005 was only partly reflected in primary and final energy consumption, which still grew by 1.0% and 1.5% respectively, compared with 2.1% and 1.8% in 2004. Electricity consumption, which reflects the state of the economy more closely, grew by 1.1%, well below the historical average of 2.5% for the last decade. The increase in electricity consumption can be attributed almost entirely to the civil sector (2.3%). Industrial consumption, the other main sector, fell by 0.2%. Natural gas consumption, on the other hand, grew by 6.9%, significantly higher than the average rate of 5.0% recorded in the decade from 1994-04. Gas consumption would have been even higher if its availability had not been affected by a further sharp fall in national production (of almost 1.0 billion cubic metres) as well as by physical limitations in import and storage infrastructure, one of which being the timescale required for imports from Libya to enter fully into play (a development which is not expected until the end of 2006).

The sharp rise in natural gas consumption mainly reflects the rise in consumption for electricity generation, where the use of gas as a primary source increased to 45% in 2005 from 39% in 2004. This increase was largely caused by the reduction in the use of renewable sources, whose contribution fell from 21% to 19% over the same period, and by the slight fall in the part played by coal (from 20% in 2004 to 19.6% in 2005). This last factor can essentially be attributed to the closure of the coal facility in the Brindisi Nord power station as a result of a court ruling following complaints on environmental grounds. Notwithstanding the sustained rise in net electricity imports (49.2 TWh), which have returned to the levels of 2003 and previous years, the restrictions on natural gas procurement ended up sustaining oil-based production, which fell less than anticipated.

Legislative developments

Between 1 January 2005 and 30 June 2006 over 80 legislative provisions were issued which had direct or indirect effects on the electricity and gas sectors. A significant number of these contained urgent measures adopted to cope with the reduced supplies of natural gas from Russia, or recurrent measures such as those establishing the procedures and conditions for electricity imports, in this case for 2006. These and other more specific provisions will be examined in greater detail in the chapters on regulatory activities and security of supply, to which they are directly linked.

Some of the most significant provisions affecting the structure and operation of the electricity and gas sectors are the decrees issued by the Ministry for Productive Activities (MAP[1]) concerning exemptions from the rules governing the right to third party access to new electricity lines providing interconnections with the electricity systems of other countries and to new gas pipelines and regasification terminals built for interconnection

[1] Known as the Ministry of Productive Activities until April 2006, and from May 2006 as the Ministry for Economic Development (*Ministero per lo sviluppo economico*, MSE).

with non-EU member states[2], in accordance with Law 239 of 23 August 2004. These decrees establish the procedures for issuing exemptions to companies investing directly or indirectly in creating or up-grading interconnection infrastructure, with a view to fostering the development of competition and new sources of energy supplies.

Other important provisions issued in 2005 include those updating the directives encouraging electricity production from renewable sources, regulating the issue of green certificates for electricity production from renewables and, more recently, establishing the criteria to incentivise electricity production through the photovoltaic conversion of solar energy[3]. In accordance with the Kyoto Treaty and with Directive 2003/87/EC of the European Parliament and the Council, the authorisations for greenhouse gas emissions for the period 2005–07 were established, as well as the arrangements for the notification of greenhouse gas emissions and for checking and monitoring these notifications[4]. However, there were delays in reporting quotas, the deadline for which was moved from 30 April to 15 September as a result of IT problems at the Italian Register of Quotas and Emissions.

Finally, the Bill for the reorganisation of the energy sector, issued shortly after the new Government took office, is also worthy of note. Although the parliamentary proceedings have not yet begun, and the Bill could well undergo a considerable number of additions and amendments before it becomes law, it is important in its own right in view of the insight it provides to the thinking of the new Government. The text approved by the Council of Ministers is divided into two parts: legislation to be applied directly, and enabling authority to the Government to issue specific regulations through one or more legislative decrees.

The legislative part of the text contains measures pertaining to taxation in the energy sector and the powers of the AEEG. The fiscal measures include the creation of a fund supplied by part of the increased VAT revenue resulting from the increases in the international crude oil price. This fund would be used on a priority basis for measures to encourage the installation of energy infrastructure in Italy, with the remainder being used to encourage the installation of solar thermal energy plants for civil use, promote the use of efficient motor vehicles with a reduced environmental impact and, lastly, reduce the cost of energy supplies for social purposes. The part of the text redefining the AEEG's powers will be discussed more fully later on, in the section on the organisation and competencies of the regulator.

The section on enabling authority to the Government concerns the completion of the liberalisation of the electricity and gas sectors, the implementation of Directives 2003/54/EC and 2003/53/EC, and new measures to boost energy savings and the use of renewable sources. The measures address the whole complex gamut of the energy economy, from security of supply to competition, from environmental sustainability to consumer protection. Briefly, the exercise of the enabling authority would have the following objectives :

- the diversification of gas sources and areas of origin, the creation of new supply infrastructure and gas storage facilities, the shared use by member states of natural gas storage facilities, and the coordination of national emergency plans;

[2] Ministry of Productive Activities Decrees of 21 October 2005, 11 April 2006 and 28 April 2006.
[3] Decrees issued by the MAP and the Ministry of the Environment on 24 October 2005 and 6 February 2006.
[4] Environment Ministry Decrees of 22 March 2005, 23 February 2006, and 2 and 13 March 2006.

- corporate, organisational and decision-making unbundling, the application of ceilings on procurement by dominant operators, measures to promote mergers by natural gas distributors, the integration of European natural gas systems, and financial derivatives linked to physical markets;
- minimum standards for energy yields from heating plants, heating pumps, domestic appliances, etc., the development of renewable sources, the improvement of energy efficiency; and
- public service obligations, transparent conditions of supply, regularity and quality of supply, and the rationalisation of local compensatory measures for the installation of energy infrastructure.

Developments in the electricity market

The gas emergency which occurred during the winter of 2005-06 highlighted the structural changes which have taken place in the Italian electricity generating system in recent years. More specifically, 2005 saw the entry of around 5,000 MW of extra installed capacity, mainly in the form of gas-powered combined cycle plants. While this change has led to an increase in overall efficiency in power generation, and was accompanied by a fall in the degree of concentration on the supply side (which, however, is still high), it has also accentuated the Italian system's focus on base load plants and at the same time brought the problem of security of supply for natural gas into sharper relief.

Fuel price movements on the international markets reflected only in part, and with a time-lag caused by the structure of raw material purchasing contracts, on wholesale electricity prices. On average, in the period from April to December 2005, the purchase price on the power exchange's day-ahead market (Italian acronym MGP, for *mercato del giorno prima*) rose by 13% with respect to the same period in 2004. This compares with a rise of over 40% in the Euro price of crude oil. In the first half of 2006, however, the National Single Price (*Prezzo unico nazionale*, PUN) rose by 34.1% compared with the corresponding period in 2005, while the oil price rose by 38.3% over the same period. We should remember, however, that the trend in the wholesale electricity price is affected not just by fuel price movements but also by a number of other factors. These may include, for example, the price of green certificates and CO_2 emission rights, changes in the overall requirement, the availability of thermoelectric units and hydroelectric production, network congestion, and operators' supply strategies.

One new development in 2005 was the significant rise in electricity exports. This continued into the first quarter of 2006, which also saw a slight reduction in imports. The reasons for this rise, which has fallen off slightly since April 2006, are to be found both in the upwards trend in foreign electricity prices which, especially during low load hours, have mostly been in line with Italian prices, and the introduction of new combined cycle plants which gave rise during night-time hours to production overcapacity that was capable of crowding out imports.

Moving on from the generation and wholesale market segments to the retail segment, we find that the final prices net of taxes paid by non-eligible customers rose by 6% as a annual average in 2005 with respect to 2004. This rise is the end-result of a marked increase in the component covering electricity supply costs (10.5%) and a fall in the components covering transmission, distribution and metering costs.

The complete opening of the market for non-residential customers with effect from 1 July 2004 led to a modest increase in the number of eligible customers supplied on the free market at the end of 2005 (about 200,000 more than the previous year). In terms of off-take, the increase was even smaller (7%). The actual free market therefore equated to 61% of the potentially free market, if measured using final withdrawals, an increase of less than 1 per cent on 2004.

A survey of Italian companies in 2005 showed that they are critical of the current degree of liberalisation of the electricity market. The companies interviewed pinpointed a number of problems that appear to be preventing them from signing contracts with new suppliers or renegotiating contracts with their usual suppliers. The issues they identified include: the lack of information (or publicity), the difficulty of operating in a market that is perceived as still being monopolistic; the lack of clarity and transparency in offers/bids; and the perception that changing supplier is not economically worthwhile.

2005 saw a further improvement in service continuity on the electricity distribution networks: both the number and duration of power cuts without notice were significantly reduced. The duration in particular was cut from 91 minutes per customer per year in 2004 to 80 minutes in 2005, taking all outages into consideration. As regards commercial quality, the data provided by operators show that in 2005 cases of failure to meet the guaranteed quality standards subject to refund and the number of compensatory payments to customers both increased slightly.

Developments in the gas market

The available data do not show significant changes in the breakdown of sales between the free market and the protected market with respect to the situation in 2004. On the whole, sales on the free market remained more or less stable, although their distribution varied across the different consumer categories. For the category ranging from 5,000 to 200,000m^3, the proportion represented by the free market increased from 12.8% in 2004 to 18.7%. For consumption levels of over 200,000m^3 the free market's share remained essentially stable, at 99.0%, while it declined (from 3.0% to 2.3%) for the category consuming less than 5,000m^3.

Significant changes can be seen in the areas of supply and intermediation. The fall in national production is entirely attributable to the fall in production by Eni (down 11%). This reduction probably explains the marked increase in Eni's net imports (an additional 5.6 billion m^3) compared with the essentially unchanged position of other operators. It should however be noted that almost 2.0 billion m^3 were then distributed as gas release. New supplies from Libya, which increased by 4 G(m^3) on the level for 2004, helped to increase the availability of gas for some of the main competitors (Edison, Energia and Gaz de France), while relieving some of the pressure on Eni's sales abroad, which fell by 0.8 billion m^3 overall with respect to 2004.

On the whole, a clear divergence still remains between traditional operators, who purchase from Eni (but also from other wholesalers) and operate essentially in sales on the retail market protected by economic conditions of supply established by the AEEG, and wholesale operators selling mainly on the free retail market. In 2005, wholesalers supplied 86% of the free market but only 33% of the protected market.

Organisation and mandate of the regulator

2005 was the first year of operations after the organisational restructuring in AEEG offices of late 2004, which introduced a planning and strategic control unit answering to the Board, with the support of a Secretary General, and a management unit entrusted to the Director General and the departmental management team. The creation of one single Tariffs Department for electricity and gas, and a Vigilance and Control Department, enabled the AEEG to continue to perform its supervisory role and institutional functions, which have become increasingly important over time.

There were no changes in the AEEG's mandate in 2005. We should however note in this respect that the Draft Bill for the reorganisation of the energy sector, presented in June 2006 by the Government, is likely to restore all the AEEG's original powers, which had been reduced by various legislative provisions over the last few years, and endow it with further powers not explicitly set forth in its founding law.

One particular task being restored to the AEEG is the definition of procedures and conditions for electricity imports, which were originally provided for in Legislative Decree 79 of 16 March 1999 and subsequently transferred by Law 290 of 27 October 2003 to the Ministry of Productive Activities. In addition, the provisions envisaging substitutive powers for the Government in the event of the AEEG failing to comply with legislative provisions that appear to threaten its independence have been superseded. Finally, an extension of the AEEG's mandate to encompass all stages of the supply chain, and not just those operating under natural monopoly conditions, is envisaged, with a view to promoting an effective competitive environment and providing balanced conditions for competition in markets characterised by the presence of dominant operators.

At the same time, the Draft Bill envisages a strengthening of Parliament's role in controlling and monitoring the activities put into play by the AEEG to achieve the general policy aims for the sector as set out by the Government in its macro-economic planning provisions and guidelines.

Finally, the Draft Bill would repeal the provisions of Law 239 of 23 August 2004, which established that the AEEG board should consist of the president and four other members. This would signal a return to the original conditions, where the board consisted of the president and two members. In practice, the board actually consists at present of the president and one member, since the member who resigned at the end of 2004 has not yet been replaced.

Main problems addressed by the regulator

Of the regulatory activities common to both the electricity and gas sectors, the handling of complaints and other reports made by individual customers and consumer associations occupies a position of prime importance. This is followed by consumer protection activities relating to billing transparency and commercial Codes of Conduct (see Chapter

6). It should be noted that in the course of 2005 the AEEG introduced an arbitration procedure for the resolution of disputes involving access to and the delivery of services, whether transportation on the high-pressure gas network or electricity transmission on the national grid.

2005 was the first year in which the procedures introduced by the ministerial decrees setting national quantitative targets for energy savings and the development of renewable sources[5], and entrusting the AEEG with the task of drawing up the rules for the implementation and management of the mechanism, became fully operational. The AEEG approved the rules for the operation of the energy efficiency certification market proposed by the Electricity Market Operator (*Gestore del Mercato Elettrico*, GME) to encourage access to the market for the highest possible number of suppliers. The AEEG has drawn up new charts to quantify primary energy savings and set specific primary energy saving targets for distributors for 2006.

2005 also saw the introduction of Regulatory Impact Assessment[6] (RIAs), which al Italian independent administrative authorities are required to conduct when issuing provisions falling within the scope of their remit. In compliance with the relevant legislative provisions, the AEEG is introducing RIAs on a gradual trial basis. In the first half of 2005 it published a consultation document with a view to establishing an initial debate with operators and associations to hear their observations and proposals. The RIA method has also been applied, for the first time, on two provisions. In the light of the observations gathered during the consultation procedure and the results of the trials, the AEEG has begun a three-year pilot of the new methodology, which will involve a number of its key provisions. RIAs were opened for three legislative provisions in the first half of 2006 and should be completed by the end of the year.

Activity in the electricity sector

Tariff regulation activities focused on: equalisation measures to ensure the correct allocation among distributors of the tariff revenue resulting from the application of the single national tariff; an evaluation of the tariff charges envisaged to remunerate the metering service and the commercial activities required for the sales service provided for customers in the captive market; the setting of tariffs for smaller electricity firms; the rules governing special tariff schemes for electricity supplies used to produce and process aluminium, lead, silver and zinc, as well as supplies used for the electro-chemical chlorine cycle in Sardinia; other special tariff schemes; the management of the incentives for solar energy plants[7]; and, lastly, the determination of nuclear costs for the three years from 2005 to 2007.

The AEEG has also identified measures to promote competition in the wholesale electricity market with a view to reducing the appeal to operators of exercising market power and has laid down the rules implementing the Community regulation[8], which envisages the application of market mechanisms for the allocation of available

[5] Ministerial decrees of 24 April 2001, subsequently replaced by the Ministerial Decrees of 20 July 2004.
[6] Article 12 of Law 229 of 29 July 2003.
[7] Decrees issued by the Ministry of the Environment on 28 July 2005 and 6 February 2006.
[8] EC Regulation 1228/2003 of the European Parliament and of the Council.

interconnection capacity and cover from the risk of congestion cost volatility on interconnection networks.

As regards technical economic regulation, the AEEG took action on a number of issues with provisions on: accounting and administrative unbundling; a review of the dispatching regulations; obligatory withdrawals for production units supplied by non-programmable sources; strategically relevant production and pumping plants; changes to the hourly bands for the period 2006-07; adjustments to the benchmarks for the classification of co-generation plants; the development of the metering service; and network connections. It also took action, within the scope of its remit, in the process of "re-bundling" the ownership and management of the national transmission network through the merger of Terna and the division of the former *Gestore della rete di trasmissione nazionale* (the Italian Transmission System Operator, GRTN) dealing with transmission and dispatching.

In the area of service quality, the AEEG confirmed for 2004-07 the regulation incentivising reductions in the duration of outages, and introduced new quality standards regarding the maximum number of interruptions per year for medium- and high-voltage customers. It also reviewed the transmission service quality parameters and began work on a voltage quality monitoring system on medium-voltage distribution networks.

Activity in the gas sector

Tariff regulation activity in the gas sector should mainly be viewed in the light of the conclusion of the first regulatory period, between the end of 2005 and the start of 2006, for tariffs for transportation, the use of LNG terminals, and storage. In particular, the new tariff regulations drawn up by the AEEG are intended to promote the development of national transportation infrastructure, regasification terminals and new storage capacity, especially at delivery points. The aim is to ensure security of supply and the functioning of the Italian gas system, develop stronger competition in the market and create liquidity that would in part be used to develop a European-level hub in Italy itself. The AEEG has also introduced changes and additions to the criteria for calculating the distribution tariffs for natural and other types of gas, not least to allow in the tariff for investments made by distribution companies.

As regards the promotion of competition and the market, the AEEG approved and published an up-dated version of the contract for the use of the Virtual Trading Point (*Punto di scambio virtuale*, PSV) and at the same time opened a consultation on the standard contract for gas trading at this point. In the international arena the AEEG worked in conjunction with the CEER and also, and in particular, with the Austrian Energy Regulator, to seek a solution to congestion problems on gas pipelines carrying imports, most notably on the TAG.

The *technical-economic regulatory provisions* included the up-dating of the Network Codes for the national and local distribution networks. The regulations governing the allocation of transport capacity were amended, and new city-gate management procedures were introduced. A consultation was also opened on the extension of hourly metering for customers with an annual consumption in excess of 200,000m^3. The AEEG drew up criteria to ensure free access to the natural gas storage service and established the obligations with which storage operators must comply and the rules governing the content of Storage Codes. In this context, it opened a consultation procedure on compulsory modulation requirements and capacity allocation criteria. The AEEG has laid down similar criteria to ensure free access to the LNG regasification service and regulations governing the Regasification Codes, thus completing the legislative framework for access to and the use of gas infrastructure. Finally, with the gas emergency of January 2006 the AEEG drew up a provision to establish a temporary voluntary interruptibility system for industrial customers, based on market principles.

The regulation of gas *service quality* focused mainly on the regulations governing the security and continuity of the gas transportation and distribution service. Stricter criteria on gas quality were introduced, with specific reference to heating power, the pressure and temperature of the gas supply and the level of odourisation. The AEEG introduced temporary, simplified rules concerning security downstream of gas redelivery points for the activation of new user-plants and related checks and inspections. As regards the commercial quality of the gas distribution and sales services, new response time requirements were introduced for sellers, in the light of their role as direct points of contact with consumers.

3 REGULATION AND PERFORMANCE OF THE ELECTRICITY MARKET

3.1 Regulatory issues

3.1.1. Overview

The complete opening of the market for non-residential customers with effect from 1 July 2004 led to a modest increase in the number of eligible customers supplied on the free market at the end of 2005 (about 200,000 more than the previous year). In terms of off-take, the increase was even smaller (7%). The actual free market therefore equated to 61% of the potentially free market, if measured using final withdrawals, an increase of less than 1 per cent on 2004.

Table 3.1 Opening of the electricity market

	Eligible customers at 30/06/2004	Eligible customers at 30/12/2004	Eligible customers at 31/12/2005	Customers supplied by the free market at 31/12/2004	Customers supplied by the free market at 31/12/2005
No. customers (withdrawal points)	278,468	7,592,912	7,747,182	126,606	329,864
Withdrawals (A) (TWh)	192.0	217.6	223.2	127.8	136.6

Note: The Italian Railway Network, which accounts for withdrawals amounting to about 4 TWh, is not included.

(A) The figure for withdrawals for eligible customers at 30/06/2004 refers to 2003.

Source: AEEG, using data from distributors

A survey of Italian companies conducted by Gfk-Eurisko in 2005 highlighted their criticisms of the current degree of liberalisation of the energy market. The companies interviewed pinpointed a number of problems that appear to be preventing them from signing contracts with new suppliers or renegotiating contracts with their usual suppliers. The issues they identified include: the lack of information (or publicity), the difficulty of operating in a market that is perceived as still being monopolistic; the lack of clarity and transparency in offers/bids; and the perception that changing supplier is not economically worthwhile.

3.1.2 Allocation of interconnection capacity and congestion management mechanisms

The Ministry of Productive Activities (MAP) decree of 13 December 2005 established the terms and conditions for the regulation of electricity imports in 2006. The decree confirms the separate allocation by foreign operators and TERNA S.p.A.[9] of 50% each of the available capacity net of long-term contracts, equating to 2,000 MW held by Enel and earmarked for the Single Buyer to supply the captive market.

[9] The reunification, or "re-bundling", of the ownership (TERNA) and management of the national transmission grid (a division of GRTN) took effect on 1 November 2005. Please refer to the section on Regulation of transmission and distribution companies.

A European Court of Justice ruling of June 2005 established that the priority allocation of cross-border capacity to long-term contracts entered into by the Dutch market incumbent in the period preceding the Community Directives is not admissible. In the Court's opinion, a state cannot allocate priority capacity to a company unless this is authorised with notification to the European Union in the envisaged time frame.

The *Commission de régulation de l'énergie* (CRE) and *Réseau de Transport d'Electricité* (RTE), the regulator and operator respectively of the French network, decided to interpret the Court's ruling, which in actual fact related specifically to the Dutch electricity market, in a wider sense and established that from 2006 they would no longer guarantee the capacity previously reserved for long-term imports by the Single Buyer. According to the recommendations put forward by the French grid operator, the capacity in question, of 700 MW, was to be assigned automatically through explicit auctions. The Italian Ministry (MAP), however, decided to disregard the French institutions' unilateral decision to eliminate the cross-border capacity reserve enjoyed by long-term contracts, since it considered the role of the electricity imported in performance of the Italian-French long-term contract to be entirely marginal with respect to the competitive structure of the relevant Italian market.

In January 2006 TERNA announced that, on the basis of a temporary agreement drawn up with RTE on 30 December 2005, and in accordance with the recommendations received from the MAP, the provisional allocations of cover certificates on the French border would be effective and guaranteed from 1 January to 31 January 2006. The allocations for the rest of the year are being guaranteed on a monthly basis under transitional agreements between Terna and RTE, pending a definitive agreement on capacity allocation by the competent Authorities.

Table 3.2 Destination of import capacity by border for 2006 (MW)

	France	Switzerland	Austria	Slovenia	Greece	TOTAL
Interconnection capacity	2,650	3,890	220	430	400	7,590
Long-term contracts for captive market	1,400	600				2,000
Capacity allocated by foreign operators	625	1,645	110	215	200	2,795
Capacity allocated to San Marino, Vatican City, Edison, Raetia Energie	94	197				291
Total available capacity to Terna	531	1,448	110	215	200	2,504
Maximum available rights allocable to captive market (26%)	*138*	*376*	*29*	*56*	*52*	*651*

Source: MAP Decree of 13 December 2005 and TERNA .

Table 3.2 summarises the breakdown (by border) of interconnection capacity for the winter period, at daily peak times, for 2006.

The MAP Decree of 13 December 2005 confirms the provisions laid down for the previous year and establishes that the use of transportation capacity should be determined through an implicit allocation method based on electricity sale and bids for cross-border trade flows by foreign and Italian operators. This essentially matches imports to the zones into which the Italian electricity market is divided.

AEEG Resolution 269/05 also recommended, in conjunction with the application of the implicit auction method, that this market mechanism should be accompanied by the introduction of financial hedges to be distributed to final users. These hedges relate to the price differentials between neighbouring countries and import zones and are intended to protect Italian final users from the risk of congestion cost volatility on interconnection networks.

More specifically, the AEEG has established that the price hedges should be allocated through an explicit auction, while in 2005 they were distributed free on a *pro quota* basis. The auction procedure for the allocation of these hedges, which are known in Italy as *Coperture dal rischio in importazione* or CCCIs, thus become an explicit expression of the secondary market, which enables price signals to be formed and the economic outcomes of the methods adopted thus far to be maintained.

Those entitled to take part in the allocation of CCCIs were users of the withdrawal dispatching service (including the Single Buyer, which is responsible for supplying the captive market), to whom price risk hedges covering a maximum of about 650 MW (26% of the interconnection capacity allocable on the Italian side) were reserved by ministerial decree. Cover for the remaining import capacity was reserved for consumers on the free market, also through their wholesalers.

By formulating offers to purchase transportation rights, interested parties put a value on the rights applied for. After the auction was held, CCCIs were allocated to the parties who had made the best bid, subject to the maximum allocable quantity. Each assignee is required to pay the marginal auction price for the rights assigned to them. Resolution 269/05 envisages that Terna should set an allocation price for CCCIs that is equal to the lowest bid price of those accepted.

The Resolution also introduced a mechanism to redistribute the proceeds of allocations. This is based on the amount of energy withdrawn on average by each operator taking part in the procedure as a proportion of national consumption levels. The mechanism was designed to reduce charges for access to the electricity system and at the same time prevent a substantial part of transportation capacity from being allocated to operators in a position to influence Italian prices, not least in the light of the evidence given by the AEEG in its report made to the Anti-Trust Authority (*Autorità garante della concorrenza e del mercato*, AGCM) on the high prices on the day-ahead market in June 2004 and January 2005.

In March 2006 Terna also announced the outline procedure for the negotiation of CCCIs allocated on an annual basis, as established by Resolution 269/05. Terna oversees the monthly negotiations, in which users of the off-take despatching service can take part as buyers or sellers, under transparent and non-discriminatory conditions. Each party who has purchased CCCIs must comply with the obligations and is the "owner" of the rights envisaged for parties to whom hedges are allocated in the annual auctions.

Alongside the CCCIs, which were already in place in 2005, Resolution 269/05 introduced a new type of hedge, called CCCEs, to cover the risk involved in electricity exports from an Italian zone to a foreign zone. In a system that is the mirror image of the one adopted for CCCIs, CCCEs confer the right to receive from Terna a sum equal to the product of the capacity to which the hedge refers and the difference between the hourly price in the virtual zone for the border to which the hedge refers and the price in the neighbouring zone.

The hedges are allocated by Terna, using auction procedures based on similar criteria to those adopted for CCCIs. However, whereas Terna allocated CCCIs on an annual basis through auction procedures differentiated by electricity border, CCCEs are allocated on a monthly basis with sole reference to the southern border, the quantity being established each month by Terna itself. Moreover, no redistribution mechanism is envisaged for the proceeds.

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 Economic Affairs and Finance, and activities connected with ownership of network infrastructure, which remains in the hands of operators. In the model adopted in Italy, inefficiencies and difficulties have however emerged in coordination between the operator and owners of the grid. This led the Government to propose the "rebundling" of transmission system ownership and operation, a process that took effect in November 2005 with the creation of Terna – Rete elettrica nazionale S.p.A..

Terna currently owns over 90% of the national transmission grid, while the remaining infrastructure is owned by a number of municipally owned companies and electricity producers, 13 in total. The companies holding the biggest stakes in the grid infrastructure are Edison Rete S.p.A., which owns nearly 3,000 km of high-voltage lines; AEM Trasmissione S.p.A., with just over 1,000 km, and Rete Ferroviaria Italiana S.p.A..

Terna today owns about 35,000 km of lines as well as 302 gate stations and 3 remote operation centres. In September 2005 the company purchased Acea Trasmissione S.p.A., which owns about 700 km of high-voltage network, or about 2% of the national grid. This purchase opened the national transmission grid unification process as envisaged by Law 290 of 27 October 2003, concerning the reorganisation of the electricity sector, and by the Prime Ministerial decree of 11 May 2004. In the course of 2005, in the light of the process of unifying the transmission network under the ownership of a single independent operator, Enel reduced its holding in Terna. As things stand at present, 29.99% of the shares of the company are owned by Cassa depositi e prestiti S.p.A., while Enel holds 5.12%. In January 2006 Terna published its Development Plan for the National Transmission Grid, subject to approval by the MAP. The Plan contains an analysis of current and future issues and problems affecting the grid and sets out the main development initiatives envisaged. These initiatives are classified according to the main benefits they will bring: the system's capacity to cover needs; operational security; reduction of congestion and market bottlenecks; and improved quality and continuity of service and supply. The initiatives were also divided into short- to medium-term works, usually relating to the coming five years, and long-term activities, referring to the next decade.

By envisaging just one distribution concession for each municipal zone and giving local authority "subsidiaries" the option of asking former monopolist Enel to dispose of branches carrying out distribution activities in their municipal area, Decree 79/1999 opened a gradual rationalisation process in this sector of activity, which is set to continue in coming years.

In 2005 and the first half of 2006 Enel Distribuzione sold divisions operating in about 226 municipalities to other distributors, for a total of 312,000 customers. Over the same period networks serving three municipal areas were transferred to the company, for a total of about 7,000 customers.

The reorganisation process led to a reduction in the number of operators in this segment of the electricity supply chain: at 30 June 2006 there were 168 distribution network operators, compared with about 200 in 2000. In most cases, the network is owned and run by the same operator.

Transmission and distribution tariffs

Last year's Annual Report provided a full description of the mechanism used to set transport and distribution tariffs. In accordance with the provisions of the Quality Code for the second regulatory period (2004-07), the AEEG is required to adjust the transmission and distribution tariff parameters on an annual basis. Metering service charges, however, are not subject to automatic annual adjustments. The annual transmission and distribution tariff adjustment for 2006 envisaged:

- the application of the price cap mechanism (see also Table 6.1) to the transmission and distribution tariff components covering operating costs and depreciation;
- a review of the value of the invested capital allowed for tariff purposes at the national level, to take into account net investments completed in 2004.

The annual adjustment did not involve substantive changes in either the transmission cost or distribution cost components; some fractional increments with respect to tariff adjustment mechanism targets were determined by the cumulative effect of the roundings applied to charges during previous adjustments.

As part of the annual adjustment of transmission and distribution tariffs, the AEEG also reviewed the tariff components covering the allowed costs arising from service quality improvements and from the adoption of initiatives designed to control and manage demand through the efficient use of resources. More specifically, the costs allowed for service quality improvements were increased by about 80%, from 50 million euros in 2005 to about 90 million euros in 2006. As regards the costs arising from initiatives to control and manage demand through the efficient use of resources (distribution tariff components), the revenue requirement was not changed with respect to the 2005 level, of 50 million euros.

Table 3.3 Regulation of transmission system operators

	Number of companies regulated at 30 June 2006	Estimated transmission tariff (€/MWh) from 1 July 2006		
		Ig	Ib	Dc
Transmission	13 (owner companies)	3.60	3.49	69.40 (A)
Distribution	168	40.2	5.83	

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

Electricity service continuity – commercial quality

2005 saw a further improvement in service continuity on electricity distribution networks. As an effect of the provisions introduced by the AEEG with effect from 2000 and re-defined for regulatory period 2004-07 (base levels for outages and annual improvement targets for each region), both the number and duration of interruptions without notice were significantly reduced in the course of the year.

Table 3.4 Electricity service continuity indicators

Indicators	2000	2001	2002	2003(A)	2004	2005
Duration of outages per low-voltage customer (minutes lost per customer)	187	149	115	104	91	80
Number of long outages per year per low-voltage customer	3.6	3.1	2.8	2.7	2.5	2.3

(A) Excluding scheduled disconnections and blackouts.

Source: AEEG

The overall duration of interruptions for low-voltage customers fell from 91 minutes per year per customer in 2004 to 80 minutes per year per customer in 2005 (taking all outages into consideration), an improvement of 58% on the figure for 1999 (table 3.4). The number of long outages (lasting more than 3 minutes) was reduced from 2.5 per customer in 2004 to 2.3 in 2005 (again taking all outages into consideration), an improvement of 39% on the figure for 1999.

It should also be noted that in 2005 a new mechanism was introduced to regulate interruptions attributable to external causes, which were previously excluded from the scope of regulation. The new mechanism envisages greater accountability on the part of operators and is based on the voluntary adoption of measures involving a reduction in outage-recording requirements.

With effect from 1 January 2006 new quality standards for the maximum number of outages (long and without notice) per year for medium and high voltage customers came into force. Customers in these categories who experience more outages than envisaged in the standards are eligible for automatic compensation in proportion to the extent of the outage and the inconvenience or damage suffered.

By the end of 2007 all distribution companies should be in a position to identify precisely all individual customers (including low-voltage customers) involved in each outage, so that in future the individual standards and related compensation can also be extended to low-voltage customers. To this end, in the early months of 2006 a survey of the state of progress of the procedures and systems needed to achieve this objective was conducted.

Finally, in 2005 the monitoring of medium- and high-voltage quality on a sample representing 10% of the distribution network continued, with a view to introducing new regulatory measures.

As regards the quality of the transmission service, the rules introduced in this area in 2004 were implemented in 2005. For the first time, these envisage obligations to record interruptions to supply affecting users of the national transmission grid, and transparency in various aspects of transmission service quality. In January 2006 the AEEG approved the quality targets for the transmission service, which cover interruptions in supply to customers and distribution companies (directly connected to the national transmission grid) for which Terna can be held responsible.

The rules governing commercial quality standards were reviewed in 2004, with the introduction, *inter alia*, of a system to monitor telephone service quality with respect to waiting times and the time elapsing before customers making calls to commercial call centres hang up. In 2006 an investigation was opened into the quality of electricity and gas suppliers' call centre replies to consumers.

Balancing

In the Italian electricity system a special market, known as the Dispatching Service Market (*mercato per il servizio di dispacciamento*, MSD), has been operating since April 2004. This market is intended to ensure the "physical" balancing of electricity demand and supply by addressing imbalances between scheduled and actual flows. In this market GRTN and Terna procure the resources needed to solve congestions, ensure balance and provide an adequate system reserve.

From the point of view of the operation of the MSD, 2005 saw no further changes with respect to those made in 2004 and described in last year's Report.

The results recorded in the MSD in 2005 illustrate the different nature of this market compared with the energy markets (day-ahead market (*mercato del giorno prima*, MGP) and adjustment market (*mercato di aggiustamento*, MA)). The average prices of step-up and step-down offers/bids actually bear little relation to the prices recorded in the MGP. Operators' average sales prices are also considerably higher than the value attributed to electricity on the MGP, while purchase prices are lower, as a reflection of the diverse structure of this market and the different nature of the resources traded in it.

In 2005 GRTN/Terna's average purchase prices on the step-up MSD was €96.29/MWh, while the average sales price was €22.03/MWh.

The step-up bids accepted *ex ante* on the MSD in the course of 2005 amounted to 11.59 TWh in terms of volume, or 3.6% of the volumes traded on the Italian system. Step-down bids amounted to 13.07 TWh, or 4% of the volumes traded on the system.

2005 saw a number of changes in the regulation of imbalances, in conjunction with the participation of the demand side in the Power Exchange. More specifically, a simplified system was envisaged to quantify imbalances, the aim being to reduce their cost for operators withdrawing electricity with respect to the conditions envisaged once their participation in the despatching service market is fully up and running. The adoption of this system is intended to give demand-side operators whose off-take programmes are not significant to the TSO's projections of the resources required for despatching, the time needed to improve the accuracy of their projections.

More specifically, for dispatching points for non-relevant consumption units, for that part of the imbalance that exceeds 10% of the overall schedule for the point in question the normal imbalance prices are replaced with prices that reflect a deduction from or addition to the zonal prices, depending on whether the aggregate zonal imbalance is plus or minus. For the rest of the imbalance, the zonal price is applied for calculation purposes.

In 2005 imbalances at consumption units belonging to the captive market were quantified and evaluated in accordance with the provisions of Resolution 168 of 30 December 2003 as supplemented and amended. The quantity of unbalanced electricity attributed to the Single Buyer in its role of dispatching service user for these consumption units amounted to about 1.1% of the total requirement.

To ensure that the demand side has the necessary learning time to manage their transactions on the MGP efficiently, the rules governing the electricity market also envisage that GRTN/Terna should be able to present additional offers on that market to ensure that the resulting level of demand does not diverge by more than 5% in absolute terms from their projections.

As in 2004, the rules governing imbalance charges were not applied to dispatching service users with responsibility for dispatching points for non-relevant production units.

For the years subsequent to 2005, Resolution 293 of 28 December 2005 amended Resolution 168/03, concerning the conditions for the delivery of the despatching service and the supply of the related resources, by introducing a number of new measures to improve the flexibility of the negotiation system. More specifically, in the light of the outcome of the transitional regulations applied for imbalance charges for 2005 at non-relevant consumption units, and reports by operators on this subject, the AEEG considered that once the system was fully up and running the same charging structure should apply to both consumption and production non-relevant units. With this adjustment, imbalances at all non-relevant units are penalised less heavily than imbalances at relevant units.

The main differences between the method used to determine the imbalance charge for non-relevant units and the method previously envisaged by Resolution 168/03 and the arrangements envisaged for dispatching points at relevant consumption and production units include:

- the fact that the imbalance price is independent of the "sign" (plus or minus) of each dispatching user's actual imbalance: the imbalance charge depends not on this factor but on whether the aggregate zonal imbalance is positive or negative;
- the arrangements for determining the actual imbalance charge, which refers to the average price rather than the marginal price of the bids/offers accepted for real-time system balancing purposes.

To enable a gradual transition to this method of calculating imbalance charges for non-relevant consumption units, a transitional mechanism is envisaged for 2006. This includes the application of a threshold of 7%, below which imbalances are calculated at the MGP price. This system is similar to the transitional one applied for 2005, with the exception of the threshold level, which has been lowered from 10% to 7%. One effect of this reduction is to encourage consumption units to schedule their requirements more accurately, while reducing the overall charge incurred and limiting the possibility of subsidies among dispatching users.

3.1.4 Regulation of unbundling

At present in Italy, on the basis of the legislation currently in force and pending the complete implementation of the European Directives concerning the common rules for the Single Market for electricity and gas, most electricity distribution companies also operate in sales to the captive market. Legislative Decree 79/1999 of 16 March 1999, implementing Directive 96/92/EC, envisaged a requirement for the owners of distribution plants supplying more than 300,000 customers to set up one or more companies limited by shares, to which to transfer their assets and liabilities relating solely to electricity distribution and sales to non-eligible customers. Law 239 of 23 August 2004 subsequently reformulated this provision by establishing that "operators owning distribution concessions may set up one or more companies limited by shares, of which they shall retain control and to which they shall transfer existing assets and liabilities relating to electricity distribution and sales to non-eligible customers. The Authority for Electricity and Gas shall issue the criteria for the timely operational and administrative unbundling of the activities engaged in by the above-mentioned companies".

In 2005 the AEEG embarked on a review of the rules governing accounting and administrative unbundling in the electricity and gas sectors. This reform will take into account:

- the need to harmonise the AEEG's resolutions with the principles contained in the European Directives concerning the common rules for the Single Market for electricity and gas;
- the principles and guidelines contained in the enabling authority to the Government envisaged by Law 62 of 18 April 2005, for the transposition to Italian law of the above-mentioned Directives[10];

[10] Given that the enabling authority for transposition, as contained in Law 62 of 18 April 2005 (Community Law 2004) has expired, the Bill presented by the Minister for Economic Development (formerly Minister for Productive Activities)

- the changes in the rules governing companies limited by shares introduced by Art. 1 of Legislative Decree 6 of 17 January 2003, with particular reference to the content of financial statements and annexes;
- the need for a more systematic and uniform framework for the provisions governing accounting and administrative unbundling for operators in the gas and electricity sectors.

On 16 March 2006, a consultation document was therefore issued in which the position expressed in the resolution opening the review process was set out in more specific terms. These proposals concern the timeliness, for some services in the energy supply chain, of moving towards the ownership unbundling of the activities in question, and the aims pursued through the introduction of administrative and accounting unbundling rules in the electricity and gas sectors, which is to say:

- guaranteeing neutrality in the operation of networks and, more generally, of infrastructure operated on a concession basis or else essential to the development of a free energy market. This would require companies and groups of companies owning and operating such infrastructure to be organised in such a way that, including during any transition to ownership unbundling, would safeguard their independence with respect to the interests of operators of other segments of the electricity and gas supply chain, especially those operating in liberalised segments;
- guaranteeing, through the correct and transparent disaggregation and attribution of the balance sheet and income statement items of the activities concerned, the absence of crossed subsidies between these activities, especially between those subject to tariff regulation and those operating in markets undergoing liberalisation;
- guaranteeing a reliable, uniform and detailed information flow regarding the economic situation and financial status of companies operating in the electricity and gas sectors. Here, and in accordance with the regulatory objectives laid down by the AEEG's founding law, the focus would be on their cost structure in matters concerning the promotion of competition and efficiency and the definition of a reliable, transparent tariff system.

In this light the consultation document envisages the introduction of functional unbundling, the aim being to guarantee, in terms of organisation, decision-making and management powers, and the availability of commercially sensitive information, the independence and neutrality of activities operated on a concession basis or essential to liberalisation.

The document also proposes a simplified approach to accounting unbundling. Without requiring the creation of a separate general accounting system for each activity, this envisages the adoption of a model which would still provide meaningful accounts for each, in keeping with the organisational models adopted by the companies concerned and through the use of appropriate instruments such as management accounting.

Since the application of the rules governing functional unbundling will have potentially significant repercussions on the organisational structure of the companies concerned, the

in June 2006 envisages a series of measures designed to complete the liberalisation of the electricity and gas sectors in implementation of Directives 2003/54/EC and 2003/55/EC.

AEEG intends to initiate further timely studies, with the creation, for example, of a working group with the operators involved. The aim here is to draw up guidelines for the application of functional unbundling principles, with particular reference to the structure of companies' compliance programmes. On completion of the consultation process, by the end of 2006, the AEEG will adopt a provision on functional and accounting unbundling, while the arrangements for compliance programmes will be formalised and defined by the end of 2007 in a separate provision.

For information on transmission activity, please refer to the points set out in section 3.1.3.

3.2 Competition issues

3.2.1 Description of the wholesale market

In 2005 demand for electricity, at 329.4 TWh, increased by 1.3% with respect to the previous year. Demand peaked in December, at 55,015 MW.

In spite of the increased demand, gross national generation, at 302.4 TWh, decreased by 0.3% as a result of the significant increase in the balance with abroad. 2005 also saw an increase in thermo-electric production as a proportion of overall gross output with respect to 2004, with a rise of 2.4% to about 246.3 TWh.

Generation using natural gas increased by about 15% on 2004, to 148.9 TWh, in parallel with a contraction in production from oil products (down 24.1%) and solid fuels (down 3.6%). The increase in natural gas consumption for electricity production in 2005 can be explained by the lower use of interconnection capacity with abroad, which coincided with the entry into service of new gas installations. These circumstances, along with the problems experienced with natural gas imports, gave rise to an emergency situation in the supply of the necessary reserves at the beginning of 2006.

As regards renewable sources, 2005 saw a significant reduction, of 16%, in hydro-electric production from natural sources, mainly as a result of the low rainfall in Northern Italy in the winter months. Overall, generation from renewables fell by two percentage points as a proportion of gross production, from 18.4% in 2004 to 16.4% in 2005.

The foreign balance for 2005 – the difference between imports, which amounted to 50,264 GWh, and exports, which amounted to 1,109 GWh – was - 49,155 GWh. This was an increase of 7.7% on the balance for 2004, although the figure was lower, of about 1,800, GWh than that recorded in 2003. This latest increase reversed the trend that had emerged over the previous two years, which saw a reduction in imports after several years of continuous growth. The foreign balance covered 14.9% of the national electricity requirement in 2005, compared with 14.0% the previous year.

Two contrasting factors affected the import-export balance. The first was the significant increase, of 8.3%, in imports in 2005, partly as a result of the entry into service of the new 380 kV San Fiorano-Robbia and Gorlago-Robbia interconnection lines with Switzerland. These lines paved the way for an increase in maximum transportation capacity, which ranged on a daily basis from 7,450 MW to 6,300 MW during the winter period and from 6,350 MW to 5,800 MW during the summer period (May-September 2005, with the exclusion of August). The second factor affecting the balance was the 40.2% growth in exports, which in all months of the year except July and August were higher than in the previous year.

In terms of electricity generated, 2005 saw a further contraction in Enel's market share, to 39.0%, a reduction of about 4.5 percentage points which benefited some of the other big producers such as Eni, Endesa Italia, Tirreno Power and AEM Torino. At present, the second producer in Italy is the Edison group (11.7%), followed by Eni (9.0%), Endesa Italia (8.2%) and Edipower (8.0%). The other operators all have market shares of less than 5%.

The Herfindahl-Hirschman Index (HHI) shows a reduction in market concentration, with reference to gross generation. The index value for 2005 was 1,900, compared with 2,220 in 2004.

Table 3.5 Development of the wholesale market

	Total demand[(A)] (TWh)	Peak demand (GW)	Net installed capacity (GW)	No. of companies with a > 5% share of generation	% share of generation held by the 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	325.4	53.6	81.5	5	64.4
2005	329.4	55.0	86.8	5	59.7

(A) Net of energy for pumping stations and gross of network losses.

Source: AEEG using data from Terna and producers.

2005 saw an increase of more than 5,000 MW in gross installed capacity, a rise of about 6.4% on the previous year. The new capacity, amounting to about 4,400 MW, was mainly from thermo-electric plants and included the thermo-electric capacity of the Edison and Eni groups in particular, each of which declared increases of about 1,000 MW on 2004. Maximum net generating capacity at 15 May 2006, considering plants with power of more than 10 MW[11], was 75,089 MW. Five operators had a market share of over 5%: Enel Produzione (49.6%), Edison Group (9.9%), Edipower (8.8%), Endesa Italia (8.0%) and the Eni Group (6.0%). The first three operators accounted for 68.4% and the HHI index was 2,759.

If we consider plant use categories, just under half of the maximum net available power of Italy's generating plants consists of base load plants, of which the great majority are thermal. 37.5% are mid-merit plants and 8.3% are peak plants, about two-thirds of which are pumping plants. 6.5% of capacity consists of auto-production plants.

As regards the functioning of the electricity market, the most important new development in 2005 concerned the active participation of demand in the bidding system. When the Power Exchange opened in 2004, transitional provisions were adopted restricting access to

[11] Net of long-term down-time.

the Exchange to the supply side, the aim being to enable the new negotiating mechanism to build up gradually to full operational status. Further to the ministerial guidelines issued on 24 December 2004, these transitional arrangements were amended for 2005 to enable the gradual participation of the demand side in the bidding system.

Table 3.6 Breakdown of generating capacity by type of plant use

Plant type	MW	Share %
Base load	35,781	47.7%
of which thermal	30,468	
of which hydro	3,128	
of which other	2,185	
Mid-merit	28,196	37.5%
of which thermal	16,013	
of which hydro	8,173	
of which pumping	4,010	
Peak	6,231	8.3%
of which thermal	2,202	
of which pumping	4,029	
Auto-producers	4,883	6.5%
TOTAL	75,089	100.0%

Source: AEEG using Terna data (Production units register, 15 May 2006)

The regulated market run by the Electricity Market Operator (*Gestore del mercato elettrico S.p.A.*, GME) can be divided into two sub-markets: the day-ahead market (MGP), and the adjustment market (MA). Then there is the despatching service market (MSD), in which first GRTN and now Terna procure the resources they need to carry out their transmission and despatching activities and guarantee the security of the electricity system. The regulations envisaged for the dispatching market in its fully operational form envisage the active participation of demand in all these markets, but under the transitional provisions for 2005 it participates only in the MGP.

The fact that demand only takes part in the MGP has made it necessary to introduce transitional mechanisms to make up for the reduced negotiating flexibility of demand-side operators unable to take part in the MA and MSD. These mechanisms take the form of:

- scheduled imbalances, which enable operators who are party to contracts drawn up outwith the bidding system to present unbalanced in-put and off-take schedules on the MGP. In such cases, in-puts must be higher than off-takes and the difference is considered as a sale on the MGP by the purchasing operator to GRTN/Terna at a price equal to the National Single Price (*Prezzo Unico Nazionale*, PUN);
- the Bilateral Adjustment Platform (*Piattaforma di aggiustamento bilaterale per la domanda*, PAB) for the demand side, in which balanced hourly electricity trading can be conducted by operators of off-take points belonging to the same geographical zone. Any trading notified to the GME through this platform, which performs a similar

function to the MA, along with any commitments deriving from bilateral contracts or from purchases on the MGP, determine the binding schedule for each off-take point.

In addition to the above measures, and the envisaged simplified system for quantifying imbalances, the electricity market regulations also provide for GRTN/Terna to present supplementary offers/bids on the MGP to ensure that the level of demand resulting from this market does not diverge from its projections by more than 5% in absolute terms.

In 2005 the new mechanisms introduced with the active participation of demand affected significant volumes of electricity which, with respect to the volumes traded overall on the Italian system (trading on the MGP plus bilateral contracts), amounted on average to 2.7% for the supplementary GRTN/Terna bids/offers, 2.9% for the PAB and 4% for scheduled imbalances.

The overall performance of the MGP in 2005 confirms that some structural problems still remain, mainly on the supply side. These translate into prices that are on average high and growing progressively (net of seasonal cycles) as a result of the continuing tensions in the markets for oil and the other fuels used in generation. The average purchase price, given by the weighted average sales price for consumers' purchases, was €64.00/MWh, an increase of 13.1% on the previous year. If we take the arithmetic average, the purchase price was €58.59/MWh.

The volumes traded on the MGP in 2005 amounted to 203.0 TWh, of which 139.2 TWh were sold to the Single Buyer, which procures electricity for the captive market; 47.7 TWh were sold to other operators; 8.1 TWh were used for pumping; 2.8 were sold abroad; and 5.3 TWh were used in supplementary offers/bids by GRTN/Terna.

On the MA, the market designed to adjust the schedules resulting from the MGP, the weighted average price for purchases was €62.40/MWh, a rise of 23.8% on 2004.

Table 3.7 Electricity market (TWh)

	Total consumption (net of pumping)	Trading on organised *spot day-ahead market* (net of pumping)	Trading on *forward market*	Bilateral trading – OTC and auto-consumption (net of pumping)
2002	310.7	0	0	310.7
2003	320.7	0	0	320.7
2004	325.4	65.3	0	260.1
2005	329.4	194.9	0	134.5

Source: AEEG using data from Terna and GME

The regulations governing GRTN/Terna's procurement of resources for use in the delivery of ancillary services did not change with respect to 2004. The MSD is the market on which the TSO procures dispatching services to solve intra-zonal congestions, create an electricity reserve and ensure real-time balancing. The market is held in two sessions: the first, which takes place immediately downstream of the adjustment market, is where the TSO buys and sells electricity to generate reserve margins and solve any residual congestions (*ex ante* MSD); the second lasts for the whole of the following day and is used by the TSO to buy and sell electricity to balance the system in real time (*ex post* MSD).

Sale bids/offers, i.e. those indicating agreement to increase in-put (step-up bids/offers), and purchase bids/offers, i.e. those indicating agreement to reduce in-puts (step-down bids/offers) must both be submitted on the MSD. At present, users of the off-take dispatching service do not take part in the market.

Table 3.8 shows the market shares and HHI index for each of the 4 segments into which the MSD is divided, for 2005. The quantities sold by the TSO on the *ex ante* step-down MSD amounted to 13.07 TWh, while 11.59 TWh were purchased on the step-up market. 7.94 TWh were sold on the *ex post* step-down MSD, and 9.81 TWh were purchased on the step-up market.

Table 3.8 Market shares and HHI index in the four segments of the MSD

	ex ante MSD bids/offers step-up	ex ante MSD bids/offers step-down	ex post MSD bids/offers step-up	ex post MSD bids/offers step-down
Gruppo Enel	46.3	75.3	79.5	85.0
Endesa Italia	24.0	7.8	8.4	5.3
Edipower	15.8	14.3	7.1	6.1
Edison Trading	4.9	0.2	0.8	0.3
Tirreno Power	3.0	1.9	2.3	1.9
AEM Trading	2.3	0.2	0.8	0.5
ASM Brescia	1.8	0.1	0.8	0.5
Azienda Energetica - Etschwerke	0.8	0.1	0.0	0.0
S.I.E.T	0.5	0.0	0.1	0.2
AGSM Verona	0.3	0.0	0.0	0.0
AceaElectrabel Trading	0.2	0.0	0.0	0.1
Ottana Energia	0.1	0.0	0.1	0.1
Other	0.1	0.1	0.0	0.0
Total	100.0	100.0	100.0	100.0
HHI Index	**3,010**	**5,945**	**6,451**	**7,299**

Source: AEEG using data from GME and TERNA .

Table 3.9, which provides an overview of electricity procurement in Italy, shows auto-consumption; trading in the bidding system, with details of CIP6 electricity (produced by plants using renewable and/or assimilable sources and benefiting from incentives under Interministerial Pricing Committee Provision no. 6 of 1992) and supplementary bids/offers by GRTN/TERNA; and the electricity sold through physical bilateral contracts. The total includes electricity earmarked for pumping. CIP6 electricity is bought by GRTN/Terna pursuant to Legislative Decree 79/1999 and then sold by them in the Exchange; the same decree also established that this electricity should enjoy priority dispatching status.

In the years between the approval of Legislative Decree 79/1999 and the start of operations on the Exchange, GRTN sold this electricity to consumers through the sale of annual and monthly bands of electricity assimilable to bilateral contracts. With effect from 1 January 2005 GRTN/Terna has offered CIP6 electricity directly on the Exchange. Operators to which quotas of this electricity are allocated are required to enter into a contract for differences with GRTN/TERNA, in which they undertake to procure the amounts assigned to them on the electricity market. Under this contract, in 2005 assignees received or paid the difference between the average market price (PUN) and the allocation price, of €50/MWh, for their allocated capacity quotas. In confirming the mechanism drawn up the previous year, the MAP decree of 5 December 2005 established a new set price applicable throughout 2006, of €55.5/MWh. This price is constant for all hours of the year.

Table 3.9 **Structure of electricity procurement for 2005 (TWh)**

Requirement including pumping	338.8
Auto-consumption	21.5
Net electricity sold on the bidding system	203.0
of which Cip 6	51.9
of which supplementary GRTN/Terna offers/bids	3.4
Physical bilateral	114.3

Source: AEEG using data from GME and TERNA .

Overall, the electricity procured through bilateral contracts amounted to 114.3 TWh. No detailed information is available on the duration of these contracts, although most of them are annual.

As regards the integration of the Italian market with the markets of neighbouring countries, the period from January 2005 to June 2006 confirmed that a significant price differential still remains between the Italian Power Exchange (IPEX) and the main foreign exchanges, although the PUN rose less on average than in the other exchanges. The IPEX showed the highest price for peak-load hours, with the average price as much as double that of the other European markets. Even in off-peak periods, the Italian price was one of the highest over the period as a whole.

As a result of this price differential, flow on the interconnection lines with abroad was essentially unilateral, in the form of imports, which accounted for 100% of the hours on the northern border and 33% on the southern border (compared with an export flow of 8%). In percentage terms, as in 2004, transit saturation levels were reached in only a small number of hours, less than 2% on an annual basis on the northern border and 1% on the southern border.

The high volumes of electricity trading with neighbouring countries are still not giving rise to true market integration, given the persisting congestion and transmission constraints preventing alignment between the Italian price and prices in the other markets. This is reflected in the limited correlation between prices on the Italian exchange and prices on the other European exchanges in the period January 2005–June 2006, as shown in Table 3.10.

Table 3.10 Average daily price correlation indices for European day-ahead markets (1 January 2005 – 30 June 2006)

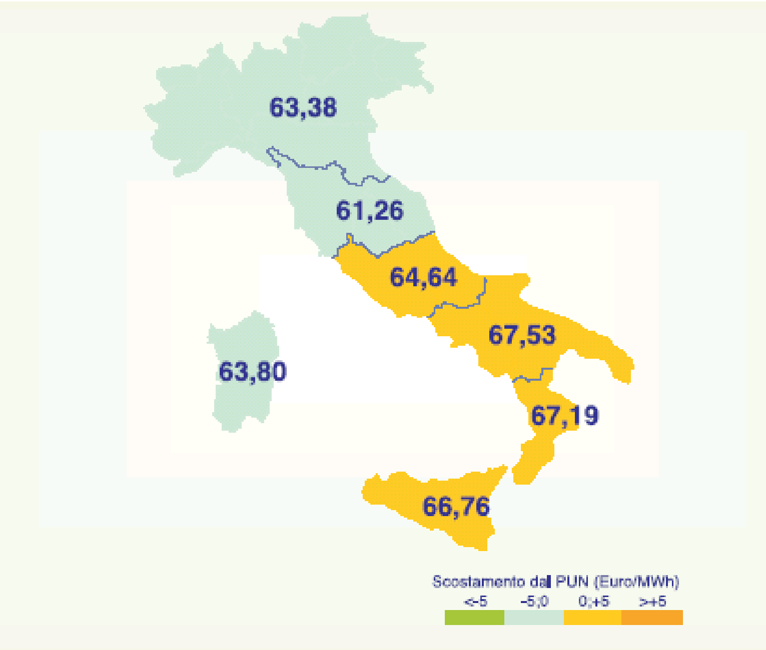
	EXAA	APX	EEX	PowerNext	OMEL	NordPool	IPEX
EXAA	100%						
APX	77%	100%					
EEX	95%	75%	100%				
PowerNext	93%	76%	90%	100%			
OMEL	66%	53%	64%	68%	100%		
NordPool	34%	28%	32%	32%	18%	100%	
IPEX	62%	47%	61%	59%	52%	50%	100%

Source: AEEG using data from European electricity exchanges.

As regards the level of zonal fragmentation within Italy, 2005 saw a decrease of 29% in the average number of zones into which the market is divided, from 3.17 in 2004 to 2.25. Italy acted as a single market zone in 20% of the hours (compared with 3% in 2004) – the second most frequent configuration. The mainland zones remained unseparated in 62% of the hours (compared with 36% in 2004).

2005 also saw a considerable reduction in the sales price differential between the different zones of the electricity market, from €22.13/MWh to €6.27/MWh. The growth in the PUN, in particular, was driven by the zones which in 2004 had the lowest prices, a trend which nudged zonal prices upwards. Average annual prices in the North and Centre North were once again lower than the PUN average (at €63.38/MWh and €61.26/MWh respectively), while the South and Calabria once again had the highest average prices, of €67.53/MWh and €67.19/MWh respectively.

Figure 3.1 Average zonal sales prices on the MGP (€/MWh)



Source: GME
[Colour bands indicate divergence from PUN (€/MWh)]

Turning to mergers in the electricity sector, the acquisition of a joint holding in Edison by EDF and AEM Milano was completed in the second half of 2005.

On 16 September, Transalpina di Energia (TdE) acquired about 63% of Edison's ordinary share capital from Italenergia Bis along with 240,000 Edison warrants convertible in ordinary Edison shares.

Edison is controlled by TdE, a company which is not itself controlled, under the terms of Art. 93 of Legislative Decree 58/1998, by any natural or corporate person. TdE is jointly owned by two partners, WGRM Holding 4, wholly controlled by EDF, and Delmi, which in turn is 51% controlled by AEM. No party exercises management and coordination functions over Edison.

The result of this operation was the creation of a stronger actor in electricity generation, which can be equated to the Enel Group in Northern Italy and which could have a positive effect on exchange prices in the medium-to-long term. This will of course depend on the time taken to finalise arrangements between the parties to the agreement, the industry-level repercussions and the risk of possible collusion with Enel in wholesale price-setting.

At the same time as the EDF-AEM agreement, the Italian Government issued a decree law on 14 May 2005 removing the 2% limit on EDF's voting rights in Edison. This limit was established by Law 301/2001 and prevented any foreign company from holding significant interests in energy companies in Italy.

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 (non-household customers who have chosen to change their supplier).

In 2005, consumption on the captive market, based on the preliminary figures provided by distributors, declined by over 2% on the previous year, to 152,6 TWh[12] or about 53% of the total market net of auto-consumption. This fall is wholly attributable to a contraction in withdrawals by non-eligible, non-household users. For these consumers, mainly small firms, craft businesses, professional practices, etc, who acquired eligible status on 1 July 2004, demand fell by about 4%, while residential consumption showed virtually no change on its 2004 level.

The captive market continues to show a high degree of concentration, mainly to the benefit of Enel Distribuzione, which still holds an extremely high market share of 85.5%. The three principal distribution companies, Enel Distribuzione, Acea Distribuzione and Aem Elettricità, cover 93.6% of the captive market.

At 31 December 2005, there were about 7.7 million eligible, and therefore potentially free, customers, who in the course of the year withdrew 223.2 TWh of electricity (net of consumption by Rete Ferroviaria Italiana), about 5.6 TWh more than the previous year.

[12] On the basis of the preliminary estimates provided by Terna, electricity consumption by non-eligible customers amounted to 150.8 TWh in 2005.

The average off-take per customer remained essentially stable with respect to 2004, at 28,814 kWh.

About 330,000 customers were actually procuring their electricity on the free market by 31 December 2005, for an overall volume of 136,6 TWh[13], or 61.2% of the potential market.

The operators selling electricity to users on the free market are wholesalers and producers; on the basis of a survey carried out by the AEEG the number of wholesalers who in 2005 were operating in the sales market independently of distribution companies was 193[14], out of 247 who responded to the survey. It is estimated that the total number of wholesalers is about 400, although many of these do not appear to have engaged in any trading activity in 2005. Supplies to the free market were mainly provided by wholesalers, with sales of between 1 and 10 TWh. These represent about 52% of the market, with the biggest wholesalers accounting for about 36%. Overall, producers only provided about 3% of supplies to the free market.

Five companies held a market share of 5% or over in 2005: the Enel Group (13%), the Edison Group (10.8%), Egl Italia (9.1%), the Eni group (8.5%) and Energia (5.3%). Overall, these groups cover just under half of free demand. In terms of demand by large industrial users, with annual consumption of over 5,000 MWh, Enel, Egl Italia and Eni led the field, covering 40.3% of demand. In the case of medium-sized industrial users and commercial users, 26.7% of demand was covered by Edison, Enel and Energia.

In the course of 2005 the AEEG took part in the Energy 2005 multi-customer survey conducted by GfK-EURISKO on electricity and gas demand in Italian companies. The survey was conducted on a representative sample drawn from the entire Italian non-household customer base (2,700 local business units), stratified by geographical area, product sector and employees. The aim of the survey was to provide a snapshot of customers' awareness of energy market liberalisation issues and examine their behaviour in this respect. As regards this last point in particular, 6% of the non-household customers interviewed had signed a new contract (mainly those with high consumption); about 2% of these had changed contracts but stayed with the same supplier. For the approximately 95,000 companies with annual consumption of over 100,000 kWh/year, the effects of market opening are more evident: it is in this segment that the biggest advance of alternative suppliers to the former monopoly holder can be seen.

In spring 2006, the AEEG conducted a survey on electricity sales to retail customers. The results (which include information on switching rates) will be available at the end of September.

[13] On the basis of the preliminary estimates provided by Terna, electricity consumption by eligible customers amounted to 135.7 TWh in 2005.

[14] These companies are either not included any corporate group, or are members of groups which do not include companies engaged in distribution.

Table 3.11 Conduct with respect to liberalisation

Percentages of responses to the question: "How has your company behaved with respect to market liberalisation?"

	LOCAL UNITS WITH ANNUAL CONSUMPTION OF:					TOTAL COMPANIES
	UP TO 5,000 kWh	5,001 – 10,000 kWh	10,001 - 100,000 kWh	100,001 - 500,000 kWh	OVER 500,000 kWh	
Has signed a new contract with a new supplier	1.17	0.84	7.75	36.30	66.55	4.32
Has signed a new contract with a new supplier but then returned to the previous supplier	0	0	0.05	1.12	0.24	0.05
Has signed a new contract with the old supplier	2.21	0.57	0.9	1.25	3.30	1.46
Has not done anything, has kept old supplier	96.67	98.59	91.29	61.33	29.90	94.17

Source: Energy 2005 multi-customer survey.

Electricity prices paid by standard customers as defined by Eurostat, and a breakdown of these prices, are illustrated in table 3.15.

Table 3.12 Electricity tariffs

July 2005

Standard customer (Eurostat definition)	Dc	Ib	Ig
Wholesale price of electricity or cost of generation	75.78	76.51	69.49
Transmission tariff (excluding general charges)	67.23	3.50	3.27
Distribution tariff (excluding general charges)		37.61	5.83
Estimated energy sales marketing margin		1.23	0.003
Grid losses	9.12	4.09	3.71
General charges	7.30	9.22	8.40
TOTAL (€/MWh)	159.43	132.16	90.70

July 2006

Standard customer (Eurostat definition)	Dc	Ib	Ig
Wholesale price of electricity or cost of generation	86.80	94.98	82.80
Transmission tariff (excluding general charges)	69.40	3.60	3.49
Distribution tariff (excluding general charges)		40.21	5.83
Estimated energy sales marketing margin		1.23	0.003
Grid losses	10.30	5.02	4.37
General charges	14.20	16.62	15.80
TOTAL (€/MWh)	180.70	161.66	112.30

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.
- General charges include: stranded costs, incentives for renewable sources and other residual costs not connected to production and network services.
- The domestic tariff at July 2006 is calculated on the basis of a different tariff option from the one used for July 2005, which is no longer applicable for new users.

3.2.3 Measures to Avoid Abuse of Dominant Position

The AEEG's activity to promote competition in the wholesale market continued throughout the year. The conclusions of the fact-finding investigation on the state of liberalisation of the electricity sector conducted jointly with the Anti-Trust Authority (AGCM) and published in Resolution 19 of 9 February 2005, and the results of the monitoring of the wholesale and dispatching markets conducted by the AEEG, gave rise to Resolution 212 of 7 October 2005 containing "Measures for the promotion of competition in the wholesale electricity market for 2006".

The joint investigation showed that the structural framework of the wholesale electricity market was characterised in 2004, and presumably in subsequent years, by the presence of one operator, Enel, with varying but extensive degrees of market power in all four relevant markets, known as macro-zones (Macro-zone North, Macro-zone South, Macro-zone Sardinia, and Macro-zone Sicily), and by the presence of one operator, Endesa Italia S.p.A., with market power in Macro-zone Sardinia. The results of the wholesale and dispatching market monitoring confirmed for 2005 the problems connected with the presence of operators with extensive market power in electricity supply.

The conclusions of the joint investigation and monitoring activity led the AEEG to conclude that there was a need to take urgent steps to remove the remaining obstacles to the development of effective competition in the wholesale supply of electricity.

In Resolution 212/05 the AEEG proposed the adoption of Virtual Power Plants (VPPs), which take the form of an asymmetrical regulatory measure designed to "sterilise" the appeal to the dominant operator – as indispensable operator in satisfying electricity demand in a high number of hours of the year – of exercising its unilateral market power. To this end, the AEEG provided for a temporary obligation on Enel Produzione to sell part of its available production capacity to unconnected (to Enel) third parties. The amounts to be sold are decided in advance at prices based on an auction conducted according to rules verified by the AEEG.

The VPP contract envisages:

- payment by the seller (the dominant operator) of the positive differential between the exchange prices set in the hours which it is indispensable to the formation of market prices and a strike price that ensures a fair return on invested capital;
- a premium, paid by the buyer, less the value of the positive differential between the exchange prices and strike prices.

The auction procedure also envisaged that Enel would not be required to adopt the VPP method if the premium offered by participants was lower than a reserve premium set by Enel itself in line with the fixed costs attributable to production units located in the macro-zone to which the VPP referred.

At the same time, the AEEG balanced the need to safeguard Enel's economic equilibrium with that of protecting consumers' interests, by setting an upper limit on the reserve premium. If set at a level higher than costs, this would render the provision ineffective.

For the sale of virtual generating capacity for 2006 Enel organised two auctions, which took place on 30 November and 13 December 2005. These consisted of a pay as bid discriminatory auction, with upwards bidding from a starting premium and bid selection continuing until all the virtual capacity was accounted for. The two auctions did not actually give rise to any capacity allocation since, given the level of the starting premium, Enel's VPP products did not come up to operators' expectations.

Enel Produzione appealed against Resolution 215/05 to Lombardy Regional Administrative Court (Italian acronym TAR) which, with ruling 246 of 6 February 2006, annulled it. The AEEG appealed against this ruling to the Council of State.

Again on the subject of market power and the development of competition, in July 2006 the Italian antitrust Authority (AGCM) submitted two opinion papers to Parliament and the Government.

The first concerns the arrangements for the disposal of Enel S.p.A. shareholdings in Eurogen S.p.A., Elettrogen S.p.A. and Interpower S.p.A., established by the Prime Minister's Decree of 8 November 2000. This Decree limited to 30% any holdings by public bodies or publicly owned companies, Italian or otherwise, in these companies, for a period of at least five years. In the case of Eurogen, which is now called Edipower, this rule was breached since the company was bought by Edison, which is in turn owned jointly by EDF and AEM, both of which are publicly owned. Exceeding the limit imposed by the law could create distortions in the development of the liberalised market. The AGCM has therefore requested that steps be taken to remedy this breach.

The second opinion paper concerns the incentive scheme for the production of electricity from renewable and assimilated sources. This scheme is deemed to be both distortive, since it introduces inefficiencies to the national electricity system, and inadequate in the light of the liberalisation process initiated in 1999. The AGCM has therefore urged an urgent review of the incentive scheme with a view to reducing the distortions in question and the cost to consumers.

4 REGULATION AND PERFORMANCE OF THE NATURAL GAS MARKET

4.1 Regulatory issues

4.1.1 Overview

In the gas sector, in spite of the advances made in the regulatory and legislative framework, the situation in terms of competition is progressively worsening as a result of insufficient infrastructure development, which has not kept up with demand, and of Eni's dominant position with respect to the market as a whole.

The degree of market opening has not changed, given that Italy decided to open the market completely with effect from 2003 (on 1 January of that year all customers became free to choose their supplier) and since 2000 has envisaged the unbundling of gas transportation and sales activities, and regulated network access. As with last year, it must be stressed that the adoption of an advanced degree of regulation is a necessary, but not in itself sufficient, condition for the establishment of true competition in the market.

4.1.2 Allocation of interconnection capacity and measures to deal with congestion

Table 4.1 shows the results of the continuous transportation capacity allocation at the beginning of thermal year 2005-06. With respect to the capacity allocated the previous thermal year, 2005-06 saw no significant changes in allocable capacity, with the exception of Gela, where the build-up is still on-going, and Gorizia, which saw a slight increase (imports at Gorizia are a "virtual" operation resulting from the lower physical volumes exported there). The results of the allocation for thermal year 2005-06 show nearly all continuous transportation capacity being allocated at the entry points to the national network interconnected by pipeline with abroad. At the beginning of the thermal year, 26 operators applied for and obtained access at these points while all capacity applications were met, in some cases through recourse to interruptible capacity allocations. The table does not show the Panigaglia entry point where, under current procedures, the daily allocable capacity of 13 M(m^3)/day is assigned to the operator of the Panigaglia terminal, GNL Italia S.p.A., which injects the gas to the network on behalf of the users of its regasification service[15]. The aim here is to enable the efficient use of transportation capacity at the terminal interconnection. In the meanwhile, Snam Rete Gas is completing its planned up-grading initiatives in various parts of the country in line with allocated capacity.

It should be noted that transport capacity levels are calculated through hydraulic simulations of the transport network that take into account the off-take scenarios envisaged for the year under consideration. Capacity at each entry point is determined by considering the most intensive transportation scenario (the summer one for the entry points of Mazara del Vallo, Tarvisio and Gorizia, and the winter one for Passo Gries).

[15] Italy only has one LNG regasification plant, at Panigaglia. It belongs to GNL Italia S.p.A., which is wholly owned by Eni.

More specifically, Snam Rete Gas has calculated the maximum amounts that can injected to the network from each entry point without exceeding either the minimum pressure constraints at the different points of the system, or the maximum plant performance levels. The aim here is to ensure availability of the transport service at the required level throughout the thermal year.

Table 4.1 Continuous transport capacity in Italy

Standard M(m^3) per day, unless otherwise indicated, for thermal year 2005-06

ENTRY POINT TO THE NATIONAL NETWORK	ALLOCABLE	ALLOCATED	AVAILABLE	PROPORTION ALLOCATED/ ALLOCABLE
Passo Gries	57.5	57.5	0.0	100%
Tarvisio	88.3	84.1[B]	4.2	95%
Mazara del Vallo	80.5	80.4	0.1	100%
Gorizia	2.0	0.86	1.1	43%
Gela[A]	22.8	22.8	0.0	100%
TOTAL	**251.1**	**245.7**	**5.4**	**98%**

A) Available capacity with effect from January 2006.

B) The capacity shown in the table corresponds to the capacity allocated with effect from January 2006.

Source: AEEG, using data from the Ministry for Productive Activities and Snam Rete Gas.

In November 2005 the AEEG opened a consultation exercise with a view to amending and supplementing Resolution 137 of 17 July 2002, concerning the conditions for access to and delivery of the transport service. The planned amendments focused on the possibility of extending the annual transport capacity allocation procedure to the month of September, by altering the timescale for submitting applications and for the allocation of transport capacity at entry points interconnected with foreign pipelines, and at all other points of the transport system. These changes were intended to leave users enough time to formalise their supply contracts following the allocation of import capacity, and to apply for their allocations of out-going or re-delivery capacity on the basis of these contracts.

In the light of the observations and needs expressed by operators during the consultation exercise, AEEG Resolution 53 of 15 March 2006 amended the transport capacity allocation regulations. These amendments were made with due consideration for the limits imposed by the timescale required for transport companies to carry out the necessary technical checks to ensure they can satisfy capacity allocations. To this end, Resolution 53 gives interested parties the option of submitting their application for access to re-delivery points within the first seven working days of September, for allocations taking effect from 1 October of the same year (the previous deadline was 1 August).

Secondary capacity and gas market

As part of the procedures for the implementation of the regulated market for capacity and gas, in July 2005 the AEEG opened a consultation on the proposed standard contract for gas trading at the Virtual Trading Point (VTP, or Italian acronym PSV). This initiative concerns the definition of standard contracts for bilateral trading of gas and capacity: a step deemed to be useful in promoting liquidity in the market by facilitating the completion of transactions by operators, who would be able to define just the price and volumes of the transactions.

It emerged from the consultation that the stakeholders welcomed the AEEG's plan to facilitate the development of the PSV, which they considered to be a key step in the creation of a mature national market for natural gas. They agreed with the principle that a standard form of contract would be useful and helpful to the development of liquid, efficient and transparent energy markets. However, a number of concerns also emerged that are deserving of further examination. These mainly regard the degree to which these contracts would be binding as well as their inherent ambiguity, given that the Guidelines establishing the architecture of the market in which they would be inserted have not yet been fully defined.

To encourage the development of a spot market, operators considered that all possible forms of negotiating flexibility should be retained, and that the clauses of the contract should at all times be open to amendments and additions by the contracting parties.

The contract should therefore serve purely as a benchmark to be adopted on an entirely voluntary basis. At present, market conditions are not yet mature for the introduction of a binding standard contractual model. In view of the low degree of liquidity of the market, caused *inter alia* by the continuing dominant power of the incumbent and the limited number of operators in the market, such a model could itself create the risk of market distortion.

A further examination of the issue therefore seems necessary to identify which elements of the contract can be applied to all natural gas trading contracts, and which changes need to be introduced to the clauses currently subscribed to by the parties with a view to promoting further competition in the gas market.

4.1.3 The regulation of transmission and distribution companies

The ownership structure and infrastructure situation in the gas transport segment has not changed significantly with respect to last year.

The gas transport network, divided into the national and regional networks, is operated by a small number of companies. The main transport company, Snam Rete Gas, is the dominant operator in the sector. The second is Società Gasdotti Italia S.p.A., which operates a number of regional networks[16].

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 significant concentration process that has taken place in recent years, ownership of the distribution network remains fragmented, with about 430 operators. The Eni Group controls about 30% of the market, through Italgas.

[16] There are currently three smaller operators (Retragas Srl, Comunità Montana Valtellina di Sondrio, and Netenergy Service Srl) which own small stretches of the regional networks.

In June 2006 the AEEG approved the standard Distribution Network Code, which contains rules for access to and delivery of the gas distribution service. The Code is a key step in the development of the gas market since it acts as a contractual instrument which regulates and clarifies relations between the companies operating distribution plants and the sales and wholesale companies using these facilities. As a result of the Code, distribution companies can provide the distribution service to sales companies and wholesalers in a neutral and non-discriminatory manner. Alongside the main service (taking delivery of gas which users are entitled to inject to the distribution plant, and transporting it to the redelivery points where access is required), the standard Code also regulates the services required by sales companies in the light of their specific needs, such as ancillary and optional services.

Table 4.2 Regulation of transport and distribution companies

	Number of regulated companies	Estimated network tariffs(A) Euros/m^3		
		I4 (418600 GJ)	**I1** (418.6 GJ)	**D3** (83.7GJ)
Transmission	2	0.0172(A)	0.0257002(B)	0.0280(C)
Distribution (D)	430	-	0.0563	0.0816

(A) With reference to a gas consignment from entry point with load factor of 0.9 and load factor at exit and re-delivery point of 0.7, distance covered on the regional network 12 km.

(B) With reference to a gas consignment from entry point with load factor of 0.9 and load factor at exit and re-delivery point of 0.31, distance covered on the regional network 12 km.

(C) With reference to a gas consignment from entry point with load factor of 0.9 and load factor at exit and re-delivery point of 0.27, distance covered on the regional network 12 km.

(D) average PCS =38.73.

Transport tariffs

The criteria governing the tariff system for the second 4-year period of regulation (1.10.2005 to 30.9.2009) were established in July 2005 by Resolution 166/05.

With respect to the transportation tariff structure, the AEEG provided for:

- an initial 70% to 30% division of revenues between the capacity and commodity components and the elimination of the fixed component, which in the previous regulatory period amounted to 3%;
- confirmation of the entry-exit tariff model to determine capacity charges on the national network; a number of amendments have been made to these, such as the definition of specific charges for export points and the setting of counter-flow transport costs at 14% of flow costs;
- provisions for an interruptible transport service at entry points to the national gas pipeline network to incentivise the use of interruptibility contracts by large users, in order to increase the flexibility and security of the system in the event of weather-related emergencies;

- the setting of specific exit charges for gas transiting on the national pipeline network, with the application of reduced variable charges being confirmed in such cases;
- the introduction from thermal year 2006-07 of a new charge for the metering service to replace the fixed charge introduced in the first regulatory period, the aim being to remove restrictions on the development of competition in the market for sales to retail customers; in the first year of application of the new rules the metering charge has been set at zero;
- the introduction from thermal year 2006-07 of a single regional tariff applicable at the national level, both to lessen the penalisation of areas less well served with infrastructure, and to prevent users of the service being affected by pancaking, the situation where they are required to pay a number of transport charges if they need to apply for the service from more than one regional operator;
- confirmation of the possibility of obtaining tariff reductions in start-up situations and for withdrawals concentrated in off-peak periods; these reductions were introduced in the first regulatory period with Resolutions 44 of 5 August 2004, and numbers 5 and 6 of 18 January 2005.

To determine the tariff levels the AEEG has provided for:

- a reduction of the real pre-tax rate of return on invested capital, from the 7.94% of the first regulatory period to 6.7%, in line with the rates adopted for the other Italian and European network services;
- the application of the profit-sharing criterion to determine allowed operating costs, with firms entitled to half of any further productivity gains they achieve over and above those set pursuant to Resolution 120 of 30 May 2001, taking into account the operating costs allowed for new investment made in the first regulatory period;
- incentives for the development of national transport infrastructure and infrastructure for interconnections with abroad, to improve security of supply and create the conditions for Italy to become a hub at the European level. This incentive, which would vary with the type of investment, is obtained by allowing for additional revenue from new investment, in the form of an increased rate of return and relative amortisation; the incentive would remain in place for longer than the regulatory period and the returns would be guaranteed regardless of the volumes transported;
- allowance for incremental operating costs in respect of direct investment in new interconnection infrastructure, or used to bring new import/export infrastructure into operation, in cases where the economic and financial equilibrium of the transport company is compromised;
- a review of the adjustment mechanism by spreading the amount over several thermal years in cases where corrective factors higher than a given reference revenue threshold are calculated, to provide greater tariff stability during the regulatory period;
- the application of the price cap, during the annual tariff adjustment, to the tariff constraint components for operating costs and depreciation, and no longer to the total constraint, as was the case in the first period of regulation. The new rules envisage that the portion of guaranteed revenue linked to the return on net invested capital should be adjusted each year by recalculating using the revalued historic cost method and

taking depreciation into account. For the second regulatory period, the productivity target set for the capacity component has remained unchanged, at 2%, while it has been reduced to 3.5% for the commodity component (from 4.5% in the first regulatory period).

Companies set transport tariffs annually on the basis of the tariff criteria established by the AEEG at the beginning of the regulatory period. The tariffs only enter into force if approved by the AEEG, which verifies their compliance with these criteria.

The transport charges for thermal year 2005-06 were definitively approved by the AEEG through Resolution 204/05. This provision envisaged, at constant volumes of gas transported, a reduction in revenues of 3.9% in nominal terms and 5.9% in real terms, taking inflation to be 2%.

Distribution tariffs

As with transport tariffs, distribution tariffs are set by companies following the criteria established by the AEEG at the beginning of each four-year regulatory period. Each year, the AEEG checks and approves the tariffs set by distribution companies on the basis of their reference revenue.

With Resolutions 170/04 for natural gas and 173/04 for other types of gas, the AEEG selected the criteria for the new regulatory period, which runs from 1 October 2004 to 30 September 2008. Following a dispute initiated by distribution companies with regard to these criteria, in the course of 2005 the AEEG, in partial compliance with the provisions of a ruling by the Regional Administrative Court of Lombardy, opened a procedure to amend and supplement the criteria for the calculation of the distribution tariffs for natural and other types of gas. This procedure focused on the arrangements to allow for new investments by distribution companies following those taken into consideration for the approval of the revenue constraint for thermal year 2003-04. The outcome of the procedure was the adoption of resolutions 122/05 and 128/05 which, by amending and supplementing Resolutions 170/04 and 173/04, envisaged a new round of tariff proposals to be submitted by distribution companies for thermal year 2004-05.

Once the proposals were presented and checked by the relevant offices, those formulated by 332 natural gas distributors were able to be approved. To complete the regulatory framework, a procedure was also opened to determine the natural gas distribution tariffs for thermal year 2004-05 for 47 operators who had missed the deadline for submitting proposals formulated under the amended regulations. The procedures for the approval of the tariffs for the distribution and supply of gas other than natural gas for thermal years 2004-05 and 2005-06, and for the distribution of natural gas for thermal year 2005-06, are still being affected by the situation created by the administrative dispute. In both cases, the decision of the Council of State concerning the level of the price cap for the calculation of the revenue constraint is awaited.

Pending this decision, the AEEG has extended the validity of the distribution tariffs for thermal year 2004-05. To be more precise, the AEEG has provided for the application of the above-mentioned tariffs, subject to subsequent adjustment, in order to provide a reliable framework of reference for consumers. The AEEG's decision is also intended to protect consumers from any negative effects that would arise if the tariff adjustment for natural gas distribution were applied in the absence of the revised price cap rules, and from any abuses they might be exposed to in the absence of proper approval of the tariffs by the AEEG itself.

Storage tariffs

With the end of the first regulatory period for storage on 3 March 2006, in Resolution 50/06 the AEEG defined the criteria to determine the storage service tariffs for the second regulatory period (1 April 2006 to 31 March 2010).

The general aim of this provision was to encourage the creation of new storage capacity, especially peak delivery capacity, to ensure the security of the national gas system and develop a system of physical and virtual storage to support the operation of a hub on Italian territory serving the rest of continental Europe.

To promote the up-grading and development of new storage sites and existing, less efficient facilities, a single national tariff is envisaged. To ensure that each company receives the revenue it is due, an equalisation system has been set up. This system is managed by the Electricity Equalization Fund (*Cassa Conguaglio per il Settore Elettrico*, CCSE). An additional, variable charge applicable to the energy handled has also been introduced to cover any imbalances in the equalisation system.

Another feature of the new rules is the introduction of a special charge for the peak service at the injection stage and differentiated charges for the injection and delivery stages, with a view to encouraging the proper use of available storage by users and supporting system performance at the end of these stages.

Finally, tariffs were introduced for “special” services such as counter-flow off-takes and parking, which were previously provided by storage companies under conditions negotiated by the parties. In view of the difficulty of separating out the costs of delivering the various special services from those of the basic services, the AEEG felt that the setting of storage tariffs should take into account the overall costs incurred to deliver the range of available services, whether basic or “special”.

To determine the tariff levels the mechanisms in force in the first regulatory period were essentially confirmed and a real pre-tax rate of return on invested capital of 7.1% was set. To determine the fixed assets, the categories and their lifespan were slightly amended with respect to the first regulatory period for the purpose of improving cost allocation to the different categories.

Allowed operating costs were determined with reference to the recurrent expenses actually incurred in the 2005 financial year, net of costs incurred by technical consumption of compression and processing stations, which are passed directly to users of the storage system. It is also envisaged that in the third regulatory period a profit-sharing criterion should be applied in determining operating costs.

Incentives for investments take the form of a higher rate of return than that allowed on existing capital at the end of the 2005 financial year, over a longer timescale than the regulatory period. Both the increased rate of return and the duration are differentiated on the basis of the different types of investment.

As regards the structure of the storage tariff, the application of a multi-part tariff has essentially been confirmed. This takes the form of a linear combination of the unit charges for the elements making up the storage service. In the more general formulation, the tariff is calculated on the basis of: the capacity (in terms of space, injection and delivery) allocated to the user; the energy associated with the gas handled at delivery and input; and the energy associated with the quantities of gas held for strategic storage purposes. Only in the event of the physical movement of gas from the system do storage companies pass a percentage share of the costs covering the technical consumption of compression and processing stations to users of the service, in proportion to the quantities allocated.

The tariff structure is adjusted annually by applying the price cap, which amounts to 1.5% for the capacity component and 2% for the commodity component (see Table 6.1), to the variable unit charge and to the depreciation component. The portion of the guaranteed revenues relating to the return on net invested capital is adjusted by recalculating the revalued historic cost of the capital each year, taking depreciation into account.

Table 4.3 Single national storage charges included in the tariff

CHARGES	AMOUNT
unit charge for space f_S	0.155673 (€/GJ/year)
unit charge for injection capacity f_{PI}	9.503475 (€/GJ/day)
unit charge for delivery capacity f_{PE}	11.295975 (€/GJ/ day)
unit charge for handling of gas *CVS*	0.102119 (€/GJ)
unit charge for strategic storage f_D	0.156773 (€/GJ/year)

In accordance with Resolution 50/06, storage companies sent the AEEG the data needed to verify their charges for thermal year 2006-07. After the data had been checked, with Resolution 56/06 the AEEG approved the company's charges and established the single national charges for the year (Table 4.3).

The regulation of transmission and distribution service quality

The main change in 2005 in terms of service quality regulation was the introduction, through Resolution 243/05, of a system of incentives for improvements to the security of the natural gas distribution service. This rewards virtuous conduct by operators providing a service featuring higher security standards than the minimum standards established by Resolution 168/04.

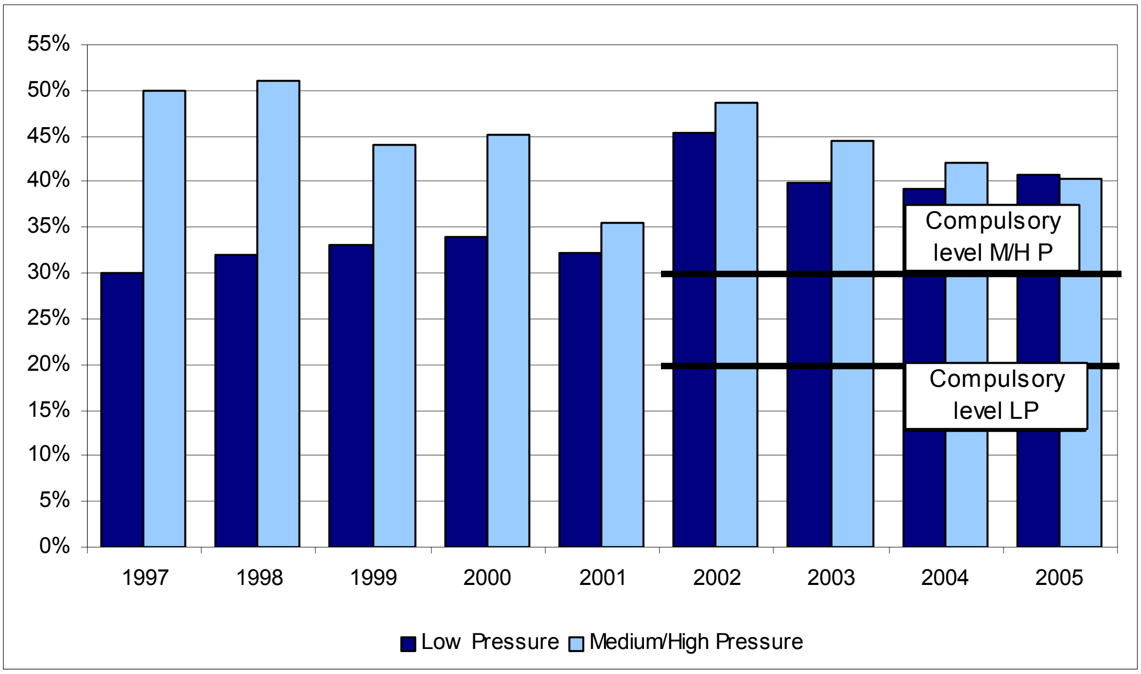
The rules governing the security of the gas distribution service have until now been applied mainly through obligatory security requirements. They provided adequate minimum standards that were, however, unevenly applied in Italy from one distributor and distribution plant to the next. To prevent the situation arising where a system based solely on obligations might encourage a tendency in future merely to apply the minimum obligatory security standards, the AEEG has decided to encourage distributors to increase their plant security levels with a view to bringing all plants more closely into line with the levels of excellence already achieved in some parts of the country.

The new system of incentives rewards reductions in gas leaks, increased numbers of checks on the degree of odourisation, and a reduction in the number of gas-related incidents in distribution plants. For 2006-08, participation by distributors is voluntary, while from 2009 the system will gradually become compulsory, with the incentives being accompanied by penalties for failure to achieve the obligatory pre-determined improvement standards.

The incentive scheme has two components: the first related to odourisation (rewards for operators carrying out more than the minimum annual number of checks set by the AEEG) and the second related to leaks (rewards for reductions in the numbers of leaks located following reports by third parties). For the component relating to leaks, an annual improvement rate has been set with respect to the average level for the period 2003-04.

To apply these incentives, distribution plants are divided up on the basis of concentration of consumers connected to their networks. For each of the three categories (high, medium and low density) and with reference to the component envisaged for leaks, target levels have been set for attainment by 2016, along with benchmark levels (of excellence) above which rewards are not given. These target and benchmark levels will be reviewed and possibly revised at the end of the three-year period 2006-08 in the light of the improvements actually achieved. In the event of a gas-related incident for which the distributor can be held responsible occurring in a distribution plant, a penalty equating to the reward applicable to that plant will be applied. The AEEG's provision envisages a ceiling on the incentives allowable, amounting to 2% of the distribution revenue constraint approved by the AEEG. The principal data regarding the progress made in the security of the gas distribution service are shown in figure 4.1, which illustrates the percentage of network inspected from 1997 to 2005. Figure 4.2 illustrates the number of emergency calls involving distribution plants and the average response time (in minutes) from 2001 to 2005. Finally, Table 4.4 shows the number of leaks located in 2005.

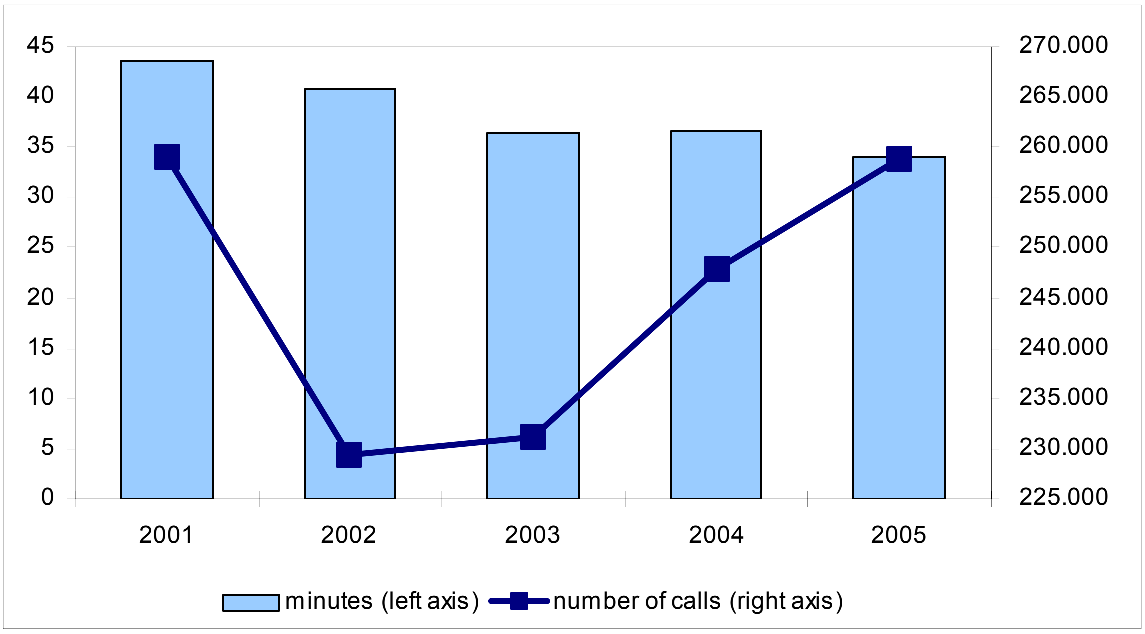
Fig. 4.1 Percentage of network inspected from 1997 to 2005



Source : Operators' declarations to the AEEG.

Fig. 4.2 Emergency calls by distribution plant

2001-05; average response time (in minutes) and number of calls



Source: Operators' declarations to the AEEG.

Table 4.4 Number of leaks located in 2005

LOCATION	FOLLOWING SCHEDULED INSPECTIONS	FOLLOWING REPORTS BY THIRD PARTIES	TOTAL
On network	5,300	7,300	12,600
On below-ground section of users' feeder plant	1,572	9,811	11,383
On above-ground section of users' feeder plant	3,370	42,362	45,732
On metering units	666	60,707	61,373
TOTAL	10,908	120,180	131,088

Source: Operators' declarations to the AEEG.

With respect to the regulation of the commercial quality of the gas distribution and sales service, it should be noted that this criterion was introduced in Italy in 2001, reviewed in 2004 and further amended and consolidated in 2005 (Resolution 158/05). In July 2005, with a view to improving consumer protection, the AEEG introduced new response time requirements on gas sales companies, as the direct contact points with retail customers, for the onward transmission of applications for services falling within distributors' remit, such as connections and quotes. With effect from 1 January 2006 these applications must be forwarded to distributors within three working days. In addition to recording the time of receipt and onward transmission, sales companies must also provide customers with an identification code for the request submitted.

In terms of gas transport service quality, in 2005 the Ministry for Productive Activities established that regional transport companies should provide guaranteed qualitative and security standards in the transport service for the protection of customers directly connected to their networks.

Although it had already regulated a number of aspects of the quality of the transport service provided by Snam Rete Gas and Società Gasdotti Italia within the scope of the approval of their respective codes of conduct, the AEEG deemed it necessary to introduce a more general set of regulations to govern the quality of the transport service. This new approach is independent of the operator providing the service. As a result, Resolution 15/06 opened a procedure to draw up provisions governing the quality of the natural gas transport service and regulating the general aspects of service quality: these include, at the very least, security, continuity and commercial quality, in accordance with previous provisions.

Balancing

No significant changes were made to the provisions governing balancing since July 2005, apart from the amendments made when the new storage tariff was established.

To ensure the operational balancing of the network and provide for hourly modulation, it is envisaged that transport companies should draw up contracts with storage companies for the use of storage services. The regulated tariffs applied in the bills issued by storage companies for the sale of both basic and special services determine the cost allowed in the transport tariff (balancing revenue).

Prior to March 2006, the allowed charge for storage companies for the purchase of special services was negotiated by the parties.

4.1.4 Regulation of 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 4.5).

Table 4.5 Current rules governing gas sector unbundling in Italy

	Accounting unbundling	Administrative unbundling	Corporate unbundling	Ownership unbundling
DSO < 100,000 customers	Obligatory	Partly regulated	Obligatory (derogation until 1 January 2003)	Optional
DSO > 100,000 customers	Obligatory	Partly regulated	Obligatory	Optional
TSO	Obligatory	Partly regulated	Obligatory	Optional

In Italy the main transport operator, Snam Rete Gas, is 50.01% controlled by the incumbent, Eni. This situation is set to change in 2007 as, in view of the provisions of Law 290/2003, from 1 July 2007 no company operating in the natural gas sector will be able to hold more than a 20% interest in companies owning transport networks.

The second transport company, Società Gasdotti Italia S.p.A., is owned by the private equity fund Clessidra Capital Partners, which bought it in 2004 from Edison T&S.

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.. Netenergy Service Srl, owned by the Valle del Biferno Industrial Development Consortium, operates a small natural gas transport network in Molise.

As mentioned earlier, in spite of the significant concentration process that has taken place in recent years, distribution remains fragmented, with about 430 operators. Of these, about 79% distribute only natural gas; the rest distribute natural and other types of gas, or only other types (such as LPG).

At the beginning of each year the AEEG carries out a wide-ranging survey on the electricity and gas markets. 299 distributors responded to the survey in 2005 (280 distributing natural gas, with or without other types, and 19 distributing other types of gas).

Of these 280 natural gas distributors, 198 result as being unbundled in corporate terms, since they are part of a group within which there is at least one other company that carries out sales activities.

272 of the 299 distributors, or 91%, had less than 100,000 customers, understood as points of supply; as we know, distribution in Italy is highly fragmented and carried out by small local companies.

In terms of asset ownership, the results emerging from the replies to the survey are summarised in Table 4.6. This shows that in most cases distributors wholly own the infrastructure they operate. It is rare for distributors to operate on networks they do not own, and cases where they operate networks, stations or gate stations in co-ownership with others are even rarer.

Table 4.6 Ownership of the assets operated by natural gas distributors

DISTRIBUTORS	NETWORK	STATION	FINAL GATE STATION
Do not own the infrastructure they operate	47	69	57
Own less than 50% of the infrastructure they operate	23	8	18
Own 100% of the infrastructure they operate	118	111	113
No reply	10	10	10
TOTAL	198	198	198

Source: Operators' declarations to the AEEG.

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 breakdown 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 their compliance with civil and commercial law and with the regulatory provisions, as shown in Table 4.7.

Table 4.7 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 (S/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

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

After the first period of application of Resolution 311/2001, the AEEG initiated a review of the directives governing accounting unbundling. In March 2006 the AEEG published a consultation document setting out its proposals. A summary of this document, which also concerns the electricity sector, can be found in the previous chapter.

4.2 Competition Issues

4.2.1 Description of the wholesale market

In 2005 natural gas[17] consumption totalled 86.2 G(m^3), of which 14% produced in Italy. Domestic production amounted to 12.0 G(m^3), a decrease of 7.6% on the figure for 2004. This segment of the market is dominated by Eni, which accounts for the lion's share (84%) of natural gas production.

[17] The average heating power of natural gas in Italy is 38.1 MJ/m^3.

Italy is a net gas importer. Imports increased by 8% (73,5 G(m^3)) in 2005 with respect to the previous year and covered 85% of consumption (the import capacity allocated for thermal year 2005-06 amounted to 89.7 G(m^3)).

Table 4.8 Development of wholesale market

	Total demand(2) (G(m³))	Peak demand(3) (M(m³)/day)	Production (G(m³))	Import capacity (1) (G(m³)/year)				No. of companies with >5% of production and import capacity	No. of companies with >5% of available gas	Share occupied by 3 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	0.5	77.3	4.2	3	3	67.4%
2003	123.6	n.a.	13.9	84.8	0.5	78.8	3.1	3	3	63.8%
2004	127.3	386	12.9	88.7	0.5	84.6	2.1	3	3	62.4%
2005	138.3	421	12.0	90.9	0.5	73.5	16.9	3	3	68.0%

(1) Provisional estimates for 2005.

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

(3) In-put peak in calendar year 2004, reached on 26 January; in 2005 the peak was reached on 19 December. The volume shown here includes injections, deliveries from storage, losses and consumption within networks.

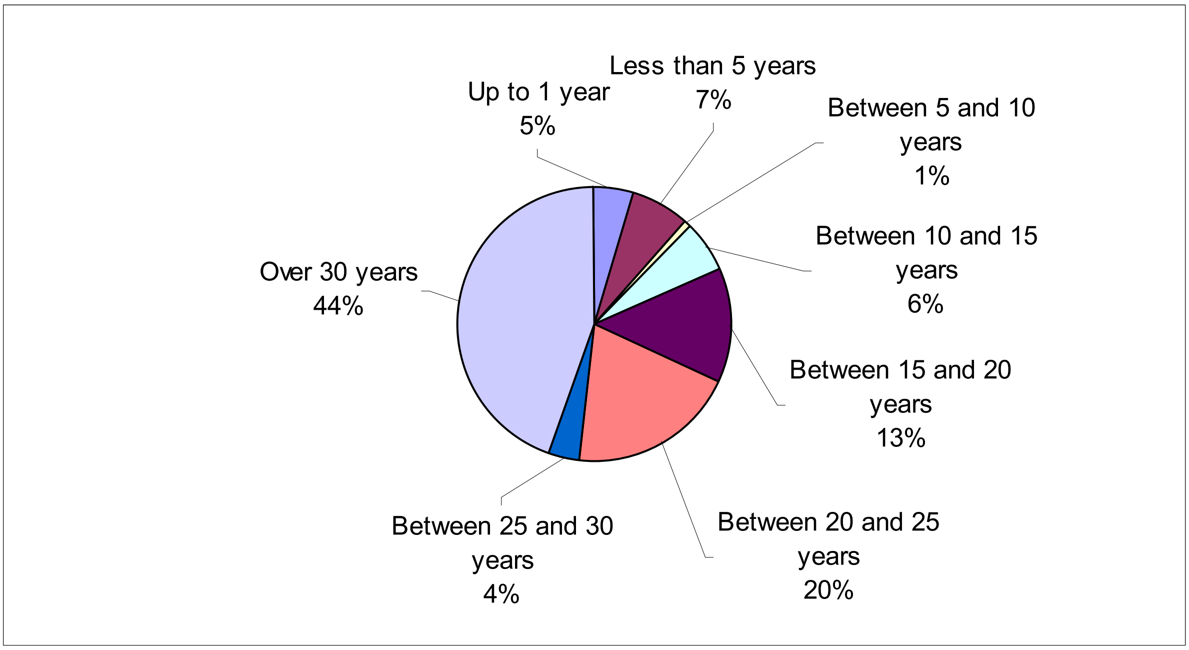
Operators (including groups[18]) with a share of over 5% of total gas supplied are Eni, Enel and Edison, which cover 86.8% of the total; other operators account for 3.5% and upwards of the gas imported and/or produced.

Procurement is based mainly on non-EU sources, especially Algeria and Russia. 37% of total imports come from the former (almost entirely via pipeline, with entry to the national network at Mazaro del Vallo; 3% is imported by sea), and 32% from the latter, through the entry points at Tarvisio and Gorizia. Imports from northern Europe, which enter the Italian network at Passo Gries, account for 23.2% of the total. Of this segment, 10.9% comes from the Netherlands and 7.8% from Norway. 7.6% of total imported gas arrives through Gela (from Libya and other non-EU countries). 3.4% of imports, including those from Algeria, are regasified at the Panigaglia terminal.

Procurement activity is conducted mainly through long-term take or pay contracts. Calculations based on operators' declarations to the AEEG continue to show Italy's dependence on very long-term contracts, of over ten years, led by Eni contracts dating from the late 1970s and early 1980s. If we consider contractual volumes for 2005 (ACQ 2005) over their entire duration (Figure 4.3), over 44% of the total consists of contracts of over thirty years' duration, followed by those of 20-25 years (20%) and 15-20 years (13%).

[18] In the context of the gas market survey, membership of a corporate group is defined in relation to the provisions of Art. 7 of Law 287 of 10 October 1990: briefly, membership of a group is considered to exist even if there is a *de facto* control by the stakeholder in the subsidiary.

Figure 4.3 Breakdown by duration of import contracts in force in 2005

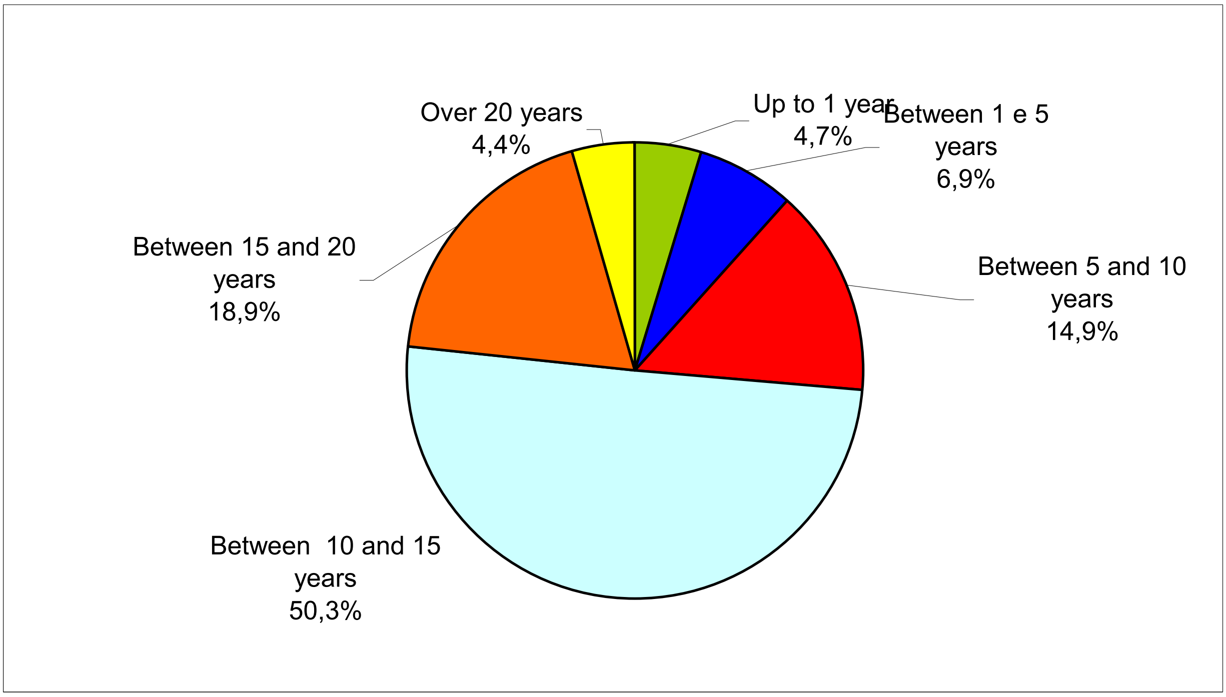


Source: AEEG from operators' declarations

Contracts of one year or less (numbering about 180) involve small volumes of gas and account for just under 5% of total contractual volumes.

If we analyse these same contracts by residual duration in 2005 (Figure 4.4), we see that contracts with a residual 10-15 years are the biggest category (50%), followed by those of 15-20 years (19%).

Figure 4.4 Breakdown by residual duration of import contracts in force in 2005



Source: AEEG from operators' declarations

In 2005 the Ministry for Productive Activities (MAP)[19] granted a further 27 permits for imports from non-EU countries, of which 21 for imports of less than one year (spot) and 6 for long-term imports. 45 EU import notices were submitted in the course of the year. The number of permits does not, however, reflect the number of operators actually importing natural gas, merely the completion of the red tape required before imports can go ahead, under the provisions of Legislative Decree 164/2000. Importing is a free activity with respect to gas produced in EU countries, but subject to ministerial authorisation for that originating in non-EU countries.

Total demand in the gas sector in 2005, understood as volumes of gas sold on the wholesale and retail markets (therefore including re-sales), amounted to 138 G(m^3), an increase of 8.4% on the previous year (Table 4.8). Operators with a share of over 5% in that market were, once again, the Eni, Enel and Edison groups. The three groups together cover 66.7% of total demand, with shares of 43.3%, 14.4% and 9.0% respectively, far higher than those of competitors, which start from just 2.4%.

Purchases on the secondary market (Table 4.9) illustrate the rapid growth of this market. Total trading at the Virtual Trading Point (Italian acronym PSV) accounted for 2.4 G(m^3) and 4.6 G(m^3) were purchased on the Italian side at entry points interconnected with abroad. Of these, about 1.7 G(m^3) were purchased by Eni, which then sold them through gas release operations.

Table 4.9 Gas market (G(m^3))

	Total consumption(1)	Trading on organised spot market	Trading on 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
2005	86.2	not applicable	not applicable	7.0

(1) Gas availability gross of consumption and losses.

(2) Volumes of gas purchased at PSV 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).

4.2.2 Description of the retail market

At 31 March 2006 the companies authorised by the Ministry of Productive Activities to engage in gas sales numbered 380. Most of these companies came into being after the sales division was hived off from the former integrated distribution companies. The restructuring of the natural gas trading sector, with the merger of the sales companies or their incorporation in other larger companies, is still on-going. 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.

[19] Now known as Ministry for Economic Development (*Ministero dello sviluppo economico*)

319 operators in the sales sector responded to the AEEG's 2005 survey of the gas market. Of these, 259 were selling to the retail market, 40 were wholesalers selling to other operators or to the final market, and 20 were "pure" wholesalers, who sell gas only to other operators.

Of the 319 respondents, 123, or 39%, resulted as independent operators, in that they are not part of any corporate group or are members of groups that do not include any distribution or transport companies.

Table 4.10 shows the main data for this market. Total gas consumption continues to grow, reaching 86.2 G(m^3) in 2005, an increase of 6.% on the previous year.

Table 4.10 Development of the retail market

	Total consumption (G(m^3))	No. of companies with >5% of final market	No. of independent companies (A)	Market share of the first three companies (%)				Cumulative % share of 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 household 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.	85.7		54.3		n.a.	n.a.	n.a.	n.a.
2003	76.4	5	n.a.	74.4		45.6		n.a.	n.a.	n.a.	n.a.
2004	80.6	5	110	80.3	54.1	n.a.	33.2	53(E)		6(F)	1(G)
2005	86.2	3	123	91.2	71.1	43.1	47.3	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 > 200,000 m^3/year. Figure from 1 June 2005.
(F) Standard consumers with annual consumption 5,000-200,000 m^3/year. Figure from 1 June 2005.
(G) Standard consumers with annual consumption < 5,000 m^3/year. Figure from 1 June 2005.

Although the market has been expanding from year to year, it remains firmly concentrated in the hands of the three principal groups: Eni (43.9%), Enel (15.4%) and Edison (7.7%). Any reduction in the degree of market concentration is only apparent. In 2004, 5 operators[20] owned interests amounting to over 5% of the market, since Italgas Più was distinct from Eni Gas & Power, just as Enel Trade was distinct from Enel Gas. If we consider the groups, in 2005 the number of operators owning over 5% of the market was once again three.

In 2005 these three operators covered:

91% of sales to electricity producers (in order: Eni, Enel and Edison);

71% of sales to industrial customers (in order: Eni, Enel and Gaz de France);

43% of sales to commercial and service sector customers (in order: Eni, Enel and Hera);

[20] More precisely, these operators were, in order: Eni – Divisione Gas & Power, Enel Trade, Italgas Più, Edison Gas, and Enel Gas. Italgas Più was incorporated in Eni – Divisione Gas & Power on 1 January 2005.

47% of sales to households (in order: Eni, Enel and Aem Milano)

Switching

The switching data described in last year's Annual Report were the result of a survey conducted by the AEEG in which transport and distribution network operators were asked to indicate the number of consumers who had changed supplier between June 2000 and 1 June 2005; these figures also hold for 2005.

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

23% for large consumers (with consumption of over 200,000 m^3/year);

3% for medium consumers (with consumption of between 5,000 and 200,000 m^3/year);

1% for small consumers (with consumption of less than 5,000 m^3/year).

It should be noted that the percentages rise considerably when the relative quantities of gas consumed by customers who have switched are considered, in which case the figures are 53%, 6%, and 1% respectively.

Average sale prices

Since the complete opening of the market in 2003 the gas price in Italy has been free. As liberalisation took place in a context of low effective competition, however, it was deemed appropriate to retain the compulsory requirement on sales operators to offer the economic conditions of supply established by the AEEG both to customers who at 31 December 2002 had non-eligible status, and to eligible customers who at that date had not yet exercised the option to enter into free contracts. Under the provisions of Resolution 34/06, with effect from 1 October 2006 the economic reference conditions must be offered only to household customers. These conditions can naturally be accompanied by other proposals formulated by individual operators. In analyses of the average prices applied on the gas market in Italy a distinction can therefore be made between protected customers, who accept the economic conditions of supply calculated by the AEEG, and free customers, who pay a price freely negotiated with sales companies.

In 2005 the trend in the prices of international oil products, which have essentially been rising continually since spring 2003, again caused a marked acceleration in the cost of gas for Italian consumers.

the average price of gas (weighted by quantities sold and net of taxes) applied in 2005 by sales or wholesales companies operating on the retail market was c€34.95/m^3 for customers on the protected market and c€22.76/m^3 for customers on the free market. This result emerges from the first, provisional, analyses of the data from the AEEG's survey of the gas sector in 2005.

As we can see from Table 4.11, the data confirm the expected trends and quantitative relationships: customers on the protected market pay significantly more than those on the free market with similar consumption profiles. As customer size grows, in terms of volumes consumed annually, the price tends to fall, more for free than for "captive" customers.

In categories subject to regulatory protection the price appears to be essentially in line with the economic conditions laid down by the AEEG (which in 2005 averaged c€34,49/m^3 net of taxes). However, smaller customers seem to be paying c€36.5/m^3 on average, compared with c€32.02/m^3 for medium-sized customers and c€29.39/m^3 for large customers, giving a price differential of c€7.07/m^3 between small and large. In the free market small customers pay c€9.04/m^3 more than large customers, who pay on average c€22.9/m^3 for their gas supplies.

A comparison with the equivalent data for 2004 show an increase in the cost of gas that differs markedly by consumption category, with relatively smaller increases experienced by small customers on both markets, protected and free. The trend in the crude oil price therefore seems to have weighed more heavily, in proportionate terms, on medium-to-large customers.

Table 4.11 Average sale prices net of taxes on the final market (c€/m^3)

CUSTOMER CATEGORY	2004	2005	% VAR.
Protected market			
Consumption less than 5,000 m^3	35.32	36.46	3.2
Consumption between 5 and 200,000 m^3	30.44	32.02	5.2
Consumption of more than 200,000 m^3	27.04	29.39	8.7
AVERAGE FOR PROTECTED MARKET	33.65	34.95	3.8
Free market			
Consumption less than 5,000 m^3	32.99	31.94	-3.2
Consumption between 5 and 200,000 m^3	27.24	29.74	9.2
Consumption of more than 200,000 m^3	18.46	22.90	24.0
AVERAGE FOR FREE MARKET	18.76	22.76	21.3

Source: AEEG from operators' declarations.

The average price levels for Eurostat standard customers are shown in Table 4.12. These prices are essentially in line with the average values described above.

Table 4.12 Breakdown of final price components for Eurostat standard customers (€/m^3) – 2005

	I4(A)	**I1**(B)	**D3**(C)
Network tariffs (excluding general costs)	0.0172(D)	0.0820(D)	0.1096(D)
General costs included in network tariffs	0	0	0
Raw material and marketing costs	0.20221(E)	0.2305(E)	0.2509(E)
Taxes	0.0347	0.1975	0.2348
Total (including taxes)	0.2540	0.5100	0.5953

Values for the following standard customers:
(A) Industrial customer or electricity producer with annual consumption of 2,000,001 to 20,000,000 (m^3/year)
(B) industrial or commercial customers with annual consumption of 5,001 to 200,000 (m^3/ year)
(C) Residential customers with consumption between 500 and 5,000 (m^3/ year)
(D) See table 4.2
(E) Includes storage cost.

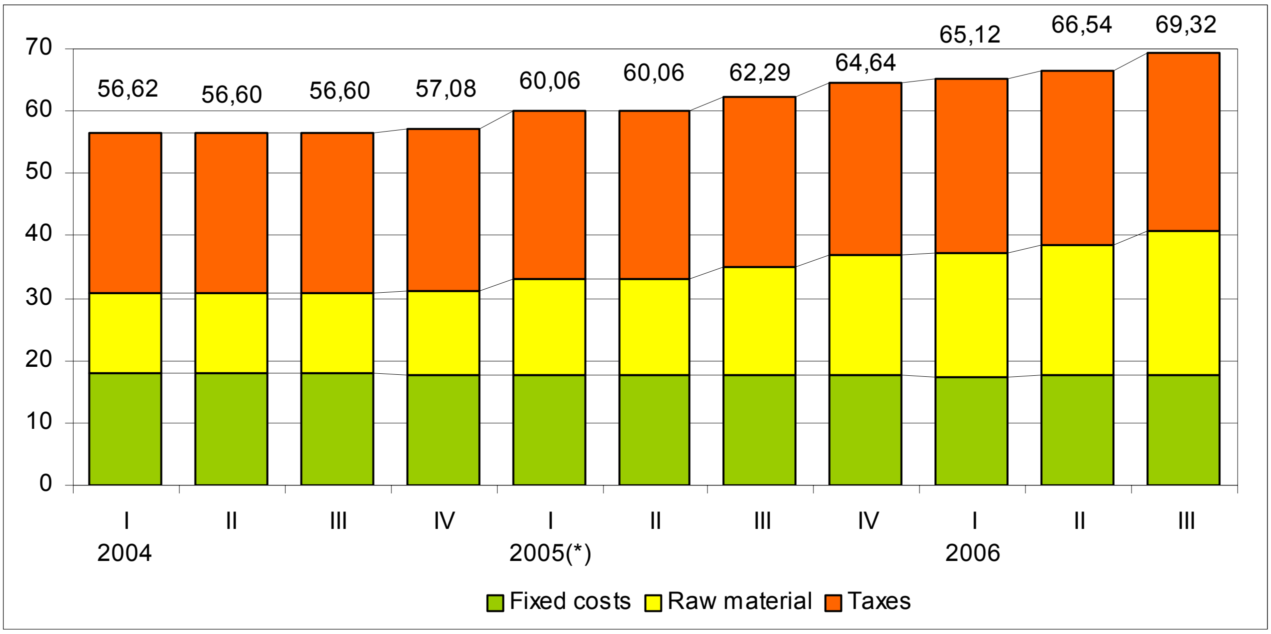
Economic reference conditions

The trend in the average national benchmark tariff published by the AEEG with reference to small consumers using less than 200,000 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 the first three quarters of 2004 the impact of the oil price rises was lessened by the indexation mechanism, thanks to which the value of the raw material component (QE) remained stable or rose only slightly. The new, marked rise of this component in the last quarter of the year was partly offset against the value of the total tariff by the concurrent reduction in the component covering the costs of distribution on local and urban networks (included under fixed costs). 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, 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%. 2005 opened with a new, pronounced tariff increase, the causes of which lie once again in the continuing upwards trend in oil prices, as well as the increased tax burden on gas.

With a view to easing the pressures caused by oil prices 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 made 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, and the rise in the total tariff to c€59.09/m^3. Following the suspension of Resolution 284/2004 by the Italian administrative courts, 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. From the third quarter of 2005, the continuing upwards trend in international oil prices led to repeated, substantial increases in the tariff which took it to c€66.51/m^3 in the second quarter of 2006. It must be stressed that these increases would have been even more pronounced if the Authority had not applied, as it has done since the first quarter of 2006, the indexation mechanism for the QE component as established by Resolution 248/04, over which the legal dispute was partly resolved at the end of last year.

Figure 4.5 Trend in the average national reference tariff published by the AEEG with reference to small consumers using less than 200,000 m³/year.



At 1 July 2006 about 59% of the average national reference tariff was made up of cost-cover components and the remaining 41% of taxes applicable to the natural gas sector (consumption tax, regional surtax and VAT).

The raw material cost accounts for over one third (33.6%) of the total tariff, marketing costs for 8.6% and the cost of infrastructure use and maintenance for the remaining 16.7%. In the context of infrastructure costs the most significant component is distribution: the Cd component accounts for 10.9% of the total tariff. The transport cost component amounts to nearly 4.4%, and the storage component to 1.4%.

5 SECURITY OF SUPPLY

5.1 Electricity

Peak demand in 2005 and projections for 2006 - 2008

The power required by the Italian electricity system reached a historic peak of 55,015 MW in December 2005, an increase of 2.6% on the previous year (53,606 MW). Because of the torrid heat, summer peaks were even recorded in June, and reached a new historic peak of 54,163 MW, an increase of 1.2% on the previous high of 53,507 MW, which occurred in July 2004.

2005 saw a reversal of the trend towards a narrowing of the gap between the summer and winter peaks, with a difference of 852 MW compared with 99 MW in 2004. It is, however, significant that the two summer peaks occurred at very different times (the end of July in 2004 and the end of June in 2005) and were influenced not only by the summer temperatures but also by changes in the contribution of household consumption and industrial production to total demand.

The growth projections formulated by GRTN/Terna and shown in Table 5.1 are slightly lower than those made in 2005 and indicate that the summer peak could overtake the winter peak as early as 2006.

Table 5.1 Peak demand for power from 2004 – 2011 (GW)

	2004	2005	2006	2007	2008	2009	2010	2011
Winter average	53.6	55.0	55.4	57.2	58.9	60.5	62.1	64.0
Torrid summer	53.5	54.2	56.1	58.1	60.0	61.9	64.0	65.9

Source: GRTN/Terna

Generating capacity in 2005

2005 saw a notable increase in generating capacity, which grew by more than 5 GW, from 81.5 GW in 2004 to 86.8 GW in 2005 in terms of net efficient installed power. The increase was substantially larger than the previous year, as shown in Table 5.2, and corresponds to an increase in reserve power, compared to 2004, of 3.8 MW at the winter peak and 4.6 MW at the summer peak. The strongest growth in absolute terms occurred in thermoelectric power (+4.4 GW) and in relative terms in wind and solar power (+48%).

The actual power available was, however, significantly lower, as will be discussed later.

Table 5.2 Net efficient generation in 2005 (MW)

	2003	2004	2005	Change	
				2003 - 04	2004 - 05
Hydroelectric	20,660	20,744	21,000	84	256
Thermoelectric[(A)]	56,047	58,990	63,400	2,943	4,410
Geothermal	665	642	687	-23	45
Wind and solar	877	1,135	1,675	258	540
TOTAL	78,249	81,511	86,762	3,262	5,251

(A) Thermoelectric generation includes plants using biomass and waste.

Source: Terna

New generating capacity for 2006 – 2009

The new thermoelectric generating capacity expected to come into service over the next few years amounts to over 15 GW, as shown in Table 5.3[21]. The projections shown in this table for thermoelectric power stations are fairly reliable as they refer to plants which have obtained all the necessary permits, and a good proportion of which are already at the construction stage. It is more difficult, however, to identify future developments for wind power plants. Applications for connection to the national transmission grid and distribution networks currently equate to around 10 GW, but actual installed power is in fact less than this. This situation can be explained by authorisation problems and by the fact that the technical regulations governing connections are not yet complete. The projection of 1,200 MW shown in the table refers to authorised plants, whose operators have also made financial commitments covering connection costs.

Table 5.3 Projections for new power coming into operation in 2006 - 2009

Year	Thermoelectric	Wind	Total
2006	3,795	520	4,315
2007	3,110	473	3,583
2008	6,440	226	6,666
2009	1,600	15	1,615
TOTAL	14,945	1,233	16,178

Source: Terna.

Two thirds of the new thermoelectric power (including biomass plants) expected to come on line between 2006 and 2009 will be located in mainland Southern Italy, with the remaining third from the Northern regions, mainly Piedmont and Lombardy (North West 2,870 MW; North East 1,615 MW; Central Italy 510 MW; Southern Italy 9,805 MW; Islands 150 MW).

[21] The figures shown are taken from Terna's *Development plan for the national transmission grid 2006*.

This distribution pattern is in notable contrast to the one seen for the previous four-year period (2002–2005), when 80% of the new power was located in Northern Italy, for an overall capacity of 6,900 MW.

The biggest contribution to power generation from renewable sources in coming years will be from wind power plants, with no substantial developments expected on the hydroelectric front. Practically all of the wind power due to come into operation over the next few years (like nearly all that already in operation) will be located in the southern regions and the islands.

Peak power availability

In the last five years overall plant availability has remained at between 63% and 65% of total net power[22]. The low availability of hydroelectric plants can mainly be explained by low reservoir levels in the winter months, when demand has traditionally tended to peak. As regards thermoelectric plants, low availability has been caused by unscheduled down-time, as well as long-term stoppages for alterations and up-grades, especially in recent years. In the case of wind plants and those using other renewables, the reason lies in the discontinuous nature of these sources.

Table 5.4 Peak power availability (GW)

	2003	2004	2005
Net power of plants	**78.3**	**81.5**	**86.8**
Hydroelectric	20.7	20.7	21.0
Traditional thermoelectric	56.0	59.0	63.4
Geothermal	0.7	0.6	0.7
Wind and solar	0.9	1.1	1.7
Peak availability	**49.7**	**52.8**	**56.4**
Hydroelectric	13.5	13.6	13.8
Traditional thermoelectric	35.5	38.4	41.7
Geothermal	0.6	0.6	0.6
Wind and solar	0.2	0.3	0.4
Peak demand	**53.4**	**53.6**	**55.0**
Power surplus/deficit	**-3.7**	**-0.9**	**1.4**

Source: Terna for 2003 and 2004 (final figures); AEEG for 2005 (estimate).

After the lows reached in 2001 and 2002, peak electricity availability has risen constantly, from 49.7 GW in 2003 to 52.8 GW in 2004 and 56.4 GW in 2005, as shown in Table 5.4. However, it is only in this last year that available power has been higher than peak demand. The deficits of 3.7 GW in 2003 and 0.9 GW in 2004, resolved through imports, were transformed to a surplus in 2005, of 1.4 GW. Over the next few years, a significant

[22] 65% in the case of hydroelectric plants, 64% for thermoelectric plants, 83% for geothermic plants and 23% for wind plants.

growth of this surplus can be expected, thanks to the substantial increases in power production described above.

Composition of electricity generation

The balance sheet for national electricity production and imports with respect to final demand on the grid for the period 2000-2005 is shown in Table 5.5, along with the projections to 2009. In 2005, the penetration of natural gas use in electricity generation continued, partly to make up for the shortfall in hydroelectric and coal-powered generation caused by the reasons cited at the start of this chapter. The historic decline in electricity generation from fuel oil and other oil products has also continued, albeit more slowly, again in relation to the need to offset the lower hydroelectric and coal input. Slower growth of generation from renewables is attributable to authorisation problems, especially in the case of electricity generation from wind energy and waste.

Table 5.5 Electricity balance sheet for 2000–2005 and projections for 2006–2009 (TWh)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Gross production	**276.6**	**279.0**	**284.4**	**293.9**	**303.3**	**302.4**				
Conventional thermoelectric	***218.5***	***216.8***	***227.6***	***238.3***	***240.5***	***246.3***				
Solid fuels	*26.3*	*31.7*	*35.4*	*38.8*	*45.5*	*43.9*				
Natural gas	*97.6*	*95.9*	*99.4*	*117.3*	*129.8*	*148.9*				
Oil products	*85.9*	*75.0*	*77.0*	*65.8*	*47.3*	*35.9*				
Other sources(A)	*8.8*	*14.1*	*15.8*	*16.4*	*17.9*	*17.6*				
Hydroelectric	***50.9***	***53.9***	***47.3***	***44.3***	***49.9***	***42.5***				
From natural input	*44.2*	*46.8*	*39.5*	*36.7*	*42.7*	*35.9*				
From pumping	*6.7*	*7.1*	*7.7*	*7.6*	*7.2*	*6.6*				
Other renewables	***7.2***	***8.3***	***9.5***	***11.3***	***12.9***	***13.6***				
Geothermal	*4.7*	*4.5*	*4.7*	*5.3*	*5.4*	*5.3*				
Biomass and waste	*1.9*	*2.6*	*3.4*	*4.5*	*5.6*	*6.1*				
Wind	*0.6*	*1.2*	*1.4*	*1.5*	*1.8*	*2.1*				
Solar	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*				
Auxiliary service production	**13.3**	**13.0**	**13.6**	**13.7**	**13.3**	**12.7**				
Net production	**263.3**	**266.0**	**270.8**	**280.2**	**290.0**	**289.7**				
Electricity for pumping	**9.1**	**9.5**	**10.7**	**10.5**	**10.3**	**9.4**				
Electricity for consumption	**254.2**	**256.5**	**260.1**	**269.7**	**279.7**	**280.3**				
Net imports	**44.3**	**48.4**	**50.6**	**51.0**	**45.6**	**49.2**				
Electricity demand on the grid(B)	**298.5**	**304.8**	**310.7**	**320.7**	**325.4**	**329.4**	**339.0**	**346.9**	**354.0**	**362.3**

(A) Other sources include gas derivatives and other forms of energy.

(B) Excludes network losses

Source: Terna for the final figures for 2000-2004 and the projections for 2006-2009; for 2005, AEEG using Terna data.

The electricity demand projections carried out annually by Terna (by GRTN in 2005) are essentially designed to provide a frame of reference within which to draw up the development plan for the national grid. Although such projections necessarily take into account the planned location and capacity of plants, they do not generally specify the origin by source of the electricity generated.

Grid planning process

With the Ministerial Decree of 20 April 2005, the Ministry for Productive Activities (MAP) awarded Terna S.p.A. the concession for electricity transmission and dispatching in Italy for a period of 25 years. This is effective from the date of transferral of all grid operation activities to Terna S.p.A.[23]. Under this concession, Terna is responsible for defining the necessary actions to promote security in the operation of the grid and for deciding on maintenance and development initiatives on the National Transport Network (*Rete di trasporto nazionale*, RTN), with which the other companies owning parts of the RTN must comply. The merging of the ownership and operation of the national grid in November 2005 also provided an opportunity to review and up-date the Network Code, with the aim of resolving the problem issues identified during its initial implementation period.

In its grid development activities, Terna pursues the objectives of security, reliability, efficiency, transmission service continuity, and low dispatching costs. The means it uses to achieve the objectives include adequate planning of RTN development initiatives, with the aim of achieving an appropriate level of transmission service quality and reducing network congestion, with due respect for environmental and landscape obligations[24]. To this end, by 31 December each year Terna is required to prepare a development plan which is subject to verification to ensure compliance with the Government's policy guidelines.

Relations between the transmission service concession holder and other network operators are defined with a view to encouraging the interoperability and coordinated development of the national electricity networks. The Code states that operators of high-voltage networks with obligations to provide connections for third-parties interacting with the RTN must submit the following information to Terna by 30 July each year:

- mid-term projections (5 years),
- estimated production on medium-voltage (MV) networks;
- outline of connection scheme;
- maximum power capacity of planned power stations and of plants corresponding to consumption units for connection to high-voltage (HV) and very high-voltage (VHV) networks; and
- all planned alterations to networks with voltage equal to or greater than 120kV.

As envisaged by Article 9 of the regulations governing concessions, Terna's general objective is to ensure that the transmission and dispatching service is delivered in a secure, reliable and continuous manner in the short, medium and long term, by identifying and carrying out all those measures that fall within its remit. In this respect, the concession envisages that the development plan drawn up by Terna for the RTN should essentially focus on the need to: ensure that projected demand over the duration of

[23] As envisaged by Prime Minister's Decree of 11 May 2004 in implementation of Law 290 of 27 October 2003.
[24] Network code pursuant to the Ministerial Decree of 11 May 2004.

the plan will be met; ensure the secure operation of the network; increase and/or upgrade interconnections with abroad; and minimise the risks of inter-zonal congestion.

The planning process is based both on developments in the supply and demand of electricity at a necessarily local level, and on current issues that need to be addressed in the operation of the RTN. With reference to the supply and demand of electricity, Terna focuses on the following considerations:

- the growth of electricity demand by zone;
- the expected development of the country's overall generating facilities by type of generation;
- connections of users and distribution plants to the RTN;
- applications for interconnection with abroad through private lines;
- the planned development of distribution networks and other transmission networks.

As regards the current operation of the RTN, Terna takes the following factors into consideration:

- the risks of overload, with the aim of identifying the critical elements of the network in terms of operational safety and security;
- day and night-time voltage values in the various areas analysed;
- the risks of interruptions to the supply;
- signals emerging from the operation of the day-ahead market (zonal prices, congestion frequency and revenue etc.), and the dispatching service market (congestions within zones and at the borders, procurement of dispatching resources, use of production units essential to security, etc.).

The planning procedure identifies the main problems affecting the transmission system and the related development requirements based on network operation simulations[25] in the most likely scenarios for developments in supply and demand. Problems are identified in terms of the risk of overloading on the primary grid, with at least one network element (line or transformer) transporting a current over 20% higher than the normal maximum operational level.

Under actual operating conditions, the risk of overloading identified in the simulations is, however, reduced, with respect to the theoretical risk envisaged during the planning stage, by the effect of the electricity market, which produces economic signals of the true extent of congestions. Indeed, in the operational phase the simulations consider the levels of supply and demand emerging from the market and the restrictions on trading between congested network zones and operating limits on production units are established ex ante with a view to eliminating overloads.

The area of the network most at risk is the North-East of Italy, particularly the Veneto and Friuli Venezia Giulia regions. This area is affected by the shortfall in transport capacity with respect to the power imported over the border with Slovenia, and by production from local generating facilities. The Milan area is also in a critical position, mainly because of the limited transport capacity of the grid supplying the city and the presence of

[25] With reference to the time of maximum load (usually at 11am), from a sample of 150 working days.

intensive power transits from Piedmont and from local production facilities. Piedmont also has less critical problems arising from transport towards Lombardy, power imports from Switzerland and local hydroelectric production. Problems identified on the Campania network are infrequent, but significant, as the primary network contributes directly to the power supply of the region's major cities.

Development of private interconnections

In its grid simulations and analyses, Terna takes into account the expected construction of private interconnections (merchant lines), which are trans-national lines built by operators who do not hold electricity transport and distribution concessions. The Italian legislative framework for the authorisation of said interconnectors, based on exemption from the rules governing third-party access, was completed in 2005, with due consideration for the EU and national-level regulatory systems.

As envisaged by Law 290 of 27 October 2003, and with due respect for European Regulation 1228/2003 on the conditions for access to the network for cross-border exchanges in electricity, the MAP decree of 21 October 2005 defined the arrangements and criteria for the granting of exemptions for alternating current (AC) and direct current (DC) lines connecting nodes (at a voltage not less than 120 kV) belonging to the electricity grids of different countries. The exemption is granted by the MAP for a maximum period of 16 to 20 years from the start of operation, depending on the capacity made available to third parties.

The principle conditions for granting exemptions are that:

- the new line should serve to ensure security and efficiency in the operation of the national electricity system;
- the operation of the line promotes competition in electricity supply on the market;
- the risks of the investment are so high that without the exemption the line would not be built;
- the procedures for regulating third-party access have been agreed by the regulators of the two countries;
- transport capacity does not exceed 1000 MW for each interconnection line;
- the new line does not increase the total capacity of the private interconnectors expected to be in operation by 2010 by more than 4,000 MW (AC and/or DC).

Of the 4 projects currently at various phases of authorisation, two have reached the closing stages, for a Net Transmission Capacity (NTC) of between 1,000 and 2,000 MW.

Main works carried out in 2005

One of the most important works carried out on the RTN was the up-grading of the grid in Calabria with the new 380 kV Rizziconi-Laino line of over 200km. This made it possible to improve reliability and safety and reduce a number of operational constraints in the interconnection between Sicily and the mainland. The construction of 380 kV connectors linking the Ravenna Canala station to the Ferrara–Forlì line enabled previous limitations on production facilities in the Ravenna area to be overcome. The 380 kV connection between the Edison power station at Candela and the Foggia station added 370 MW of power to the network in Puglia. The return to service of the 380 kV line from La Spezia to Acciaiolo and improvements to the La Spezia station reduced bottlenecks between the North and Centre–North zones of the electricity market. The improved functioning of the network and market in central Italy was also facilitated by the 380 kV Pian della Speranza–Montalto and Suvereto–Valmontone connectors. Finally, the decade-long dispute over the Matera–Santa Sofia line has been resolved. The completion of this line in 2006 will enable import capacity from Greece to be used to the full, and provide greater stability and security in energy flows between Puglia, Basilicata and Campania.

Two important international connections were also completed In 2005. The 380 kV S. Fiorano–Robbia line, which began operating in January 2005, is the first new long-distance interconnection to span the Alps for almost 20 years. The last line before this to come into service on the northern border dates back to 1986 (the Rondissone-Albertville line linking Italy and France). The S. Fiorano–Robbia line, completed in just 7 months, is 46 km long and increases import capacity by 1,100 MW (15%). Work on the laying of the undersea cable between the Bonifacio station (Corsica) and a new 150 kV switching station in the town of S. Teresa (Sardinia) was completed at the end of 2005, for the new 150 kV "Sardinia–Corsica" (SAR.CO.) connection. This connection came into service in January 2006, with mutual benefits in terms of security of supply deriving from the synchronous interconnection of the two electricity systems.

Criteria for the authorisation of new generating investment

There were no important developments in the authorisation of new investments in generating capacity. However, the draft legislative decree containing environmental regulations[26] attempts to inject some degree of order to this complex subject with respect to electricity power stations and other installations contributing to pollution. Article 269 sets out the procedure for issuing permits for atmospheric emissions and the specific role of the various authorities. The draft decree also establishes the minimum power threshold for which authorisation must be sought.

Implicit and explicit incentives for the construction of generating capacity

There were no significant changes to the situation found in 2004 with the start of merit order dispatching. The remuneration system, based on Legislative Decree 397 of 19 December 2003, has remained in place. This decree envisaged that administered remuneration should remain in force until a competitive capacity remuneration mechanism had been defined. This however is still pending. The implementation of the Decree, through AEEG Resolution 48 of 27 March 2004, means that the charge covering the costs for the remuneration of production capacity availability should be determined by Terna once a month for each user of the dispatching service. The charge is based on the

[26] Legislative Decree 152 of 3 April 2006.

unit charge set by the AEEG and on the electricity withdrawn in each of the hourly bands F1, F2, F3 and F4.

5.2 Gas

Gas consumption in 2005 and projections for 2006-2015

Gas consumption increased considerably in 2005, mainly as a result of the particularly cold winter and the growth in generation from new or recently converted combined cycle plants, which was in part driven by the strong increase in hydroelectric production. Gas demand on the network increased from 80.6 billion m^3 in 2004 to 86.2 billion in 2005, an increase of 5.6 billion m^3 surpassed only by the of 7.1 billion m^3 increase seen in 2003, when the cold winter was, however, combined with an exceptionally hot summer. A decisive role in meeting demand was played by (net) imports, of 73.1 billion m^3, followed by domestic production of 12.0 billion m^3 and withdrawals from strategic storage amounting to 1.1 billion m^3.

Future demand for gas depends on a number of factors, of which the most significant are: electricity demand; the contribution made by coal and renewables to electricity generation; electricity imports, depending on power availability and relative average prices with respect to other European countries; the structure of industrial production and services; the development of the methane network in Sardinia; per capita GDP and household consumption; and the amount of energy savings achieved[27]. Moreover, from one year to the next cyclical factors (such as winter and summer weather extremes; rainfall and reservoir levels; price differences between the power exchanges of European countries; and variations in the price of gas itself) can all give rise to margins of 3-5 billion m^3 either way with respect to a no-change scenario.

Table 5.6 Gas requirement, 2005–2015 (G(m^3))

Projection	2005	2006	2007	2008	2010	2015
Minimum	86.2	86	89	90	91	98
Maximum		88	91	96	104	112

These data refer to minimum and maximum values drawn from all projections, not to the average of all minimum and maximum values.

Source: Comparison of the scenarios envisaged by AEEG, AIE, MAP, ref. (energy think-tank), Snam Rete Gas and Unione petrolifera.

Table 5.6 shows the minimum and maximum and projections in the short, medium and long term drawn from the most authoritative studies available in the first half of 2006. The minimum increase in demand envisaged for 2006 with respect to consumption in 2005 (of between 0.1 and 2.2 billion m^3) reflects both the excessive use of natural gas in 2005 to make up for the shortfall in hydroelectric generation, and the saving of about 2.1 billion m^3

[27] With reference to the objectives set by the two MAP decrees of 20 July 2004.

achieved through the procedures to manage the gas emergency in the first few months of 2006, as described below.

The gas emergency of the winter of 2005-06

The first warning signs of problems with national stocks emerged in the spring of 2005, towards the end of the period when heating systems are still in use, when the delivery of available working gas for modulation fell short of demand and the MAP was obliged to authorise the use of the gas intended for strategic storage. Conditions of abnormal depletion of the national stockpiles were already evident in the first half of December, to the extent that the Gas System Emergency and Monitoring Committee[28] declared a state of emergency on 19 December. This set in motion the first stage in the system surveillance procedures implemented by infrastructure operators, led by Snam Rete Gas S.p.A., which carries out most of the tasks of monitoring and coordinating the system.

The anticipated shortfall in storage gas was caused only in part by the early arrival of the winter, with colder than normal temperatures as early as November and December. The main cause was actually the strong increase in electricity generation using gas, mainly by the new combined cycle plants that came into service in the course of 2005 and 2004. Therefore, in the last few months of the year electricity exports grew disproportionately (by 40% from October to December), driven by the favourable prices in foreign power exchanges[29]. Overall, in 2005 the consumption of natural gas for electricity generating purposes increased by 13.9% (compared with 3.3% in other sectors). December saw a particularly sharp increase, with gas consumption 30% higher than the January-to-November average.

In the presence of import capacity constraints, which were intensified by the fall of about 1.0 billion m^3 in domestic production, Italian companies fell back on stockpiles, with the result that the storage deficit with respect to the "normal" year increased from about 1 billion m^3 in mid-December to over 2 billion at the end of the month. The second stage of the procedure envisaging an obligatory requirement for operators to maximise imports and domestic production kicked in on 29 December. As we well know, the emergency took a marked turn for the worse in January with the reduction in gas imports from Russia, initially (first few days of January) as a result of the crisis with the Ukraine and then of the cold spell which increased withdrawals in all the countries of the former USSR.

In January the Emergency Committee planned the step up to the next two stages of the emergency procedure, which envisage interruptions for customers with interruptible contracts and a changeover to BTZ fuel oil in dual fuel industrial and thermoelectric plants. In addition, with a view to postponing the use of strategic storage until the second half of February (the most critical period, even in normal conditions, in view of the advanced degree of storage depletion), the last stage of the emergency procedure was also activated. This made it possible to achieve an overall saving of about 1 billion m^3 of gas through:

- incentives for users in the industry sector to sign up to further interruptibility;

[28] Set up in September 2001 by decree of the MAP.
[29] Given that Italy is a net importer of electricity, in actual fact this was the end result of a fall in imports.

- temporary rules regulating indoor temperatures and the maximum[30] daily heating hours;
- compulsory requirement for thermoelectric plants to use ATZ fuel oil until the end of March, accompanied by derogations from the environmental regulations;
- instructions issued to companies producing gas from Italian fields to increase production above normal operating limits;
- guidelines issued to the main storage company (Stogit S.p.A.) for the management of strategic reserves, including through a temporary pressure reduction on parts of the transport network.

At the height of the emergency, between the end of January and the first half of February, stockpiles were about 3.5 billion m^3 down on the level for "normal" years. 1.1 billion m^3 had to be brought into play from strategic storage – about a quarter of the total available, and with some difficulty in view of the low pressure of the gas at the end of the cold season.

Once the critical period was over, on 22 February the interruptions to customers with interruptible contracts were suspended. On 22 March the end of the emergency was declared and the procedural plan drawn up for a resumption of normal conditions for dual fuel plants and the reconstruction of stocks, with priority given to the strategic reserve. Overall, the emergency measures produced an estimated saving of 2.1 billion m^3 of gas.

Domestic production in 2005 and projections for future years

Domestic gas production continued its decade-long decline in 2005. Production from Italian gas fields and territorial waters amounted to 11,977 million m^3, compared with 12,961 million in 2004. In spite of the marked increase in crude oil and natural gas prices that characterised 2005, all the key indicators of exploration activity (number of permits, number of wells, metres drilled) continued their historic decline, as shown in Table 5.7.

Table 5.7 Hydrocarbon exploration in Italy 1985-2005

Period	Permits	Number of wells	Metres drilled
1985 - 1989	312	88	189,358
1990 - 1994	175	40	101,210
1995 - 1999	164	28	75,597
2000 - 2004	123	12	27,079
2005	90	7	15,085

Source: MSE: *Hydrocarbon exploration and exploitation in Italy: Annual report 2005*, published May 2006.

Given that the cost of developing national resources is relatively low in Italy compared with the world average, this situation appears to reflect problems of a legislative rather

[30] A reduction of one degree centigrade produces an estimated saving of 11 million m^3/day as a national average.

than an economic nature. In any case, given the long technical timescales between discovery and exploitation, production is destined to fall at least for the next 3-5 years, even if exceptional findings and/or significant progress in processing exploitation permits were to be made. The Ministry for Economic Development (MSE) envisages a fall in production to about 10.8 billion m^3 in 2006 and 6.5 billion by 2010.

Import capacity in 2005 and up-grades planned in subsequent years

Table 5.8 shows transport capacity at entry points for imported gas in thermal year 2005-06 and projections to thermal year 2009-10. The figures include up-grades to the TAG transit pipeline in Austria (of 3.3 billion m^3 in 2008-09) and the TTPC transit line in Tunisia (3.2 billion m^3 in 2008-09) [31]. They do not, however, include the second tranche of the two up-grades originally envisaged for 2011, but which the MSE would like to bring forward by a few years. Nor do they include import capacity at the terminals of:

Rovigo, for about 22 million m^3/day, which is scheduled to begin operating in 2008;

Brindisi, for which the start of operations could slip to the following year or later[32];

Rosignano, for which the authorisation process is almost complete.

In view of the complexity of the authorisation procedures currently in progress, which involve joint decisions at both the central government and regional levels, other additions or up-grades to import infrastructure are not expected in the timescale covered in the table.

The figures shown in the table point to a significant increase in import capacity, which in normal conditions should be capable of ensuring security of supply in the light of the projected growth in demand.

Table 5.8 Continuous import capacity at entry points to the Italian network (millions of m^3/day)

Entry point	Thermal year					
	2004 - 05	2005 - 06	2006 - 07	2007 - 08	2008 - 09	2009 - 10
Tarvisio	88.2	88.3	100.9	100.9	109.7	109.7
Gorizia	1.0	2.0	2.0	2.0	2.0	2.0
Passo Gries	57.5	57.5	57.5	57.6	59.4	59.4
Mazara del Vallo	80.5	80.5	86.0	86.0	94.8	94.8
Gela	21.5	22.8	25.0	25.0	25.0	25.0
Panigaglia	11.4	13.0	13.0	13.0	13.0	13.0
TOTAL	260.1	264.1	284.4	284.5	303.8	303.8

From thermal year 2008-09, these figures include the TAG and TTPC up-grades envisaged on the basis of the commitments entered into by ENI with national and European regulators

Source: MSE and Snam Rete Gas.

[31] In the emergency plan the MSE schedules the up-grade as early as 2008.

[32] These are the only terminals to have completed their authorisation procedures. While the construction of the offshore terminal at Rovigo is at an advanced stage, the Brindisi facility has encountered repeated delays as a result of local opposition, even though the permits have already been obtained.

Gas emergency plan for winter of 2006-07

As Table 5.8 shows, potential imports for thermal year 2006-07 have increased by about 20 million m^3/day with respect to the previous thermal year as a result of the work envisaged on the TAG pipeline in relation to imports of Russian gas by Eni. Annual demand is expected to increase by less than 10 million m^3 and should therefore be manageable by the TAG up-grade under normal conditions. However, many uncertainties remain as to the development of demand over time, given that the maximum available for delivery from stockpiles will for some years remain limited to 253 million m^3/day in conditions of maximum storage replenishment. Moreover, concerns still remain as to the actual availability of gas over the winter months, in the light of demand in Russia and the other former USSR countries, the capacity of Gazprom and other producers to increase their production sufficiently, and geographical factors which could restrict supplies.

The MAP therefore took action well in advance to limit the effects of a potential crisis along the lines of the one that occurred in the winter of 2005-06, by drawing up an Emergency Plan in July. The Plan is based on an increased demand of 3 billion m^3 compared with 2005, a figure which would be nearer 3.5 billion (about 10 million m^3/day) in the event of low hydroelectric production and restrictions on imports such as those experienced the previous winter.

The Emergency Plan takes into consideration a higher supply of modulation storage from Stogit, amounting to 0.6 billion m^3 obtained through increased pressure in some facilities thanks to improvements to compressors. The increased modulation storage should enable reduced recourse to strategic storage, to prevent pressure from becoming so low that demand peaks caused by particularly cold days towards the end of winter cannot be covered. To discourage an excessive use of gas in electricity generation, the Plan envisages an increase in the tariffs for transporting gas to power stations. If an emergency did occur, Terna would be required to include fuel oil power stations in the category of “must run” plants, using STZ oil as far as possible. The Plan also envisages mechanisms to incentivise the application of interruptible clauses. All things considered, the measures envisaged are similar to those adopted in the winter of 2005-06.

The Plan also envisages measures that would have a lasting effect in subsequent years. These take the form of new import and storage infrastructure, or up-grades to existing infrastructure, which are discussed below.

Infrastructure planned or under construction

Import pipelines

As mentioned above, up-grades to the TAG and TTPC pipelines are envisaged, for a total of 13.0 billion m^3, and should be completed some time between 2008 and 2011. Other important projects expected to begin operating after 2010 are currently at the feasibility study or engineering analysis stage (Table 5.9).

The project nearest to completion is the Greece-Italy Interconnection (Italian acronym IGI), which is already at the engineering study stage and could come into service in 2010. This would enable imports of over 8 billion m^3/year of gas passing through Turkey and originating from Russia, the Caucasus and Iran. The project is included in the Trans

European Networks (TEN) programme and has obtained the relevant funding. A concurrent project, again funded under the TEN programme, is the Trans Adriatic Pipeline which would cross the Adriatic and pass through Albania, essentially carrying out the same role as the IGI. The only major pipeline project not included in the TEN programme is the Italy-Algeria Pipeline, passing through Sardinia (known by its Italian acronym GALSI). The feasibility studies for these last two projects have not yet been completed and they will be not up and running until after 2010.

Table 5.9 New pipeline projects

	Capacity G(m^3)	Date of entry to service	Proposer	State of progress
IGI (Greece-Italy Interconnector)	8 - 10	2010	Edison and DEPA	Engineering study under way.
Algeria - Sardinia - Corsica - Italy	10	n.a.	Edison, Wintershall, Sonatrach, etc.	Feasibility study in 2006.
TAP (TransAdriatic Pipeline)	10	n.a.	EGL	Feasibility study in 2007.
InterconnectTirol (Bressanone-nnsbruck)	1 - 2	n.a.		Feasibility study in 2006

Source: MAP

LNG terminals

The overall state of progress in Italian LNG projects has not changed significantly with respect to the situation described for last year.

Table 5.10 State of progress of the new LNG terminals

Terminal	Capacity G(m^3)/year	Proposing company	State of authorisation
Brindisi	8	BG Group	Authorised but disputed by the new local authorities
Rovigo	8	Edison - ExxonMobil - Qatar Petroleum	Work on the structure and tanks making good progress.
Rosignano	8	Edison - BP - Solvay	Alterations requested by local authorities.
Toscana offshore	3 - 6	Olt Lng Terminal	Relocation of terminal requested by local authorities.
Trieste Zaule	8	Gas Natural	Environmental Impact Analysis (EIA) under way
Trieste offshore	8	Endesa	Still at preliminary stage
Gioia Tauro	12	Società Petrolifera Gioia Tauro	EIA under way
Taranto	8	Gas Natural	EIA under way
Porto Empedocle	8 - 12	Nuove Energie	Procedure opened with the Joint Services body
Priolo - Augusta - Melilli	8 - 12	Erg Power & Gas - Shell Energy Europe	EIA under way.

Source: MAP

With respect to the only two terminals that had by then been granted authorisation to proceed, construction work is under way on the Rovigo facility but is practically at a standstill at the Brindisi plant. The permit for the construction of the Tuscan offshore terminal would appear to be tied to the relocation of the facility to a more suitable site. The

San Ferdinando project has been merged with the Gioia Tauro one. For these and the other remaining projects, a small degree of progress has been made in the authorisation procedure. A slight increase in the average capacity of the projects can also be observed, from about 7.5 to 8.5 billion m^3/year.

Storage

Table 5.11 shows the state of progress for new storage site concessions issued by the MAP. These concern both deep rock aquifer and depleted gas facilities. The Ministry intends to speed up the development of the new reservoirs as far as possible with a view to bringing them into service by the end of 2009. To achieve this, a partial exemption from the third-party access requirement (currently envisaged for up to 80% of capacity for 20 years) has been provided for).

If all the planned storage facilities are actually built, total working gas capacity should increase from 13.2 billion m^3 in 2005 (13.8 billion in 2006) to about 22 billion by 2009-10. At the same time, maximum deliverable capacity would increase from its current level of 253 million m^3/day to 347 million.

Table 5.11 Storage concessions at March 2006

Project	Type	Working gas M(m^3)	Peak delivery M(m^3)/day	Year procedure started	Assignee	Stage of progress
Alfonsine	Depleted field	1,650	15.0	n.a.	Stogit	MSE still evaluating development plan
Bordolano	Depleted field	1,350	16.3	2006	Stogit	MSE still evaluating development plan
Cornegliano	Depleted field	800	16.5	2004	Gas Storage	MATT[33] to conduct screening.
Cotignola – San Potito	Depleted field	915	8.0	2004	Edison Stoccaggio	EIA under way.
Cugno le Macine – Serra Pizzuta	Depleted field	742	6.6	2004	Geogas	MATT to conduct screening.
Rivara	Aquifer	3,000	32.0	2004	IGM	MATT to conduct screening.
TOTAL		8,457	94.4			

Source: MAP

Role of the regulator and other authorities

Supplier of last resort

There were no changes to the rules governing the supplier of last resort in 2005. Only three suppliers changed, as a result of one change of company name and two corporate mergers[34].

[33] Ministry for the Environment and Protection of the Territory.

The role of supplier of last resort only concerns gas supplies to customers with annual consumption of 200,000 m^3 or less who, for reasons outside their will, are without a gas vendor authorised by the MAP. Under the MAP decree of 12 February 2004, a supplier of last resort has been selected for each of the 17 catchment areas connected with exit points from the national gas network. The competitive selection process was only open to companies who were able to provide sufficient technical and financial resources to deliver the service, from applicants who:

- were already providing natural gas to customers in the catchment area in question;
- in 2003 had already supplied no less than 15 million m^3 of gas at the national level;
- had not sold the biggest volumes of gas in the catchment area in question;
- had not been selected as suppliers of last resort in other catchment areas;
- had undertaken to apply a lower price for the supply of natural gas than the reference price set by the AEEG.

The 2004 decree establishes that the supplier of last resort is entitled to take on the contracts agreed by the previous supplier with transport, distribution and storage companies, in proportion to the number of customers, and relative supplies, transferred to it. For storage and modulation requirements it is entitled to transfer the corresponding modulation capacity allocated to the previous supplier.

In the period under consideration no notifications were received of contract transfers by the supplier of last resort in any catchment area.

Incentives to increase infrastructure capacity

The provisions of the AEEG have always placed a great emphasis on mechanisms to promote and foster new investment through differentiated remuneration that rewards new infrastructure investment and incentives to increase the output of regulated activities. Since 2002 the AEEG has also promoted investment in new gas infrastructure through exemptions from the rules governing third party access for the parties making such investment[35]. These provisions were taken up by the Italian legislation (Law 273/2002 of 12 December 2002), confirmed by European Directive 2003/55/EC and picked up again by Law 239/2004 of 23 August 2004, which differentiated between exemptions for infrastructure for imports from EU member states and priority allocation in the case of infrastructure for imports from non-EU countries[36].

More recently, the decree of 28 April 2006 implementing the provisions contained in Law 239/2004 established the conditions for access to the national pipeline network in cases of exemption from the rules on third party access to new interconnections with European natural gas transport networks, new and up-graded regasification terminals, and entitlement to priority allocation. The same decree also establishes the criteria of efficiency, cost effectiveness and security used by the AEEG to draw up the procedures for the allocation of residual capacity not subject to exemption or priority allocation.

[34] MAP notification of 18 May 2006.
[35] Resolutions 91 of 15 May 2002 and 137 of 17 July 2002.
[36] Articles 17 and 18 respectively.

Storage availability for the public service

In most of Italy, gas consumption for heating accounts for over 80% of total gas consumption in the household sector. The correct modulation of supply is therefore of critical importance, as pointed out in Legislative Decree 164/2000, the law originally liberalising the gas sector. This decree imposes an obligation:

- on operators carrying out sales activity to customers with annual consumption less than or equal to 200,000 m^3 to provide the modulation and seasonal, daily and hourly peak service requested by these customers;
- on the AEEG to establish the obligatory seasonal peak modulation requirements for each municipality (based on climatic factors) and the criteria to determine the storage capacity needed to meet customer demand.

New provisions were issued in 2005 in the light of the storage code and last winter's gas emergency with a view to preventing critical conditions from arising, especially in the residential sector. More specifically, Resolution 119 of 21 June 2005 envisaged balancing charges to ensure the prompt replenishment of stockpiles in cases where more capacity than the amount committed is used, as well as more detailed provisions for coordination between storage and transport companies. With particular reference to household customers, Resolution 119 established that storage users setting up new supplies to household consumers previously served by another user are entitled to take on the modulation storage capacity (space and peak) allocated to the previous supplier.

Resolution 21 of 30 January 2006, issued at the height of the gas emergency, envisages that charges for the use of gas from the strategic reserve should only be set at the end of the thermal year. The reasoning behind this is to avoid the situation arising where the availability of information on these charges months in advance might encourage speculation driven by sudden price hikes and involving arbitration between this gas and other sources.

6 PUBLIC SERVICE ISSUES AND CONSUMER PROTECTION

Supply to the final market

Companies selling natural gas must be distinct from distribution companies and authorised as vendors by the Ministry of Economic Development (MSE)[37]. In March 2006 there were 386 authorised sales companies. In order to apply for authorisation, companies must demonstrate the origin of the gas and be in possession of transport contracts, sufficient modulation and storage capacity, and sufficient technical and financial capacity. Operators granted permits are also required to comply with the supply service obligations defined by the AEEG (see below) and with the relevant informational requirements (notification of monthly sales figures and average sales prices to the AEEG and the MAP). The penalty for non-compliance is the suspension or the partial or total withdrawal of the authorisation. In 2004 the Ministry selected a supplier of last resort for each of the 17 catchment areas. The supplier of last resort is required to ensure the continuity of the natural gas supply for customers with annual consumption of 200,000 m^3 or less.

In the electricity sector, no form of authorisation to engage in the sale of electricity on the final market currently exists, nor is there a supplier of last resort. However, if customers were unable to find a supplier on the market, the Single Buyer would guarantee their electricity supply. On the captive market, sales activity is generally carried out by distribution companies (with the exception of some operators that have set up companies, distinct from the distribution company, specifically to carry out sales activities in both the free and the captive markets). On the free market, as a rule, sales activity is conducted by the wholesaler, defined as the natural or legal person buying or selling electricity without engaging in any production, transmission or distribution activity in any country of the European Union.

Suppliers' obligations, conditions of supply and consumer protection

The obligations on suppliers in the two sectors are for the most part defined by the regulations issued by the AEEG on issues other than price and intended primarily to protect consumers. These encompass:

- commercial quality and the continuity and security of the services provided;
- billing transparency and consumer information;
- minimum binding contractual conditions of supply;
- the Commercial Codes of Conduct with which suppliers must comply;
- complaints handling.

Failure by operators to observe the overall and guaranteed commercial quality standards, or the violation by them of any contractual clause, entitles the customer to automatic compensation. Between 2004 and 2005, the number of automatic compensation awards to

[37] Until May 2006, Ministry of Productive Activities (MAP)

customers for failure by operators to comply with the commercial standards increased from 18,692 to 29,522 in the gas sector, and from 48,183 to 59,497 in the electricity sector.

Service quality is regulated by a system of requirements on operators to communicate data, as well as incentives (or penalties) for operators who attain (or fail to attain) performance targets. The AEEG has the power to bring sanctions against operators if they fail to comply with safety requirements, contractual conditions, or the Codes of Conduct. In the case of the Commercial Code of Conduct for the gas sector, non-compliance by operators can lead to suspension or revocation by the MAP of the authorisation to sell.

The performance standards required of suppliers in order to provide uniform commercial quality standards throughout the country, the security requirements, and the regulations designed to improve service continuity are discussed separately for the electricity and gas sectors in Chapters 3 and 4 respectively of this Report.

Billing transparency and consumer information

The availability of clear and transparent bills is of fundamental importance both to protect certain basic customer rights (to check amounts charged and rectify any errors, manage and plan expenditure, and monitor consumption and energy savings), and to facilitate price comparisons should customers choose to move to the free market. The AEEG has defined all the information relating to consumption, charges, and conditions of supply which must be included in billing documents. The rules on transparency and obligatory informational requirements have been in place since 1999 for the gas sector, and from 2000 for the electricity sector. They concern:

- contract and supply: identification data of the customer and contract, type of supply, tariff or tariff option applied;
- contract and supply: name of customer and supply address, type of service, tariff applied;
- billing: date of issue of bill, period to which the bill refers;
- consumption: date of meter reading or self-reading, energy consumed (in kWh or m3);
- consumption: date of meter reading, energy consumed (kWh or m3);
- detail of charges: itemised details of fixed and variable components, taxes, and any credits (for example automatic compensation payments);
- other charges: itemised details of charges for services other than the supply of energy, which the customer can ask to pay separately;
- payment: due date, payment method and status of payments.

Specific informational obligations are also envisaged relating to the option, for entitled customers, to pay in instalments; the consequences of non-payment; the service for dealing with faults; and emergency assistance. Once a year, suppliers are required to inform their customers of the quality standards defined by the AEEG and the performance standards attained by the supplier. They are also required to provide information on variations in average daily electricity consumption; details of the tariff components covering costs incurred in the general interest and the general charges pertaining to the electricity system; information on the most advantageous tariff options if different from those applied; and information on insurance schemes for the gas supply.

In view of the complete liberalisation of the electricity market, in July 2006 the rules regarding the transparency of billing documents were redefined. The revised version will become effective for all low-voltage customers, in both the free and captive markets, on 1 January 2007. The new rules require that the information on bills be shown in two different sections:

- a section summarising the principal items making up the total amount of the bill to enable the customer to see the total expense at a glance, in relation to the type of supply, consumption and price applied;
- a detailed table enabling those customers who so wish to analyse in greater detail all the components making up the final price and the calculations on which the final amount billed has been determined. This detailed section can also help customers evaluate and compare offers from competing suppliers. For household customers a "simplified" version of the detailed section is envisaged.

The additional information contained in the bill has also been revised, with the double aim of facilitating customers in their relations with their electricity supplier (i.e. the complaints procedure) and keeping them better informed of their own consumption patterns (i.e. average daily and annual consumption, broken down into time bands if possible). At least once a year, customers must also be informed of the mix of sources used in electricity production in Italy; the description of the mix should include types of plant and the sources and fuels used to generate electricity. The provisions of EU Directive 2003/54/EC, according to which electricity suppliers must specify in bills, and in all promotional material sent to consumers, the contribution made by each energy source to the overall fuel mix used by the supplier over the previous year, have therefore been implemented only in part.

Contractual conditions of supply

The AEEG has defined the contractual conditions of supply which must be adhered to in supply contracts. These minimum standards have been effective since July 2000 for electricity and since 2003 for natural gas and are binding on all suppliers in Italy.

The contractual conditions of supply concern:

- meter readings;
- billing frequency;
- the method for calculating consumption;
- the timing and arrangements for paying bills;
- the arrangements for late or non-payment;
- the arrangements and timescales for suspension of supply;
- payment by instalments;
- deposits;
- the procedures for submitting complaints; and

- the arrangements for reconstructing consumption in the event of meter failure (only in the electricity sector).

In the electricity sector these terms 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 July 2006, following numerous complaints from customers and recommendations from consumer associations, the AEEG tightened up and updated the rules enabling customers to pay their electricity bills by instalments, if faced with particularly large "adjustment" bills. As an additional guarantee for consumers, provisions have been introduced regarding: the minimum number of instalments the operator is obliged to grant; the principle whereby instalments cannot be accumulated in any one single bill; and the requirement that the timescale and frequency of payment be the same as that used for billing.

The possibility for customers and operators to draw up alternative agreements envisaging customised solutions where required has been retained.

In the natural gas sector the contractual conditions of supply must be proposed as minimum benchmark conditions to all customers in market; alternatively, customers may choose other terms offered by the operator.

Commercial Codes of Conduct

In the natural gas sector, as described in full in last year's report, a Commercial Code of Conduct (with retro-active effect for contracts agreed since January 2003) is in force. The Code must be respected by all vendors on the liberalised gas market who intend to offer supply proposals to small-scale consumers (households, condominiums, operators with annual consumption of up to 200,000 m^3).

The Commercial Code of Conduct for the sale of gas also stipulates the principal clauses which must be included in contracts.

As regards the electricity sector, in May 2006 a Commercial Code of Conduct was approved for the protection of eligible low-voltage customers, including household customers who, with effect from 1 July 2007, will be able to choose their own supplier.

As in the gas sector, the Commercial Code of Conduct is a means of allowing customers to make a considered and transparent choice from the various offers they find available to them when they enter the free market. Special protection is provided at the pre-contractual stage, in the form of rules of correct behaviour and transparency that vendors must apply when promoting offers, finalising contracts, and amending contracts already agreed. These rules involve transparency of information, the appropriate use of sales techniques, completeness of information regarding the content of economic and contractual offers, prices comparability, the clarity of contracts and the simplicity of the language used. In particular, the Code:

- applies to all operators involved in the sale of electricity to eligible low-voltage customers;
- establishes the general rules to be observed in the promotion of commercial offers;

- identifies the minimum essential components of commercial communications and the general principles to be applied to avoid inappropriate behaviour in promotional activities addressed to eligible customers;
- indicates the minimum information to be supplied concerning the economic and contractual terms of commercial offers which must be made clear to eligible customers before they sign a new contract (a requirement which is also intended to facilitate comparisons between offers);
- establishes the criteria for the wording of contracts and envisages that operators, in their sales activities, must deliver to customers a copy of the whole contract, an information note drawn up by the AEEG and a summary of charges;
- also similar lines to the Commercial Code of Conduct for the sale of gas, also extends the right to a cooling-off period, as defined by Legislative Decree 206/2005 (Consumer Code), to non-household customers, who do not come under the definition of consumers.

By establishing uniform rules of behaviour applicable throughout Italy, the Code also ensures that competition between vendors develops under equal conditions and in this respect provides a further stimulus to the effective play of competition.

Conditions of supply with reference to Appendix A, gas and electricity Directives

In Italy, the consumer protection measures indicated in Appendix A of the 2003 Directives on the internal market for gas and electricity are implemented in the two sectors by the regulatory provisions and the obligations on suppliers as cited in the previous sections. In particular, the definition of Commercial Codes of Conduct has reinforced consumer protection, as regards the information that must be supplied to customers both in the pre-contractual phase (transparency of offers, vendor conduct, minimum information requirements, and the right to a cooling-off period), and once the contract has been entered into (clarity of and access to the contract and, for gas contracts, clauses that must necessarily be included; information for customers if the contract is subsequently amended). The Code of Conduct therefore reinforces the measures envisaged at points a) and B9 of Appendix A to the Directives.

As regards point c), sufficient prominence and space has been given on the AEEG's website to information publicising the obligatory economic conditions of reference it has established for the gas sector and to tariffs in the captive market, and to performance levels with respect to the quality of the service provided by suppliers. Operators too are required to publicise full and transparent details of the services they offer and their performance quality standards, both in the pre-contractual phase and in the information they are required to provide on a regular basis in billing documentation. The measures stipulated at point d) are more than satisfied by the regulations governing the contractual conditions of supply (reference conditions for gas customers and minimum binding conditions for customers on the captive electricity market). These regulations state that the supplier must provide at least one cost-free means of payment, to be made clear on the bills themselves. No costs are envisaged for changing supplier in either sector (point e) Appendix A).

Finally, as illustrated in last year's report (point f) Appendix A), the regulations governing the minimum contractual conditions of supply also lay down the complaints procedures, which have not changed in the course of this year. The AEEG also envisages, as one of the quality standards laid down for both sectors, that in 90% of cases operators' response times to complaints should not exceed 20 working days. This target is met on average in both sectors, and in many cases is exceeded.

As stated in last year's report, an obligatory insurance scheme has been in operation for household customers in the natural gas sector since 2004. The scheme covers injuries, fire and third party liability, and protects customers from any damage arising from accidents connected with the use of gas. Any civil customer whose gas is supplied via a distribution network to both household and non-household buildings can benefit from the scheme (with the exception of customers whose gas is supplied in cylinders). The cost to the customer has not changed, staying at €0.40 per year. In thermal year 2004-2005, the number of reported incidents was 56.

The requirements of point f), on information to be provided to electricity customers on their right to a universal service, and to gas customers on their right to a service that offers a given quality and price level, are amply covered by the consumer protection regulations described here.

Treatment of vulnerable customers

The regulations governing the treatment of vulnerable customers have not changed over the last year. The provision providing general guidelines in this regard, as set out in Law 481/1995 establishing the AEEG, is still in place, but not does enter into specifics. Of the provisions issued subsequently, worthy of note is the prohibition on disconnections of customers who need electricity to power life-supporting or medical treatment machines, even when their accounts are in arrears.

As regards tariffs, by July 2007 at the latest the AEEG will set a reduced tariff for financially disadvantaged customers in the electricity sector. These customers will be identified using a government-defined threshold based on the indicator of socio-economic well-being, the ISEE (Indicator of Equivalent Economic Situation), and also with respect to other categories of vulnerable customers.

In the gas sector, local administrations will be able to set up funds (financed by a surcharge of not more than 1% of distribution tariffs, net of tax) to cover the cost of supplying gas to economically disadvantaged, elderly or disabled customers, using criteria defined by these same local bodies. In thermal year 2004-2005, 288 of the 7,200 "methanised" town councils applied such a procedure to about 4 million users out of a total of 18 million.

Disconnections for non-payment

The contractual conditions of supply laid down by the AEEG (in force since 2000 in the electricity sector and since 2003 for gas) also govern the suspension of supply for failure to settle bills. Operators may only disconnect supply for arrears after they have issued a written warning to the customer stating: the payment deadline; the means of advising the operator if the bill has been paid in the meantime; and the period beyond which the supply will be suspended if the payment is not made. The supply may not be disconnected, however, if it is needed for medical equipment, or on Fridays, Saturdays, Sundays, public holidays or the day immediately preceding public holidays.

The AEEG does not monitor the number of disconnections for non-payment, but rather the number of reconnection applications following such disconnections. In the electricity sector these amounted to 310,540 in 2004 (for low-voltage customers), while in the natural gas sector they numbered 39,279 (low-pressure customers). The maximum re-activation time following disconnection for arrears is regulated by the obligatory commercial quality standards for suppliers. If these times (one working day in the electricity sector and 2 for gas) are not respected, operators are required to pay compensation to the customer.

Regulation of tariffs and final prices

Tariff regulation primarily concerns infrastructure activities conducted through networks and is implemented in conformity with the law establishing the AEEG (Law 481/95) through the price cap mechanism, described in last year's report. It sets out the regulator's efficiency objectives for a regulatory period of four years.

The current regulatory period for the electricity sector (transmission and distribution) is 2004-2008, and so the price cap coefficients are unchanged with respect to last year. In the gas sector the first periods of regulation for the transport tariff and the tariff for the use of GNL terminals ended during 2005. The respective price cap parameters have therefore been revised. The first period for storage tariffs ended in March 2006.

Table 6.1 Price cap coefficients in the two sectors in July 2006

ELECTRICITY SECTOR		NATURAL GAS SECTOR	
Transmission *(2004 - 2007)*	2.5%	Transmission *(2005 –2009)*	2% (*capacity*) 3.5% (*commodity*)
		Distribution (2004 –2008) (A)	5% (only on 58.16% of th constraint)
Distribution *(2004 –2007)*	3.5%	LNG Regasification *(2005 – 2009)*	1.5% (*capacity*) 1.5% (*commodity*)
		Storage *(2006-2010)*	1.5% (*capacity*) 2.0% (*commodity*)

(A) The tariff and coefficients will be revised in September 2006.

In the electricity sector, where a captive market still exists (made up of household customers and non-household customers who have chosen not to obtain their supply on the free market), the final prices paid by customers are tariffs rather than market prices.

The natural gas sector has been entirely free since January 2003, but given that competition has been struggling to take off in the sales market to end-users, the AEEG has deemed it necessary to impose conditions providing greater protection to consumers. Since 2003, all natural gas vendors have been obliged to offer, alongside their own terms, the benchmark economic conditions of supply calculated using criteria established by the AEEG to customers whose annual consumption is less than 200,000 m^3. The results of the survey on the conditions for natural gas sales in Italy, conducted by the AEEG in 2005 and published on-line on 16 February 2006 (entitled "Situation of the market for natural gas sales to consumers in Italy"), confirmed the continued existence of non-competitive conditions in this segment of the market. The need to maintain benchmarked prices as a form of protection for consumers was therefore also re-affirmed.

In the natural gas sector, over 90% of the gas used by household customers is supplied using economic conditions of supply stipulated by the AEEG. This figure has remained stable with respect to last year, as have the figures for the amount of gas supplied at non-market prices in the commercial and service sectors (72.1%), in industry (5.6%), and in electricity generation (0.01%). In the electricity sector, 100% of household customers are still supplied on the captive market as these consumers will only be eligible from July 2007. The amount of energy bought on the captive market by non-household customers has decreased by around 3.5% compared with last year.

Table 6.2 Regulation of final prices

	Electricity			Gas			
	Large industrial undertakings	Small-medium industrial and commercial undertakings	Household sector	Thermo electric uses	Industrial under takings	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[B]	Y[B]
% customers with regulated tariffs	38.8		100	0.01	5.6	72.5[C]	90.7[D]
Possibility of returning to regulated tariff (Y/N)	Y	Y	n/a	Y	Y	Y	Y
No. of suppliers with tariff proposal obligation	168[E]			380[F]			

(A) Only household customers are obliged to buy electricity at regulated tariffs as they are not eligible customers. Non-household customers may opt to obtain their supply on either the free or captive market.

(B) Customers in this sector with consumption less than 200,000 m^3 can accept the AEEG's economic conditions of supply.

(C) With reference to commercial and service firms of any size.

(D) With sole reference to the household sector.

(E) Distributors at 30 June 2006.

(F) Figure for 31 March 2006.