GME
Gestore
Mercati
Energetici

ANNUAL REPORT
2011

FOREWORD

In the light of the success of the previous editions, GME has decided to publish again its annual report; the goal is to contribute to the analysis of results in the energy sector in 2011.

Starting from the illustration of the main events which characterized the energy sector in 2011 and with an eye to the future, the sixth edition of GME's Annual Report (Gestore dei Mercati Energetici) aims at offering a detailed description of the national energy markets with reference to a broader international context during a year characterized by a serious global economic crisis.

In 2011, GME strengthened its activities in the gas sector, by means of the full operation of the Spot Gas Market (M-GAS), followed by the Natural Gas Balancing Platform (PB-GAS).

As to the electricity sector, there has been an increase in volumes traded on the Forward Market (MTE), as proven by the growing interest of operators in clearing options at MTE for bilateral contracts entered outside the organized market.

In 2012, GME will focus, in collaboration with the relevant institutions, on the implementation of the Forward Gas Market (MT-GAS). This will enable operators to enter into physical forward contracts for the delivery of natural gas on a longer time horizon relative to those currently existing in the spot market.

On an international level, after successfully starting the Market Coupling pilot project with Slovenia, GME will keep integrating the energy markets across Europe through the Price Coupling of Regions project, where the electricity exchanges of the main European countries are involved.

We do hope that this report provides helpful facts and figures for an easier analysis and understanding of how energy markets evolve: a positive contribution to fact-finding tools in the energy sector.

Chairman

Alfonso Maria Rossi Brigante

Alfonso Maria Rossi Brigante

Chief Executive Officer

Massimo Guarini

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INTRODUCTION

After some timid signs of recovery observed in 2010, the economic-financial crisis characterized the year 2011. In some Eurozone countries, including Italy, the crisis caused a drastic economic slowdown and started a recessionary downturn which will continue at least throughout 2012.

The GDP growth slowdown from 1.5% to 0.4%, with a negative trend during the last quarter of 2011 and an estimated GDP value of -2.2% this year, caused a stagnation in the electricity demand which remained stable in 2011 (332 TWh, +0.6%), with the first signs of decline in the first quarter of 2012. This scenario further emphasized a blatant overcapacity; this is also due to the inertial growth of renewables, a phenomenon characterizing the electricity sector for some years now. In other words, the gross net maximum installed capacity equals 121 GW (+10%) with a further improvement of the supply competitiveness indicators. Although an increasing competition on the supply side has brought prices to the same levels as variable costs, as indicated by the collapse of the spark spread – which hit a historical minimum with levels close to zero -, prices kept being quite different from foreign ones (approximately 20 €/MWh) due to the high cost of domestic gas and to the inflationary dynamics of the Brent (+33%, gross of the exchange rate). Such dynamics caused the electricity market to move in a "lose-lose" scenario. On one hand, small margins for producers may entail a plant shutdown period; on the other hand, Italian final customers keep paying a heavy premium relative to their foreign counterparts. In this scenario, the most striking finding is not the nominal growth of the PUN (National Single Price), stable at 72.23 €/MWh (+13%), but a further flattening of the peak/off-peak price ratio, hitting a historical minimum level of 1.29. During the month of April 2012, this ratio seemed to be close to a structural reversal, due to the impact of the increasing generation by photovoltaic plants. Finally, in 2011, while the progressive elimination of the price spread between Sardinia and the mainland was confirmed (7.70 €/MWh, -18%) thanks to the full operation of the new Sapei cable, such differential remained high for Sicily (21 €/MWh), awaiting the completion of the new interconnection with the mainland, expected by the end of 2013. In 2011, the gas sector was characterized by a drop in consumption levels, down to 77 billion cubic meters (-6.4%). This was not caused by an industry crisis – on the opposite, sector consumption levels were quite stable - but by a milder weather, which favored a drop in household consumption levels and by a sharp decline in consumption by thermal power plants– a true growth engine in recent years – after a decreasing demand for electricity and a growing displacement of gas-fired generation by renewable-energy plants. Nonetheless, during the year the wholesale prices of gas nearly reached 28 €/MWh (+21%). This was driven by the Brent dynamics, with a differential vis-à-vis foreign countries close to 5-6 €/MWh.

In this context, 2011 was a year of major novelties to GME.

The electricity sector featured a true explosion of volumes traded over the Forward Market, up from 6 TWh in 2010 to 33 TWh and already stable at 9 TWh in the first quarter of 2012; this was a clear sign of the growing interest of market participants in clearing their OTC contracts in the MTE. Broadly speaking, the Italian forward market showed a growing trend in 2011. The same happened with the OTC Platform (PCE) showing a volume of 296 TWh (+25%); this latter caused the churn ratio to reach a new high of 1.58. Spot markets equally presented major novelties: for the first year, the intra-day market (MI) had four, fully operational sessions, including two sessions during the delivery day. Overall, they amounted to 22 TWh (+ 50%, mostly accounted for by the MI1); despite a fall in volume (180 TWh, -10%), the Ancillary Services Market (MGP) was

characterized by the full operation of the market coupling with the Slovenian border. At year-end, it achieved a level of about 1,156 GWh. It was originally supposed to stay within the limit of 262 GWh. Such success confirms the positive market appreciation of this tool, enabling a more efficient management of cross-border energy trading.
Still, the most important novelty of 2011 was GME's full entry into the gas sector. After the P-gas take-off during 2010, participants can now fulfill their obligation to bid domestically produced and imported gas quotas. In 2011, also the gas market (M-Gas) entered into full operation. The M-Gas is a spot market consisting of a day-ahead and an intra-day session. In December, the Gas Balancing Platform run by GME pursuant to AEEG'S Decision ARG/gas 45/11 was set up.

In 2011, such markets were into the first year of full operation. During the year, liquidity was not very high. Overall, they collected slightly less than 5 TWh, 2.9 of which in the P-Gas Royalties Segment with 1.7 TWh traded on the PB-Gas during its only month of operation. However, prices look mutually consistent and in line with those at the PSV (Punto di Scambio Virtuale – Virtual Trading Point), still the most important reference for the Italian market in the short run. However, the startup of such markets is very positive for the market as a whole. On the one hand, they create the most efficient conditions to handle the excess supply, now characterizing the Italian gas market while providing the system with a new, unprecedented commercial flexibility; on the other, they lay the foundations required to promote increasingly oil-independent prices, in line with what has already happened in the North American and Continental European markets. The development of markets, therefore, could turn out to be a key element to eliminate the historical price spread vis-à-vis the rest of Europe for both gas and, indirectly, electricity prices.
As to the environmental markets, traded volumes on both the Green Certificate and Energy Efficiency Certificate Markets kept increasing. As to the GC market, targets falling on conventional electricity producers and importers contributed to a rise in trades: on the regulated market, volumes rose by 60% whereas those traded bilaterally increased by 18.3%, with an overall volume increase of 22.5%. In 2011, a reform of renewable sources incentives was introduced with the enactment of Legislative Decree 3 March 2011, nr.28. This provision entails the gradual replacement of a market system based on green certificates for a feed-in tariff system. Plants starting their operations by the end of 2012 will keep receiving GCs; those starting their operations from 1 January 2013 will receive a pre-set fixed incentive.
The Energy Efficiency Certificates Market (TEE) grew thanks to tighter annual savings targets falling on distributors, with a total increase of trades equal to 32.7%; the regulated market accounted for a 30.3% increase; bilaterally traded certificates grew by 33.8%. Moreover, TEE prices increased continuously. This was due to a limited supply relative to the demand level. To address this situation, AEEG defined new guidelines for TEE issuing; amongst others, it introduced a coefficient of duration which considers the varying length of projects, thereby allowing owners of projects with a longer useful life to obtain more certificates.
Finally, on an international level the year 2011 was marked by the accomplishment of significant goals in view of the establishment of the energy single market by 2014. A major development was the operational takeoff of ACER, Agency for the Cooperation of European Regulators; ACER promotes the integration of market coupling regional implementation projects of energy regulators. On a different level, the European Commission published a consultation document on the Governance model best suited to foster such integration. GME, given the positive pilot experience with Slovenian coupling, continued, along with the most important European exchanges, developing the European coupling project known as PCR (Price Coupling of Regions). In 2011, the design stage of the future European coupling system was completed; also, the implementation of the future European coupling algorithm started with the development of a prototype embedding the major characteristics of the various European exchanges. Finally, in December 2011, the European Parliament and Council adopted Regulation 1227/211 on the integrity and transparency of the wholesale energy market (REMIT). REMIT introduced, for wholesale energy markets as well, a number of

measures aimed at fighting against insider trading and market manipulation. ACER was given the task of carrying out specific transnational monitoring activities; national regulators will have broader sanctioning and oversight powers whereas those responsible for the arrangement of wholesale transactions (including energy exchanges) shall abide by a number of monitoring and reporting provisions, and shall report to their respective sector-specific authorities.

SECTION A

THE COMPANY

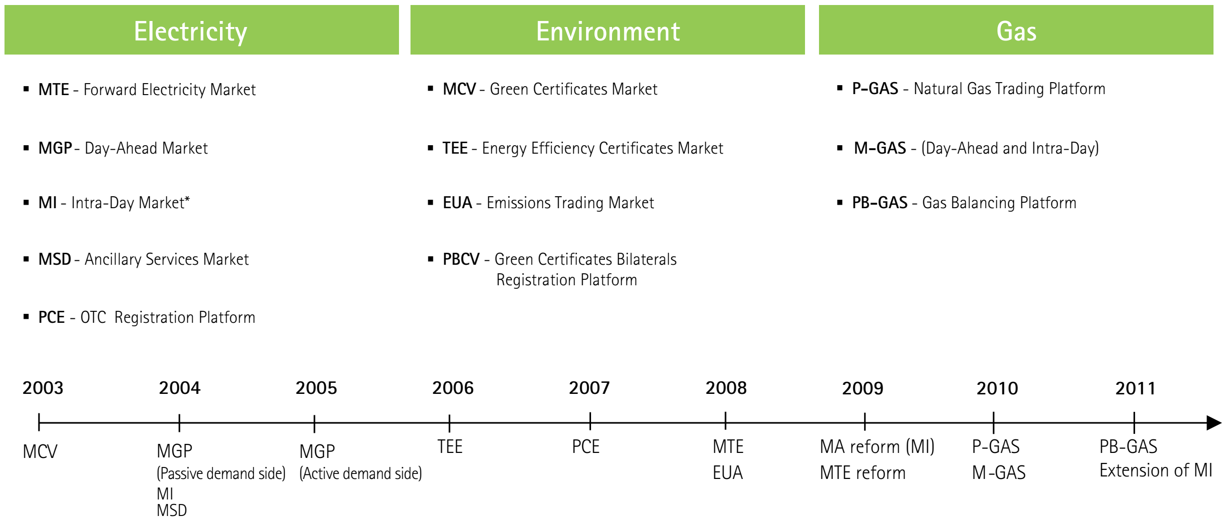
THE COMPANY

1. GESTORE DEI MERCATI ENERGETICI

1.1 Governance

Gestore dei Mercati Energetici S.p.A. (GME) is a publicly-owned company and was set up in 2000 pursuant to art.5, Legislative Decree 79/99 (the so called "Bersani Decree"); it is vested with the organization and economic management of the electricity and natural gas markets according to criteria of neutrality, transparency, competition and objectivity. The Company is also entrusted with the management of the OTC Registration Platform (PCE) to register electricity sale and purchase forward contracts entered outside the bidding system.
Moreover, GME, organizes and manages the Environmental Markets, i.e. markets where Green Certificates, Energy Efficiency Certificates (the so called "white certificates") and Emission Units are traded.

Fig A.1.1 **GME's markets**



*previously adjustment market (MA)

GME's sole shareholder is Gestore dei Servizi Energetici (GSE), a company supporting the development of renewable sources through incentives for electricity generation. Also, GSE promotes sustainable development by means of public awareness campaigns on the efficient use of energy. GSE' shareholder is the Ministry of Economy and Finance (MEF), which exercises its rights as agreed with the Ministry of Economic Development (MiSE).
The rules for the electricity market, Green Certificates market, Gas Market and P-GAS Bilateral Platform functioning were defined by GME and approved by the Ministry of Economic Development, after hearing the Electricity and Gas Regulator's opinion.
The rules for the Energy Efficiency Certificates Market functioning, a market set up pursuant to article 10 of Ministerial Decrees 20 July 2004, are defined by GME in agreement with the Electricity and Gas Regulator.
As to the operation of the Emission Unit Market, established by GME in compliance with Directive 2003/87/EC, its rules are drafted and approved by GME.
Finally, the rules for the Green Certificates Bilaterals Registration Platform as well as the rules for the Electricity Accounts Platform and the Gas Balancing Platform are defined by GME upon AEEG prior approval.

Operation on electricity markets is subject to supervision and monitoring by AEEG, pursuant to AEEG Decision ARG/elt 115/08 and following amendments.

The EU Regulation nr. 1227/2011 on wholesale energy market integrity and transparency (REMIT), published in the Official Journal of the European Union on 8 December 2011 defines the notion of "market abuse" on wholesale energy markets (classified as "market manipulation" and "insider trading"). Also, it adds up for European electricity exchanges, including GME, new oversight and monitoring activities. These imply a mandatory reporting of any potential market abuse to AEEG, as well as the establishment and maintenance of appropriate procedures aimed at the identification of any "market manipulation" and "insider trading" conduct.

The Company's management body is its Board of Directors, consisting of five members, appointed through a Shareholder's Meeting resolution for three financial years. The Board of Directors is exclusively responsible for the management of the Company; current Directors carry out any operations required to implement the corporate object.

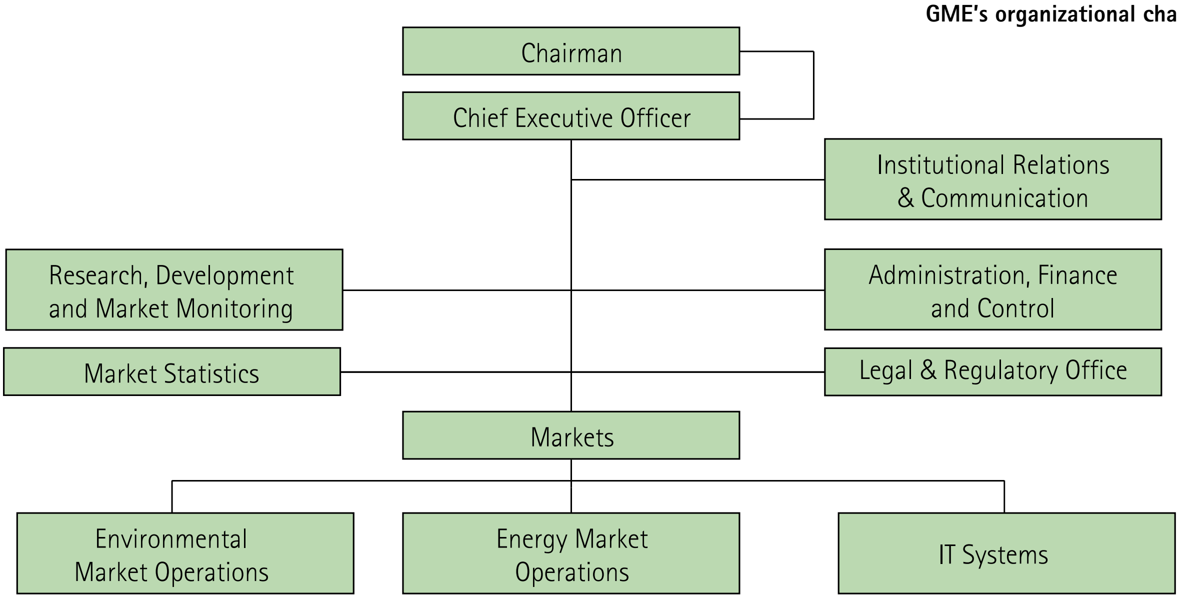
GME's Board of Directors designates the following among its members:

- *Chairman,* who holds the legal representation of the Company. The Chairman is also vested with the signing authority, chairs the Meeting, calls and chairs the Board of Directors and checks the Board Resolutions' implementation. Moreover, through a Board of Directors Resolution dated 14 April 2010, the Chairman now has operational proxy powers.
- *Deputy Chairman of the Board of Directors,* who, in the event the Chairman is absent or unavailable, under the by-laws has the legal representation of the Company and the signing authority. The Deputy Chairman's signature proves to any third parties that the Chairman is absent and/or unavailable. In case of absence or unavailability of this latter, he/she takes over in chairing the Shareholder's Meeting and the Board of Directors meetings.
- *Chief Executive Officer,* who, other than having the legal representation of the Company under the By-laws, through a specific Board Resolution, is vested with all management powers for the administration of the Company, to the exception of those assigned by law or by the corporate by-laws to other parties or those under the exclusive control of the Board of Directors. Furthermore, at least on a quarterly basis, the Chief Executive Officer reports to the Board of Directors and to the Board of Auditors on the corporate management, on the predictable development of this latter as well as on any significant transactions, given their size or characteristics, conducted by the Company.

The remaining GME's corporate bodies include the following:
- Board of Auditors;
- Supervisory Board;
- Internal Appeal Board.

The company has approximately 90 employees, divided into nine units, as shown in the diagram in Fig A.1.2.

GME's organizational chart Fig A.1.2



1.2 Institutional tasks

1.2.1 Market management

GME is in charge of organizing and managing the natural gas and electricity markets where physically-deliverable products are traded, as well as Environmental Markets. The Company is also in charge of managing the OTC Registration Platform (PCE), for the registration of electricity sale and purchase forward contracts.
Within the framework of the electricity market, GME organizes and manages the following platforms:

- **Spot Electricity Market (MPE).** Governed by decree of the Minister of Productive Activities of 19 December 2003 and any subsequent amendments, the MPE was started on 1 April 2004 in compliance with article 5 of Legislative Decree 79/99. This market has been partially redesigned since 1 November 2009, pursuant to Law 2/2009, and is split into three submarkets:
  - **Day-ahead market (MGP)**, where producers, wholesalers and eligible final customers can sell/buy electricity for the following day;
  - **Intra-day market (MI)**, replacing the former Adjustment market's function; it enables spot market participants to change their injection/withdrawal schedules as established on the MGP. The market includes four sessions: two are held on day d-1 after the MGP (MI1 and MI2) and have been in operation since 31 October 2009; another two intra-day sessions (MI3 and MI4) are held on day d and were introduced on 1 January 2011.
  - **Ancillary Services Market (MSD)**, where Terna S.p.A procures the dispatching services it requires in order to manage and control the power system. The MSD consists of one ex ante session for purchasing congestion relief and reserve services and one intra-day stage of acceptance of offers for balancing purposes (MB). The ex ante MSD includes three scheduling sub-stages (MSD1, MSD2 and MSD3) while the MB consists of 5 sessions.
- **OTC Platform (PCE).** Entrusted to GME pursuant to AEEG Decision nr. 111/06 and any subsequent amendments, it was officially started on 1 April 2007. This platform is used by participants to register forward purchase/sale bilateral contracts (the so called over the counter or OTC) or contracts closed in the MTE.
- **Forward Electricity Market (MTE).** The MTE took off on 1 November 2008, pursuant to the decree of the Ministry of Economic Development of 17 September 2008 and has been redesigned since 1 November 2009 under Law 2/2009 and in compliance with Ministerial Decree 29 April 2009. It is a regulated market where participants can sell and buy forward electricity contracts with a delivery taking-making obligation.
- **Electricity Derivatives Platform (CDE).** Since 26 November 2009, in compliance with Ministerial Decree 29 April 2009, GME has been managing a platform where participants in the electricity market can settle by physical delivery, upon registration on the PCE, any contracts entered on IDEX (electricity derivatives market, managed by Borsa Italiana SpA).

Within the framework of the organization and economic management of the electricity market, GME is also responsible for environmental markets, i.e.:

- **Green Certificates Market (MCV).** Operational since March 2003 pursuant to article 6 of Ministerial Decree 11 November 1999, finally repealed under Ministerial Decree 18 December 2008), it is aimed at trading certificates proving generation of energy from renewable sources, in order to comply with statutory obligations to inject into the grid/import a given quota, as provided for by Legislative Decree 79/99;
- **Green Certificates Bilaterals Registration Platform (PBCV).** This MCV functionality was introduced in 2007 to register bilateral trading of green certificates between market participants. In compliance with Ministerial Decree 18 December 2008, it is mandatory to report the price of such bilateral trades.
- **Energy Efficiency Certificates Market (TEE).** This market became operational in March 2006; its goal is to trade the so called "white certificates", proving the adoption of measures to curb energy consumption levels and allow subjects to comply with saving restrictions established by Ministerial Decrees of 20 July 2004 and any subsequent amendments. Ministerial Decree of 5 September 2011 governs the new support system for high

efficiency cogeneration (CAR), extending also to CAR cogeneration units access to the TEE system. As to the future evolution of energy efficiency certificates, GME will enforce the above said regulations during 2012 as applicable to white certificates trading and registration systems.

- **Energy Efficiency Certificates Register (TEE Register).** In operation since 2006 to allow TEE market activities, the TEE Register allocates an ownership account to each registered participant; the account is an "electronic portfolio" where the total number of TEEs held by each participant is entered. Thanks to the Register's functionalities, participants can check in real time the status of their portfolio and directly register individual bilateral transactions entered off the market. GME, in compliance with provisions under AEEG' Decision EEN nr. 5/08 on the *"Approval of the Rules for the registration of bilateral transactions of Energy Efficiency Certificates as per article 4, para 1, of AEEG's Decision of 28 December 2007, n. 345/07 and article 4, para 1, of the decree of the Ministry of Economic Development of 21 December 2007"* started drafting the Rules for the Register's operation.
- **Emissions Trading Market (EUA).** This market became operational in April 2007, within the framework of the European Directive 2003/87/EC establishing a European Emission Trading Scheme; purpose of this latter is to promote trading of the so called "black certificates", representing CO2 emission allowances within a set of specifically regulated economic activities (for example, energy activities); emissions are allocated through National Allocation Plans. On 1 December 2010, GME's Board of Directors passed a resolution to halt the Emissions Trading Market operations, effective immediately until a subsequent notice; this decision was made in the light of the unusual trading pattern observed during the last market sessions and, in particular, of alleged irregular or illicit conduct, promptly reported by GME to the Institutions in charge - Ministry of Economic Development, Ministry of Economy and Finance - and Supervisory Authorities.
- **Certificates of origin for renewable energy power plants (CO-FER, RECOs).** Through AEEG Decision ARG/elt 104/11, GME was entrusted with the task of managing and setting up the RECOs trading system (Certificates of Origin), as well as managing the regulated market (M-COFER) and its platform for the registration of bilateral transactions (PB-COFER), starting in 2012.

As to the gas sector, Law nr. 99 of 23 July 2009 entrusted GME with the management of gas markets, as detailed below:

- **Natural Gas Trading Platform (P-GAS).** This platform became operational on 10 May 2010. Importers of gas produced in non-EU countries and holders of leases of exploitation of national gas fields shall fulfill their obligation of bidding quotas of imported gas on this platform, as provided for by art. 11, Law 40/07. To this end, the P-GAS consists of two segments, "Imports" and "Royalties": in the Imports segment, gas quotas are offered as per art. 11, para 2, Law 40/07, along with other quotas offered by any party who is not subject to statutory obligations; in the Royalties segment, gas quotas owed to the State under art. 11, para 1, Law 40/07 are offered. In the light of provisions under Legislative Decree nr.130/10 on *"Measures for a greater competitiveness in the natural gas market and the transfer of the ensuing benefits to final customers, pursuant to article 30, paras 6 and 7, Law 23 July 2009, n. 99"*, including measures aimed at promoting the development of storage capacity, and in compliance with AEEG Decisions ARG/Gas 193/10, ARG/Gas 79/11 and 67/2012/R/gas, GME, starting from April 2012, within its own natural gas trading systems, allows to negotiate gas quotas delivered by virtual storage operators and matched to investors who avail themselves of measures under art. 9, Legislative Decree 130/10. More specifically, investors can fulfill the mandatory requirement to offer gas quantities made available by the relevant matched storage operators, alternately or altogether, in the M-GAS and P-GAS. With regard to the P-GAS, GME established an additional segment on the same platform, named "as per Legislative Decree 130/10", to allow investors to fulfill the above said obligation.
- **Spot gas market (M-GAS).** In operation since 10 December 2010, this is a regulated spot market over the day-ahead market – where transactions are performed under the continuous and auction trading mechanisms – one after another - and an intra-day market, where transactions are conducted on a continuous trading basis.
- **Natural gas balancing platform (PB-GAS).** Since 1 December 2011, GME has been organizing and running, on

behalf of Snam Rete Gas, the natural gas balancing platform (PB-GAS). On this platform, eligible users, as under article 1, para 1, letter k), AEEG Decision ARG/gas 45/11 (users of storage services, to the exception of transport firms and users of strategic storage service only), offer for sale and purchase any storage resources available, on a daily basis. Likewise, Snam Rete Gas, as the entity in charge of balancing, offers on the PB-GAS, either for sale or purchase, a gas amount equal to the overall system imbalance, in order to procure the resources offered by participants, as required to keep the system balanced. The selection of offers accepted on the PB-GAS is made according to auction trading mechanisms.

1.2.2. Electricity market monitoring

Ever since the beginning of transactions in the electricity market in April 2004, GME has been carrying out several activities to support the monitoring functions exercised by the institutional parties in charge, e.g. the Electricity and Gas Regulator (AEEG), Autorità Garante della Concorrenza e del Mercato (AGCM, the competition regulator) and the Ministry of Economic Development (MiSE). More specifically, GME supports AEEG electricity market monitoring activities, in compliance with AEEG Decision ARG/elt 115/08 (Integrated Text on Market Monitoring hereinafter, TIMM), subsequently amended and supplemented by decisions ARG/elt 60/09, ARG/elt 50/10, ARG/elt 77/10, ARG/elt 180/10 and ARG/elt 110/11.
Under the TIMM, GME:

- Implements and runs a specific data warehouse (DWH) putting together electricity market data and those listed in the main European spot electricity markets and in the various forward electricity markets (physical and financial, regulated and OTC); the data warehouse is made available to AEEG through an appropriate business intelligence tool (article 3);
- Creates specific monitoring indicators and develops true what-if market simulations aimed at evaluating the impact of alternative bidding policies by market participants, according to instructions given by AEEG (articles 4 and 5);
- Collects from participants, by means of a specific External Data Platform (PDE), confidential data on forward electricity contracts and on their generating capacity (article 8);
- Has set up a specific “monitoring unit”.

To comply with the above provisions, GME created the External Data Platform (PDE) of participants’ forward contracts.
On 28 December 2011, the European Regulation nr. 1227/2011 became effective. It establishes monitoring duties for “any person professionally arranging transactions in wholesale energy products”, including, therefore, any Exchanges. Such subjects shall report any alleged market abuse and/or insider trading conduct to the relevant authorities and shall “establish and mantain effective arrangements and procedures to identify the (above said) breaches” (art.15).

1.3 International activities

The year 2011 was characterized by activities aimed at establishing the European single market of energy, as envisaged by the so called "Third Energy Package"[1].

The establishment of ACER[2] - Agency for Coordination of Energy Regulators -, has greatly fostered the integration of domestic and regional markets. In this respect, the Agency published its Guidelines (Electricity Grid Connection, Capacity Allocation and Congestion Management, System Operation) to create an integrated, non discriminatory, competitive and efficient European electricity market, facilitating the development of cross-border trading. As a matter of fact, the guidelines aim at harmonizing the various national regulations, with respect to the electricity grid connection, as well as at identifying the most efficient models to allocate any cross-border transmission capacity with the ultimate goal of creating the European single market.

The operation and efficiency of electricity markets heavily depend on the methods of allocation of transmission capacity and on congestion management mechanisms over the grid (CACM - Capacity Allocation and Congestion Management). The identification of the most efficient capacity allocation and congestion management methods resulted from a European effort spanning over a decade; the proceedings were coordinated by the Florence Forum, within the framework of which the "Framework guidelines on CACM" were drafted and published in February 2011.

The bottom up response from the market was significant, with the launch of market coupling[3] across CWE (Central Western Europe Market Coupling, involving Germany, Luxembourg, France, Netherlands and Belgium), a new regional coupling project among the Czech Republic, Slovakia and Hungary, as well as the kick start of new significant projects like the NWE (North Western Europe, involving CWE countries, United Kingdom and Nordic countries – Finland, Sweden, Norway, Estonia and Denmark), CWE – Nordic ITVC (involving CWE and Nordic countries) and PCR (Price Coupling of Regions, including CWE and Nordic countries, Italy, Spain and Portugal)[4]. This latter is supported by the European Association of Electricity Exchanges and by the six largest European electricity exchanges: EPEX, OMIE, NORD POOL, GME, APX – ENDEX and Belpex. It is based on a decentralized price coupling mechanism, a highly appreciated solution to create a European single electricity market. The PCR enables each country to keep its institutional set up unchanged, as determined on the basis of the national legislation or contractual agreements with their own transmission system operator (TSO). Yet, such differences should not affect the operating procedures, coupling-related responsibilities and Regulators' duties. The PCR proposes a collaborative effort among exchanges to exchange aggregate data; each exchange is supposed to use the same algorithm, on a single and aggregate level, while calculating volumes and prices for each individual zone.

In October 2011, REMIT[5], the Regulation on wholesale energy market integrity and transparency, was approved. It introduced an integrated monitoring of energy markets falling under Acer's and national regulators' supervision. Alike financial markets, insider trading and market abuse are now prohibited on energy markets as well. REMIT also introduced

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1 Published in the Official Journal of the European Union on 14 August 2009: the so called "Third Energy Package" is a set of measures containing provisions which have changed the regulatory aspects of the European energy market. The Package consists of five measures: Regulation nr. 713/2009 estabilishing the Agency for Cooperation of Energy Regulators, Directives 2009/72/EC and 2009/73/EC on electricity and natural gas and Regulation nr. 714/2009 and nr. 715/2009 on access to transmission infrastructures. The deadline for transposition of the measures into the national legislation of Member States was 3 March 2011, whereas the one set by the Commission for the transposition of unbundling measures was 3 March 2012.

2 ACER – Agency for Cooperation of Energy Regulators, established by Regulation (EC) 713/2009 and officially inaugurated on 3 March 2011; its mission is to coordinate cross-border settling and remove obstacles to the integration of domestic markets of electricity and gas, other than strengthening cooperation among national regulators, including regionally.

3 Market coupling is a transit capacity allocation method involving two or more countries; it unfolds through the coordinated operation of their respective day – ahead markets.

4 PCR project is aimed at identifyng a coordinated electricity pricing mechanisms on the markets, in order to create a true European energy market. At present, an algorithm to get prices closer to each other is being implemented over the geographical area covering Portugal, Spain, Italy, Belgium, Netherlands, United Kingdom, France, Germany, Austria, Switzerland, Denmark, Norway, Sweden, Finland and Baltic Republics, accounting for over 80% of European energy consumption levels in this sector.

5 REMIT- Regulation on wholesale energy market integrity and trasparency - Reg. UE no 1227/2011 (October 25, 2011).

information and monitoring obligations for market participants and for those who perform energy trading activities by profession. Moreover, the Member states need to grant specific inspection and sanctioning powers to their respective national regulators.
In summary, GME is active on three international fronts: participation in the Association of European Energy Exchanges (Europex); operational kickstart of market coupling with Slovenia on the day-ahead electricity market and further progress of the PCR project (as further detailed in paragraph 2.3).

1.3.1 Europex

GME is a founding member of Europex[6]; the main objectives of Europex include the support to the liberalization process of energy markets, by promoting the role of energy exchanges in a market integration perspective; exchanges are deemed to be strategic instruments to enhance competition while increasing the transparency of pricing mechanisms.
GME also operates through Europex; in this capacity, it replies to European consultations (with special emphasis on transparency and congestion management) in order to help defining a target model for energy markets.
GME is involved with the definition of Europex policy lines by regularly attending the association's technical group proceedings:

- Power Market Working Group – PMWG, addressing issues about the structure and operation of spot, balancing, forward electricity markets as well as methods to manage congestions and certificates of origin;
- Environmental Market Working Group – EMWG, carring out activities of analysis, development and promotion in support of european and national environmental policies;
- Gas Market Working Group – GMWG, set up in 2009 in order to perform a fact-finding survey of the gas sector across the continent (existing regulatory framework, expected development, TSOs' status, storage conditions, opening up of retail markets, liquidity of existing hubs and role played by gas exchanges both currently and in the future) and define a shared position within the association on strategic aspects conducive to the development of efficient markets.

Last year, Europex was especially active within AESAG[7], where it contributed to defining the so called "Target Model" for the organization of the future European intra-day energy market, based on the continuous trading system already adopted in Scandinavia, known as Elbas.

1.3.2 Italy – Slovenia Coupling

Since 31 December 2010 (day of flow, 1 January 2011), market coupling has been operational on the Italian-Slovenian border. This mechanism allows the implicit allocation of physical daily transmission rights between the two countries by clearing their electricity day-ahead markets run by GME and BSP (Slovenian exchange operator), respectively.

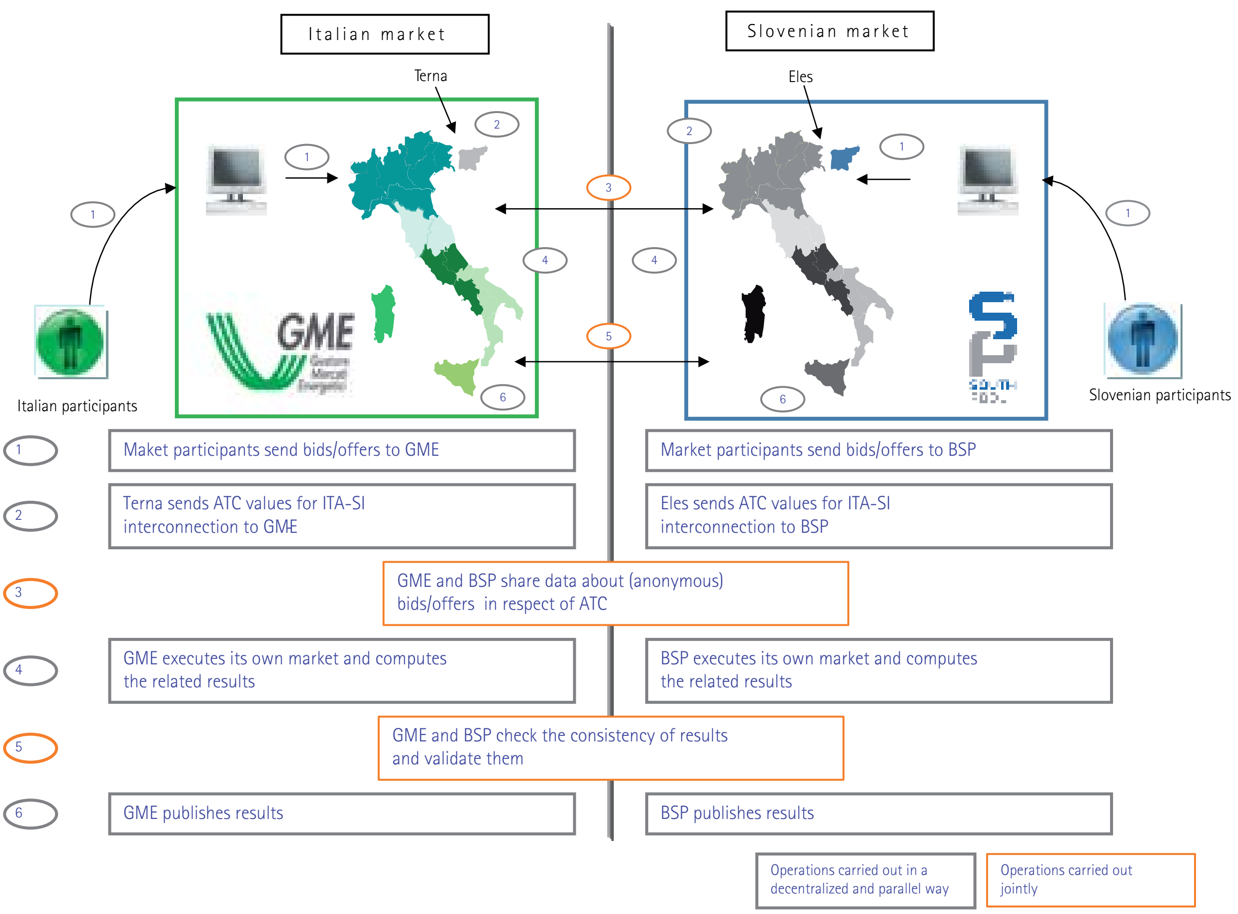
Such initiative was launched in 2008 by GME, Borzen (Market Operator in Slovenia) and BSP: it is officially endorsed by the Italian Ministry of Economic Development and by the Slovenian Ministry of the Economy, as well as by the relevant domestic regulators (AEEG and AGEN-RS).
Given the European regulations in force, the project complies with and supports provisions under Regulation (EC) nr.714/2009 and, in particular, art. 12, according to which the Member States shall promote "...the coordinated allocation of cross-border capacity through non discriminatory market-based solutions, paying due attention to the specific merits of implicit auctions for short-term allocations...".

6 In 2010, EUROPEX changed its acronym from Association of European power exchanges into Association of European energy exchanges to highlight the role of exchanges with respect to electricity, natural gas and the environment.
7 ACER Electricity Stakeholder Advisory Group.

More specifically, implicit auctions integrate the interconnection capacity with the performance of electricity markets; in so doing, they ensure an efficient use of capacity since they define a transit from the lowest price market area to the highest price one.
On the Italian-Slovenian border, a decentralized price coupling method was adopted. In this context, GME and BSP adopted a common matching algorithm reproducing the matching rules of both markets. Also, the algorithm considers a grid model representing both the Italian and Slovenian electricity grids. The algorithm is run, in a parallel and decentralized way, by each market operator. Both operators receive offers from their respective market participants; prior to running their own market, they mutually exchange any significant information on the demand and supply curves as resulting from the bids/offers received and from grid constraints over their respective market areas. After sharing such information, thanks to their common matching algorithm, GME and BSP simultaneously calculate their market results, keeping into account the grid and market conditions in each other's country; at the same time, they determine the flow of energy over the Italy-Slovenia interconnection (i.e. they allocate capacity over such interconnection) at the prices being set in their respective electricity markets.

On the one hand, decentralized price coupling, thanks to a common algorithm, allows to implement matching rules in a single system; on the other, through a decentralized management of procedures and information sharing, it enables the coordination of markets without calling for any change in GME' and BSP's domestic responsibilities, competences and roles.

Italy-Slovenia market coupling Fig A.3.1



For more information on the decentralized price coupling model, please refer to the document published in GME's website: *(http://www.mercatoelettrico.org/It/Mercati/MercatoElettrico/MC_Modello.aspx)*

1.4 Fees

Participation in GME-managed markets is subject to structured fees, based on the diagram reported in the following table.

The MPE still represents the largest market in terms of both sales volume (93.3%) and fees (56.6%). However, while environmental markets account for a significantly smaller sales volume (1.8%), they generate a remarkable share of fees (10.6%) (Tab.A.1.2).

Tab A.1.1 **Fees for participating in GME's markets – Year 2011**

	One-time fixed (€)	Yearly fixed (€)	Variable (€/MWh)	Approval	Remarks
MPE	7,500	10,000	- no fee for the first 0.02 TWh of electricity traded monthly; - fee of **0.04 €/MWh** for volumes exceeding the threshold of 0.02 TWh up to a maximum of 1 TWh; - fee of **0.03 €/MWh** for volumes exceeding the threshold of 1 TWh up to a maximum of 10 TWh; - fee of **0.02 €/MWh** for volumes exceeding 10 TWh.		
PCE	1,000		-fee of **0.02 €**/MWh from 1 Jan. to 30 Apr. 2011 -fee of **0.012 €**/MWh from 1 May to 31 Dec. 2011		If the PCE participant is at the same time an electricity market participant, he/she/it will not pay the access fee and the yearly fixed fee to GME.
MTE			0.01		
CDE			0.045		
MCV			- **for the first 2,500 certificates** traded (each of 1 MWh): **€ 0.06** per certificate; - **for certificates** traded (each of 1 MWh) **that exceed the threshold of 2,500: € 0.03** per certificate		
PBCV			- **for the first 2,500 certificates** traded (each of 1 MWh): **€ 0.06** per certificate; - **for certificates** traded (each of 1 MWh) **that exceed the threshold of 2,500: € 0.03** per certificate		
TEE			**0.2** per certificate traded		
CO2			**0.0025** per emission allowance (each of 1 t/CO2) traded		
P-GAS			0.0025 €/GJ		
M-GAS			0.01 €/MWh		
PB-GAS			0.003 €/GJ		If the PB-GAS participant is at the same time a gas market participant, he/she/it will not pay the access fee and the yearly fixed fee to GME. If the PB-GAS participant is at the same time an electricity market participant, he/she/it will not pay the access fee to GME.

Key data of GME's markets Tab A.1.2

Year 2011	Volumes	Central-counterparty turnover (thousands of €)	Fees (thousands of €)	Fees %
ELECTRICITY MARKETS		18,801,754	2,914,500.0%	86,8%
MPE	239.6 TWh	17,861,295	19,018	56.6%
MTE (*) and CDE	33.4 TWh	583,783	669	2.0%
PCE (**)	301.1 TWh	n/a	8,678	25.8%
Other items	n/a n/a	356,676	780	2.3%
ENVIRONMENTAL MARKETS		339,386	3,546	10.6%
MCV	4.1 Mln	339,386	1,907	5.7%
PBCV	27.0 Mln	n/a		0.0%
TEE - regulated market	1.3 Mln	n/a	511	1.5%
TEE - bilaterals	2.8 Mln	n/a	1,128	3.4%
EUA	n/a n/a	n/a	n/a	n/a
GAS MARKETS		4,322	391	1.2%
P-GAS	2.9 TWh	n/a	52	0.2%
M-GAS	0.2 TWh	4,322	321	1.0%
PB-GAS	2.9 TWh	n/a	18	0.1%
Other marginal revenues	**n/a n/a**	**n/a**	**493**	**1.5%**
Total		**19,145,462**	**33,575**	**100.0%**

(*) volumes traded in the MTE

(**) transactions registered on the PCE

2. NEW PROJECTS

In the course of 2011 and in early 2012, GME was involved in the following projects:
- Gas markets:
  - in December 2011, take off of the new Gas Balancing Platform (PB-GAS), in compliance with AEEG Decision ARG/gas 45/11 of 14 April 2011;
  - in April 2012, take off of a new P-GAS segment (named "as per Legislative Decree 130/10"); in compliance with AEEG Decision 67/2012/R/GAS, it will be possible to offer gas quantities on the part of investors who have requested to avail themselves of the virtual storage service governed by Decision ARG/gas/193/10;
- Environmental markets:
  - in compliance with AEEG Decision ARG/elt 104/11, implementation of certificates of origin trading (GO-COFER); these instruments ensure the transparency of renewable energy sales contracts with final customers;
  - as provided for by MiSE Decree of 5 September 2011, adjustment of the regulatory framework applicable to white certificates registration and trading; such action is required in order to introduce and make the new TEE management equally effective. The new TEEs are granted to participants who own High Efficiency Cogeneration Plants - CAR, within the framework of registration and trading schemes currently envisaged by GME;
- The Price Coupling of Regions (PCR) project, a European coupling mechanism for electricity day-ahead markets, endorsed by GME in 2010;
- Less stringent rating of banking institutions, as requested by GME with respect to the guarantees submitted by market participants in order to reflect the new credit market conditions in the aftermath of the European financial crisis.

2.1 The PB-GAS, the P-GAS segment as per Legislative Decree 130/10 and the Forward Gas Market

PB-GAS

In December 2011, GME started the Gas Balancing Platform (PB-GAS) in order to comply with the new balancing system rules, as defined by AEEG Decision ARG/gas 45/11. Snam Rete Gas S.p.A. is the entity in charge of balancing. SRG shall employ this platform to procure any resource required to make up for the overall grid imbalance. Within this system, Snam Rete Gas acts as the central counterparty for platform-based transactions whereas GME is in charge of arranging and running the PB-GAS on behalf of Snam Rete Gas.

P-GAS segment as per Legislative Decree 130/10 – Virtual Storage

In line with the overall, gradual development of the domestic natural gas market, two regulatory measures were adopted during the last two years. Such legislative measures add more market instruments to the gas system, through a number of GME-managed platforms.

During 2010, Legislative Decree 130/2010, the so called "Storage Decree" was enacted. It outlines "Measures for a greater competitiveness of the natural gas market and the relevant transfer of benefits to final customers".

The above said measures provide for the development of a natural gas storage infrastructure; after arranging a specific tender, selected entities, different from the incumbent, may contribute to the infrastructure implementation as investors. In view of the new upcoming storage capacity, article 9 of the "Storage Decree" allows industrial investors and producers alike to apply to GSE in order to be entitled - up until the gradual operation of the new storage capacity allocated to them, for a maximum period of 5 years – to get the same effects they would benefit from if the allocated storage capacity were immediately operational. Such equivalent effects, according to the rules, may be obtained by investors by means of the natural gas delivery during the summer period and the corresponding delivery of the same gas during the subsequent winter period (the so called Physical Transitional Measures). This regulatory framework is furthered by article 11 of the same decree: given the goal to promote the natural gas wholesale market

liquidity, investors who have requested to avail themselves of the Transitional Measures, shall offer for sale, on the trading systems regulated and managed by GME, the gas quantities covered by such Transitional Measures.
According to the above Decree, the Electricity and Gas Regulator is responsible for the adoption and enforcement of Transitional Measures; in implementing the decree provisions, through its Decision ARG/gas 193/10, AEEG provided, amongst others, that investors who wish to avail themselves of Physical Transitional Measures shall enter into a specific agreement with Gestore dei servizi energetici - GSE S.p.A. (GSE). Said agreement governs the methods through which an investor – i.e. any entity designated by the investor to fulfill the bidding requirement – shall offer gas quantities for sale on GME's trading systems. In particular, article 3, para 3.3, letter h) of AEEG Decision establishes the following:

- investors, or any entity designated by investors to fulfill the bidding requirement, shall comply with GME Regulation on participation in such trading systems;
- offers shall remain for sale for a minimum time, varying by type of product, as required to allow prospect buyers to review sale offers and submit their own bids;
- investors, or any entity designated by investors to fulfill the bidding requirement, can split the quantities offered for sale among various products; likewise, they can set and change, from time to time, a minimum price below which no gas will be sold.

AEEG, through its subsequent Decision ARG/gas 79/11, requested GSE and GME to act in a coordinated manner to implement provisions under para 3.3, letter h) of AEEG Decision ARG/gas 193/10; such operational provisions shall be submitted to AEEG for its approval and will be incorporated into the agreement GSE and the investor are parties to.
To implement the above regulatory provisions, after a consultation process and in accordance with the operational guidance given by AEEG, GSE and GME prepared a proposal subject to AEEG approval. With specific regard to GME trading systems at large, where investors can fulfill the bidding requirement for gas quantities made available by virtual storage operators, they shall be alternatively or cumulatively represented by:

- The Natural Gas Trading Platform (P-GAS), as under article 5 of the Decree of the Minister of Economic Development dated 18 March 2010;
- The regulated gas market (M-GAS) managed by Gestore dei Mercati Energetici S.p.A.

Rules to participate in both the P-GAS and M-GAS, as well as to submit bids/offers and perform trading activities, are detailed in the current versions of the P-GAS Regulation – approved by the Ministry of Economic Development on 23 April 2010, as subsequently amended - and the M-GAS Regulation – approved by the Ministry of Economic Development on 26 November 2010, as subsequently amended and supplemented.
With reference to the P-GAS Platform, gas quantities made available by virtual storage operators shall be traded on a specific segment named "as per Legislative Decree 130/10". Moreover, for the purpose of trading in such segment, gas quantities are measured in MWh instead of GJ, so as to get a consistent unit of measurement for the M-GAS and Legislative Decree n. 130/10.
As to the Gas Market, in an effort to concentrate and therefore increase the liquidity of the spot gas market, gas quantities shall be traded in the Day-Ahead Gas Market (MGP-GAS).

Forward Gas Market

In the medium run, GME, given provisions under article 32, para 2, Legislative Decree 1 June 2011, n.93, on the "Implementation of directives 2009/72/EC, 2009/73/EC and 2008/92/EC on common rules for the European electricity and natural gas market and a Community procedure for the transparency of prices for industrial end users of gas and electricity, as well as the repeal of Directives 2003/54/EC and 2003/55/EC", after a number of talks with the relevant Institutions and Associations, shall implement the Forward Gas Market (MT-GAS). This market will allow participants to enter into forward contracts for the supply of natural gas on a delivery time horizon longer than the current one existing on the spot market.

2.2 Environmental markets: new aspects

Certificates of Origin for Electricity Generated from Renewable Sources (RECOs)

Directive 2003/54/EC of the European Parliament and the Council of 26 June 2003 on common rules for the internal market of electricity and, more specifically, article 3, para 6, requests Member States to act so that electricity suppliers specify the following in their invoices, promotional materials and websites addressed to final customers:

- the share of each source in the overall fuel mix used by the supplier during the previous year;
- information on the environmental impact, in terms of CO2 emissions and radioactive waste, resulting from electricity generated by means of the overall fuel mix used by suppliers during the previous year.

In compliance with directive 2003/54/EC, the decree of the Ministry of Economic Development 31 July 2009 requests electricity vendors to adopt an information and transparency system to the benefit of final customers. In particular, vendors shall report in their website by 31 May each year, effective from 2010 and at least every four months, and in bills sent to each final customer, the mix of primary energy sources used to generate electricity and any information on the environmental impact of electricity generation by source.

Moreover, the decree stipulates that distributors shall provide consumers with any additional information on how to save and make an efficient use of energy.

By 31 March each year, sellers shall report to GSE the amount of electricity from renewable sources they have sold to final customers in the previous year, specifying any volumes sold by type of offering.

The ministerial decree requests GSE to prepare a procedure aimed at:

- certifying electricity from renewable sources injected into the grid by each producer for each calendar year (ICO certification – plants qualified to receive certificates of origin);
- issuing certificates of origin (RECOs) to producers of electricity from renewable sources proportionally to the electricity actually generated and injected into the grid during each calendar year.

As to the year 2010, GSE implemented this procedure and issued one-year validity RECOs. Hence, a certificate issued for production year T shall finally expire on 31 March of year T+1.

RECOs issued by GSE differ by year and type of renewable energy source. In particular, 5 different types have been identified: wind, hydro, solar, geothermal and other.

AEEG Decision ARG/elt 104/11 subsequently introduced a RECO-based market mechanism. Through the above said Decision, AEEG identified:

- Certificates of origin (RECOs) as a tool to promote transparency in the sale of electricity from renewable sources, to be mandatorily used starting from 2012;
- The trading/transfer mechanism and the subsequent cancellation of certificates, as an instrument to monitor sales; in this way, the same energy from renewable sources shall not be included in more than one sale contract.

As to the second aspect, GME has to organize and manage both the market of certificates of origin and the platform to register bilateral transactions.

RECOs can be freely traded: participants may choose whether to procure them through bilateral contracts or through the GME's regulated market. In the event they decide to buy certificates on a bilateral basis, they shall register the relevant transactions on the bilaterals platform, specifying any volumes, price and counterparty.

Also, RECOs can be purchased through auctions organized by GSE. During the auctions, GSE's own RECOs are awarded; these RECOs pertain to the electricity generated by CIP 6 plants (for electricity from renewable sources only), electricity taking benefit from the net metering scheme, electricity from plants supported through green certificates or other schemes ("ritiro dedicato" – simplified purchase and resale agreements, "tariffa fissa omnicomprensiva" – all-inclusive feed-in tariff) for which the plant owner did not request a RECO by the month of September of the year of production. RECOs awarded through GSE auctions shall be registered in GME's bilaterals platform, too.

The rules of market operation shall be similar as those provided for trading Green Certificates. Likewise, the functioning of the bilaterals platform shall be similar as the GCs Bilaterals Platform, already in operation.

New support scheme for high efficiency cogeneration – TEE

MiSE Decree of 5 September 2011 governs the new support scheme for high efficiency cogeneration, i.e. combined heat & power generation (CHP). Cogenerating units are entitled, for each calendar year during which they meet high efficiency cogeneration requirements, to receive a number of white certificates according to any primary energy saving made in the relevant year.

Hence, GME in the course of 2012 shall adjust the regulatory framework applicable to the white certificates trading and registration system. Such adjustment is necessary to ensure an equal treatment to the new TEEs issued to high efficiency cogenerators in the trading and registration systems currently run by GME.

2.3 PCR – Price Coupling of Regions

As already mentioned, GME has been focusing on the so called Price Coupling of Regions (PCR) project since 2010. This project involves the major European exchanges (Epex, Omel, NordPoolSpot, APX-Endex and Belpex) and is aimed at putting in place a market coupling project across Europe, based on a decentralized methodology. The project rests upon three pillars: a) creating a common algorithm incorporating the specific features of the various markets; b) creating a data exchange system supporting an algorithm decentralized management (so called Broker & Matcher); c) a governance structure based on contracts containing rules of cooperation among exchanges and on the joint ownership of said assets.

In 2011, the PCR developed considerably, from both an operational and institutional standpoint.

As to institutions, the project was positively received: every European Exchange, not yet member of PCR, requested to become an associate member in order receive detailed information about the project; the Florence Forum expressed a positive opinion on the project and invited EntsoE and Europex to collaborate for a shared European solution known as EPC (European Price Coupling); TSOs in the NWE[8] area did confirm their will to adopt the technical solutions proposed by PCR in order to start their own regional coupling project by the end of 2012; ACER[9], after designating the NWE area as a pilot project for the future EPC which is expected to start by the end of 2012, formally requested EntsoE to assess the feasibility of PCR-proposed technical solutions; finally, the European Commission recently published a consultation document on the Guidelines to EPC Governance and confirmed that the PCR governance model is fully compatible with the solutions suggested by the Commission itself. On a national level, alike other national exchanges participating in the project, GME cooperates with Terna on the gradual entry of Italy into EPC. GME reports the PCR project development to both AEEG and MiSE.

There have been technical developments, too. As a matter of fact, the project "design" stage ended with the identification of requirements and technical specs for data exchange solutions (the so called "broker and matcher"), to calculate market results and allocate flows (algorithm). The development activity proper has already begun and should be completed by the end of 2012. In particular, after selecting the Cosmos algorithm currently in use in CWE[10] coupling as a Starting Point to develop the European common algorithm, the six exchanges jointly began their research and development activities to realize a prototype incorporating the market requirements of the future EPC, still unmet by Cosmos[11]. Moreover, the project participating exchanges began their procurement efforts for the data exchange technical facilities.

8 North Western Europe: this area includes CWE as well as the Scandinavian system served by NordPoolSpot and the United Kingdom.

9 Agency for the Cooperation of Energy Regulators, an agency established by regulation 713/2009 to ensure cooperation among European energy regulators and promote the establishment of the European energy market through an integrated European price coupling model.

10 Central Western Europe: this area includes markets in France, Germany, Belgium, Netherlands and Luxembourg, where Epex, Belpex and Apx-Endex operate.

11 Among them, in particular, requirements for the Spanish and Italian markets, with special regard to the PUN (National Single Price) management.

2.4 Changes to the guarantee system

Although the structure of the guarantee system has not changed, GME has decided to ask a less stringent rating of credit institutions with respect to the bank guarantees submitted by participants in the energy markets, in the light of the severe international economic crisis.

By way of the urgent amendments to the Electricity Market and Gas Market Rules, introduced on 19 October 2011 and 26 January 2012, respectively, credit institutions, in order to issue guarantees for electricity and gas market participants, are now requested to have a minimum long term rating of BBB- on Standard & Poor's or Fitch scale, or Baa3 in Moody's Investor Service rating scale.

Moreover, with the urgent amendments introduced on 26 January 2012 to enable MTE participants to reduce their debt exposure vis-à-vis GME, market participants are allowed to register on the PCE, ahead of the ordinary deadline, their net delivery position acquired on the MTE itself. In this way, participants who, during the trading stage, turn out to hold net sale positions in the MTE, may opt for an advance delivery. In this way, they may benefit ahead of time of the economic effects arising from the guarantee submitted to GME (credit associated with registration of their net positions on the PCE).

3. RESULTS OF OPERATIONS

During 2011, in the light of the trend of trades in GME's markets, central-counterparty revenue/cost items[12] increased by 1.9 billion euro, up from 17.2 billion euro in 2010 to 19.1 billion euro in 2011. This result is mostly due to the increase of intermediation prices on the Stock Exchange as well as to the rise in volumes traded in the MI and MTE.

Marginal revenues[13] for the year decreased by 1.4 million euro from the previous year. This development is largely accounted for by the combined effect of the following:

- 0.9 million euro drop of revenues for services rendered on the PCE: in compliance with AEEG Decision ARG/elt 44/11, this was due to a decrease from 0.02 €/MWh to 0.012 €/MWh – effective since 1 May 2011 – of GME's fee per MWh covered by transactions registered on such platform;
- 1.9 million euro decrease in revenues for services provided to Terna on the MSD and PCE as a result of the renewal of the GME-Terna Agreement signed in December 2011, following AEEG approval of such agreement;
- 0.6 million euro increase of revenues for services provided in the spot and forward electricity markets, due to an increase in trades in the MI and MTE; this result was only partially reduced by the smaller volumes traded in the MGP and by the smaller number of participants accepted on the Exchange in 2011;
- 0.4 million euro growth of revenues (+14.0%), for services rendered in markets and bilateral platforms for trading of environmental certificates; this growth is due to the rise in volumes traded on the various platforms, after deducting the effect of the failure to trade emission allowances and the abolition – starting from the beginning of 2011 – of the yearly fixed fee paid by TEE market participants.

GME's performance, income and equity (2010 - 2011) Tab A.3.1

Data in € million	Marginal revenues	EBITDA	EBIT	Net income	Total Assets (a)	Shareholders' equity
2010	34.934	18.818	17.527	12.132	46.219	33.529
2011	33.575	15.969	7.158	2.536	58.424	23.933

Note: (a) the total assets are net of receivables from: i) sales of electricity in Energy Markets; ii) market participants; iii) GSE; iv) other items associated with OTC trades (CCT) and market segmentation

GME's key ratios (2010 - 2011) Tab A.3.2

	EBITDA/ Revenues ratio (%)	EBIT/ Revenues ratio (%)	ROI (a)	ROE (b)
2010	53.9	50.2	37.9	36.2
2011	47.6	21.3	12.3	10.6

Notes: (a) ROI is calculated as the ratio of EBIT to total assets;
(b) ROE is calculated as the ratio of net income to shareholders' equity.

Marginal costs referred to the year 2011, amounting to 17.6 million euro, grew by 1.5 relative to the previous year. This increase is mostly due to:

- 1.3 million euro increase of costs for services and other operating costs, by reason of the enlargement of the premises occupied by GME, the extension of business support activities carried out by the holding company, the development of international projects, as well as of the strengthening of rules of operation of the existing markets;
- 0.2 million euro (+2.8%) rise in the cost of labor, mostly accounted for by the annual salary raise provided for by the electricity sector national labor contract, partially offset by the reduced average number of employees.

12 Central-counterparty revenue/cost items are the positive revenue items which exactly correspond to the negative revenue items to which they refer.
13 Marginal revenues are the positive revenue items which are allocated to cover operating costs and get a return on invested capital.

Tab A.3.3 **Marginal costs and share of revenues (2010 - 2011)**

Data in € million	Raw materials and services	Leases and rentals	Personnel	Amortization, depreciation, write-downs and provisions	Sundry operating expenses
2010	6.241	1.466	8.023	1.291	0.386
2011	7.236	1.485	8.249	8.811	0.636

Share of revenues Data in %	% of revenues	% of revenues	% revenues	% of revenues	% of revenues
2010	17.9	4.2	23.0	3.7	1.1
2011	21.6	4.4	24.6	26.2	1.9

The resulting EBITDA (earnings before interest, taxes, depreciation and amortization) amounts to 16.0 million euro, down by 2.8 million euro (-15.1%) on the previous year.

Depreciation, write-downs and provisions amount to 8.8 million, up by 7.5 million euro on the previous year; this figure mainly results from a provision of 7.7 million euro from the cumulative additional operating revenue for the PCE over the 2006-2011 period - net of any sums previously paid to Terna – in compliance with AEEG Decisions ARG/elt 44/11 and ARG/elt 189/11.

The EBIT (earnings before interest and taxes), therefore, equals 7.2 million euro, with a decline of about 10.4 million euro (-59.2%) on the previous year.

The net income for the year amounts to 2.5 million euro and decreased by about 9.6 million euro on the previous year.

The following table illustrates the average number of employees during the year, by labor contract category, as well as the actual number as of 31 December 2011, compared to the same figures for the previous year.

Tab A.3.4 **Composition of personnel**

Number	Personnel members		Personnel members	
	average in 2011	at 31 Dec. 2011	average in 2010	at 31 Dec. 2010
High-and middle-level managers	9.00	9	9.46	9
Low-level managers	29.00	29	28.38	29
Office personnel	51.50	53	52.75	51
Total	89.50	91	90.59	89

SECTION

B

MARKET FUNCTIONING

MARKET FUNCTIONING

1. THE EUROPEAN SINGLE MARKET

The establishment of a single energy market constitutes a priority objective for the European Union (EU). Efforts to create a single market have been going on for several years. The single energy market should have no trade barriers, along with a highly efficient use of generating capacity and the transmission infrastructure available; it should maximize and enhance cross-border trade while minimizing the overall electricity generation costs.

Since the second half of the nineties, the European Parliament has been setting the establishment of a single energy market as one of the most important goals for its energy policy. After introducing the "Third Energy Package", in July 2009, the European Commission emphasized and endorsed such goals by presenting the Member States with methods and criteria to accomplish them. Such criteria are specified by provisions outlined in Directives 2009/72/EC and 2009/73/EC and by Regulations 713/2009 and 714/2009.

In 2009, with specific reference to the integration process of the electricity market, and in order to promote its homogeneous development, the European Commission set up a coordination group to settle cross-border issues. It is called Project Coordination Group (PCG) and consists of representatives from the Commission, national Regulators, EuroPEX, ETSO, Eurelectric and EFET, as well as Member States' representatives. The Project Coordination Group's mission consists of developing a reference model aimed at harmonizing inter-regional congestion management procedures and implement them on a pan-European basis. Also, it should set realistic deadlines for its implementation. In its proceedings, PGC – on the basis of the conclusions drawn from a survey promoted by the Florence Forum[14] and drafted by EuroPEX and ETSO on a *"Coordinated model for regional and interregional congestion management"*– outlined the foundations of what later was defined as a European "target model" to settle any congestion at the borders: a key element to truly give shape to the European single market.
In March 2011, ACER – the Agency for the Cooperation of Energy Regulators – established pursuant to Regulation EC 713/2009, began its activities under the "Third Energy Package", marking a turning point in the definition of congestion management Community methods.
ACER drew upon the preparatory work completed by European Regulators in the past few years and immediately began drafting the future European Network Codes, issuing the first "guidelines" envisaged by the Third Energy Package. Once adopted by the Member States through their own national committees, such network codes will constitute the backbone of a new regulatory framework for cross-border trades, amongst others, in view of the establishment of a European single market of both electricity and natural gas.
In the electricity sector, ACER performs a number of statutory activities. In particular, art. 6.2 of Regulation 714/2009 requests the Agency to draft its Framework Guidelines for ENTSO-E's development of network codes in the field of Capacity Allocation and Congestion Management (CACM), in compliance with art. 8.6, letter g) of said Regulation.
By assigning such responsibilities to ACER and ENTSO on an exclusive basis, the European Institutions implicitly adopted a coordinated "top-down" approach. This new approach was considered to be more effective by the European Parliament and Council in order to timely fulfill the ultimate goal, i.e. establishing a harmonized European single market; on the opposite, the previous "bottom up" approach was based on the voluntary development of the Electricity Regional Initiatives (ERIs).
It should be noted that the rules introduced by the "Third Energy Package" have confirmed, consistently with the previous regulations, the so called "two-tier approach": a clear-cut separation between congestion management

14 The Florence Forum is a European body created for the purpose of identifying initiatives which can foster the creation of the electricity single market; since 1998, the Forum has been meeting once or twice a year, with the attendance of the European Commission, National Institutions, European Regulators, the European Council of these latter (CEER) and the main industry stakeholders (industrial operators in the energy sector, associations of traders, sellers and consumers). A similar body, in the gas sector, is the Madrid Forum.

rules and principles, applicable domestically – to be defined and enforced under the exclusive scope of each individual member state - and constraints illustrated in the Framework Guidelines. Once approved by the EU, these latter shall define and harmonize cross-border interconnection congestion solutions across the continent.

Moreover, in December 2009, the 17th Florence Forum began addressing the definition of the European Target Model; it was decided to speed up the model implementation by establishing an Ad Hoc Advisory Group (AHAG): this group includes stakeholders and regulators[15] to address a number of mainstays characterizing the reference model. Within this framework, three pilot projects were initiated: Capacity Calculation, Intra-day Markets and Governance Principles of the European Market Coupling. This latter project is directly coordinated by the European Commission to establish binding guidelines and begin their transposition process.

As to the first pilot project, i.e. Capacity Calculation, in September 2010, after a preliminary consultation, the European Regulators Group for Electricity and Gas (ERGEG) submitted its proposed guidelines. In February 2011, based on the indications stemming from the consultation process, ERGEG published a final draft of the Guidelines, a starting point for the subsequent consultation round initiated by ACER at the end of July 2011[16], the final conclusions of which are still pending.
In summary, ACER started a consultation process on the Guidelines to the development of Network Codes in the field of capacity allocation and congestion management. Such guidelines focus on a number of major objectives, including the following:

1. best and coordinated use of transmission capacity available over the grid, through TSOs' adoption of a shared capacity calculation method (preferably, Flow Based criteria although ATC is equally allowed); definition of reference zones for capacity allocation in terms of market "bidding areas" (long-term, day-ahead, intra-day);
2. day-ahead allocation capacity procedure; TSOs, in cooperation with PXs, are expected to allocate capacity on the basis of implicit auctions; they may also use a single price coupling algorithm (employing the marginal price system to set the price) to simultaneously determine volumes and prices for each zone; the algorithm should be able to handle block-based offers, assigning a financial value to transmission capacity (congestion rent), based on the price spread across the relevant zones; furthermore, the day-ahead model should be able to provide appropriate price references for forward markets;
3. improved efficiency of forward markets with allocations, in the form of risk hedging options, on cross-border trading, of Financial Transmission Rights or Physical Transmission Rights according to Use It Or Sell It criteria;
4. an efficient capacity allocation process for Intra-day markets, while complying with the implementation principles of the pan-European Intra-day Target Model (see below).

As to the Intra-day Markets pilot project, the Florence Forum asked ENTSO-E, with the involvement of European stakeholders, to coordinate any activities required to draft a Target Model, manage its implementation and prepare its implementation road map[17]. Broadly speaking, this reference model provides for: adoption of the continuous implicit trading methodology, definition of reliable criteria applied to transmission capacity pricing in case of congestion, management of a Shared Order Book (SOB) by connecting Intra-day platforms across adjacent market zones, criteria to determine trading firmness on the intra-day horizon, commitment by TSOs to avoid any product-based discrimination, with special regard to block-based offers.

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15 The following take part in AHAG proceedings under ERGEG and EC coordination: CEDEC (European Federation of Local Energy Companies), CEFIC (European Chemical Industry Council), EFET (European Federation of Energy Traders), ENTSO-E (European Network of Transmission System Operators for Electricity), EURELECTRIC (Union of the Electricity Industry), EuroPEX (Association of European Power Exchanges), GEODE (European independent distribution companies of gas and electricity), IFIEC (International Federation of Industrial Energy Consumers).
16 ACER - Framework Guidelines on Capacity Allocation and Congestion Management for Electricity / FG-2011-E-002 - 29 July 2011
17 See: Ad Hoc Advisory Group (AHAG) / Intra-day Trade Project: Terms of Reference (26 April 2010).

As for the third "pilot project" on the MC governance principles, the DG Energy of the European Commission took charge of drafting the relevant guidelines. In November 2011, it began a consultation process on "Public consultation on the governance framework for the European day-ahead market coupling". The consultation process ended on 28 February 2012. The DG Energy is expected to publish as soon as possible the summary documents containing any remarks made by system operators; also, an updated edition of the Framework Guidelines is due out within shortly.

Through such document, the DG Energy specifically called for a consultation on some aspects preliminary to the drafting of the European Market Coupling (MC) Guidelines. Because of the differences in the technical drafting of Network Codes (drafted by ENTSO-E), the Guidelines should be defined through separate, independent governance agreements among those involved.
These aspects especially refer to:
- roles and responsibilities of any parties involved in the MC;
- definition of MC entry and exit procedures and of any relevant rights and obligations;
- dispute settlement procedures;
- assignment of tasks and responsibilities for the various parties involved with the MC management (TSOs vs PXs);
- drivers for MC-related costs sharing scheme.

More specifically, the Commission outlined a set of four Policy Options. These differ by degree of flexibility/ centralization in the management of the European MC as well as by the binding nature of procedures required to apply the Governance Guidelines.
In conclusion, with regard to the Community electricity market timetable, the heads of state of the different Member States met in February 2011 to set a target date ("by 2014") for the operational startup of the European single market.
With respect to EU coordination processes paving the way to the establishment of the Single Energy Market, Regulation (EU) 227/2011 "on wholesale Energy Market Integrity and Transparency" (REMIT) has been effective since 28 December 2011. REMIT introduced a new, stronger transparency scheme for energy transactions concluded by market participants[18].
Finally, it should be highlighted that the electricity sector made significant steps forward on a European level; the same cannot be said about the gas sector where, except for ENTSO-G drafting of the European Network Codes, the tentative definition and development of the Framework Guidelines is considerably lagging behind and seem to be still quite preliminary.

18 An accurate analysis of provisions contained in REMIT regulation is described under Box n.1.

Box 1 REMIT: A NEW REGULATION FOR WHOLESALE ENERGY MARKETS

The financial crisis of 2008, a growing volatility and a rise in the price of commodities, along with the need of a unified supervision of the complex European single market led the European Commission, in the aftermath of G20 resolutions passed in Pittsburgh in 2009, to propose additional legislative measures on the integrity and oversight of markets; harmonization instruments were issued to improve the integrity, efficiency, strength and transparency of both physical and derivatives markets as a way to further protect investors.
There exist different, albeit mutually related, legislative proposals. They aim at strengthening the supervision of trading of physical and financial products over every type of trading venues (organized or regulated wholesale markets, MTFs, OTFs and more) or simply over OTC markets, to prevent illicit practices which might jeopardize a fair pricing mechanism.

While the tentative versions of such proposals still exhibit some overlapping scope of action, a substantial effort to strengthen the role of national regulators and the two new European agencies, ACER and ESMA[1], is more than evident; both agencies will inevitably collaborate, playing an increasingly crucial role in supervising and monitoring markets. On the other hand, the establishment of these two new agencies and the strengthening of their powers are the natural consequence of the progressive creation of the European single market. On a European level, national regulators' powers may be ineffective when faced with transnational participants and transactions. This is why the EU decided to adopt a centralized approach. Regulatory provisions are being issued and can be directly enforced in the Member States (Regulations). This implies that the member states have no discretionary (or a very limited) power in implementing Community regulations.

As far as Community regulations on wholesale energy markets are concerned, it is worth to mention REMIT Regulation on the integrity and transparency of wholesale energy markets, effective since 28 December 2011.
After a decade of "liberalization packages", the European energy sector is now characterized by a greater standardization of bilateral trading (OTC), a growing number of wholesale exchanges to trade well differentiated energy products attracting an increasingly broader range of participants, including producers and suppliers, large users, pure traders, financial institutions and other commercial promoters.

Wholesale markets – including regulated markets, multilateral trading platforms, over-the-counter transactions (OTC) and direct or intermediated bilateral contracts – are now acting as guarantors of the reference pricing mechanism, reflecting a fair demand-supply interaction. Therefore, it is paramount for the Commission to make sure that a lack of homogeneity and/or coordination among the national regulatory frameworks in the field of monitoring and control activities does not expose such markets to unfair practices, both domestically and transnationally, to avoid repercussions on national and Community retail prices.

The European legislation was felt to be inadequate, in that insider trading and market manipulation practices were expressly prohibited for financial instruments only; a growing dissatisfaction about the proposed extension of such legislation to energy markets led the European Commission to prepare an ad hoc regulation to increase the integrity and transparency of wholesale energy markets: REMIT Regulation 1227/2011.

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1 See "European Parliament legislative resolution of 29 March 2012 on the proposed regulation of the European Parliament and of the Council on OTC, derivatives, central counterparties and trade repositories (COM (2010) 0484 – C7- 0265/2010 – 2010/0250(COD)).

The new transparency and integrity scheme introduced by the Commission is based on four types of measures. First, the definition and prohibition of insider trading and market manipulation practices. These were defined keeping in due account the specific energy market mechanisms and the interactions between raw materials and derivatives markets. The Commission[2] has the power to technically update the scope of such definitions.

Secondly, publicity and transparency obligations falling upon participants. As a result, participants shall promptly communicate any inside information available to them about their own firms or plants. The third type of measures establishes ACER monitoring duties, in collaboration with national regulators, over trading of wholesale energy products, including sale and purchase orders, to prevent market manipulation and insider trading. The Agency shall collect any information required for monitoring purposes, on the terms set by the Commission through implementing acts, which should be adopted in the second half of 2013 after a comitology process.

Finally, a fourth type of measures sets out the terms to implement prohibitions. National regulators have been vested with inquiry and sanctioning powers. They shall act in a mutually coordinated and consistent manner and shall collaborate with the Agency. They shall apply definitions set by the Regulation according to any non-binding instructions given by the Agency itself under art. 16.

Thanks to REMIT, the new European transparency scheme is taking shape; it covers various types of data/ information that participants shall make available:

1. Transparency of "fundamental data", also called pre-trade transparency; the duty to publicize inside information also includes information on generating capacity and usage, storage, consumption or transmission of electricity or natural gas, capacity and usage of LNG plants, including any planned or unplanned downtime; moreover, information to be made available under Regulations 714/2009 (art. 15) and 715/2009 (art. 18, 19).
2. Transparency of trading, also called post-trade transparency; the Agency shall have access to registers of participants' transactions in wholesale energy markets, including sale and purchase orders, identification of any purchased and sold energy products, any agreed price and quantities, execution date and time, parties involved and transaction beneficiaries, other than any other additional relevant information.
3. Availability of historical series, or mandatory record keeping; in compliance with the Third Energy Package, participants-suppliers (art. 40 Dir. 72/2009 and art. 44 Dir. 73/2009) must keep, for 5 years, any data on electricity or gas supply transactions, or about derivatives; the same obligation falls upon TSOs (art. 15.6 Reg. 714/2009 and art. 20 Reg. 715/2009). In addition, the Commission's implementing acts might allow regulated markets, or transaction reporting and control systems, to provide the Agency with a historical summary of transactions performed on wholesale energy products.
4. European register of market participants, to be arranged by ACER according to information provided by the national regulators; this register shall contain any information required for a univocal identification of participants and can be accessed by every national regulator[3].

As to the first aspect, ACER published the first edition of the "Guidance on the application of the definitions set out in Art. 2 of REMIT" of 20 December 2011, in compliance with art. 16 of the REMIT on the cooperation among national regulators and the agency itself. ACER offered some preliminary construal of the Regulation definitions (e.g. the meaning of "inside information"[4]) and of the disclosure of inside information. In this initial stage, ACER

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2 Art. 6.
3 See CEER final Advice on the introduction of a Europe-wide Energy Wholesale Trading Passport, 8 November 2011.
4 ACER, in the first edition of the Guidance, specifies 4 criteria to identify inside information, i.e. 1. Precise nature, 2. Non-disclosure, 3. A direct or indirect reference to one or more wholesale energy products and 4. Its disclosure could plausibly and remarkably affect the price of such products. For each criteria, ACER gave a preliminary, non-technical and not binding interpretation.

considers participants as compliant with the disclosure obligation provided that they make information publicly available through a TSO-run platform (for instance, the French one arranged by RTE-UFE) or exchanges (NPS, EEX transparency platform), or through their websites, by means of real time or near-real time notices. However, stakeholders are strongly recommended to adopt a centralized solution, at least on a country basis. Amongst others, such a solution would cut administrative charges while maximizing its beneficial impact on an efficient transparency and efficacy.

As to the collection of transaction data, the Commission's implementig acts will shed light on how such information should be disclosed and how and when it needs to be reported. More specifically, it is still unclear what subjects, among those listed under art. 8.4 of the Regulation, are in charge of notifying such information: participants, third parties acting on behalf of market participants, a trade reporting system, an organized market or a trade-matching system, a trade repository or an authority receiving said information to comply with provisions of a different nature.

REMIT Regulation pays special attention to the possible role of organised markets; in addition to acting as service providers for participants, for the purposes of transparency and reporting obligations, they are bound, from the settlement effective date, to comply with specific obligations outlined under art. 15: establishing and maintaining effective arrangements and procedures aimed at the identification of any insider trading and market manipulation practices and reporting any alleged violation to the national authorities. At present, ACER considers market surveillance departments, with respect to energy exchanges, and compliance officers, with respect to brokers, as best practices. Through them, it should be easier to discover any practices violating the market abuse prohibition, in line with the concluding opinion expressed by CEER – *"Regulatory oversight of energy exchanges"* – on the supervision of European energy spot markets, published on 11 October 2011. Also, REMIT Regulation allows ACER, on the occasion of its annual report of activities, to submit recommendations to the Commission on any rules, provisions and market procedures that could improve the integrity and functioning of the single market, such as the introduction of minimum requirements for organised markets in order to make them more transparent[5].

On a national level, there already exist several information obligations for gas and electricity participants, subject to the relevant authorities' monitoring power (AEEG, Ministry of Economic Development, Gestore dei Servizi Energetici, Gestore dei Mercati Energetici). They cover specific activities which pertain, broadly speaking, to commodity trading (e.g. gas importers reporting information to the Ministry of Economic Development; information on one's own market shares in the gas sector; obligations for electricity producers and importers concerning the injection of renewable energy into the grid, etc.) as well as transactions on commodity markets.

For instance, in the gas sector AEEG monitors the market on the basis of the data it receives on contracts traded at the PSV (Virtual Trading Point); in the electricity sector, AEEG implements the TIMM monitoring system (Integrated Text on Market Monitoring applicable to wholesale electricity markets and to the ancillary services market) by requesting participants to mandatorily report information on forward contracts, dispatching services as well as on any support activities carried out by Terna, GME and GSE.
It looks therefore necessary to liaise Community and national regulations, considering their partial overlapping and the aims of both domestic rules and REMIT Regulation.

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5 Art. 7.3.

The same can be said about the European Register of Market Participants, as hinted above; AEEG is already gathering participants' information, to be registered in the List of Participants. Any information requested on a domestic level shall be consistent and sufficient to fulfill REMIT Regulation requirements, too.

The above illustrated picture clearly shows the message that Community institutions wish to convey: need for more controls, less leeway and autonomy on the part of market participants, with the ultimate goal of achieving a greater transparency in markets and in the pricing of goods, avoiding any distortion.
In summary, the new regulatory framework will imply for market participants: incremental costs to implement increasingly sophisticated information systems, "migration" of trading towards regulated platforms, increasing and mandatory disclosure of one's own operations, estimated position limits subject to changes whenever the supervisory authorities request to do so.

2. ELECTRICITY MARKETS

2.1 How the electricity market is organized in Italy

The Italian electricity market stems from Legislative Decree 16 March 1999, n. 79 - *Implementation of Directive 96/92/EC on common rules for the internal market of electricity*, as well as any subsequent implementing provisions; amongst these latter, special mention should be made of Ministerial Decree of 19 December 2003, as subsequently amended and supplemented, approving the Integrated Text of Regulations for the Electricity Market as under article 5 of the above said Legislative Decree 79/99 and the Electricity and Gas Regulator (AEEG) Decision of 13 June 2006, n. 111/06 and its subsequent amendments on the *Conditions to provide public service dispatching of electricity nationally and to procure the relevant resources on an economic merit basis, in accordance with articles 3 and 5 of Legislative Decree 79/99.*

For the purpose of completing rules on the physical execution of electricity purchase and sale contracts entered under the bidding system as under article 5 of Legislative Decree 79/99 or outside such system, the merit-order dispatch rules contained in the above mentioned AEEG Decision n. 111/06 establish that electricity can be purchased and sold in the regulated market run by GME under art. 5 of Legislative Decree 79/99 (such market includes both the spot electricity market - MPE - and the forward electricity market - MTE) or through bilateral contracts (over the counter - OTC). Market participants, i.e. subjects with an injection and/or withdrawal capacity as dispatching users or are authorized by dispatching users – are engaged in trading activities. More specifically, market participants, whether or not they also qualify as dispatching users, are responsible for marketing activities (purchase/sale, registration of injection/withdrawal schedules) and for paying any system charges (CCT, on schedule deviations); on the other hand, dispatching users remain responsible for physical activities (production/consumption, executing dispatching commands given by Terna in the Ancillary Services Market - MSD) and for paying any related charges (deviation charges).

To ensure the traceability of electricity flows, the physical execution of purchase and sale contracts and the hedging of financial risks, AEEG Decision n. 111/06 introduced an "account registration system" named OTC Platform (PCE), run by GME on behalf of Terna. Under this system, each participant is assigned one injection electricity account and one withdrawal electricity account corresponding to available offer points (i.e. capacity) where each participant is entitled to register contracts. Such offer points can be injection points (in which case they correspond to both physical and virtual generation units)[6] or withdrawal points (to the exception of pumping units, generally corresponding to virtual consuming units aggregating all meters of a wholesaler's clients in the same zone). Upon signing the contract, the two parties shall register on the PCE volumes traded on an hourly basis, specifying to what account they should be allocated to. The day before electricity is delivered, the parties register their injection schedules in their respective accounts, indicating the units underlying the electricity account to which hourly volumes should be allocated[7]. In order to execute contracts, the quantities registered on each unit shall not be higher than the unit capacity and the sum of scheduled quantities shall not be higher than the quantity sold or purchased; however, the sum of quantities scheduled by each market participant can be smaller than the net balance registered (the so called on schedule deviations). Although contracts can be entered directly by the parties (the so called physical bilateral contracts), contracts and schedules need to be mandatorily registered on the PCE. When contracts are entered in the MTE, the net balance of underlying electricity is automatically registered on the PCE by GME at the end of the trading period, in both the buyer's and seller's electricity accounts. At a later time, market participants register their own schedules. Finally, under MPE contracts, accepted bids/offers are automatically converted into contracts and schedules.

Similarly, Terna allocates an Actual Deviation Account to each dispatching user, where units under his/her

6 Virtual generation units include either units grouping together several different non-relevant generation units, or generation units in foreign zones, representing the import capacity available at the border as allocated to a market participant.

7 The opposite happens for buy contracts, posted as positive; they shall match with one or more withdrawal schedules posted as negative.

responsibility are reported as well as schedules resulting from the MI and ex-ante MSD or volumes actually injected and/or withdrawn (as recorded by meters at each individual injection/withdrawal point).
Therefore, to settle economic positions:

- Electricity injected/withdrawn to execute injection/withdrawal schedules shall be settled by the parties at the price agreed by contract;
- Any positive difference between the quantity posted by each party and the quantity previously scheduled (the so called "on schedule deviations") represents a purchase/sale in the MGP and shall be settled with GME at its market value (Pun);
- Any electricity injected or withdrawn, as a deviation in the schedules described in said contracts, shall be settled by the dispatching user in favor of Terna at the so called "price of deviation" (the so called "double settlement")[8].

Schedules registered on the PCE and those resulting from bids/offers accepted in the MPE may cause grid congestions; as such, they contribute to the allocation of the available transport capacity: in this event, participants shall pay the market value of any congestion. This value is achieved by organizing the MGP as a zonal market, receiving all schedules registered on the PCE (see next paragraph for more detailed information). To this end, Terna decided to split the grid into zones, representing areas where congestions are common and significant (see diagram, – Fig B.1.1[9]). In case of congestion, injection schedules are charged a fee ("cost of the right to use transport capacity" or CCT). Such fee is calculated as the difference in each hour between the hourly purchase price in contract withdrawal zones and the hourly sale price of electricity in contract injection zones: thus, the resulting fee must be paid (charge) to inject electricity into exporting zones, since it contributes to increasing the number of congestions, and must be received (aid) for injection into importing zones, since it contributes to reduce congestions; finally, no fee is charged where no congestion occurs. As to contracts registered on the PCE, the above fee is paid to Terna by the participant who registered the injection schedule; as for contracts registered in the MPE, the fee is implicitly paid by the seller who receives the zonal price. This cost is extracted by GME as a difference between the value of purchases and the value of sales in the market and is paid to Terna. Any CCTs paid to Terna represent a congestion income; the transmission system operator returns this income to final customers by cutting system charges (the so called uplift).
Moreover, the PCE allows to manage the solvency guarantee against any charges taken with the market by participants and dispatching users. Upon registering contracts in electricity accounts, participants are requested

8 A generation deficit or a consumption surplus relative to schedules are considered as a purchase by Terna, which in turn buys electricity in the MB. On the opposite, a generation surplus or a consumption deficit relative to schedules are considered as a sale to Terna; Terna offsets these transactions by selling in the MB. The price of deviation is calculated so as to penalize only deviations that negatively affect the overall zonal deviation. In particular, with respect to relevant units for injection schedules, when the aggregate zonal deviation is positive (demand surplus), the curtailed generation is valued at the maximum between the price in the MGP (Pun) and the highest step-up price accepted in the MB; generation surplus is simply valued at the Pun. On the other hand, when the aggregate zonal deviation is negative (supply surplus), the curtailed generation is valued at the Pun, whereas generation surplus is valued at the minimum between the Pun and the lowest step-down price accepted in the MB. A similar, less penalizing scheme applies to non relevant units; for these latter, the highest step-up (step-down) price accepted in the MB is replaced by the average price among accepted step-up (step-down) prices. Likewise, with non schedulable units, the price of deviation is simply the corresponding Pun. Finally, it should be noted that – to minimize the impact of this scheme on consuming units and distribute its effect over time– a time-decreasing consumption threshold has been introduced (the so called "exemption threshold"), below which deviations are valued at the Pun.

9 Article 15.1 of AEEG Decision 111/06 clarifies that zones should be defined in such a way that "the transport capacity between zones shall be insufficient to perform injection and withdrawal schedules corresponding to the most frequent operational conditions, according to Terna's estimates of the electricity market results; execution of injection and withdrawal schedules should not give rise to any congestion inside each zone under predictable operational circumstances; the site of injections and withdrawals, even potential ones, inside each zone, should not significantly impact on the transport capacity across zones". A zonal representation of the grid resembles the real grid, leaving certain congestions potentially unresolved; these are later handled by Terna in the MSD. Such simplification represents a trade-off between minimizing congestion-settling costs (such solution would be guaranteed by a nodal system) and maximizing the market liquidity and transparency which commonly exist in a single zone system. To this end, see the analysis described in AEEG Consultation Document DCO 24/08 on "Foundations and rationale of zones: potential impact on the electricity market". In particular, the grid consists of 6 geographical zones, 5 poles of limited production and 7 virtual foreign zones. Geographical zones (North, Center-North, Center-South, South, Sicily, Sardinia) represent areas where injection and withdrawal points are located: in 2011, they accounted for 69% of total sales. Poles of limited production (Monfalcone, Brindisi, Foggia, Rossano, Priolo) represent injection points with an insufficient interconnection with the rest of the grid; they are confined in a specific zone to solve structural congestions: in 2011, they accounted for 15% of total sales. Virtual foreign zones (France, Switzerland, Austria, Slovenia, Greece, Corsica, Corsica AC) stand for interconnection segments over each foreign border and are utilized to handle cross-border congestion solutions by scheduling the allocation of interconnection capacity available for both import and export purposes: in 2011, they accounted for 16% of total sales. Since 1/1/2011, the zonal structure has been including a BSP zone covering the interconnection capacity between Italy and Slovenia, allocated through an implicit daily auction (the so called market coupling). Conversely, the virtual foreign zone of Slovenia is used for the interconnection capacity share allocated through periodic explicit auctions (monthly and yearly).

to provide GME with guarantees sufficient to cover the estimated value of any possible on schedule deviations and CCT; dispatching users are requested to provide Terna with guarantees sufficient to cover the estimated value of any actual deviations.

2.1.1 The capacity market: Capacity Payment and Must-Run Units

In January 2011, the consultation round on Capacity Payment initiated in November 2010 by AEEG with the publication of its Consultation Document (DCO) 38/10 on *"Final guidance and international comparative analysis on the market of electricity generating capacity"* was completed.
To implement provisions under art. 2, para 1, Legislative Decree 19 December 2003, n. 379 on "*Provisions on the remuneration of electricity generating capacity*", AEEG Decision ARG/elt 98/11 of 21 July 2011 sets rules, criteria and provisions to redesign the current remuneration mechanism for Capacity Payment, after the provisional mechanism defined in accordance with AEEG previous Decision 48/04.
In this way, the Regulator implemented the proposed reform of Capacity Payment as illustrated in consultation document 38/10; by means of this latter, AEEG specified and further refined the proposed reform submitted with its previous DCOs no. 27/08, 10/09 and 09/10.

The reform of the capacity payment scheme, by keeping in due account suggestions made by participants during the previous consultation round as well as possible solutions resulting from an international comparative analysis, aims at incentivizing participants to install additional generating capacity. At the same time, strong support is given to a broader mix and technology set in the generation process. On one hand, the Regulator tries to comply with high security standards and appropriate quality levels – the expected demand for electricity in the hours and zones where supply is more scanty; on the other, it tries to define an appropriate regulatory framework to support investment in new power plants on the part of new entrants.

The Capacity Payment tentative scheme – still effective – no longer complies with provisions under art. 2 of Legislative Decree 379/2003; also, it does not offer sufficient guarantees with regard to the existing relationship between the remuneration fee received by the plant owner and the scanty supply in the electricity market; for all such reasons, AEEG decided to go beyond the present system. AEEG proposed to create a capacity market where participants receive long term price indications so as to minimize and carefully assess any risk related with investment in an additional generating capacity. In a nutshell, the mechanism outlined by AEEG rests upon a capacity market based on "reliability options", i.e. option contracts on the exchange price, associated to physical obligations of capacity availability.

The availability of "generating capacity" in the capacity market of the future would be subject to capacity options between the TSO and participants operating in the electricity generation field. In return for an economic premium, to be defined *ex ante* through a tender, awardees-producers shall make the generating capacity covered by the capacity option available. They shall pay to the TSO the product of such capacity quantity and any positive difference between the reference price (arising from the results of the wholesale MGP market) and the strike price set beforehand in the capacity option.

The reference price varies by each hour and is the zonal price in the Day-Ahead Market (MGP) for the zone where the TSO's counterparty sells electricity on the basis of its own capacity. In the event the participant's bid/offer is not accepted in the MGP, this latter shall offer the remaining share of capacity covered by the option, fully or partly, in the dispatching services market.
According to this mechanism, options would not only include an actual penalty in the event the committed

generating capacity is no longer available but would implicitly and clearly define such penalty, i.e. any positive differential between the reference price (variable) and the fixed strike price.
Furthermore, the timeline for planning the new capacity to be installed and, along the same lines, the option strike period, would presumably attract "new entrants" in the electricity generation market, so as to increase the capacity market competitiveness.

The preliminary implementation rules of the Capacity Payment reform will be presumably announced by the end of this year. During this design period, Terna should submit to the Ministry of Economic Development a proposal to organize the new market. The Ministry is in charge of defining the policy documents to start the new mechanism. Supposedly, this latter will become effective in 2017 whereas the first calls for tenders - to be held by the TSO to select producers wishing to offer their generating capacity - should be announced in 2013. Participation in such tenders will be voluntary - subject to posting approppiate guarantees.

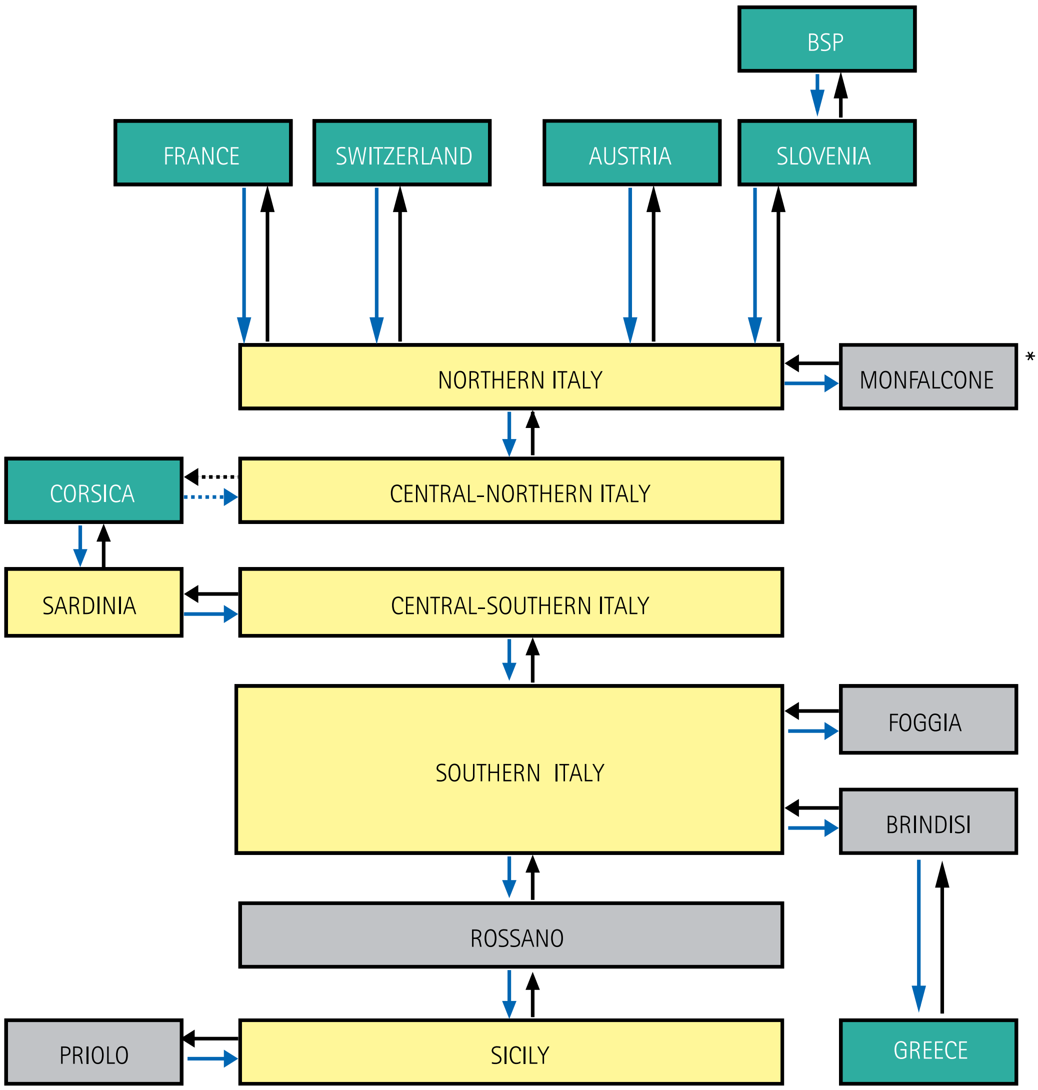
Such recently published measures aim at ensuring an adequate and secure electricity system as well as at curbing its costs, with an eye to the competitiveness and generation requirements of the Italian economic system; they also try to prevent any abuse of dominant position in the electricity market, e.g. through provisions on settlement of Must-Run Units in the Greater Islands (Sardinia and Sicily).

In these electricity market zones, there still exist competitive criticalities in the ancillary services market (MSD); the wholesale market should therefore be closely monitored, especially because only two large supply side participants operate in such zones (or participant's groups in Sicily).

As reported by AEEG in PAS 21/11 of 6 October 2011 on "*AEEG Report on the status of electricity and gas markets and their criticalities*", competition in Sardinia keeps improving after the full entry into operation of the interconnection SAPEI cable between the mainland and the island; on the other hand, the picture is less positive in Sicily, where ENEL and EDIPOWER have made a formal commitment with the Competition Regulator (AGCM) until 2014. Throughout 2013, ENEL shall submit sale offers in the MGP in the Sicily zone at prices not exceeding a given limit - 190 €/MWh in 2011 - to be adjusted in the following years according to any Brent price index variation. Likewise, during 2013 EDIPOWER shall apply to the Regulator for refund of costs, as under article 65 of AEEG Decision n.111/06, on the management of plants deemed to be essential for the system security by Terna.

Thus, the Regulator confirms that the selection and settlement process of system security Must-Run Units, governed by AEEG Decision n. 111/06, along with a close market monitoring by AEEG itself (AEEG Decision ARG/elt 115/08 - TIMM), are essential instruments to prevent or identify any unilateral and/or collective exercise of power.

Electricity market zones Fig B.1.1



* Since 2012, the "Monfalcone" zone has been included in the Northern zone

2.2 The spot electricity market (MPE)

The Spot Electricity Market started on 1 April 2004 in accordance with article 5 of Legislative Decree 79/99; it is governed by provisions under the decree of the Minister of Productive Activities of 19 December 2003 – approving the integrated text on the electricity market rules – as subsequently amended and supplemented.
The design of this market was partially redefined when provisions under the Decree of the Minister of Economic Development of 29 April 2009, implementing measures introduced by 28 January 2009, n. 2 became effective.
At present, the MPE consists of the Day-Ahead Market (MGP), Intra-Day Market (MI) and Ancillary Services Market (MSD).

- **Day-ahead market (MGP).** The day-ahead market was worth 180 TWh in 2011 and is the main market managed by GME. Hourly contracts with a physical delivery obligation are traded in the MGP with GME as central counterparty. The MGP qualifies as a physical market in three ways: it is open only to electricity operators who are bound to submitting sale offers on injection points and purchase bids on withdrawal points (in other words, trading is not allowed in the MGP); bids/offers must refer to specific injection points and, if accepted, give rise to injection/withdrawal schedules (the so called unit bids); offers are accepted by merit-order, in accordance with transit constraints across zones (the so called zonal market).

Trading is managed through hourly auctions at clearing price: bids/offers, for all units and for each of the 24 hours of the delivery day, can be submitted as soon as nine days in advance of delivery and until 9 a.m. on the day before the delivery day (gate closure). Market results are notified at 11:30 a.m. Each participant can submit, for each hour and offer point, a supply curve consisting of four price-quantity pairs (the so called simple multiple bids). Since products are hourly and bids simple, market results for each of the 24 hours can be simultaneously and independently determined. Bids/offers are accepted on non discriminatory auctioning terms (or clearing price auction), maximizing the added value of transactions. This latter is defined as the difference between the value of purchase and sale bids/offers, where each one is valued at the offered price. In a diagram, this amounts to drawing a decreasing demand curve and a growing supply curve, defining accepted bids/offers as those on the left of the intersection point, with a value resulting from the intersection price between demand and supply (the so called clearing price). However, to accept submitted bids/offers, the auction algorithm makes sure that the overall demand is as large as the supply and that transit flows deriving from accepted bids/offers are compatible with the maximum transit limits between each pair of bordering zones notified to Terna before the market is opened; in this way, a clearing price is defined for each zone making up the grid. When no limit is saturated, the sale price in each zone is the same; otherwise, zonal sale prices may vary and, by definition, will be lower in export zones and higher in import zones. In this respect, the zonal market is not just an explicit energy auction but also an implicit auction for the right of transit over the grid. This is the reason why schedules registered on the PCE to execute forward energy purchase and sale contracts are considered, under the market zonal solution, as virtual bids/offers in the MGP. They are not given a market price although they contribute to determining the congestion level and are subject to CCT. While sale offers are valued hourly at the relevant zonal price, purchase bids are valued hourly at the National Single Price (Pun), defined for each hour as the average price of geographical zones weighted for the value of purchasing by final customers in the same hours and zones[10]. This rule does not apply to purchase bids referred to pumping units and to foreign virtual units, which are valued at their respective zonal prices[11].

- **Intra-day market (MI).** The intra-day market has been replacing the Adjustment Market since 31 October 2009. It consists of four sessions: two are held on day D-1 covering the 24 hours of day D; two are held on day D covering the last 12 and 8 hours, respectively (as to the timeline, please refer to Tab. B.1.1). In 2011, volumes traded in the MI totaled 22 TWh and were lower than those traded in the MGP. While MGP's main purpose is to define energy purchase and sale contracts and their related injection/withdrawal schedules, the MI allows participants to change schedules resulting from the MGP to solve any dispatching issues (thermoelectric generation plants) or, more generally, changes in the available injection/withdrawal. From a regulatory standpoint, the MI differs from the MGP in few aspects: each participant can submit both sale offers and purchase bids on the same offer point, and all bids/offers being posted at the zonal price, including purchase bids. Until the end of 2008, bids/offers in the MA were allowed only when referred to injection points. Starting from 1 January 2009, bids/ offers can be submitted in the MA also when referred to withdrawal points. In this event, withdrawal offers are charged a non arbitrage fee, equal to the CCT applied for that hour and zone in the MGP.
- **Ancillary Services Market (MSD).** GME runs the data exchange functions in the Ancillary Services Market whereas Terna is responsible for defining the rules and accepting bids/offers.

10 It should be noted that the Pun is not calculated after the MGP solution as the mean of previously established zonal prices; rather, it is calculated along with zonal prices during the market resolution. In other words, maximizing the transaction value is subject to one further constraint: accepted purchase bids should express a maximum purchase price not lower than the Pun. If this were not the case, the market result could generate paradoxical outcomes: purchase bids with maximum purchase prices below the Pun would be accepted. For a more thorough discussion, refer to the document entitled "*Uniform purchase price algorithm*" available on GME's website at: http://www.mercatoelettrico.org/It/MenuBiblioteca/Documenti/20041206UniformPurchase.pdf

11 This exception is due to the need of avoiding arbitrage for such units; having the right to simultaneously submit sale offers and purchase bids, for each given hour they could cash the difference between the zonal price and the Pun in every zone where the first is smaller than the latter.

The MSD consists of two sessions: the first session (the so called ex ante MSD or MSD1) is held right after the MI2: it opens at 3.30 p.m., closes at 5 p.m. and results are published at 9 p.m. In this market, Terna solves any residual congestion after the MGP and MI and procures reserve margins on generation units to balance the system in real time. The second session (the so called ex post MSD or MB) is held on the delivery day; new bids/offers are not allowed whereas those previously submitted in the ex ante MSD balancing may be accepted. Unlike the MGP and MI, in the MSD accepted bids/offers are posted each at their bid price (so called 'pay as bid'). Participation in this market is allowed to dispatching users only for generating or consuming units defined as relevant by Terna. On the other hand, participation is mandatory; for each hour and each relevant unit, sale offers (step-up) and purchase bids (step-down), are submitted, at a price freely chosen by dispatching users. Such bids/offers can be accepted by Terna both in the ex ante MSD and ex post MSD. In this way, both markets are in turn comprised of a balancing up and a balancing down component. It should be noted that following the approval of Law 2/09, Terna modified the MSD rules starting from 1 January 2010. Firstly, participation has been extended to additional members, including, most notably, several CIP6 units. Secondly, multiple bids/offers can now be submitted. They show both three incremental and subsequent energy prices (GR1, GR2, GR3) and any related plant switch on and off costs. Also, such bids/offers can vary from one hour to another and can be changed in the MB. Thirdly, the number of MB sessions has increased from 1 to 5 (as to hours, please refer to Tab B.1.1). Starting from 1 January 2011, two new intra-day scheduling stages of the ex-ante MSD were introduced. On the same date, two new MI3 and MI4 sessions have been introduced, too.

Timetable of spot electricity markets Tab B.1.1

	MGP	MI1	MI2	MSD1	MB1	MB2	MI3	MSD2	MB3	MI4	MSD3	MB4	MB5
Reference day	D−1				D								
Preliminary information	08.00	12.30	15.00	n.a.	n.a.	n.a.	07.30	n.a.	n.a.	11.30	n.a.	n.a.	n.a.
Opening of sitting	08.00**	10.30	10.30	15.30	°	23.00*	16.00*	°	23.00*	16.00*	°	23.00*	23.00*
Closing of sitting	09.00	12.30	15.00	17.00	°	04.30	07.30	°	10.30	11.30	°	14.30	20.30
Individual results	10.30	13.00	15.30	21.00	#	#	08.00	10.00	#	12.00	14.00	#	#
General results	10.30	13.00	15.30		##	##	08.00	##	##	12.00	##	##	##

** time referred to day D-9
* time referred to day D-1
° use is made of bids/offers submitted in the first sub-stage of the MSD
fifteenth day of month M+2
General results are published every hour, 1 hour after the end of each hourly period. For the first three months after the take-off of the new MSD results will be published on a weekly basis.

2.3 OTC registration platform (PCE)

Vested with GME pursuant to article 16, Annex A to AEEG Decision n. 111/06 and any subsequent amendment, it officially started on 1 April 2007. On the OTC registration platform (PCE), participants notify electricity quantities – without reporting the trading prices – underlying bilateral forward contracts entered outside the MPE. The platform consists of an "electricity account system" to distinguish between the registration of commercial transactions and the relevant injection/withdrawal schedules that participants accept to execute. In the medium-long run, this mechanism allows a more efficient management of energy portfolios. Participants can easily re-negotiate, if necessary, any previously purchased/sold electricity. Also, the PCE provides a greater operational flexibility to participants who are also IPEX members, e.g. through the so called on schedule deviations. In other words, they can register schedules smaller than the net balance resulting from their own account, reporting a positive price. As a consequence, in the event such price is lower than the zonal price, they can purchase or sell an electricity volume in the MGP equal to the difference between the registered schedule and the net balance of the electricity account. With this operational function in place, contracts worth 236 TWh were registered on the PCE whereas registered schedules only totaled 119 TWh. According to AEEG Decision n. 111/06, only contracts with a maximum two month deferred delivery can be registered on the PCE. Hence, longer contracts need to be registered by subsequent tranches.

2.4 The Forward Electricity Market (MTE) and the Electricity Derivatives Platform (CDE)

In operation since 1 November 2008, following the effective date of provisions under the decree of the Minister of Economic Development of 17 September 2008, as subsequently revised (starting from 1 November 2009) to implement provisions under the Decree of the Minister of Economic Development of 29 April 2009, the Forward Electricity Market (MTE) is a regulated market where GME acts as central counterparty; participants can trade standardized forward electricity contracts, both baseload and peakload, with delivery and withdrawal obligation. To ensure the security and stability of the power system, a functional integration between the MTE and PCE was requested to fulfill the obligation of physical delivery of forward traded electricity. This has been achieved by registering on the PCE the physical positions resulting from forward contracts; clearly, they must be in accordance with the latest delivery date provided for by AEEG Decision n. 111/06 to register electricity trades on the PCE (i.e. 60 days).
While on the MTE 3 monthly contracts, 4 quarterly contracts and 1 yearly contract are simultaneously listed (with a baseload and peakload profile), the only contract being settled and delivered is the near maturity monthly one. Quarterly and yearly contracts, close to the beginning of the delivery period, fall under the cascading mechanism. According to this mechanism, they are replaced by an equal number of shorter delivery period contracts[12]. Under this method, contracts entered in the MTE are registered on the PCE at the end of the trading period, i.e. right before the beginning of the delivery period. Unlike the MGP, the MTE operates on a continuous auction mechanism, where contracts are entered by automatically matching purchasing bids and sale offers – ordered by a price and time priority – at the offer, purchase or sale price in order of submission. The reference price published by GME is the average price of any entered contracts, weighted for their respective volumes. The OTC clearing functionality is active in the MTE: participants can register – by specifying the counterparty, energy volume and trading price – bilateral forward transactions. Given GME's role as central counterparty, participants in the MTE can efficiently handle the counterparty risk implied

12 With *cascading*, a quarterly contract is split into three monthly contracts (the first one is cleared by physical delivery); the yearly contract is broken down into three monthly and three six-monthly contracts. In both cases, the time horizon covered by the new contracts is the same as in the original contract.

in such contracts. In 2011, 8,228 transactions were finalized in the MTE, totaling 33 TWh[13] versus 6 TWh traded in 2010.

From 26 November 2009, GME has been running the Electricity Derivatives Platform (CDE), with the goal of achieving a higher integration between the physical forward market and the financial market. More specifically, electricity derivatives contracts entered in the IDEX – market segment of financial derivatives of Borsa Italiana S.p.A. where electricity futures are traded – are registered in the CDE. Participants must have requested to exercise the physical delivery option in the electricity market underlying the contract. Every electricity market participant is automatically entitled to be part of the CDE; however, physical delivery in the electricity market (ME) can be requested only by participants holding an electricity account on the PCE.
Participants can exercise the physical delivery option in the ME of the electricity underlying financial contracts finalized in the IDEX – those with a monthly delivery period – under Borsa Italiana and CC&G IT systems, on the terms and conditions defined in their respective regulations.
The physical delivery unfolds by registering an electricity purchase/sale transaction, with GME as counterparty, on the PCE electricity accounts at the participant's disposal. Despite such flexibility, no physical delivery option was exercised in the CDE in 2011.

13 This value includes the amount of OTC volumes registered in the MTE for clearing purposes.

3. ENVIRONMENTAL MARKETS

3.1 Renewables support policy

The decision to introduce in Italy an incentive scheme aimed at promoting the generation of electricity from renewable sources fostered the growth of the installed capacity and a revamping of the domestic electricity generation industry.
A significant help came from the Green certificates, i.e. the incentive system, based on market mechanisms, introduced by Legislative Decree 79/99 to replace the previous feed-in tariff system known as CIP 6.
However, the system of Green Certificates, in the aftermath of the new support measures for renewable sources, will be gradually replaced by a new feed-in tariff system, starting from 2013.
Legislative Decree 3 March 2011, n. 28, on the "Implementation of Directive 2009/28/EC on the promotion of use of electricity generated by renewable sources", under art.25 establishes that producers and importers of electricity from conventional sources shall inject into the grid a proportion of energy generated from renewables (art. 11, para 1 and 2 of Legislative Decree 16 March 1999, n. 79) equal to 7.55% in 2012; this rate shall be linearly reduced from 2013 down to zero in 2015.
Therefore, plants which begin their operations by 31 December 2012 will keep receiving green certificates for 15 years; as to plants which begin operating after 31 December 2012, electricity generation from renewables will be incentivized according to general criteria ensuring a fair return on investment and running costs; also, incentives will last as the useful average life of the specific technology in use at a given plant.
Incentives shall not change throughout the incentive period and are to be allocated through private contracts concluded with GSE.
The incentive amount, for plants below a given threshold, varying from source to source and anyway not lower than 5 MW electric, will be different according to each technology and will be equal to the one in effect at the time a plant actually enters into operation.
For larger plants, the incentive will be determined through a Dutch auction arranged by GSE; each auction covers a certain capacity quota to install per each source or technology.
In Europe, Germany and Spain adopted a feed-in tariff scheme to incentivize electricity generation from renewable sources. Other countries, including UK, Belgium, Poland, Norway and Sweden adopted a market system based on the Green Certificates. In particular, Norway and Sweden jointly inaugurated their Green Certificates market on 1 January 2012, effective until 2035. This market aims at increasing generation from renewable sources in both countries, between 2012 and 2020, by over 26 TWh, i.e. approx. 50% of domestic consumption levels in Norway.
An analysis of the market that is going to develop in these two Scandinavian countries will be most helpful in the evaluation of the domestic system still in place.

3.2 Green Certificates Market

The market mechanism of Green Certificates was introduced in Italy by Legislative Decree 16 March 1999, n. 79, on the liberalization of the electricity sector and the promotion of electricity generation from renewable sources; this legislation provides for a gradual replacement of the previous feed-in tariff support scheme known as CIP 6, effective since 1992.
Under the above decree, producers and importers of electricity from non renewables, starting from 2002, shall inject every year into the grid electricity from renewable in an amount equal to 2% of electricity produced or imported in the previous year in excess of 100 GWh. This mandatory rate was later increased by 0.35% a year, relative to the 2004-2006 period, and by another 0.75% a year, for the 2007-2012 period.
Electricity from renewable sources entitles to a Green Certificate, representing 1MWh of electricity generated

by an IAFR plant ("Impianto Alimentato da Fonti Rinnovabili", Renewables-fed plant).
Gestore dei Servizi Energetici (GSE) is the entity which qualifies plants. Upon producers' request, GSE assesses the plant characteristics through an in-house committee and qualifies it as a IAFR plant. Afterwards, a IAFR producer may request Green Certificates, either at a later stage with respect to the previous year, or beforehand, with respect to the production expected for the current year or the following one.
By 31 March of each year, subjects submit to GSE a number of GCs equal to their mandatory share. Each GC is characterized by the reference year, i.e. the year on which generation from renewable sources has occurred. A GC for a given reference year is valid to fulfill the obligation for that year or the two subsequent years. After the deadline set for fulfilling the obligation of the second year after the reference year, GCs will no longer be valid. Moreover, various types of GCs can be issued: in particular, other than GCs issued for generation by IAFR certified plants, GC_H2 for generation of electricity with the use of hydrogen and energy produced in static plants with the use of hydrogen, i.e. fuel cells, can be issued, as well s GC_TRL, for electricity from cogeneration plants in district heating (limited to the share of thermal energy actually used for district heating only).
Thus, whenever a subject must fulfill this obligation, it may decide whether to invest in the erection of new plants fed by renewable sources and get GCs by generating electricity, or buy GCs from other producers. This decision is mostly based on the evaluation of marginal costs for each of the two options; new plants are erected in the event the marginal costs are lower than those related to GCs purchasing.
To promote the GC trading, Ministerial Decree of 11 November 1999 later repealed and replaced by Ministerial Decree of 18 December 2008 on "Support to electricity from renewable sources, pursuant to article 2, para 150, Law 24 December 2007, n. 244" established that GME organizes and manages a platform to trade such Certificates.
Established in March 2003, the GC market consists of sessions where transactions are performed under the continuous trading mechanism. When the market is open, participants can enter purchase bids and sale offers, with the relevant quantities and price. Bids/offers are matched when the price of the best purchase order is equal or greater than the best sale order and viceversa. Furthermore, purchase and sale orders can be posted without a price, and are automatically matched with the best order of opposite sign. Sessions are generally held once a week, 9 a.m. through noon.
GME is the central counterparty in this market, so as to ensure a positive result of transactions. According to the market rules, to guarantee the delivery of traded GCs to buyers, only GCs available in the account held by each participant on the GC register handled by GSE can be sold. In this manner, short selling and failure to deliver traded certificates is prevented. Likewise, to guarantee payment to sellers, prospect purchasers need to pay a sum, the day before each market session, in a bank deposit held by GME, as a full guarantee of transactions. Buyers, therefore, cannot enter purchase orders unless fully covered by their down payment, net of any previously concluded purchasing.
Other than trading in the regulated market, green certificates can be sold freely in the open market. To register over-the-counter transactions, GME developed a functionality called Green Certificates Bilaterals Registration Platform (PBCV). Participants can notify their bilateral contracts to transfer any bilaterally traded GCs from the seller's to the buyer's account. Since 2009, every bilateral contract and its price must be registered on the PBCV. Bilateral transactions can be registered with the so called "adequacy verification" or "without adequacy verification".
With the "adequacy verification" registration, GME, prior to validating a transaction entered by seller and confirmed by purchaser, double-checks the following: it verifies the availability of the number of GCs for sale from the seller and verifies that the purchaser has paid, in a GME bank deposit, the transaction amount pending its validation. If the verification outcome is positive, GME transfer the transaction amount to the seller and orders the GCs ownership transfer from the seller's to the purchaser's account, through a direct connection between PBCV management system and GSE Register.
Under the "without adequacy verification" registration, GME, prior to validating a transaction, simply checks

that GCs are available to the seller, without checking the purchaser. If the verification outcome is positive, GME orders the GCs transfer from the seller's to the purchaser's account.
GME is not a counterparty in transactions registered through the PBCV, whether or not they have been registered with the "adequacy verification".

3.3 Energy Efficiency Certificates Market

Directive 2006/32/EC provides for the Member States to adopt measures aimed at achieving a non binding energy saving target of 9% within 9 years from the Directive's effective date.
Italy, in line with its policy supporting renewable sources, decided to incentivize energy saving by introducing a market mechanism based on Energy Efficiency Certificates (TEE). Prior to the approval of the above said Directive, Ministerial Decrees 20 July 2004 of the Ministry of Industry and Commerce were introduced. Such decrees set national targets to increase energy efficiency for electricity and gas distributors with a minimum of 100,000 users as of 31 January 2001 for the 2005-2009 five-year period. Later, Decree 21 December 2007 of the Ministry of Economic Development lowered the eligibility threshold for distributors (50,000 users) and set new targets for the 2010-2012 three-year period, while setting tighter targets for the years 2008 and 2009.
We report below a table with the yearly energy saving national targets until 2012, following any previous amendment:

Tab B.2.1 **Yearly national energy saving targets**

Obligation year	Obligations of electricity distributors (Mtoe)	Obligations of gas distributors (Mtoe)
2005	0.1	0.1
2006	0.2	0.2
2007	0.4	0.4
2008	1.2	1
2009	1.8	1.4
2010	2.4	1.9
2011	3.1	2.2
2012	3.5	2.5

A greater level of energy efficiency will be achieved through projects including energy saving measures. In the light of the actual saving achieved, projects are entitled to receive Energy Efficiency Certificates, generally for 5 years in a row after the entry into operation of each project.
TEE can be issued to obliged distributors who have implemented such projects or to non obliged distributors. Also, they can be issued to energy services companies (ESCOs) for projects they have implemented, or to companies who employ an energy manager (in accordance with Law n. 10/1991).
AEEG prepared and published its Guidelines to prepare, implement and assess projects and TEE-issuing terms and conditions in the light of the saving accomplished. Also, AEEG has also the task of verifying any implemented projects and certify the actual saving achieved; AEEG then requests GME to issue TEE to project owners, in accordance with Ministerial Decrees of 2004. TEEs are divided into three categories:
- type I: certificates giving evidence of primary energy savings through measures reducing final consumption of electricity;
- type II: certificates giving evidence of primary energy savings through measures reducing gas consumption;
- type III: certificates giving evidence of primary energy savings through measures other than those described

above.

AEEG Decision 27 October 2011 EEN 9/11, amongst others, introduced two new types of certificates for projects implemented in the transportation sector:

- type IV: certificates giving evidence of primary energy savings other than electricity and gas, implemented in the transport sector, assessed as described under article 30 of Legislative Decree 3 March 2011, n.28;
- type V: certificates giving evidence of primary energy savings other than electricity and gas, implemented in the transport sector, assessed through methods different from those envisaged for type IV certificates.

To handle TEE issuing, GME arranged the TEE Register, i.e. a computerized archive where an ownership account is opened for each market participant. TEEs issued by GME are held in each ownership account and certificates transactions are regularly registered. Transactions concluded through bilateral contracts are entered by participants into the register, to move TEEs from the seller's to the purchaser's ownership account. To fulfill their obligation, by 31 May of each year, starting from 2006, distributors notify their TEEs to AEEG for the year prior to cancellation. In its turn, AEEG checks that each distributor does own the certificates corresponding to the yearly target, and orders GME to cancel them.

For each surrendered and cancelled certificate, obliged distributors receive a "tariff contribution" to partially cover their administrative costs.

Obliged parties, in a system based on the market mechanism, must choose whether to independently implement energy saving projects to receive any TEEs they need to comply with the law, or buy certificates in the market.

To facilitate TEE trading and search for the trading counterparty, GME was requested to organize a venue for TEE trading, as provided for by art.10 para 3 of Decrees 20 July 2004. The rules of market operation were defined jointly with AEEG (Decision n. 67/05) and the market has been in operation since 2006.

Similarly to the Green Certificates Market, the Energy Efficiency Certificates Market trades certificates under the continuous trading mechanism. Also rules to match TEE purchase and sale orders are the same as in the GC market, including any guarantees to ensure the successful outcome of transactions. The only difference is that GME is not the central counterparty in the TEE market. In fact, purchasers are requested to pay a cash deposit to partially cover the value of transactions. Such deposit has to be available in a GME bank account the day before each market session.

A direct link between the regulated market and the TEE Register has the purpose of guaranteeing that any sold TEEs are actually available, avoiding short-selling practices. It is the market to ensure transparent and secure transactions, other than facilitating the identification of the counterparty and an efficient TEE pricing. The decree of the Ministry of Economic Development 5 September 2011 extends the white certificates support measures to high efficiency cogeneration as well. Its provisions apply to:

- cogeneration plants starting their operation, as new cogeneration plants, i.e. as a remake of existing plants on the terms defined by the present decree, effective from 7 March 2007, the effective date of Legislative Decree 20/2007;
- cogeneration plants starting their operation after 1 April 1999 and prior to 7 March 2007, acknowledged as cogeneration plants in accordance with any applicable rules on the date of entry into operation of said plants, on the terms and criteria and within the scope set out by article 29, para 4, Legislative Decree 28/2011.

The decree establishes that these plants are entitled to receiving white certificates because of their high efficiency cogeneration, considered as a Type II equivalent; also, certificates issued by GME can be used to fulfill the mandatory segment on the part of obliged subjects or can be traded in the market. Alternatively, participants can ask GSE to take them back at the price set under article 6 para 1, Decree 21 December 2007. GME shall therefore issue TEEs for projects certified by GSE. Any issued certificate will be registered in the ownership account on the TEE Register run by GME, and CHP plant owners shall open an ownership account. Also, GSE grants the guarantee of origin for electricity generated by CHP plants (GOc), in compliance with Legislative Decree n. 20 of 2007.

3.4 Emissions Trading Market

Of the many initiatives taken by the European Union to introduce measures curbing greenhouse gas emissions, a fundamental role is played by Directive 2003/87/EC on Emission Trading.
This Directive introduces an emission allowance trading system among the Member States, preliminarily applicable in 2005-2007. Afterwards, measures will be applied for 5-year periods, starting from 2008.
Starting from 2005, every plant performing activities outlined in annex I to the Directive need to receive a permit to emit greenhouse gases.

Furthermore, each Member State, for each reference period (initially, 2005-2007, 2008-2012 and so forth) shall draft a National Allocation Plan (NAP) specifying the number of emission allowances to be allocated to each plant subject to this obligation and the allowances allocation methods.
NAPs need to be approved by the European Commission; the Commission can reject them, if incompatible with the Directive. During the first period (2005-2007), at least 95% of allowances had to be allocated for free; for the subsequent 5-year period (2008-2012), free allocation is supposed to cover at least 90% of total emission allowances.

By 30 April of each year, plant owners shall return a number of allowances equal to the total emissions from their plant in the course of the previous year. Allowances submitted to fulfill the obligation are cancelled.
In the event the mandatory surrender of emission allowances is not complied with, plant owners at default shall pay a € 40 fine, for the 2005-2007 period, and a € 100 fine, for the subsequent five-year period (2008-2012), for each ton of carbon dioxide emitted against which the owner has not surrendered the relevant emission allowance. Payment of fines shall not relieve plant owners from the duty to surrender any allowances due.

The Emission Trading mechanism minimizes the total cost of emission reduction; if one accepts that reduction is achieved regardless of the geographical location and emission rights are allowed, emission reduction costs, on the whole, will be smaller. Indeed, reductions are more cost-effective when the marginal cost is smaller and permits can be transferred, rather than asking every participant to curb emissions whatever the cost. Hence, financing emissions reduction in a different country may be cost-effective to countries where high marginal costs are high, provided that they buy the emission rights (instead of performing direct interventions on their own).

To facilitate plants' compliance with such obligation, Directive 2004/101/EC (known as "Linking Directive") was approved. This Directive acts as a "bridge" between the Kyoto Protocol, through flexible mechanisms, and the ET Community scheme. According to the Directive, emission reduction certificates are acknowledged where resulting from Joint Implementation (JI) projects and a Clean Development Mechanism (CDM) complying with the Emission Trading scheme. Acknowledging the validity of credits obtained through JI and CDM projects allows to pay smaller marginal costs in curbing emissions, leading to a lower price of allowances and positive repercussions on compliance costs.

To promote emissions trading, both "spot" and "forward" regulated markets were established in Europe starting from 2005.

In Italy, from 2 April 2007, GME has organized a trading platform. Its rules of operation are similar to those applicable to the green certificates markets: it functions under a continuous trading mechanism, with weekly sessions, and has been in operation until 1 December 2010.

In the light of the abnormal trading patterns observed during the last market sessions in the second half of 2010, the emissions trading market was suspended until indefinitely on 1 December 2010.

In the last two years, the emissions allowance markets weakened, both because of an extremely high liquidity and the serious global economic crisis, with prices hitting their historical minimum, to the detriment of any new investment to reduce atmospheric CO2 emissions.

4. GAS MARKETS

4.1 How the gas market is organized in Italy

In Italy, transportation of natural gas falls under the responsibility of Snam Rete Gas, the TSO handling and monitoring the transport system to make any required gas quantity available anytime and everywhere across the network.

In this respect, the gas system functioning heavily depends upon its physical and commercial balancing[14], governed by the network code.

Physical balancing is the set of activities through which the TSO, by means of dispatching, monitors in real time flow parameters in order to guarantee, at any given time, the secure and efficient handling of gas from injection to withdrawal points. Storage is the instrument used for the physical balancing of the network on a gas-day; despite a shift from "storage-based balancing" to "market-based balancing", methods used for the physical balancing of the system have not unchanged. Snam Rete Gas, according to the new "market-based balancing" system, keeps having access to gas in storage made available by enabled users on the PB-GAS Platform, as well as to the strategic reserve at storage operations, if necessary.

On the other hand, commercial balancing includes activities required for a proper accounting and allocation of transported gas, as well as for the fee system encouraging market participants to keep any quantities injected and withdrawn from the network equal; in this way, they assist the TSO in its physical balancing activity.

Market participants need to define their injection and withdrawal schedules, other than the net balance of transactions concluded on platforms and/or markets existing in Italy, by arranging a balance equation.

In such equation, net injections into and withdrawals from storage systems are calculated as "nominated = allocated"; by definition, they are posted as the difference between total injections and total withdrawals from the TSO's network, net of transactions registered in gas markets. Any balance of said difference is defined as an imbalance and entered as such at the price set on GME's Balancing Platform, run on behalf of Snam Rete Gas.

According to the present regulation, in Italy the wholesale purchase and sale of gas can be made through bilateral contracts (OTC) or market transactions and GME's platforms.

The balance of transactions is included in TSOs' transport equation to allow these latter to balance their positions in the gas system.

Transactions concluded by participants, in order to be included in the transport equation, must be registered at the Virtual Trading Point (PSV). The PSV is the electronic platform managed by Snam Rete Gas, covering all points of entry and exit from the National Network of gas pipelines.

The PSV, in operation since 1 October 2003, is a virtual point situated between Points of Entry and Exit of the National Network of Gas Pipelines, where users and any other eligible subject can buy and sell gas injected into the network, on a daily basis.

Users who wish to operate at the PSV need to hold a transport contract with Snam Rete Gas effective for the current year, i.e. they must designate an "offsetting party" and exhibit acceptance from this latter, who in turn must hold a transport contract.

Participants can conclude and register gas transactions on the PSV thirty days ahead of the accounting date, for balancing purposes. Moreover, they can conclude and register gas transactions on the same day they are accounted, so that users can balance their own positions.

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14 In accordance with Article 8.6 of Legislative Decree n° 164/00, the Transmission System Operator monitors gas flows and any auxiliary services required for the system operation, including the physical balancing of the system.

4.2 Gas Trading Platform (P-Gas)

On 10 May 2010, implementing provisions under article 30, para 2, Law 23 July 2009, n. 99, and Decree of the Ministry of Economic Development 18 March 2010, GME started the trading platform (P-GAS, Import segment) through which those importing[15] gas from non European Union countries can fulfill their obligation to bid quotas of imported gas in the market. Moreover, this platform enables to trade gas quotas offered on a voluntary basis.

The exact definition of bidding terms for such quotas falls under the scope of subsequent AEEG regulatory provisions[16].

To implement provisions under the above mentioned Law, MiSE enacted Ministerial Decree 6 August 2010 setting out the terms on which gas producers fulfill their duty[17] to sell royalties owed to the State for exploitation of gas fields; in particular, said royalties must be offered by holders only on the Platform organized and managed by GME (P-GAS, Royalties' Segment). In accordance with the decree, AEEG Decision ARG/gas n.132/10 of 9 August 2010 later defined the economic terms for bidding royalties on the P-GAS, consistently with any previous provisions on this matter.

GME amended provisions contained in the P-GAS Platform Rules in compliance with Ministerial Decree 6 August 2010; as from 11 August 2010, the new P-GAS functions aimed at managing royalties' bids are fully operational.

Furthermore, to implement article 11 of Legislative Decree 130/2010 and AEEG Decisions ARG/Gas 193/10, ARG/Gas 79/11 and 67/2012/R/gas, GME arranged a new P-GAS segment where investors can bid gas volumes made available by their corresponding virtual storage operators[18].

The P-GAS is comprised of three segments:

- import segment, for the management of: i) supply offers and demand bids for gas quotas as under article 11, para 2, Law n.40/07 (import quotas); ii) bids/offers covering quotas other than those as under article 11, para 2, Law n.40/07. The import segment is based on the continuous trading mechanism. Contracts covering lots with monthly and yearly delivery periods can be traded;
- royalties' segment, where purchase and sale bids/offers for royalties owed to the State as under article 11, para 1, Law n. 40/07 are traded. In the royalties' segment, trading is organized in the form of auctions; contracts for monthly deliverable lots are traded in this segment;
- as per Legislative Decree 130/10 segment, where purchase and sale bids/offers are handled for gas quantities as under article 9 Legislative Decree 130/2010. The as per Legislative Decree 130/10 segment is based on the continuous trading of contracts for quantities with a monthly and six-monthly delivery period.

The P-GAS is managed by GME acting as a broker (not as a central counterparty). The delivery of traded gas, guarantees, invoicing and payments are handled by participants. This means that the terms of supply are set by the seller who notifies GME which in turn simply publishes them in its website. It follows that contracts traded by each participant can be quite different from one another.

The P-GAS units of measurement in the Import and Royalties' Segments are GJ, for gas quotas and Euro cents/GJ, specifying three decimals, for unit prices. As to the as per Legislative Decree 130/10 segment, its measurement units are MWh, for traded gas quantities, and Euro/MWh, specifying three decimals. The minimum quantity

15 Importers shall fulfill their obligation as under article 11, para 2, Law 2 April 2007, n. 40.

16 AEEG Decision ARG/gas n. 20/11 of 16 March 2011 defined provisions on the economic terms for bidding import quotas for thermal year 2011/2012 and subsequent years, on the P-GAS.
AEEG Decision 13 July 2011 - ARG/gas 95/11: Provisions on the economic terms for bidding in the regulated market of gas and capacity royalties owed to the State for exploitation of gas fields, pursuant to decrees of the Minister of Economic Development 12 July 2007 and 6 August 2010.

17 Producers shall fulfill their obligation as under article 11, para 1, Law 2 April 2007, n. 40.

18 Investors can fulfill the mandatory bidding requirement for gas quantities made available by their matched virtual storage operators, alternatively or cumulatively, in the M-GAS and P-GAS segment "as per Legislative Decree 130/10".

tradable (minimum lot) is 3.6 GJ/day, equal to 1 MWh[19].

On the P-GAS Import segment the following contracts are simultaneously traded:

- 1 monthly, referred to the second month after the current month;
- 1 yearly, referred to the thermal year after the current year.

Monthly contracts can be traded from the open market day following the last day of trading for monthly contracts, referred to the previous month, until the last open market day in the second month prior to the beginning of the delivery period.

Yearly contracts can be traded from the open market day after the last day of trading of the yearly contract, referred to the previous year, until the last market session of August of the previous thermal year.

As to gas quotas different[20] from those offered by subjects, the following contracts are simultaneously traded:

- up to a maximum of 6 (six) monthly contracts;
- 1 yearly contract.

Each monthly contract can be traded from the first open market day of the sixth month prior to the beginning of the delivery period until the day before the last open market day in the month before the beginning of the delivery period. The yearly contract trading period is as long as the yearly contract for import quotas.

On the P-GAS Royalties Segment, only monthly contracts can be traded; these have the same trading period as the monthly contract offered by importers in the import segment.

Finally, on the P-GAS as per Legislative Decree 130/10 segment, the following are traded at the same time:

- monthly contracts;
- 1 six-monthly contract.

The monthly contract is tradable from the first day of open market of the second month before the beginning of the delivery period till the last day of open market of the month before the beginning of the delivery period.

The half-yearly contract is tradable from the first day of open market in the month of March of the thermal year before the beginning of the delivery period until the last day of open market in the month of September of the thermal year before the beginning of the delivery period.

19 For example, 3.6 GJ/day correspond to lots by 108 GJ for a monthly contract covering a 30-day month and 1,314 GJ for a yearly contract.

20 Following a review of the emergency occurred on 23 July 2010 due to the unavailability of the gas cross-border transport system managed by Transitgas SA (hereinafter, Transitgas), MiSE issued a policy to safeguard the continuity and security of gas supplies, for the coordinated functioning of storage and to reduce the vulnerability of the domestic gas system. In order to promote a solution to the criticalities which emerged after the Transitgas gas pipeline interruption, MiSE requested GME, on 13 September 2010, to amend the P-GAS Regulation. Within the import segment, the goal is – with respect to gas quotas different from those subject to mandatory bidding only – to extend the trading period for monthly contracts. Such contracts should be traded starting from the first open market day of the sixth month prior to the delivery month and until the day before the last day of market open during the month prior to the beginning of the delivery period. Following MiSE's approval of amendments made by GME to the P-GAS Regulations, said products can be traded on the P-GAS Import segment starting from 24 September 2010.

4.3 Spot Market

Pursuant to article 30 of Law 23 July 2009, n. 99, GME started the spot gas market operations (M-GAS) on 10 December 2010.

Only participants enabled to perform transactions at the Virtual Trading Point (PSV) are allowed to trade in the M-GAS.

In the M-GAS, unlike the P-GAS, GME acts as central counterparty for transactions concluded by participants. It guarantees the delivery of traded gas and the positive outcome of payments.

To guarantee the delivery of gas traded in the M-GAS, GME entered into a specific agreement with Snam Rete Gas governing the exchange of certain information flows, essential for an appropriate management of market activities and those required to register gas quantities traded in the PSV (this latter is managed by Snam Rete Gas).

The positive outcome of payments for gas volumes is backed by a system of financial guarantees (as to the rules of the guarantee system, please refer to the next paragraph).

The M-GAS consists of:

- Day-ahead gas market (MGP-GAS), where gas sale and purchase bids/offers for the gas-day following the day on which the auction session ends are selected;
- Intra-day gas market (MI-GAS), where gas sale and purchase bids/offers for the gas-day corresponding to the day on which the session ends are selected.

The product traded in both market sessions refers to the gas-day (from 6 a.m. till 6 a.m. of the following day). To make an easy comparison with the price of electricity and gas traded in other European exchanges, the price and quantity unit of measurement are, respectively, Euro/MWh and MWh.

The MGP-GAS functions according to a continuous trading mechanism with closing auction. Therefore, it consists of two subsequent stages: during the first one, continuous trading applies whereas auctions are arranged during the second stage. The continuous trading session opens at 8 a.m. on the third day before the gas-day offers are referred to and closes at 10 a.m. the day before the gas-day offers are referred to. During continuous trading, transactions are concluded by automatically matching bids/offers, according to a priority order (price and time).

At the end of the continuous trading session, outstanding bids/offers, verified as valid and adequate, are automatically moved to the auction sessions, at the price entered in the book and with the time priority of the original proposal. Participants, however, can change or cancel such bids/offers during the session. The closing auction is held in a single session on the gas-day prior to the day offers are referred to; it opens at 10 a.m. and closes at 11 a.m. During the closing auction, participants can submit up to a maximum of four simple or multiple offers. To determine the market results, each multiple offer is considered as a set of simple offers.

The MI-GAS, on the contrary, consists of a single continuous trading session held once the MGP-GAS session is over. The MI-GAS opens at 2 p.m. the day before the gas-day bids/offers are referred to; it closes at 3.30 p.m. on the gas-day bids/offers are referred to.

4.4 Balancing Platform

Since 1 December 2011, the gas merit-order dispatch market has been active in Italy. It is managed by GME and was introduced to quantify deviations between any scheduled quantities and those actually delivered, according to the market value of gas as required to balance the system. The new regulations for the simplified balancing system is based on market criteria (SBSM) and were defined by AEEG to comply with provisions under art.11 of Legislative Decree 13 August 2010 n. 130, through AEEG Decision of 14 April 2011, ARG/gas 45/11. This latter reflects Community regulations contained in the so called Third Energy Package, most notably EC Regulation CE n. 715/2009, and Transposition Law n. 96/10.

In a context characterized by the gradual shift of the domestic gas market towards a more mature situation, the balancing service reform and its market-based evolution have increased flexibility and liquidity on the supply side. This is a key element to promote market competition and positively affects the development of the spot gas market, given the close tie between the spot market and the balancing market. Defining transparent and objective market mechanisms to sell and buy gas for balancing purposes is a prerequisite for non-discriminatory procedures; these latter should allow market participants, including any new entrants, to access the market itself. Moreover, trading prices resulting from a transparent market mechanism send out appropriate economic indications to participants, as required for an efficient use of capacity and an improved management of portfolio strategies.

The new regulations paved the way to establishing a gas balancing platform (PB-GAS) used by SNAM to procure any resources necessary to make up for the overall network deviation. Within this system, SNAM acts as central counterparty in platform transactions whereas GME is in charge of organizing and managing the PB-GAS on behalf of SNAM itself.

The market consists of daily sessions. Each one refers to the gas-day before the session closing day and functions under the marginal price auction trading method. To guarantee a secure system, with SBSM the physical dispatching of the system from SNAM keeps revolving around storage. To this end, it is mandatorily established that all users who purchased rights over storage services (defined as eligible users) take part in this market. One exception is represented by users of the strategic storage service. To avoid management complexities and allow a better system monitoring, art. 13 of AEEG Decision ARG/gas 45/11 provided for the existence of a first stage until 31 March 2012. During this stage, bids/offers accepted in the balancing session and the deviation price would solely be based on bids/offers eligible to make up for the overall system deviation. After this initial period, there would be a combination of step-up and step-down orders submitted by authorized users in the same session and the order corresponding to the overall system imbalance presented by SNAM. In this manner, the deviation price better reflects the value of gas required for system balancing.

5. THE PAYMENT AND GUARANTEES SYSTEM

The system of payment and guarantees for the electricity and gas markets is based on first request bank guarantees, the amount of which must cover the net debt for each participant during the invoicing and payment cycle. Payments are respectively cleared on the fifteenth business day of the second month after the invoicing month, i.e. on the fifteenth business day of the months following the invoicing month.
In particular, as far as the electricity market is concerned, participants need to submit one or more financial guarantees to hedge their obligations in the energy market, i.e. in the PCE, in the form of first request bank guarantees, or cash non-interest bearing deposits. Guarantees must fulfill requirements set by the electricity market regulations. In case of bank guarantees, these must comply with the various forms attached to the electricity market regulation (art. 79)[21] and can be updated through an update letter compliant with such forms (art. 80).
Finally, with regard to the gas market, to submit adequate offers in the M-GAS, participants may submit, either jointly or severally, a first request bank guarantee fulfilling requirements described in the gas market Regulation, or a cash non-interest bearing deposit.

21 A participant submitting to GME a cumulative bank guarantee may allocate a portion of such guarantee to cover any payables that may arise in the various energy markets or on the PCE. Participants can exhibit to GME a declaration by their legal representative, or any other designated subject vested with such power, drafted in accordance with the form published in GME's website, reporting the amount of the bank guarantee that they wish to allocate to the various markets and/or to the PCE.

SECTION C

MARKET TRENDS

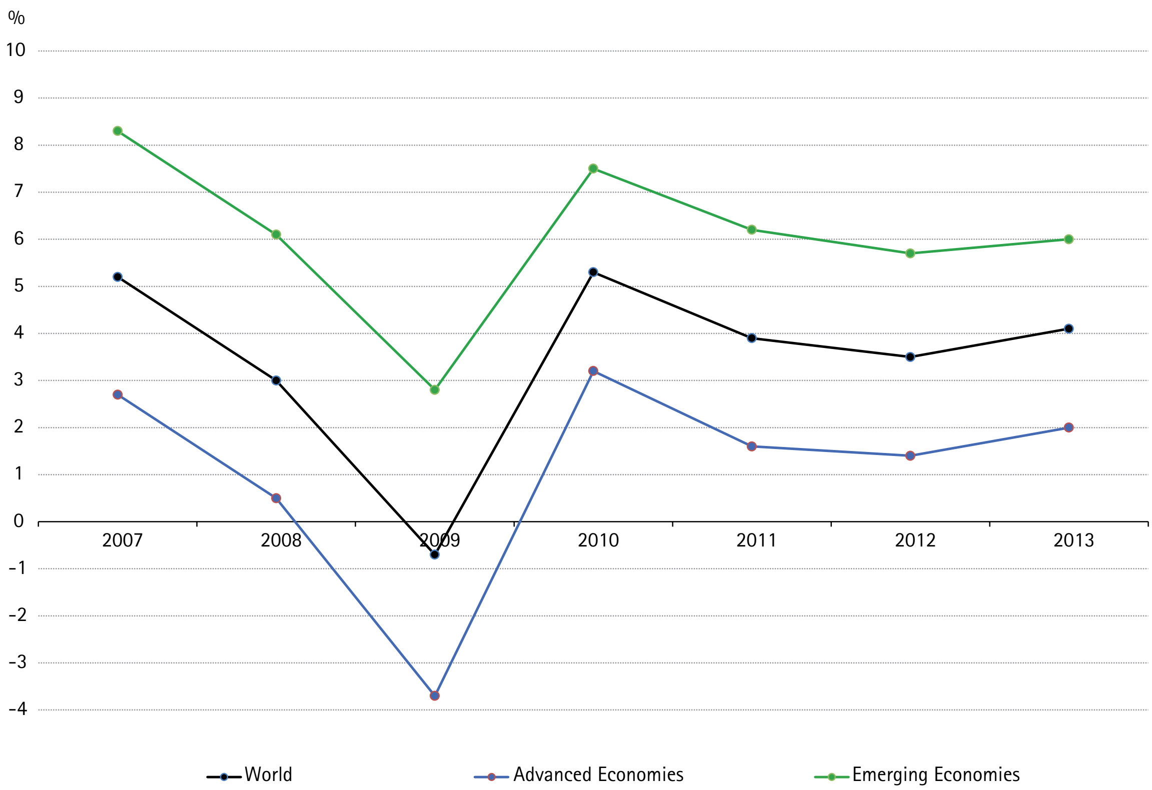
MARKET TRENDS

1. THE CONTEXT

1.1 International scenario

In 2011, the European market was influenced by the American economic crisis; however, such crisis has taken on some new, unique connotations in Europe. After the dire straits of 2008 – 2009, the United States seemed to react better to the economic challenges raised by the difficult financial situation of 2011. On the opposite, the European crisis seems to be inevitably destined to worsen in 2012. A comparison of these two macro-systems clearly shows that the initial crisis of bank indebtedness in the US has subsequently turned in a crisis of sovereign debt in Europe, with heavy effects across the Eurozone. This fast, profound shift dispelled every previous forecasts: while most expected a "V" shaped course of the crisis, such expectations proved to be too optimistic. In 2010, signs of recovery were seen particularly in the emerging economies. At the same time, the GDP fell dramatically in every country in the course of a two-stage, two-year period. At first, the economy gradually slowed down; later, it headed for stagnation with some European countries facing a full-fledged recession (Italy, Greece, Portugal and, in 2012, Spain, too) (Fig.C.1.1).

Fig C.1.1 **GDP growth trend**



Source: WEO 2011 IMF

However, even though the economic slowdown shows a number of common features across the most important world economies, its aggregate figure hides highly diversified regional and national situations (Tab.C.1.1).
For instance, newly industrialized countries (Brics[1]) responded better to the crisis. They simply contained their growth

1 Brazil, Russia, India, Cina and South Africa.

keeping an average development rate of approximately 6.2%. In this respect, Russia and the confederated countries (CIS) look quite unique: their GDP is at least stable or slightly growing, thanks to energy export revenues. Overall, thanks to Brazil, Russia, India, China and South Africa the global GDP growth, despite a remarkable drop, was around 3.9% in 2011.
In the United States, the GDP growth sharply fell from 3% to 1.7%, the highest decline among the advanced economies. In this country, therefore, employment increased less than expected and last year ended with a still high unemployment rate of approximately 8.5%. Nonetheless, the USA is showing encouraging, positive signals. According to estimates, in America the GDP will grow by 2.1% in 2012.

Percentage growth of GDP and other variables Tab C.1.1

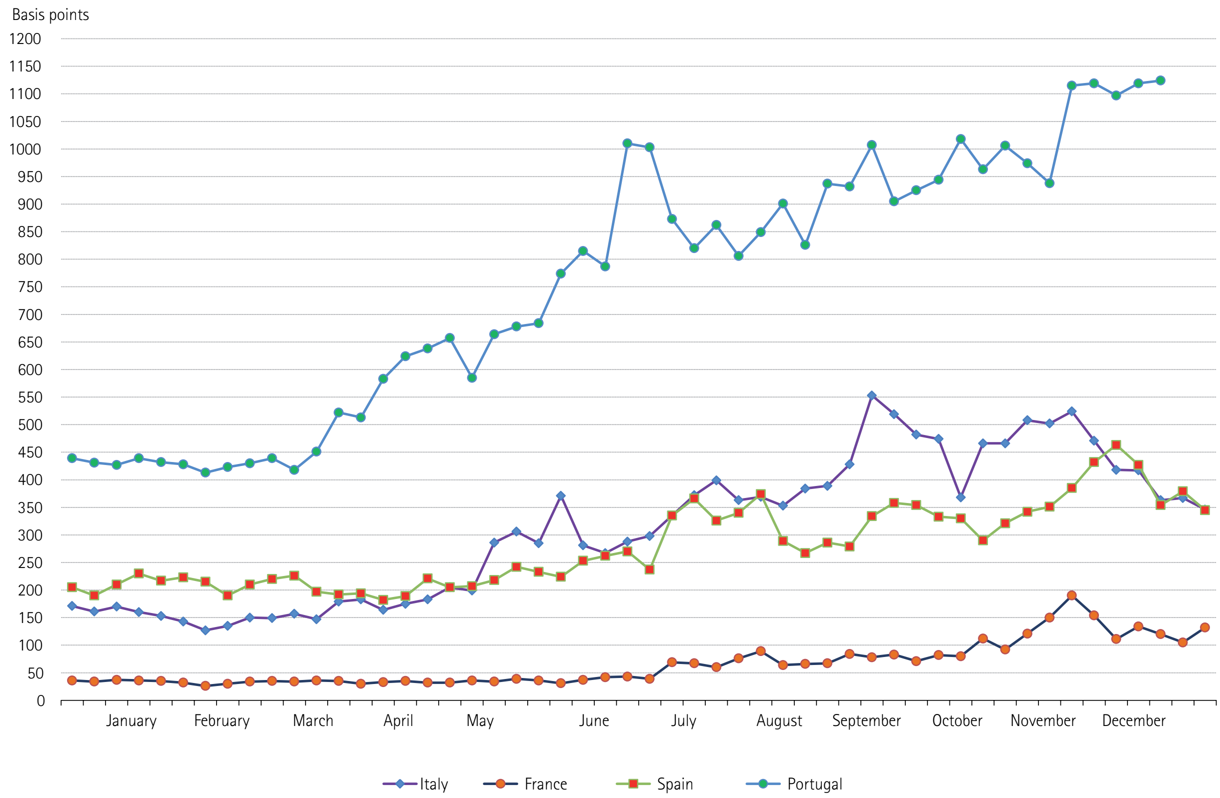
				Projections	
PIL	2000	2010	2011	2012	2013
World	4.7	5.3	3.9	3.5	4.1
Advanced economies	3.9	3.2	1.6	1.4	2.0
USA	3.4	3.0	1.7	2.1	2.4
European Union	3.4°	1.9°°	1.4°°°	-0.3	0.9
Italy	**2.9**	**1.8**	**0.4**	**-1.9**	**-0.3**
Germany	3.0	3.6	3.1	0.6	1.5
France	3.6	1.4	1.7	0.5	1.0
United Kingdom	3.0	2.1	0.7	0.8	2.0
Spain	2.8	-0.1	0.7	-1.8	0.1
Japan		4.4	-0.7	2.0	1.7
Emerging economies		7.5	6.2	5.7	6.0
Russia	8.3	4.3	4.3	4.0	3.9
China	8	10.4	9.2	8.2	8.8
India	6	10.6	7.2	6.9	7.3
Brazil	4.4	7.5	2.7	3.0	4.1
World trade volumes		12.9	5.8	4	5.6
Oil price**		27.9	31.6	10.3	-4.1
Inflation					
Adv. economies	2.3	1.5	2.7	1.9	1.7
Emer. economies	6.1	6.1	7.1	6.2	5.6

° EU-15; °°since 2005 EU-25; °°°since 2006 EU-27
**Simple average of Brent. WTI and Dubai prices equal to $ 104.01 in 2011

Source: IMF, World Economic Outlook, April 2011

The economic outlook is quite different in the Eurozone, the epicenter of an especially tense economic-financial situation in 2011. As far as the real economy is concerned, despite a Gdp growth rate declining less than elsewhere (0.5%), it remained weak (1.4%), with sharp differences and inhomogeneities across continental countries. In particular, Germany and France grew by 3.1% and 1.7%, respectively; Spain and United Kingdom had a growth rate below 1%, whereas other European countries were close to stagnation, like Italy (0.4%), or even exhibited a negative growth like Greece (-6.9%) and Portugal (-1.5%). At the same time, the huge public deficits, enormously inflated to face the first wave of the 2008 – 2009 financial crisis, turned into a target for financial speculation, giving rise to a widespread lack of confidence. Backed by the substantial liquidity injected into the system during the previous decade, the Government Securities yield spread in a number of countries increased disproportionately, turning into a real threat for the government debt of the most indebted countries (Fig. C.1.2). The first direct effect of this situation was a pronounced credit crunch, at once one of the causes and effects of a generalized liquidity crisis in the real economy. By way of exemplification, just consider the interbank market which hit a record figure worth 411 billion euro in ECB deposit accounts in 2011.

Fig C.1.2 **Weekly trend of 10-year government bond/Bund spread**



Source: Bloomberg 2012

Generally speaking, the Eurozone countries have reacted to the crisis by passing extremely tight public finance policies. These have been specially crucial in countries under the attack of speculators and are aimed at public debt consolidation with inevitably recessive short-term effects. This development, along with operators' bleak expectations and a halt to the investment cycle, may well account for the negative outcomes expected in 2012, with stagnation in France (0.5%) and Germany (0.6%), or a heavy recession in Spain (-1.8%) and Italy (-1.9%).

A closer look at Italy highlights how the year 2011 was characterized by a net decline of the Gdp growth rate, down from 1.8% in 2010 to 0.4%. This drop substantially led the Italian economy towards stagnation, with a progressive decrease in commodity and energy products consumption levels. The last quarter of 2011 ended at -2.9% whereas the first quarter of 2012 showed a worrying -0.8%[2]. The country is formally into recession; according to the Bank of Italy, recession is going to last over one year, provided that no additional negative factors take their toll, like, for instance, a deterioration of the Greek and Portuguese economies. In spite of its feeble reaction, with a slightly positive yearly average rate (+1.27%), the industrial manufacturing sector suffered a heavy slowdown in the last quarter of the year.

Given the long lasting nature of the crisis, with at least three years of extra outlays for the CIG[3] (Redundancy Fund) and for the overall welfare costs, borrowing has greatly intensified. While this approach has held society together, the average yearly deficit rose, due to the lack of Gdp growth in support of such public spending commitments. It became therefore paramount to pass new budget consolidation measures (government debt/ GDP ratio equal to 119.6%)[4] with a debt level which in absolute terms was worth 1897.9 billion last December.

2 Istat estimates (April 2012).
3 Cassa Integrazione Guadagni (Redundancy Fund).
4 Government estimate.

In addition, the average yearly inflation rate was up in 2011 (2.8% vs 1.5% in 2010). It has been the highest average yearly inflation rate since 2008 (+3.3%).
As a consequence, also due to the economic policy measures adopted at year-end, inflation turned from creeping into substantial, i.e. capable of affecting the final price of goods and services (e.g. 1% increase of VAT).
As far as the energy sector is concerned, the two most significant effects supporting the price dynamics are a rise in the prices of grid services (electricity, gas, water) and, most importantly, of energy products. Also, the price of fuel increased considerably in 2011: gasoline (+11.2%), car diesel fuel (25.2%) and heating oil (15.2%).
In summary, the current two-year period is characterized by a "stagflation"[5] due to low consumption levels and a rising inflation; on the other hand, there exists a risk posed by the so called "liquidity trap", i.e. a limited confidence in timely payments and in the credit institutions' propensity to hold cash, instead of starting a new investment process. Government measures, especially consolidation measures, may not translate into a progressive Gdp increase; such measures might well have repercussions on prices, triggering a second inflationary wave which could place an additional burden on both Import and Export operations.
Moreover, domestic growth negative projections have caused a widening of the spread – the differential between Italy's multiyear bonds (BTP) and the German bund, a benchmark across the Eurozone – and a simultaneous extreme volatility of an already very high average level.

1.1.1 Primary energy consumption levels

In 2011, primary energy consumption levels suffered from the widespread uncertainty caused by the economic crisis, given the close tie between economic trends and energy consumption, especially electricity consumption.
Moreover, a number of unique events occurred, bringing potentially significant consequences to the energy sector; among these, resurgent movements in the Mediterranean Islamic countries, with an ensuing gas procurement turbulence in southern Europe; the nuclear explosion at Fukushima in Japan, causing an increase in LNG demand from this country and repercussions on Asian gas markets as well as a reformulation of energy policy elsewhere. Already in 2011, after the Fukushima incident a number of Governments which, just a few months before the catastrophic incident had announced their plans to extend the life of nuclear power plants or erect new ones (Germany, Italy, Finland), suddenly changed their mind. Such attitude immediately created tensions in the European energy markets, due to a reduced availability of peak capacity. However, it is still too early to analyze the impact of those decisions. The German nuclear power generation is still available while the economic crisis actually limits the energy demand. Overcoming these two obstacles may give rise to an imbalance in the European demand-supply equilibrium. There could be consequences on electricity prices in Europe as well as on the renewable energy and gas demand; also, the ongoing transition from a traditional source- to a renewable source-based model may speed up considerably.
According to IEA forecasts, fossil fuels (oil, coal and gas) are bound to be the main energy source in the long run (2035); nonetheless, their weight within the reference mix is already and significantly changing. In particular, gas seems to be increasingly appreciated, thanks to the discovery of several unconventional gas fields and to its intrinsic versatility. These features make natural gas an ideal energy source for endless uses, including the "decommissioning" of nuclear power plants.
As a matter of fact, a comparison of primary energy sources between 2010 (the last year for which data are available) and 2000 shows that oil is still the most utilized fuel in absolute terms (4118 Mtoe), despite its

5 Not exactly the stagflation induced by the oil shock in the seventies, but kind of a variation with similar effects (increase in prices, low or zero Gdp growth); however, its constituents are quite different (extra costs for the system are due to the debt/ economic crisis and not to skyrocketing oil prices).

quite moderate growth rate (Tab C.1.2; +12%); its role grew significantly in BRICS and Africa while sharply dropping in industrial countries, where it is mostly used for transport purposes these days. In the last decade, the oil share out of total consumption levels declined by 5%.

As to coal, its growth rate would be quite limited without China and India. Both countries are heavy users of coal in pursuing their economic development, mainly because of the low cost of this energy source. These countries account for over half global consumption levels of coal, the second most widely used source during the decade. On a ten-year horizon, coal consumption rose by +54% on the year 2000, for a total value of approximately 2300 Mtoe.

On the other hand, the gas growth rate is equal to +33%; most likely, the economic development of the next decade is going to largely draw upon this energy source, in the transport sector as well, especially if the global supply of shale gas will rise to the point of keeping international prices at bay.

As for nuclear power, outlooks are uncertain. Broadly speaking, in 2011 European countries went for a "revision" policy, pursued quite differently in each individual country. On a global level, there has been a widespread consensus toward the decision to perform "stress tests" of the existing plant fleet. Most likely, in the near future countries like France, USA and China will adopt this approach. In these countries, nuclear power is generated in large amounts; hence, it makes sense to check the status of the existing power plants and perform a stress test prior to planning any future energy policy.

In spite of their still limited role, renewables are attracting a great deal of interest: in the last decade, their development was striking (+210%); their potential looks enormous everywhere in the world, to the only exception of the Middle East. However, renewable sources, at least during the current decade, are going to complement, rather than substitute, conventional sources.

Tab C.1.2 **Primary energy consumption (Mtoe)**

	2010 - VOLUMES (Mtoe)							'00-'10 % change						RES and total % change		
	Oil	Natural gas	Coal	Nuclear energy	Hydro	RES	Total	Oil	Natural gas	Coal	Nuclear energy	Hydro	RES	Δ% '09-'10	Δ% '09-'10	Δ% '00-'10
North America	906.6	642.6	534.2	242.2	141.7	42.4	**2,509.7**	-5%	3%	-5%	7%	-1%	116%	15%	3%	-1%
USA	814.6	564.5	510.5	218.6	58.8	39.1	**2,206.1**	-7%	3%	-4%	5%	-7%	121%	16%	3%	-2%
Japan	207.5	87.4	115.6	75.1	19.3	5.0	**509.9**	-19%	33%	19%	-11%	4%	19%	-7%	7%	-3%
EU-27	571.6	448.7	274.5	238.7	105.8	62.4	**1,701.8**	-8%	14%	-15%	-3%	6%	380%	12%	4%	0%
Middle East	323.2	310.4	8.6	0.0	3.0	0.1	**645.2**	45%	106%	7%	0%	67%	--	0%	5%	68%
Africa	158.2	88.2	107.6	3.3	23.2	1.1	**381.6**	48%	74%	19%	-3%	41%	83%	22%	4%	42%
BRICS	868.1	563.0	2.163.4	77.2	316.3	26.8	**4,014.8**	54%	51%	114%	61%	82%	406%	43%	8%	85%
Brazil	103.0	22.2	13.9	3.8	89.6	7.9	**240.3**	16%	185%	6%	140%	30%	216%	27%	9%	32%
Russia	149.8	388.2	102.8	44.2	38.1	0.1	**723.3**	19%	22%	-14%	30%	2%	0%	0%	9%	14%
India	163.3	59.7	303.8	6.7	25.2	5.0	**563.6**	45%	159%	90%	51%	45%	614%	9%	7%	77%
China	425.4	88.7	1.643.5	19.2	163.1	12.1	**2,352.1**	94%	327%	158%	341%	224%	1,728%	75%	8%	152%
World	4,118.4	2,752.5	3,531.6	717.6	775.6	158.6	**12,054.4**	12%	33%	54%	6%	29%	210%	15%	5%	29%
% individual source in the 2010 total	34.2%	22.8%	29.3%	6.0%	6.4%	1.3%	**100%**	-5.0%	0.7%	4.8%	-1.3%	0.0%	0.8%			

Source: Enerdata and Bp.

In this scenario, the incremental growth of domestic electricity consumption levels, one of the major growth engines for the economy, will play a crucial role (Tab C.1.3). Between 2000 and 2010, primary energy consumption grew by 27% whereas domestic electricity consumption rose by 41%. Moreover, primary energy consumption greatly increased in the Middle East, Africa and Brics; over the same period, consumption declined in Europe and North America, partly because of the economic crisis and partly thanks to an improved efficiency of national energy systems. However, domestic electricity consumption levels were positive everywhere, despite any differences between industrial and emerging countries. The development of electricity 'intensity' never slowed down during the decade, except for 2009, characterized by a decline followed by a quick recovery:

as early as during the first months of 2011, a new high consumption level[6] was reached. Additionally, this phenomenon is one of the most important factors with respect to the energy mix; amongst others, it explains why some primary sources (gas, renewables) grew more than others.

In particular, while in 2000-2010 the oil global consumption grew by 12% as driven by newly industrialized countries, using oil for electricity generation is less and less common everywhere, with a heavy aggregate negative figure (-13%). Conversely, while gas primary consumption increases by 33% globally, in terms of electricity generation it grows as much as by 57%, reaching significant levels in just every country. Finally, the aggregate consumption of coal grew by 54% and by just 47% when used for electricity generation, mostly because of its declining use in some regions (-11% in the UE-27 and -15% in Russia).

Domestic consumption of primary sources for electricity generation Tab C.1.3

	Domestic consumption of primary sources for electricity generation																Domestic electricity consumption				
	Oil				Gas				Coal and brown coal				Consumption of other sources for direct electricity generation*								
Mtoe																					
	2000	2009	2010	Δ% '00-'10	2000	2009	2010	Δ% '00-'10	2000	2009	2010	Δ% '00-'10	2000	2009	2010	Δ% '00-'10	2000	2009	2010	Δ% '00-'10	Δ% '00-'10
North America	32.7	13.8	13.5	-0.6	144.3	181.0	192.7	0.3	518.5	465.1	489.8	-0.1	287.9	310.9	312.0	0.1	352.0	363.6	377.2	0.0	0.1
USA	29.6	11.3	10.8	-0.6	136.9	172.7	183.9	0.3	492.0	445.8	469.8	-0.0	241.2	258.5	259.9	0.1	308.7	320.3	333.8	0.0	0.1
Japan	27.6	16.9	17.6	-0.4	46.9	53.8	55.5	0.2	47.5	57.6	59.5	0.3	94.3	82.3	84.3	-0.1	82.3	81.6	84.0	0.0	0.0
EU-27	41.1	24.8	22.2	-0.5	93.9	132.0	138.0	0.5	234.4	205.0	207.7	-0.1	284.6	280.7	290.1	0.0	225.9	242.5	251.8	0.0	0.1
Middle East	51.4	79.8	85.3	0.7	61.7	116.4	126.2	1.0	6.4	7.5	7.6	0.2	0.7	1.5	1.9	1.7	33.7	56.9	62.0	0.1	0.8
Africa	11.0	19.4	19.5	0.8	23.5	41.6	45.7	0.9	51.3	63.1	65.6	0.3	10.4	14.0	14.4	0.4	31.6	45.9	48.4	0.1	0.5
BRICS	38.0	25.1	23.7	-0.4	138.2	184.3	215.2	0.6	532.8	1,104.7	1,204.6	1.3	116.0	189.8	205.3	0.8	230.2	453.2	507.8	0.1	1.2
Brazil	3.9	3.3	2.7	-0.3	0.8	2.5	6.0	6.1	3.2	2.6	3.6	0.1	31.6	40.5	42.4	0.3	27.5	35.0	37.7	0.1	0.4
Russia	11.9	6.0	6.5	-0.5	126.8	147.3	168.5	0.3	65.2	58.2	55.4	-0.2	47.0	56.7	56.2	0.2	59.6	69.5	72.5	0.0	0.2
India	9.0	10.7	8.7	-0.0	9.3	23.2	25.7	1.8	118.0	201.4	208.1	0.8	11.1	16.5	19.4	0.7	29.6	54.1	61.9	0.1	1.1
China	13.1	5.1	5.8	-0.6	1.3	11.3	15.0	10.6	299.4	784.4	876.7	1.9	22.8	72.7	84.1	2.7	98.3	277.0	317.3	0.1	2.2
World	292.2	253.8	253.4	-0.1	642.6	923.0	1,008.5	0.6	1.519.9	2,103.3	2,240.9	0.5	947.1	1,068.4	1,103.0	0.2	1,127.4	1,483.4	1,584.9	0.1	0.4

*excluding solar and biomass

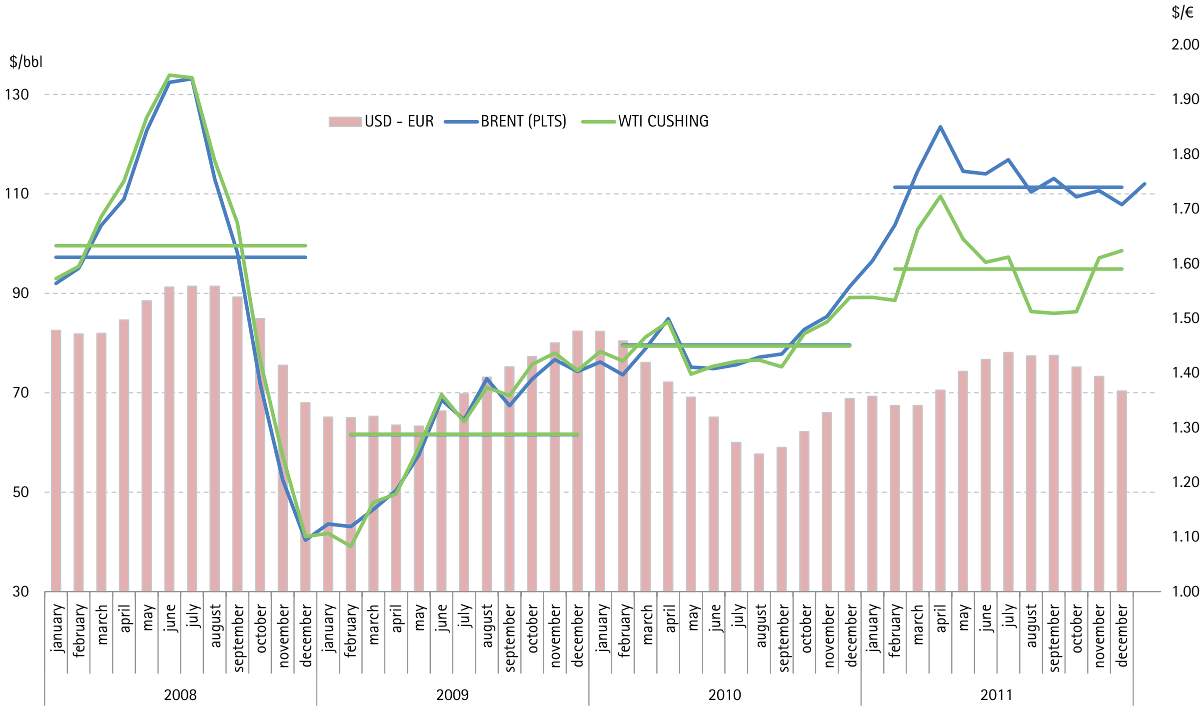
Source: Enerdata - Global Energy & CO2 Data

6 Electricity self-consumption included

1.1.2 The oil market

In 2011, Brent dated rates showed a yearly average increase up to approximately 111.32 $/bbl; throughout the year, except for January, the oil price constantly exceeded 100$/bbl.

Fig C.1.3 **Monthly Brent prices (Platts) $/bbl**



Source: Thomson Reuters data

In 2011, the oil price fluctuated only weakly, within a +/– 10% range between a minimum of 96.43 and a maximum of 126.64 $/bbl. It should be noted that in 2010 the average price was around 79.60 $/bbl; in 2009, a difficult year for the world economy, it was remarkably cheaper at a price of 61.58 $/bbl. (Fig C.1.3).

Such a rise is due to the peculiar €/$ exchange rate correlation, more pronounced in recent years, as well as to oil costs, most notably at WTI level. On average, the dollar was weaker than the euro – in 2011, the European currency on average was worth 30% more: naturally, it is in the interest of oil producing countries to keep the price per barrel on medium-high levels, so as to preserve its real value, given that oil prices are conventionally expressed in dollars.

Financial speculation played a major role: despite the disappointing performance of the Western economies, it keeps seeking new investment opportunities, after the large liquidity injected into the system in the 2000s; from time to time, speculators focus on commodities, private debt, public debt, always keeping the oil price at high levels. In 2008, oil price peaks could be easily explained by the potential supply bottlenecks, during years of low investment; however, the general picture was quite different in 2011, with a low demand and a partial revamping of investment. Within this framework, it is worth recalling the sudden and fast rise in prices after the geopolitical tensions in the strait of Hormuz, crossed by one third of world oil. In the aftermath of that episode, the EU and the USA declared an embargo against Iran.

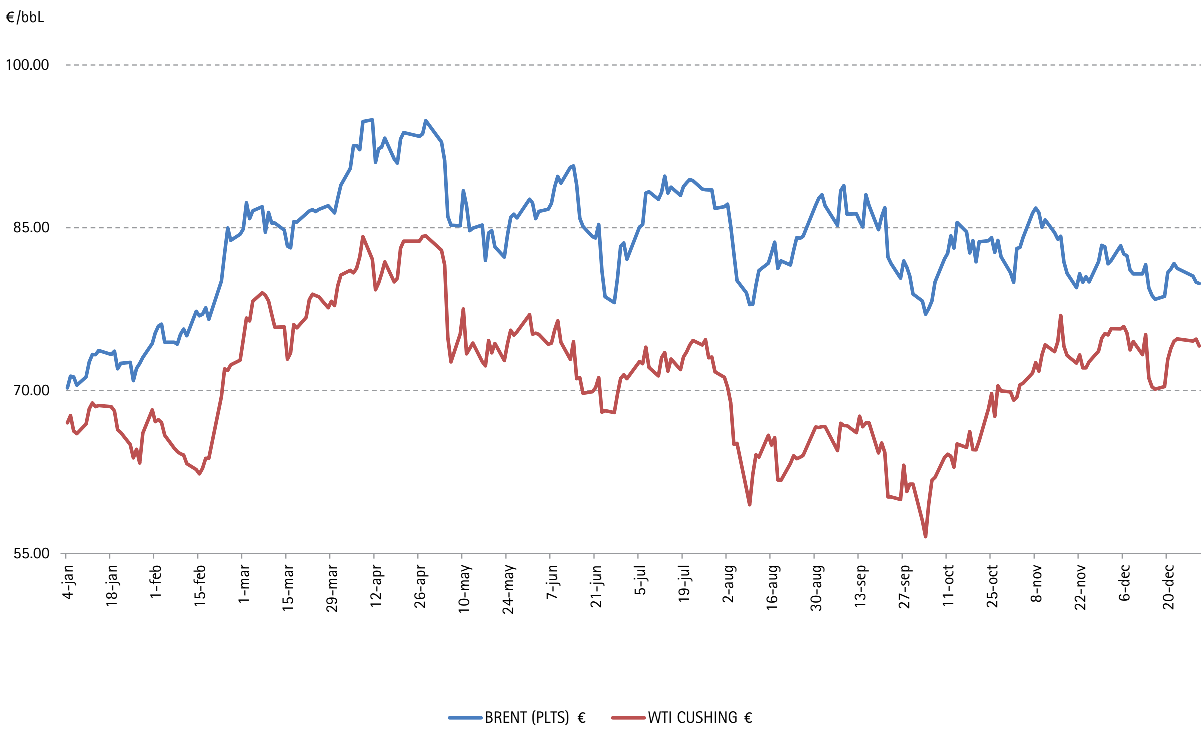
Special mention should be made of the evolution of the two Asian giants (China and India); altogether, their average growth rate (8.2%) looks even more stunning, being achieved in a time of crisis. A sufficient spare capacity[7] prevented to reach the record prices hit in the summer of 2008, with a reassuring level of 5.2 million barrel a day at the beginning of 2011. This market system managed to limit the average volatility of oil prices while meeting any sudden demand peak, as it happened in the aftermath of the catastrophic explosion in the Fukushima nuclear power plant. Quite logically, the

7 The spare quota set aside by OPEC to face emergencies; more specifically, price spikes due to a demand-supply imbalance, whatever its root cause.

spare capacity sharply declined by about one million barrels. On a longer term horizon, this negative effect will turn into a price increase. In 2012, prices are estimated to be 20% higher, on average[8]. After-markets, i.e. adjacent markets (other hydrocarbons and refined oil products at large) seem to pay the dearest price. The same applies to instrumental markets, first and foremost the transport industry. Any inevitable price increase in other end sectors will presumably slow down any attempt of economic recovery.

Finally, one should highlight a pronounced difference between the Brent and WTI trend patterns. As a matter of fact, the American crude oil price is less expensive than the Brent's, with a price gap much bigger than in the past. Historically, it is not a new phenomenon: still, in the last five years the spread between these two types of crude oil has amounted to approximately 5 $, with a few peaks around 10 $. Last year, the difference was substantial (up to 22 $ in summer) and persistent (every month of the year). Such distortion is due to macro factors, like the European financial crisis which along with the paucity of sweet crude oil in the old Continent, causes the WTI price to increase even more, as well as to more contingent phenomena like "the Cushing's bottleneck"[9]: with an opposite movement, WTI quotes were pushed down. Noteworthy, in early 2012 the gap between these two commodities narrowed down to more customary levels, around 15$ (Fig C.1.4).

WTI/Brent comparison. Weekly prices Fig C.1.4



Source: Thomson Reuters data

8 Source: IMF forecasts.
9 Town in Oklahoma where WTI travelling through the Seaway pipeline is delivered.

1.1.3 The coal market

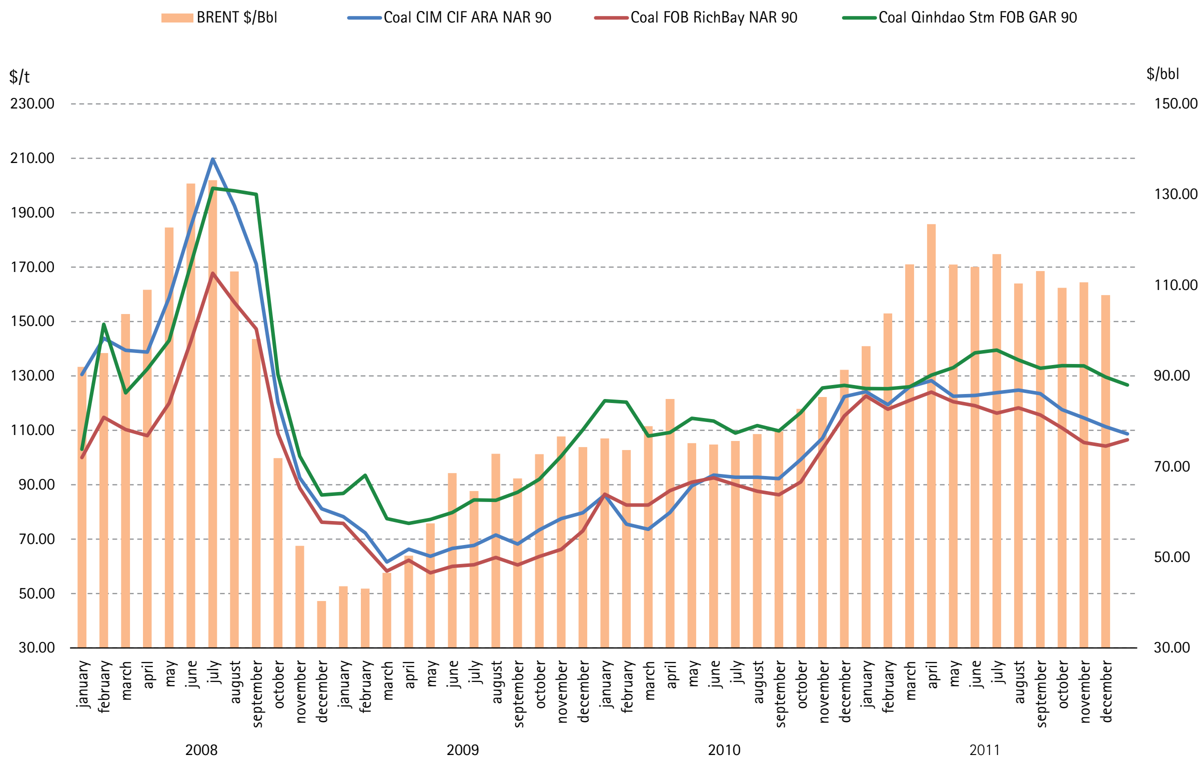
An analysis of international price levels in the last couple of years does confirm the strong relationship between coal and oil prices. Despite the decreasing use of oil in end products, it keeps being a reference price for every other energy commodity. However, differently from petroleum derivatives or other oil-indexed related products like gas, coal prices are increasingly linked to the demand and supply drivers, both globally and in the various macro-regional markets. The trend shown by the main coal quotes reflected the Brent dynamics, both during the 2011 recovery (+14-32% for coal, +40% for Brent) and in the last four years. Yet, the degree of such recovery is in the first case much lower than in the latter; coal prices are 3-17% less than in 2008 and, in the case of oil, 15% higher. Even the monthly movements look remarkably different for coal and oil, respectively (Tab C.1.4, Fig C.1.5).

Tab C.1.4 **International coal market prices**

	Yearly average			
	2008	2009	2010	2011
Coal CIM CIF ARA NAR 90 ($/t)	146.96	70.55	92.06	121.55
Coal FOB RichBay NAR 90 ($/t)	120.13	64.01	91.34	116.30
Coal Qinhdao Stm FOB GAR 90 ($/t)	144.45	87.43	115.43	131.96
Brent ($/bbl)	96.99	61.51	79.47	111.27

Source: Thomson Reuters

Fig C.1.5 **Monthly international coal market prices ($/t)**



Source: Thomson Reuters data processing

On one hand, this different trend can be explained by the specific dynamics of the coal market: driven by China and India, despite a growth trend over twice as big as every other energy commodity, this market suffers more heavily the effects of speculation and exchange rates.

On the other hand, the coal market is more segmented than other fossil fuels, due to the high cost of transport from extraction to consumption sites, with local dynamics affecting the price-setting process more than the gas or oil market.

In recent years, the usual commercial flow of coal towards traditional geographical macro-areas has changed with the different growth speed of each region. For example, substantial shares of South African products (a historical reference commodity for the European market) are by now exported to China and other Oriental countries (+2.5 M/t[10] in 2011). Coincidentally, at Richards Bay port – South Africa, prices rose by 26%, from an average 91 $/t in 2010 to 116 $/t in 2011. In Qinhdao, this phenomenon speaks for itself: prices are clearly on the rise (+14.3%), showing a clear recovery after the 2009 collapse, with an average of 132$ in 2011.

This year, the pre-crisis level will most likely be achieved and even exceeded. A similar price dynamics can be accounted for by the impressive size and liveliness of the South Eastern Asian market. Indeed, already in 2011 China imported 182 M/t of coal, with a 20% import growth on 2010 and a consumption level of 3.7 billion tons, mostly met by the domestic production (3.52 billion tons). China alone represents about 50% of world consumption; despite a modest share of its procurement on the international market (5.1%), China heavily affects the eastern market which consequently pays the highest prices. In India, too, import was relentless and grew by 28%, with approximately 115 M/t imported in 2011: the third leading world consumer – after the United States – and the third largest importer – after the EU – in spite of its 10% share of the overall world spare capacity.

On the Atlantic shore, the market picture looks more mature with a much slower growth rate. At the port of Rotterdam, price levels were moderately dynamic (CIM CIF ARA: +8%), with a yearly mean value slightly above 120 $/t, quite better than a year before (92.5 $/t). However, pre-crisis prices are still a distant memory (147.5 $/t) and most likely will not be equaled until 2013. The rise in prices is largely due to the demand level in the two main European importers, Germany and Great Britain. In this latter country, the share of imported steam coal was up by 30%. Overall, import levels across the EU-27 are slightly increasing at around 190 M/t, with consumption patterns quite in line with 2010 (738.2 M/t).

On its side, the United States, a key player in the Atlantic region, tends to pursue a commercial policy less geared toward its domestic market. In 2011, production amounted to 1080 M/t, quite stable relative to the previous year, with a slight decline in domestic consumption (-4.5%) at approximately 910 M/t. This surplus allowed the United States to consider foreign market exports (+48% for exported steam coal), capitalizing on the growing price of coal in the different world markets.

The general trend observed in the last year may precede, also by virtue of a substantial international spare capacity, a future uncoupling of coal prices from oil, at least in the Asian market. Until now, it was oil to set the price level, with the local demand indicating the share of such level; in the future, a reversal of this trend is anticipated. China and India, accounting for less than 65% of the global demand in 2011, will de facto establish a near-monopsony affecting coal prices regardless of oil quotes. In this respect, the recent International Energy Agency (IEA) report - *Coal Medium-Term Market Report 2011* – emphasizes that «…any event or decision made in China in the next five years may have a disproportionate effect on coal and therefore on electricity prices, too. To understand why, just consider that the Chinese domestic market is three times as big as the international trade of coal».

10 Million tons.

1.1.4 The gas market

Natural gas presently covers about one fourth of world consumption of primary energy versus less than 35% for oil and less than one third for coal. However, while oil reached a peak in 1975 followed by an inexorable decline and coal is stable at around 30%, natural gas is expected to be widely used for at least twenty years.[11] Generally speaking, the world gas trade tends to follow regional trading patterns. The world market is split into three large trading areas: North America, where the production of shale gas has been skyrocketing in the last two years; the Euro-Mediterranean area, leading world market in terms of consumption; the Far East, notably Japan, mostly focused on LNG. Such principal macro-areas and their sub-markets mutually influence each other, especially in the LNG segment whose mode of transport promotes interconnection across different areas. Still, the pricing process is mostly or entirely based on local phenomena and on the unique features of each individual market.

Europe is the largest world gas market with over 538 billion cubic meters (2010). No gas is produced in Europe, with the only, albeit significant, exception of gas fields in the North Sea, mostly serving United Kingdom, Netherlands and Norway. It follows that the market has been growing through imports travelling across trans-European pipelines originating in Russia and North Africa, where take or pay (TOP)[12] contracts are the rule. Being the market so unbalanced, trading is more profitable for sellers who have tied up take or pay gas contracts to oil prices.

The recent creation of a network of gasification plants in some areas and an excess supply, resulting from the economic crisis and the growth of American shale gas, did allow the emergence of spot markets and more liquid hubs in non-producing countries; over time, gas should gradually uncouple from oil, with a shift of power from non European to European suppliers and consumers. Such phenomenon is being exacerbated by the majestic development of renewable sources all over Europe, partly downsizing gas consumption.

The interplay of these two factors explains why, in 2011, gas prices increased so much in the wake of oil prices, despite a demand level quite stable or slightly lower than the previous year. Likewise, the variable liquidity of hubs and the subsequent possible gas-oil decoupling help us understand the varying increase of prices from one country to another. At Zeebrugge, the reference hub for the Euro-Atlantic area, gas price rose by 31.4%; at the Baumgarten hub, prices were up 15.30%. This pattern was observed at every other continental Exchange-hub (Tab C.1.5).

Tab C.1.5 **Gas prices at the main European and American hubs (€/MWh)**

		Yearly average			
		2011	2010	2009	2008
American market	WTI CUSHING $/bbl	95.23	79.57	65.98	99.57
	Henry Hub $/MWh	10.03	11.68	9.35	20.48
European market	Zeebrugge €/MWh	22.50	17.97	10.61	25.26
	PSV €/MWh	28.30	23.67	16.47	29.05
	CEGH €/MWh	22.90	19.86	n.a.	n.a.
	TTF €/MWh	22.63	18.26	10.88	24.94
	NBP €/MWh	22.20	15.57	23.85	24.96

Source: Thomson-Reuters data processing

Even during the 2011-2012 winter season, the core and evident issue was the inadequacy of infrastructure, i.e. storage and gasification plants, vis-à-vis variations in climate, thermoelectric consumption or other causes changing the load profile. This is why the inauguration of the North Stream was considered to be so important,

11 IEA Special report: *"Are we entering a golden age of gas?"*.

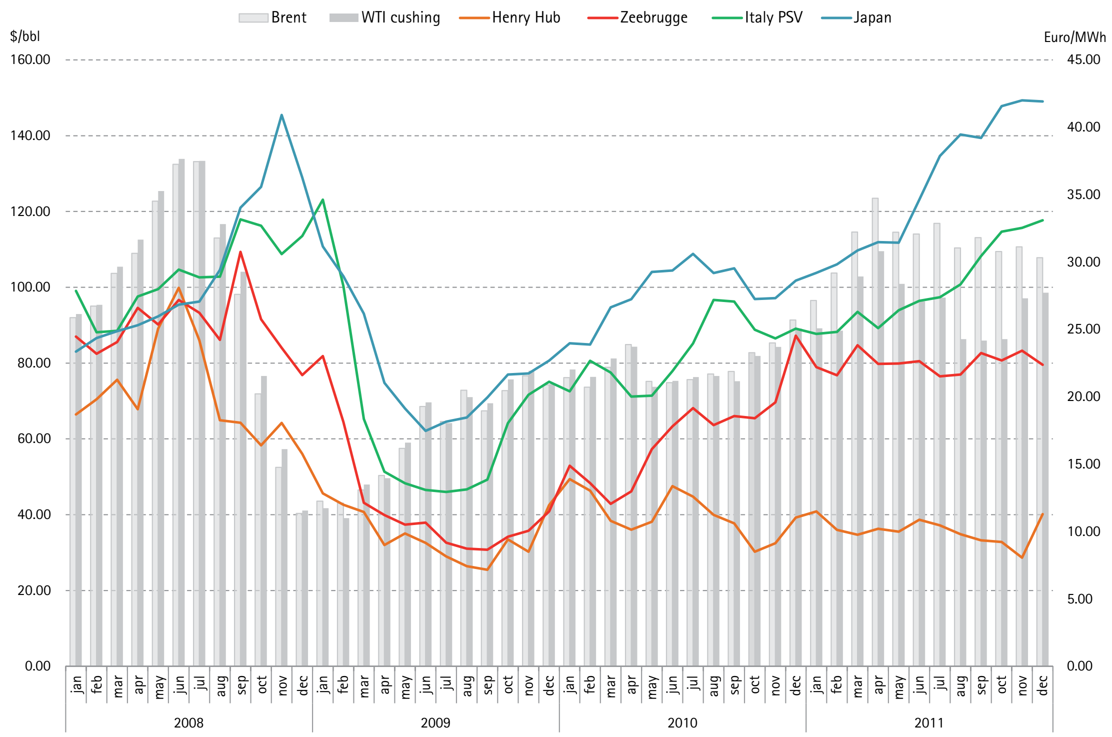
12 For a specific discussion, see the recent paper "Putting Price on Energy: International Pricing Mechanisms for Oil and Gas", Energy Charter Secretariat's 2007.

in November 2011. This gas pipeline crosses the Baltic Sea establishing a direct connection between Russia and Germany and, through this latter, the whole of Northern Europe up to the United Kingdom. This and other infrastructure allow Northern European wholesalers to try a gas-oil decoupling, paving the way to new trading patterns in the next decade.

In the United States, the second largest world market, 2011 was a year of light and shades. On one hand, an increase in shale gas production (around 4%), despite a declining demand (-5.7%); on the other, conventional gas markedly dropped, with a one third decrease of production. While this development was predictable, given the record size of inventories (+6.9 % last year and nearly 12% more than the average level for the last five years), the demand reduction was due to an exceptionally mild Fall both in the United States and in Europe, a significant market for American gas. A persistent minimum price is seriously questioning whether or not shale gas operations should continue: a clearing price of about 5 $ represents the minimum requirement to obtain a ROI of at least 10%. In 2011, spot prices at the Henry Hub (HH) on average amounted to 10 $/MW (versus a mean figure of 11.68 $/MW in 2010), reflecting a demand decrease with a slight, although persistent declining trend (Fig C.1.6). In 2012, a further price drop is anticipated.

In the United States, unlike Europe, the availability of a large domestic supply may explain the oil-gas price decoupling; furthermore, trading is performed centrally through gas exchanges and hubs rather than long-term import contracts. A comparison of the Henry Hub and WTI prices is quite telling. Until the end of 2008, they were quite aligned: then, price trajectories changed direction starting from the end of March 2009: WTI prices began rising up to 109.4 $/bbl in April 2011 (+37.7% relative to the average price of 2010, equal to 79.4 $/bbl) whereas the gas price, after a physiological recovery in the winter of 2009/2010, went through ups and downs: in the end, it decreased by 6% in 2011 after a more significant drop during the previous year (-11%). Therefore, gas seems to follow a trend based on its own extraction and distribution supply chain, without being directly or heavily affected by oil costs. This equally explains a new, significant price gap between the two shores of the Atlantic, presumably due to a high degree of regionalization in European markets and to the lack of a true gas single market, well interconnected and provided with a fair degree of liquidity.

Monthly gas prices at the main hubs (€/MWh) Fig C.1.6



Source: processing of Thomson-Reuters data

Finally, Japan represents a unique example out of Asian markets: with its 287 gasification plants, it is the leading LNG buyer worldwide (about 35% of the global market) with supplies mostly coming from Malaysia; after the tragic events of Fukushima, Japan suddenly focused its energy policy on the import expansion. In 2011, import levels suddenly rose to 78 million tons of LNG, with a price and consumption increase of over 20% throughout the year. At the beginning of the year, it achieved a price of 29.18 €/MW, more than twice as much as the gas futures price traded in the *Henry Hub*[13]; at year end, it reached 42 €/MW, that is slightly less than twice as much as Zeebrugge and nearly a third more than Italian prices (PSV). Such figures can be explained by the fact that as of 9 December 2011 a whopping 33 reactors were standing by on scheduled maintenance; in the Spring of 2012, all nuclear plants will stop operating. In 2010, they covered 25% of household consumption. Carbon dioxide emissions into the atmosphere are equally increasing: in November 2011, for instance, Japan emitted 3.8% more CO2 relative to the same month of 2010.
Finally, one year after the tsunami, agreements are being finalized with South Korea, too. Their goal is to expand storage sites-gasification plants, especially in collaboration with the Russian Gazprom. In the years to come, large quantities of gas, originally bound to Europe, will detour towards Asia; first, they will reach Japan and later, in the medium-term, China and India, too.

1.1.5 The environmental policy

With the beginning of this decade, the environmental issue has been growing in importance, also due to the upcoming deadlines to comply with international climate change measures (Kyoto, 20-20-20 targets).
The World Meteorological Organization announced that, in 2011, the global mean temperature has been the tenth highest in history and the Arctic pack the second smallest surface with the lowest volume ever.
Another serious alarm was sent off by IPCC (Intergovernmental Panel on Climate Change)[14] with respect to a series of extreme natural phenomena. Unless the current trend is reverted, such events may no longer be considered an exception, with serious repercussions on crops and urban settlements (like the Katrina typhoon in New Orleans), or, to a lesser extent, on network systems, from electricity to telephone lines. This danger is even worse in Third World countries, whose economies are largely based on agriculture and, more often than not, on just one or few top crops. In that context, damage could be enormous, since it would affect the main income-generating activity of those countries.
In the awareness that the economic crisis would place environmental needs in the background, priority being given to employment and economic revamping policies, the latest IPCC Conference held in Durban (Cop17, United Nations Framework Convention on Climate Change), South Africa, raised limited hope. Climate change talks are extremely complex and articulate; also, they clash against the very nature of political mandates, since any climate policy is by definition a long term, extremely costly policy.
However, Durban represents a milestone: this year, the Kyoto Protocol (11 December 1997 - Cop3) will come to an end. Despite its deficiencies and inadequacies, it does remain the most important international agreement to reduce climate change inducing gases as well as a starting point for the climate policies of the new decade.

13 Source: Bloomberg and Thomson Reuters.
14 Intergovernmental group of experts on climate change: this scientific forum was set up in 1988 by two United Nations agencies, the World Meteorological Organization (WMO) and the United Nations Environmental Program (UNEP), to address global warming.

Tab C.1.6

Kyoto Protocol allocations: greenhouse gas emission reductions (Annex I countries)

EU-15	-8%		
Austria	-13%	Iceland	10%
Belgium	-7%	Ireland	1%
Denmark	-21%	Poland, Hungary	-6%
Finland, France	0%	Croatia	-5%
France	0%	Bulgaria, Estonia	-8%
Germany	-21%		
Greece	25%	Russian Federation	0%
Ireland	13%	Ukraine	0%
Italy	-6.5%		
Luxembourg	-28%	Japan	-6%
Netherlands	-6%		
Portugal	27%	USA	7%
United Kingdom	-12%	Canada	-6%
Spain	15%	Australia	8%
Sweden	4%	New Zealand	0%

The last minute acceptance of a general, legally binding agreement related to the new Kyoto-extending agreements already in place, should be seen positively. Emission producing countries - United States, China and India – did accept the agreement, although Japan, Russia and Canada declared they do not wish to accept such extension. Japan's refusal is easily justifiable, after the catastrophe of Fukushima; as to the Nordic giants, one possible explanation for their position is the potential exploitation of hydrocarbons, especially shale gas, in the Arctic region. In addition, the global CO2 market, despite the economic crisis, is worth 10% more than in 2010, with a 22% (8.2 billion tons) increase in volumes through allowance trading. A significant figure, even more so in the light of the clear-cut price drop of CO2, down from 12.4 €/Ton in 2010 to 11.2 €/Ton in 2011 (-9.6%)[15].

In Europe, the crisis of the last three years mitigated pollutant gas atmospheric emissions; indirectly, it helped Europe as well as Italy to more easily reach the objectives set by Directive 2009/28/EC (20-20-20 Package). However, it is just a coincidental result: a sign of the intensity and extension of the crisis, rather than the success of jointly agreed policies. Hence, such reduction cannot be considered as a true solution to the structural issues that still exist.

At any rate, at the end of 2010, as noted by the EU Commission report, "Review of progress made within the framework of the Kyoto Protocol and the objectives set for 2010" by the European Environment Agency (EEA), the EU-15 was well off to accomplish Kyoto goals, with an overall 15.5% cut of emissions since 1990.

In the last twelve months, the environmental issue, while still important, has attracted less attention than the economic crisis and unemployment, in Italy. Our country is still committed to its manufacturing base: the

15 Source: Bloomberg.

long manufacturing crisis of the last decade, with the closing down of major industrial plants, has eventually placed the environmental issue in the background. According to the European Environment Agency estimates, Italy, along with Austria and Luxembourg, will hardly comply with CO2 reduction targets set for 2008-2012. To this end, a reassuring, further hypothetical reduction of 10.9 Mton (RIE) vis-à-vis the European Agency's projections, if confirmed, would bring Italian emissions in line with Kyoto commitments (-6.5% relative to emission levels in 1990) (Tab C.1.7).

Tab C.1.7 **Estimated emissions from combustion of fossil sources in Italy in 2011**

SECTOR	2011	2010	2011 – 2010 Change	
	Mt	Mt	Mt	%
Electricity	91	96.3	-5.2	-5.40%
Refining	25.4	25.9	-0.5	-2.00%
Industry	65.9	65.5	0.3	0.50%
Transport	116	117.4	-1.4	-1.20%
Residential	74.8	82	-7.2	-8.80%
Other	17.8	15.8	1.9	12.10%
TOTAL	390.9	403	-12.1	-3.00%

Source: RIE (EEA SNAM, MSE data)

1.2 The Italian energy sector

1.2.1 The National Energy Balance

In Italy, the 2011 economic crisis, after a five-year stagnation, had a direct impact on the energy sector. In 2011, the Gross Domestic Consumption (GDC) and end usage fell down to approximately to 183.891 Mtoe (-2%) and 134.5 Mtoe (-3%), respectively (Tab C.1.8, Tab C.1.9).

This figure is particularly negative if the decade is considered globally; a drastic GDC drop in the last five years (-6.26%) cancelled the expansion of the previous five-year period. The present level shows a tiny 1% difference from 2000. The same applies to final consumption, with a note of special concern for final industrial consumption levels which dropped by nearly 21% in the last ten years; of this, only 7% is accounted for by an improved efficiency. Hence, the remaining decline seems to be due a volume shrinking[16].

In this scenario, it is clear the electricity sector may drive either a growth or drop of consumption in the various energy sources.

National energy balance (2000, 2010 and 2011) Tab C.1.8

	Gross Domestic Consumption[1]			*Conversion into Electricity*			*Total End Uses[2]*			*Share of the Source in Total Gross Domestic Consumption*			*Δ of 2011 Gross Domestic Consumption by item and total vs. specified years*		
Mtoe	2000	2010	2011	2000	2010	2011	2000	2010	2011	2000	2010	2011	2000	2009	2010
Solid fuels	12.882	14.946	15.927	-7.232	-10.679	-11.864	4.227	3.969	3.75	6.93%	8%	9%	23.64%	21.68%	6.56%
Natural gas[3]	58.365	68.056	63.814	-18.826	-24.618	-22.895	38.876	41.991	39.509	31.40%	36.20%	35%	9.34%	-0.14%	-6.23%
Oil products	91.989	72.216	69.666	-19.426	-4.030	-3.647	66.800	62.078	60.198	49.48%	38.40%	38%	-24.27%	-4.95%	-3.53%
RES[4]	12.904	22.852	24.447	-11.316	-18.041	-19.313	1.522	4.805	5.127	6.94%	12.20%	13%	89.45%	21.23%	6.98%
Electricity	9.757	9.715	10.038	56.800	57.368	57.719	23.469	25.741	25.911	5.2%	5.10%	5%	2.88%	1.49%	3.32%
Total	*185.897*	*187.785*	*183.891*	-	-	-	*134.809*	*138.584*	134.494	*100.0%*	100%	*100%*	-1.08%	*1.97%*	*-2.07%*

[1] Defined as the amount of energy produced at national level, plus imports, net of exports and changes in stocks.
[2] Including consumption/losses in the energy sector
[3] From 2008 on, evaluated with a lower calorific value (LCV) of 8.190 kcal/m3 instead of 8.250 kcal/m3 for consistency with international statistics.
[4] Net of pumped storage.

Source: Bilancio energetico nazionale (2008, 2009, 2010), MSE

This is quite striking in the case of oil products. In 2011, their consumption dropped (-3.5%), in line with the drastic reduction of the last ten years (-24%), after the gradual, steady dismissal of fuel oil in thermoelectric generation and the transformation of plants into gas combined cycles promoted by the liberalization in the 2000s. In GDC terms, oil still holds a major share (+38%), largely due to the transport sector and, to some extent, to the industrial sector.

The growth of solid fuels, with a rise of GDC both on 2010 (+6.5%) and 2000 (+23.6%), is basically driven by the thermoelectric sector; conversely, end use consumption decreased considerably both on the previous year (-5.5%) and on 2000 (-11.3%).

This development affects natural gas, too. During the 2000s, natural gas was widely used in the thermoelectric sector as the leading source of electricity generation. However, the increase in consumption during the last decade was more limited, up from 31.4% to 35% of GDC; most notably, back in 2000 gas was commonly employed in the residential and industrial sectors.

Last year's GDC decline (-6%), in this specific case, is largely due to the renewables' expansion and to the simultaneous demand stagnation in the electricity market.

16 This estimate results from figures published in the 2010 Enea Report on Energy Efficiency, showing an improved energy efficiency in the industry of 0.7% (yearly average) in the 1990-2009 period.

One further example of how the electricity sector influences the national energy mix is represented by renewable sources; in the last decade, the high growth rate of renewables (+89.5%) was also due to an absolutely low starting level. In 2011, however, such growth rate kept being extremely positive (+6.7%). In 2010 alone, the development of renewables reached 7 GW of installed capacity at year-end.

Tab C.1.9 **Energy and uses by source and sector (Mtoe)**

	2011									
	Industry	Transport	Residential	Agriculture	Non-energy uses	Bunkers	Total	% of each source in total	Δ % of yearly total vs. 2010	Δ% of '00 -'11 total
Solid fuels	3.658	-	0.004	-	0.088	-	**3.750**	**2.8%**	-5.5%	-11.28%
Natural gas	12.668	0.717	25.504	0.143	0.477	-	**39.509**	**29.4%**	-5.9%	1.63%
Oil products	4.709	39.332	3.667	2.222	6.852	3.416	**60.198**	**44.8%**	-3.0%	-9.88%
RES1	0.228	1.296	3.458	0.145	-	-	**5.127**	**3.8%**	6.7%	236.86%
Electricity	10.565	0.91	13.954	0.482	-	-	**25.911**	**19.3%**	0.7%	10.41%
Total end uses	**31.828**	**42.255**	**46.586**	**2.992**	**7.417**	**3.416**	**134.494**	**100%**	-3.0%	-0.23%
% of each source in total	**23.7%**	**31.4%**	**34.6%**	**2.2%**	**5.5%**	**2.5%**	**100.0%**			
Δ% of yearly total vs. 2010	**-1.0%**	**-0.4%**	**-5.2%**	**-1.4%**	**-11.6%**	**-1.5%**	**-3.0%**			
Δ% of '00 - '11 total	**-20.78%**	**1.80%**	**17.35%**	**-7.25%**	**-1.11%**	**26.52%**	**-0.23%**			

Source: MSE

The resulting picture, when compared with Europe according to the latest homogeneous available data for 2010, does confirm the traditional "diversity" of the Italian energy mix relative to the pattern prevailing in the rest of the Continent. On one hand, the complete lack of nuclear energy (which on average accounts for 14% of the energy requirement in Europe, with a high 40% level in France); a very low weight of coal, one of the lowest in Europe (7% against a Community average figure of 16%); a still high weight of oil (41% against a EU average of 34%), despite a 17% decline in the last ten years; on the other hand, a higher than the European average rate for gas (39% vs 26%), second only to the United Kingdom, a producing country. Quite remarkable is the share of renewables (7%): nearly twice as much as the Community average, on the same level as Germany, with Spain taking the leading position, followed by Italy.

Tab C.1.10 **Primary energy consumption in some European countries (2010)**

	2010 - % of each source in total by country							00 - '10 % change						
	Oil	Gas	Coal	Nuclear	Hydro	RES	TOT (Mtoe)	Oil	Gas	Coal	Nuclear	Hydro	RES	TOT
EU	33.6%	26.4%	16.1%	14.0%	6.2%	3.7%	1701.75	-8.1%	14.0%	-15.1%	-3.1%	6.0%	380.3%	0.2%
Italy	41.0%	38.6%	7.4%	0.0%	6.4%	6.6%	176.10	-17.0%	17.4%	6.1%	0.0%	12.0%	625.0%	4.3%
France	30.1%	16.2%	4.5%	42.5%	5.4%	1.3%	262.99	-6.8%	19.0%	-19.8%	3.2%	-6.5%	385.7%	1.2%
Germany	32.9%	24.8%	23.8%	11.4%	1.3%	5.8%	322.19	-15.5%	11.4%	-10.0%	-17.1%	-12.2%	564.3%	-3.6%
Spain	43.3%	22.8%	5.9%	11.8%	7.0%	9.1%	136.50	-4.8%	104.9%	-61.9%	-0.7%	24.7%	726.7%	10.2%
UK	31.6%	42.3%	15.3%	8.1%	0.4%	2.4%	200.80	-13.4%	-2.9%	-17.0%	-26.9%	-33.3%	308.3%	-9.6%

Source: Enerdata

1.2.2 The gas system

The structural characteristics of the gas sector in Italy are well known and relatively stable. In a nutshell: a) demand higher than the European standard, largely driven by growing consumption levels in the thermoelectric sector; b) supply largely based on long term import contracts; c) a poorly flexible system, despite its significant storage facilities.

Gas consumption, imports and storage capacities in European countries (2010) Tab C.1.11

Consumption (billion m³)(1)	Italy	France	Germany	Spain	UK	EU-27
Total consumption	**83.0**	**46.3**	**96.7**	**34.1**	**98.2**	**538.3**
Industry	12.6	8.8	21.8	10.1	11.9	107.8
Households	35.2	26.6	50.0	5.3	42.2	220.8
Energy uses	34.6	9.3	22.4	18.1	43.2	193.3
Other	0.6	1.5	2.4	0.6	0.8	16.5
Domestic production	**8.3**	**0.7**	**12.7**	**0.0**	**60.1**	**200.6**
Total imports (billion m³)(1)	**74.7**	**45.6**	**84.1**	**34.1**	**38.1**	**337.7**
Share of imports in consumption	**88.4%**	**51.9%**	**61.8%**	**86.1%**	**21.5%**	**55.3%**
Imports/pipelines(2)	***88%***	***71%***	***100%***	***24%***	***65%***	***81%***
Russia	21%	23%	37%	-	-	32%
Algeria	37%	-	-	19%	-	12%
Libya	14%	-	-	-	-	2%
Other non-EU-27	-	-	-	-	-	1%
EU-27	16%	48%	63%	5%	65%	34%
Imports/LNG terminals(2)	***12%***	***29%***	-	***76%***	***35%***	***19%***
Algeria	2%	14%	-	14%	1%	4%
Libya	-	-	-	2%	-	-
Other non-EU-27	10%	15%	-	54%	32%	14%
EU-27	-	-	-	6%	2%	1%
Storage (billion m³)(3)	**14.9**	**12.6**	**20.4**	**4.1**	**4.3**	**85.0**
Number of storage days	**62**	**98**	**80**	**17**	**16**	**54**

(1) Source: AEEG
(2) Source: BP
(3) Source: GIE; the Italian figures include strategic stocks (5.1 billion m³)

Italy is the third largest consuming country in Europe, after Germany and United Kingdom, with a share close to 16% in the EU-27[17]. Still, after the sudden and large growth in the 2000s and an increase in thermoelectric consumption, the demand began slowing down in 2008 and in 2011 went back to 2009 figures, i.e. 77 billion cubic meters (-6.4%). While in 2009 only the thermoelectric and industrial sectors declined, in 2011 the greatest drop occurred in the thermoelectric sector (-7%) with the lowest figure in seven years, and in the household sector (-8%) hitting again a historical low; on the contrary, the industrial sector mildly recovered after the previous two years (+1.7%).
This suggests that while the first crisis was largely macroeconomic, stemming from the crisis of American subprime mortgage loans, the second one is macroeconomic only to some extent (more specifically, the second crisis is affecting the European sovereign debts). In the thermoelectric sector, consumption levels are

17 In this paragraph, international comparisons are always referred to 2010, the last year for which – at the time of completing this publication – international, homogeneous data are available.

low and competing with renewable sources; in the household segment, temperature was constantly above the average throughout the year. (Tab C.1.11, Tab C.1.12).

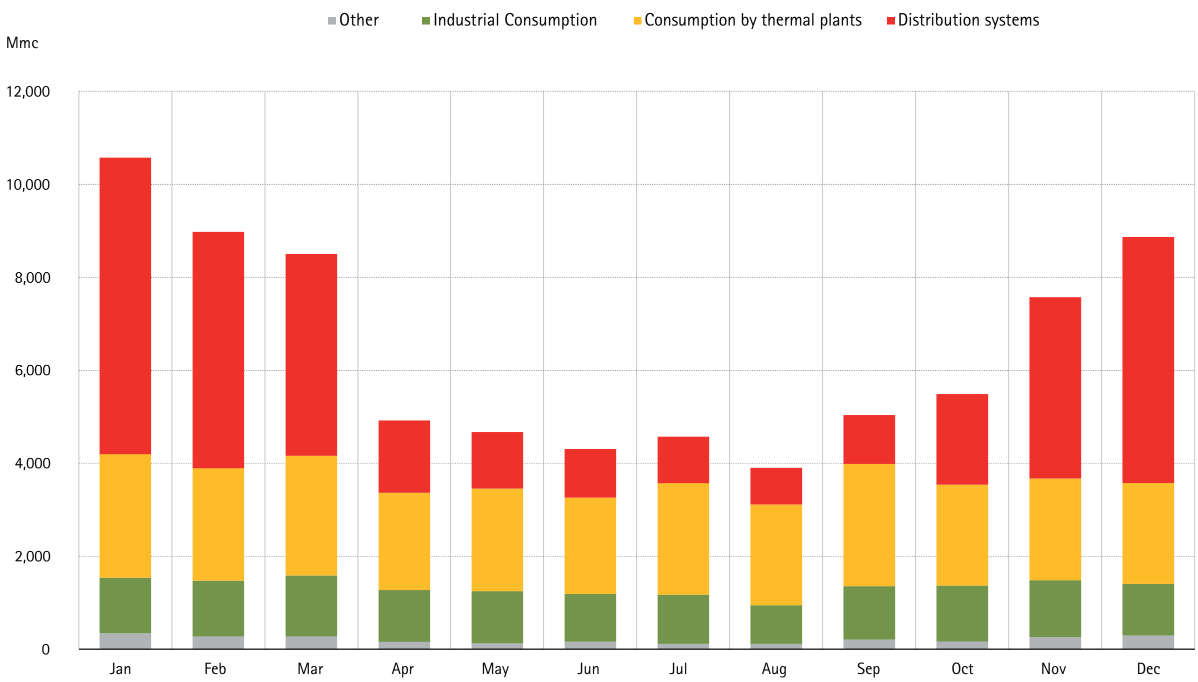
Despite a declining demand, consumption peaks tend to increase over time. This is related with household behaviors – the largest component in high demand winter months - and with thermoelectric consumption, more volatile in nature; partly, a role is played by the growing impact of renewable sources in the electricity sector (Fig C.1.7-C.1.8-C.1.9)[18].

Tab C.1.12 **Gas supply and demand in Italy**

million m³ (38.1 MJ)	2011	2010	2009	2008	2007	2011/2010 Δ%
Demand	**77,406**	82,675	77,682	84,526	84,534	**-6.4%**
Industrial consumption	13,543	13,319	12,133	14,560	15,514	1.7%
Distribution systems	33,614	36,521	33,968	33,376	32,449	-8.0%
Consumption by thermal plants	27,731	29,818	28,672	33,477	33,718	-7.0%
Third-party networks/system cons.	2,518	3,018	2,909	3,114	2,854	-16.6%
Imports	**70,274**	75,165	68,676	76,526	73,512	**-6.5%**
Domestic production	**8,028**	8,146	8,229	9,120	9,776	**-1.4%**
Storage systems	**-896**	-641	776	-1,123	1,248	**40.0%**
Delivery	8,047	8,041	9,272	5,668	5,665	0.1%
Injection	-8,943	-8,681	-8,496	-6,791	-4,417	3.0%
Virtual trading point (PSV)						
Physical volumes	24,098	22,537	11,552	16,417	7,159	6.9%
Traded volumes	60,580	45,274	24,623	16,417	12,062	33.8%
Churn Ratio	2.5	2.0	2.1	1.0	1.7	-

Source: SRG

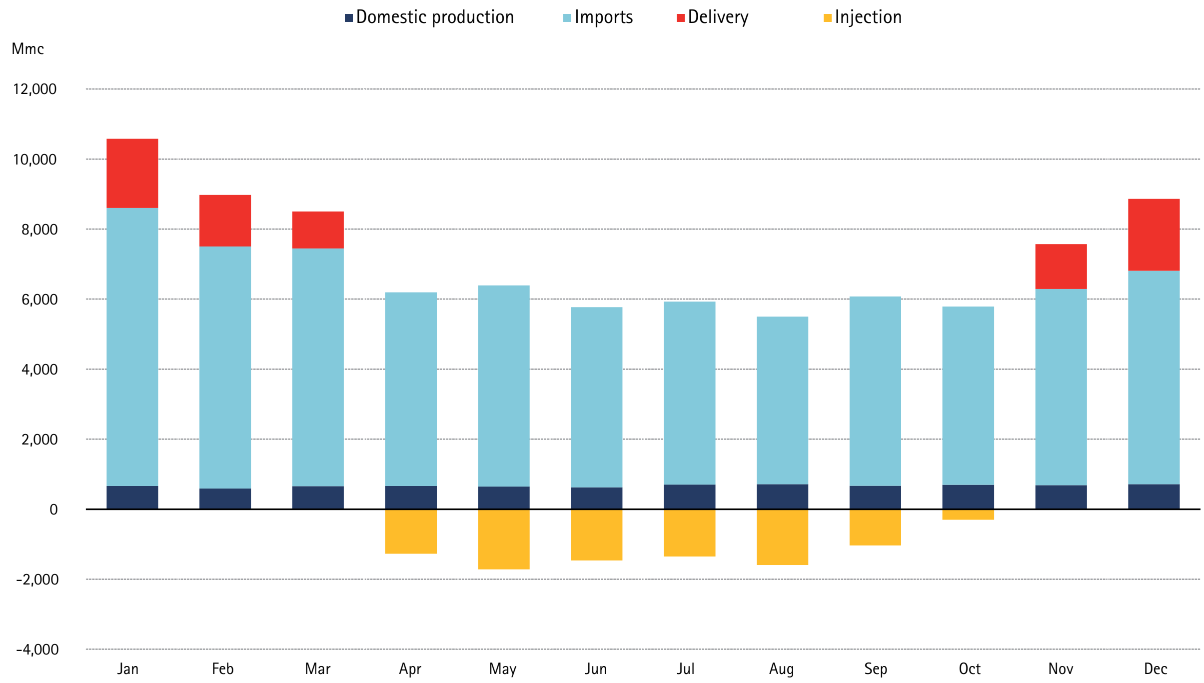
Fig C.1.7 **Monthly gas demand in 2011, by sector**



Source: SRG

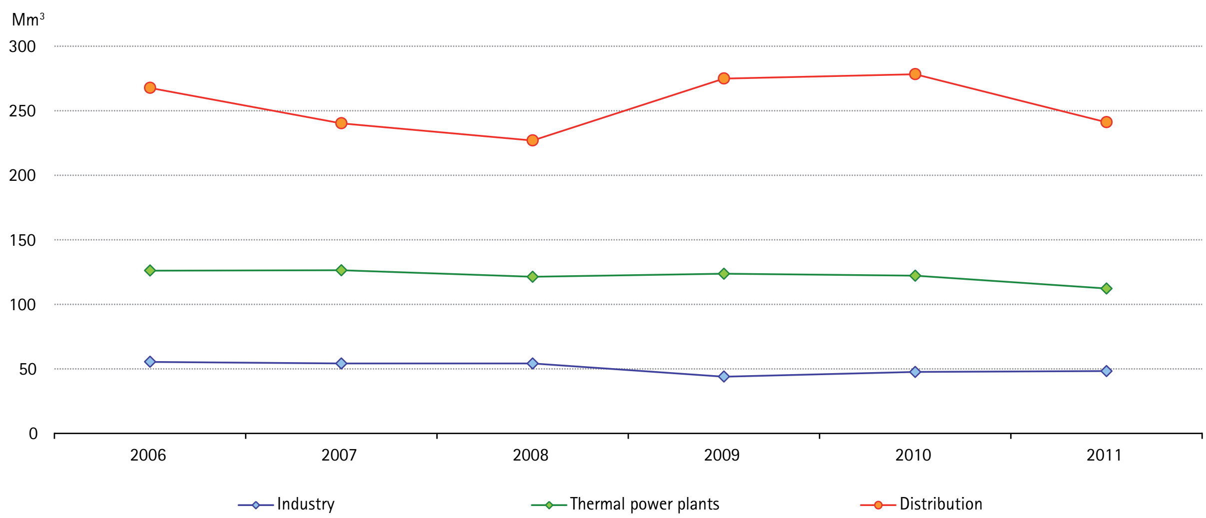
18 In particular, consumption volatility after 2006 was equal to 21-23% in the thermoelectric sector, and close to 14-15% in the household and industrial sectors.

Monthly gas supply in 2011, by component Fig C.1.8



Source: SRG

Yearly peak-demand series, by sector Fig C.1.9



Source: SRG

Overall, these phenomena make the supply size a less compelling issue, being already geared toward a surplus; what looks more significant is the flexibility of supply, both in terms of the demand short term adjustment speed and of its resilience whenever certain individual elements disappear.

In a country with a scanty domestic production, the growth or drop of consumption was basically met by imports, covering around 90% of the demand. In particular, the consumption crunch of 2011 was minimally made up for by the modest domestic production, reaching its minimum in the last eight years, with a total of 8 billion cubic meters (-1.4%). Imports also diminished to 70 billion cubic meters (-6.5%), close to the minimum level of the last seven years.

Italy's dependency on foreign supply, similar to other large non producing European countries like Germany, France and Spain, is more problematic for two reasons: on one side, 74% of imports arrive from three non EU countries at a high geopolitical risk (Algeria, Russia, Libya): elsewhere, they do not exceed 40%; on the other side, due to the lack of LNG terminals, in Italy 88% of imported gas comes from a limited number of rigid infrastructure, such as pipelines, against smaller figures elsewhere (less than 71%, to the exception of Germany) (Tab C.1.13).

In particular, in spite of a larger supply availability after the official opening of the Greenstream gas pipeline with Libya (starting from 2004, 9 billion cubic meters a year) and the entry into operation of the Rovigo LNG terminal (in 2009, 7 billion cubic meters a year), there are still just 7 entry points, four of which cover 85% of the demand (Tab C.1.13):

- Tarvisio, entry point with Gorizia, for gas coming from Russia through the Tag gas pipeline; it gives access to the Austrian hub of Baumgarten. With its 119 million cubit meters/day, it is the most significant infrastructure and covered 34% of the demand in 2011, +24% vs 2010;
- Mazara del Vallo, landing point of Algerian gas through Transmed; with its 105 million cubic meters/day, it fulfilled 28% of the demand in 2011 and suffered the largest drop, with volumes declining by -6.8% and a 62% usage rate;
- Passo Gries, entry point for gas coming from Northern Europe through Transitgas; it gives direct access to the Dutch hubs of Zeebrugge and TTF; with its 65 million cubic meters/day, it covered 14% of requirement, with increasing volumes after a drastic decrease in 2010, caused by extraordinary maintenance operations when a landslide blocked any procurement for most of the second half of that year;
- The new LNG terminal of Rovigo, receiving gas from the Arab peninsula, boasting a 26 million cubic meters/day capacity, covered 9% of the demand in 2011.

The flexibility of storage facilities plays a crucial role; their overall capacity equals about 15 billion cubic meters, 9 of which for extra needs and 5 for strategic reserve purposes (Tab C.1.4).

Tab C.1.13 **Gas import capacity and related utilization rate**

Entry point	Country of origin	Reference hub	Capacity mln SM3/g	Allocated mln SM3/g	Available mln SM3/g	Saturation %	Share of consumption %
Total			370.4	322.5	47.9	58%	91%
Pipelines			331.0	289.5	41.5	57%	79%
Passo Gries (Transitgas)	Netherlands Norway	Zeebrugge TTF	64.8	58.1	6.7	51%	14%
Tarvisio (Trans Austria Gas -Tag)	Russia	Baumgarten	118.8	111.5	7.3	65%	34%
Mazara del Vallo (Transmed)	Algeria	-	105.0	92.2	12.8	62%	28%
Gorizia (Trans Austria Gas -Tag)	Russia	-	4.8	0.4	4.4	96%	0%
Gela (Greenstream)	Libya	-	37.6	27.4	10.2	22%	3%
LNG terminals			39.4	32.9	6.5	71%	12%
Panigaglia	Nigeria	-	13.0	8.3	4.8	59%	2%
Cavarzere	Oman	-	26.4	24.7	1.7	75%	9%

Source: SRG

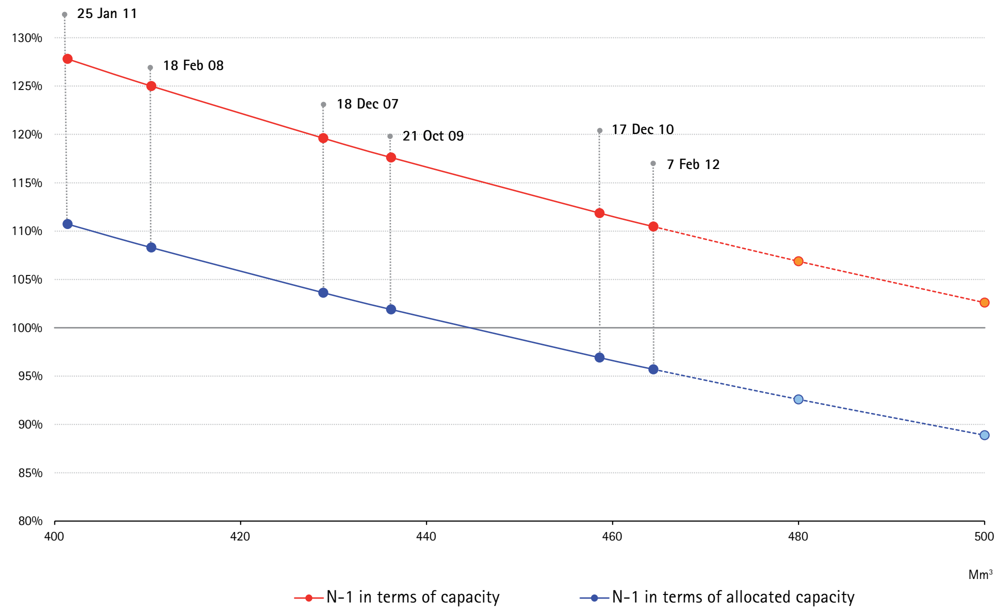
Tab C.1.14 **Gas storage system**

Storage (million m^3 – 38.1 MJ)	2011	2010	2009	2008	2011 / 2010 Δ%
Space allocated	14,932.2	14,461.4	14,082.1	13,998.1	3.3%
Strategic stocks	5,166.5	5,177.1	5,235.7	5,254.1	-0.2%
Balancing and mining service	564.4	531.3	529.3	575.6	6.2%
Modulation service and Legislative Decree 130/10	9,201.3	8,753.0	8,317.1	8,168.3	5.1%
Stocks as of 1 Nov (*)	10,458.0	9,078.1	8,611.3	8,717.6	15.2%
Number of days of storage	49	40	40	38	23.0%

(*) Start of delivery season

Source: Stogit

N-1 security vs demand Fig C.1.10



Source: processing of SRG data

The above data make the Italian system fragile; despite an excess supply induced by the consumption crisis and a rise in the global supply of non conventional gas, there still exists a risk of peak scantiness in the event an import line is lost or a sudden rise in consumption occurs; this condition is accurately measured by the N-1 security index. In the case of Italy, it is equal to 100% , slightly above the safety threshold[19]. As a matter of fact, with a daily peak demand which in recent years ranged between 400 and 460 million cubic meters/day, the potential supply can cover a maximum of 631 billion cubic meters/day, 34 of which produced domestically, plus 227 supplied from storage facilities and 370 from import capacity (however, in recent times these three elements never exceeded 27, 177 and 347 million cubic meters/day, respectively). Fig. C.1.12 shows that by calculating the indicator on the basis of the pipelines' capacity, the system could safely work up until consumption levels of nearly 500 million cubic meters[20].

In addition to a limited number of entry points, at least three more aspects need to be considered:

a) the average life of import contracts (for 11% of contracts, less than one year; for 86% of contracts, more than 10 years)[21] and the rigidity of take or pay covenants in import contracts through pipelines, both in terms of price and flexible withdrawal for users/importers;

b) reduced share of available capacity in the pipelines for a short-term re-allocation, on average below 13%;

c) low liquidity and reduced transparency of market adjustment mechanisms; so far, they were linked to the regulated gas release obligation (two *Gas Release* in 2003 and 2007, as well as the obligation to allocate imports and royalties, run by GME on the P-GAS, for volumes of 0.53 Billion cubic meters) or OTC agreements between the parties, registered on PSV (strongly growing up to 60 Billion cubic meters). In 2011, more transparent market mechanisms started for both the wholesale (by establishing the M-GAS) and balancing markets (through the PB-GAS).

Overall, these events have often generated price tensions, at times even volume problems. On occasion, it

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19 N-1 measures the system resilience when faced with the loss of the main supply element; it is calculated through the formula N-1(%) = 100 x (EP*m* +P*m* + S*m* + LNG*m* – I*m*)/ *Dmax*, where EP*m* is the maximum capacity of entry points served by gas pipelines, P*m* is the maximum domestic production capacity, S*m* is the maximum design capacity of storage facilities, LNG*m* is the maximum send out capacity of LNG terminals, I*m* is the capacity of the largest infrastructure, *Dmax* is the maximum daily gas demand in the last 20 years. The more the index is greater than 100, the greater the security.

20 N-1 is calculated differently by different institutions. This is why Fig C.4.1 also reports the index related to the demand fluctuation, calculated with reference to assigned rather than available capacity levels. Clearly, its value appears to be much lower.

21 According to information given in AEEG 2010 Annual Report.

was necessary to ration the interruptible industrial demand, re-open fuel oil power plants to promote the reduction of thermoelectric demand and, in the worst cases, use was made of a portion of strategic reserves. The most significant crises happened in 2006 and 2009, when international tensions between Russia and Ukraine caused a physical scantiness leading to consumption rationing for some users. Milder tensions, the effect of which was limited to a rise in wholesale prices, occurred in 2010, when the Transitgas pipeline suffered a fault, and in March 2011, during the political conflict in Libya. The latest critical time is very recent (February 2012): a wave of Siberian cold hit Europe, with a spike in consumption and smaller flows of gas from Ukraine, with effects on prices and consumption rationing.

One final rigidity suffered by the Italian gas system in recent years is the lack of a true spot market, only partly fixed by the Virtual Trading Point (PSV), i.e. the Italian hub run by SRG where participants can register bilateral gas trades; its overall trading volume grew from 12 to 60 billion cubic meters with a delivery amount up from 7 to 24 billion cubic meters. Due to this lack, in Italy more than abroad, pre-existing contract formats – generally regulated and indexed – are still quite common; these contracts provide for Brent-related prices (strongly related) and seem unable to reflect any abundance or scarcity. Here, reference is made to the QE index (administered component of gas price, linked to the raw material cost coverage) and to the *Gas Release 2007* – the main gas indexed formula on the Italian market to sell gas, imposed by the Regulator. Both formats, which follow quite strictly the Brent price, converted into Euros and delayed by 6 months, suggest a price increasing trend which began last year. At the same time, they highlight a progressive upward deviation of the *Gas Release*, whose practical trading value is actually discounted by some scores of € to achieve a significant level.

Within this framework, GME organizes and runs the natural gas market (M-GAS), where participants eligible to perform transactions at the Virtual Trading Point (PSV), can buy and sell spot quantities of gas.

1.2.3 The electricity system

After weak signs of recovery in 2010, the year 2011 was characterized by an electricity demand stagnation, in line with a macro-economic picture where the aggregate demand suffered from a zero growth rate. Despite a tiny Gdp increase (+0.4%), power consumption (311.7 TWh) moderately grew (+0.6%) and especially suffered from a sharp decline in the last quarter (-3%), when financial markets were highly turbulent and the real economy more in trouble. A consumption drop seems to be confirmed also by partial data on 2012; in the first quarter, the demand decreased by nearly 2%, in line with the economic recession that is characterizing the first half of the year. By looking at consumption by sector, stagnation seems to be highly homogeneous across all industries and segments (Fig. C.1.11). Industrial consumption raises special interest, being by its very nature more sensitive to the aggregate demand trend. In this case, it increased by just 1 TWh (+0.7%) and always remained below the pre-crisis level, i.e. before 2009. In 2011, moreover, a tendency which emerged up in the last five years was confirmed, i.e. purchases from pumping units sharply fell down to 2.5 TWh (-43.5%). This was largely due to the progressive convergence between peak and off-peak prices on the MGP, minimizing any hourly trading opportunities. In terms of requirement peaks, no significant change from 2010 has occurred, with a consumption peak (56.5 GW) similar to the previous year, both in terms of levels (+0.1 GW) and hours/periods; in fact, the demand peak was achieved on 13 July, just three days before the 2010 peak (16 July). This confirms a trend that seems to have begun in 2008, with a shift from the winter to the summer peak given the increasing, large scale use of air conditioning systems (Tab C.1.15, Tab C.1.16).

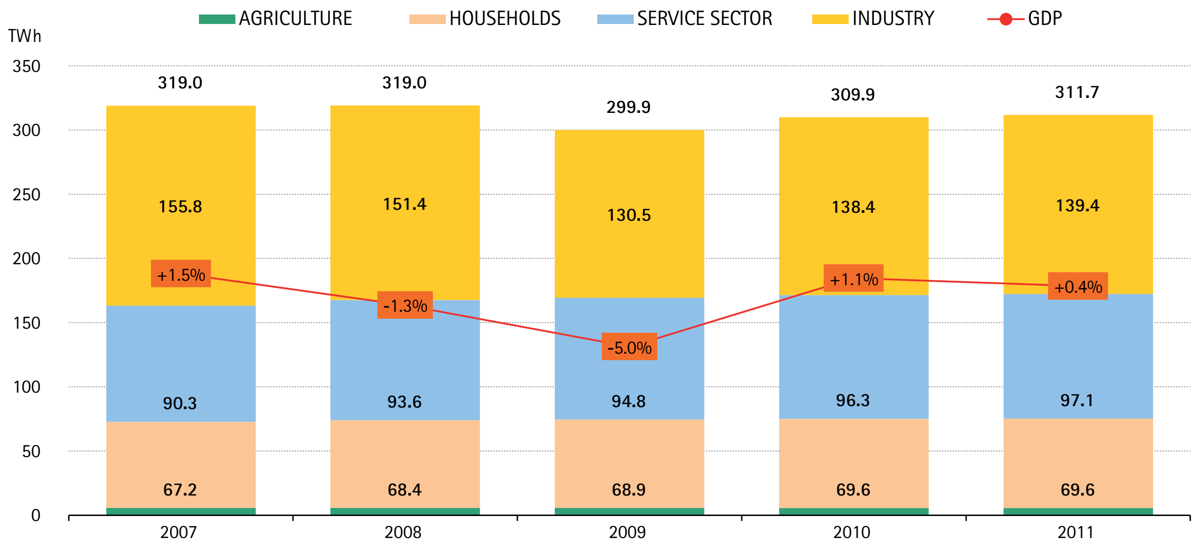
Despite a static demand, generating capacity increased again in 2011, achieving an all-time high of 121.5 GW, further strengthening the long lasting supply surplus that has been characterizing the Italian electricity system for years now. Although this larger installed capacity (+10.2%) is fragmented across nearly all types of plants, in 2011 the growth of thermal power grew (+1%) only to a point, given the extraordinary renewable installed

capacity (+112%). This exceptional average increase is accounted for by a true explosion of photovoltaic power (+267.4%) and by a more moderate increase of wind power on 2010, which however remains significant (+19.7%)[22]. A pronounced misalignment between the thermal power and renewable power growth rates does emphasize a tendency from the recent past. The development rate of power from thermoelectric plants, stable at 5-6% between 2003 and 2008 by reason of the significant growth of combined cycles, has been heavily deteriorating since then; on one side, a widespread overcapacity, made even worse by the recent stagnating consumption levels: on the other, a progressively smaller return on investment after the collapse of the spark spread. The growth trajectory of wind and photovoltaic power shows, on the opposite, that investment in such types of plants is heavily anelastic to the electricity demand. This type of investment is mostly stimulated by incentives; this gave rise to a growth of the installed power, especially significant in the last three years[23], when electricity consumption dramatically fell (Fig C.1.11). Nonetheless, the prevailing share of consumption keeps being satisfied by thermal generation (approximately 70%, mostly through combined cycles), wind and photovoltaic power (net generation of about 19 TWh), accounting for 6% of total consumption (+2.6 p.p.).
Although small in absolute terms, the growing weight of renewables is having a significant impact on the wholesale market (prices and hourly profile) as well as on the system as a whole (reliability of schedules and criticalities related to the adjustment of injections from such sources). The expansion of renewables caused a depressive effect on market prices; an abundant supply at zero price contributes to reducing the relative scarcity of the supply while increasing marginal competitiveness, with the most costly bids/offers being out of merit-order; the profile has changed considerably, by pushing prices downward during peak hours with the highest solar irradiation; an indirect effect is a price increase at night when the market concentration is higher and conventional sources set higher prices to protect their margins (see as reference paragraph 2.2 under section C). System-wise, the poor reliability of schedules[24] and the reduced dispatchability of renewable sources reduce the system security while increasing balancing charges for all; hence, TSOs have more problems in managing the grid in a balanced manner. They are forced to consider such difficulty in putting together their spare capacity. Therefore, being these technologies so popular, investment seems to be necessary for minimizing any criticalities resulting from non schedulable nature of such sources.
To this end, it is worth recalling a number of measures already put in place by Terna in 2011; special emphasis should be put on measures aimed at defining the NTC – Net Transfer Capacity – with foreign countries. On weekends with a reduced expected requirement (end of March through mid-June 2011), Terna restricted foreign interconnections. This measure was justified by the need to guarantee, in the MGP, acceptance of a supply share from national thermal plants, sufficient to maintain an appropriate revolving spare capacity. With a low demand and a growing supply of non schedulable sources, keeping the usual foreign interconnection capacity might give rise to a situation where, after MPG schedules, the requirement is nearly totally met by the foreign supply and by renewables, to the detriment of the system security. This phenomenon heavily impacts on MGP competitive patterns and prices and looks even more pronounced in the first half of 2012. More than once, in low consumption weekends the Pun was even greater than the previous business days, thus reversing the usual price cycle observed during the week. In the new few years, therefore, the share of net import, which rose up to 45.6 TWh (+3%) in 2011 thanks to a wider price gap with foreign countries (14% of overall demand), might change.
Finally, as for the evolution of the transmission network, the 2011 most important enhancement was the full operation of the second Sapei cable, enabling an interconnection capacity between Center South – Sardinia and Sardinia – Center South of 870 MW and 1,050 MW, respectively. This promoted a greater integration

22 Source: Terna; 2011 provisional data.
23 In particular, as shown by the percentage increase recorded between 2011 and 2010, this power increase was largely driven by wind power and, at present, by photovoltaic power.
24 This latter is due to the logical, greater approximation of forecasts; under the present dispatching rules, participants may or may not submit their schedules in the MGP.

between the Island and the mainland. In the MGP, the price gap between Sardinia and the mainland diminished (about -18%). On the opposite, the interconnection capacity between Sicily and the continent is not supposed to change until the entry into operation of the Sorgente-Rizziconi line, expected by 2014, increasing the import capacity of the island by approximately 900 MW.

Fig C.1.11 **Final electricity consumption by sector and GDP**



Source: Terna; provisional 2011 data.

Tab C.1.15 **Electricity balance**

TWh	2011	2010	2009	2008	2007	2011/2010 % change
TOTAL DEMAND	**332.3**	**330.5**	**326.1**	**347.1**	**347.6**	0.6%
DOMESTIC CONSUMPTION	311.7	309.8	299.9	319.0	319.0	0.6%
GRID LOSSES	18.1	16.2	20.4	20.4	21.0	11.7%
PURCHASES BY PUMPED-STORAGE PLANTS	2.5	4.5	5.8	7.6	7.7	-43.5%
NET GENERATION	**289.2**	**290.7**	**281.1**	**307.1**	**301.3**	-0.5%
HYDRO	47.7	53.8	52.8	46.7	38.0	-11.4%
THERMAL	217.4	221.0	216.1	250.1	254.0	-1.6%
GEOTHERMAL	5.3	5.0	5.0	5.2	5.2	5.2%
WIND	9.6	9.0	6.5	4.9	4.0	5.7%
PHOTOVOLTAIC	9.3	1.9	0.7	0.2	0.0	394.0%
NET IMPORTS/EXPORTS	**45.6**	**44.2**	**45.0**	**40.0**	**46.3**	3.3%
IMPORTS	47.3	46.0	47.1	43.4	48.9	3.0%
EXPORTS	1.7	1.8	2.1	3.4	2.6	-5.7%

Source: Terna, provisional 2011 data.

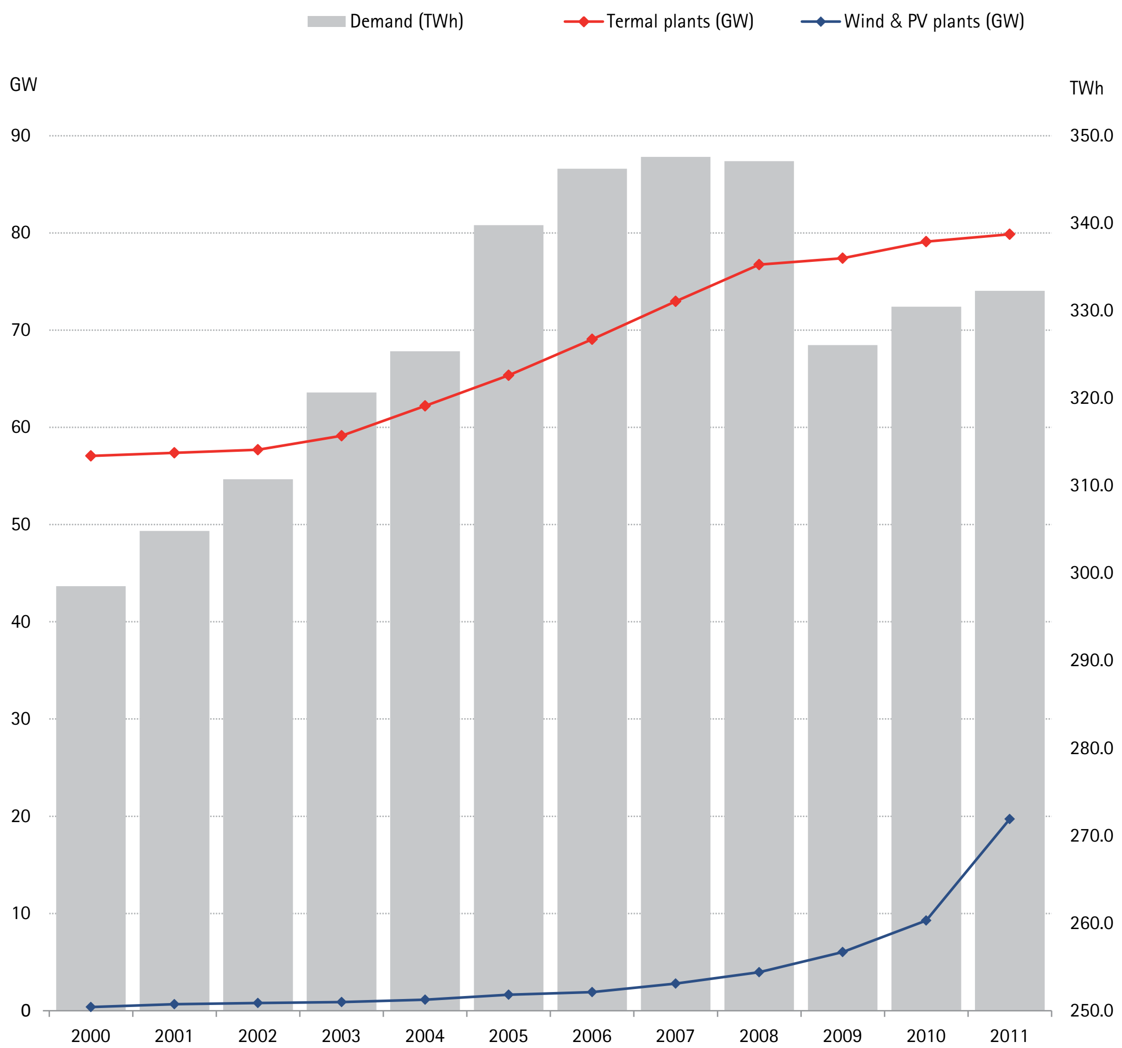
Maximum generating capacities and peak loads Tab C.1.16

GW	2011	2010	2009	2008	2007
GROSS MAXIMUM CAPACITY	121.5	110.3	105.2	102.3	97.2
HYDRO	22.0	21.9	21.7	21.6	21.5
THERMAL	79.1	78.3	76.7	76.0	72.2
GEOTHERMAL	0.8	0.8	0.7	0.7	0.7
WIND & PHOTOVOLTAIC	19.7	9.3	6.0	4.0	2.8
AVERAGE PEAK-LOAD CAPACITY*	n.a.	69.3	67.0	63.5	61.2
PEAK LOADS	56.5	56.4	51.9	55.3	56.8
DAY	*13 July*	*16 July*	*17 July*	*26 June*	*18 December*
TIME	12	12	12	12	17

* net of import capacity

Source: Terna; provisional 2011 data.

Yearly series of capacities installed in thermal, wind and photovoltaic plants Fig C.1.12



Source: Terna, provisional 2011 data.

2. ELECTRICITY MARKETS

2.1 Market participation

In 2011, the economic crisis affected the electricity market only to some extent. Most likely, the most significant impact will be felt in 2012.
In terms of market participation, during the first year after the Exchange takeoff, there have been fewer enrolled participants in the electricity market (207 in 2010 vs 192 in 2011). However, this figure does not reflect a corresponding decrease of market participants; on the contrary, the number of this latter has been growing on all platforms this year, too. Significant numbers were observed in intra-day markets (+22), where the larger number of bidders is quite favored by the new MI3 and MI4 sessions, an additional flexibility tool allowing participants to modify, until the morning of the delivery day, any schedules registered after the MI2[25]. The smaller number of enrolled participants most likely depends on the decision of these latter, albeit inactive, to leave the market. As to the OTC Registration Platform (PCE), a record number of enrolled companies (208) was achieved. Also, the participation rate grew, with 103 bidding participants versus 95 in 2010 (Tab C.2.1).

Tab C.2.1 **Participation in the market**

	2011	2010	2009	2008	2007
PCE					
Registered participants	**208**	205	167	146	116
Participants with bids/offers	**103**	95	88	100	108
Participants with supply offers	**79**	75	68	76	94
Participants with demand bids	**73**	71	65	70	73
IPEX					
Registered participants	**192**	207	172	150	127
MTE					
Participants with bids/offers	**22**	15	16	8	-
Participants with supply offers	**20**	12	13	8	-
Participants with demand bids	**14**	13	15	6	-
MGP (excluding PCE)					
Participants with bids/offers	**138**	131	115	105	89
Participants with supply offers	**112**	104	92	84	71
Participants with demand bids	**108**	102	90	90	74
MI					
Participants with bids/offers	**91**	69	53	37	32
Participants with supply offers	**81**	65	48	34	29
Participants with demand bids	**79**	59	49	36	32
MSD					
Participants with bids/offers in the ex-ante MSD	**28**	23	20	22	19

As to volumes, the electricity demand noted by Terna is similar as last year (332 TWh; +0.6%)[26], in spite of a mild decrease of quantities traded in the MGP, down to 311.49 TWh (-2%). This theoretically physiological discrepancy – on one side, it could either reflect a difference between scheduling and actual consumption or, on the other, specific energy purchasing strategies – is significantly higher than in the recent past. However, it is not due to a decline in the demand of scheduled purchase but to the exponential growth of photovoltaic generation (approximately +394%)[27]; this latter flattens purchases in the day-ahead market – bilateral contracts included – in

25 More specifically, in MI3 and MI4, with sessions closing at 7:30 and 11:30 on the delivery day, respectively. In this way, participants can modify their schedules covering the last 12/8 hours of the delivery day.
26 Source: Terna.
27 Source: Terna.

favor of a growing share of self-consumption covered by generation not traded in the market.
In this context, the volume of trades registered in GME markets and platforms rose again up to 525 TWh (+15%), an absolute record figure. This increase is driven by the growth of forward trading (322.49 TWh; +34%)[28], in line with the overall size of the Italian forward market of energy (523 TWh)[29], up by 37%. Although the largest share of volumes is referred to over the counter trading, MTE trading skyrocketed (+404%). This proves that such market is more and more used as an hedging instrument against the spot price volatility risk[30]. As to the PCE, the increase of registered contracts (+23%) is induced by the growth of the underlying (up to 131 TWh) and by a more intensive trading by participants, as confirmed by a further increase of the "churn ratio"[31] (Tab C.2.2).

On the other hand, in spot markets the drop of volumes in the day-ahead mostly refers to the Exchange, with a loss of about 19 TWh (-10%), at a historical minimum level of 180 TWh, with more schedules to execute bilateral contracts.
This pattern certainly suffers from the generalized decline of day-ahead buys, although in itself this explanation is not exhaustive: assuming a 2010 constant liquidity level – i.e. assuming that the demand drop affects equally both the exchange and bilaterals - Ipex volumes should just decrease by 4.5 TWh, i.e. 184.8 TWh. On the opposite, a trend toward a lower MGP liquidity, defined as a share of day-ahead total volumes traded in the MGP, has been observed since 2009. In 2011, an all time-low of 58% was hit with a 5% drop on 2010 and 10% on 2009 (Fig C.2.1). Therefore, the reasons of such volume and liquidity decline should be found elsewhere, as illustrated below.
Relative to 2010, volumes traded by institutional participants – GSE and AU – on the regulated market shrank by 2%. To date, institutional participants still represent 48% of the exchange traded volumes. However, this is not sufficient: it simply contributes to reducing the quantitative level of Exchange trading but not liquidity, since the drop in Exchange volumes traded by institutional entities is proportional to volumes at large. In this respect, it is interesting to note that this fall expresses the result of opposite patterns followed by GSE and by the Single Buyer. In other words, if sales by the first were down to a historical minimum (39 TWh) (partly because of plants no longer eligible to measures defined by CIP 6/92), the latter remarkably changed its procurement strategy from the previous year, cutting the OTC share in favor of a stronger presence in the regulated market (+6 TWh)[32]. In this framework, the AU finding looks quite significant: AU was the main buying counterparty in the MTE, which proves that the smaller liquidity in the MGP cannot be due, or can be explained only to a very small extent, to a shift of exchange volumes in the spot market in favor of MTE trading.
The origin of a drop in volume and Exchange liquidity, therefore, lies in the decline of volumes traded by non institutional participants (-17 TWh); in 2011, their share went down to 30%, with a 5% smaller Exchange liquidity. Yet, this pattern basically reflects three distinct and at least partially exogenous phenomena.
a) The first one is exquisitely regulatory and has to do with the effect of measures covering the virtual interconnector: in the last two years, about 17.5 TWh were registered on the PCE in 2010 and 21.5 TWh in 2011[33]. Based on the assumption that without the virtual interconnector a share equal to the MGP liquidity in 2009 (68%) would have

28 However, out of 322.49 TWh forward volumes, a substantial proportion is refererred to volumes to be delivered in 2012. This is even more important in the MTE, where the yearly baseload product for 2012 is the most liquid (73% of traded volumes).
29 This value is reported in Table C.2.33 and is greater than in Tab C.2.2: on the PCE, commercial positions can be registered over a maximum time horizon of two months; also, it includes financial contracts traded on regulated markets (Idex) and OTC.
30 Conversely, it is appropriate to underline that trading is still quite limited in the MTE.
31 The "churn ratio" is the ratio between registered volumes and nominated volumes on delivery; it measures the relationship between the financial and physical dimensions of a market.
32 This figure refers to AU's buys net of CIP6. Quite remarkably, the growth of purchase by AU on the Exchange is more striking, since in 2011 the share of CIP6 rights allocated to the Single Buyer was set to zero versus 697 MW in 2010.
33 This measure is governed by law 99/09: investors in foreign interconnection projects are entitled to early receive any commercial benefits they would get in the event lines were already in operation. As a matter of fact, such subjects can procure an amount of energy equal to the one they could transport at the capacity they were awarded, at the price of a foreign market among those they selected. Practically speaking, since the purchase of energy for the capacity of such subjects is made by entering into procurement contracts registered on the PCE with importing subjects (*shippers*), this provision actually drains volumes and liquidity from the MGP. Initially, 2000 MW were allocated for 2010, plus another 500 MW allocation in February-December 2011. The figures of 17.5 and 21.5 TWh were calculated as energy corresponding to the capacity allocated in 2010 and 2011. In mathematical terms: 17.5 = (2000 MW*24*365); 21.5 = (2000 MW*24*31)+(2500 MW*24*334).

been traded on the Exchange, and that *shippers* have totally nominated on the PCE schedules for investors, the drop in Exchange volumes resulting from this provision can be estimated as equal to 12 TWh in 2010 and another 3 TWh in 2011. This phenomenon explains most of the volume drop recorded in 2010; also, it does contribute to explaining, although not entirely, the decline observed in 2011.

b) The second one has to do with the marked fall of pumping purchases (-67%), induced by the smaller gap between peak and off-peak prices. Such purchases have always been made in the MGP only, so as to catch hourly trading opportunities for bilateral contracts; the decrease of these latter was entirely accounted for by the MGP, with about 2 TWh less in Exchange volumes.

c) The remaining portion of volume reduction, on the other hand, does not seem to originate from external factors. More specifically, on the PCE on schedule deviations became more common, up to 18 TWh on the withdrawal side and 0.4 TWh on the injection side (+128%). In this case, the increase is consistent with the growing trend exhibited by generation costs as observed in 2011; to some participants, it was more cost-effective to choose on schedule deviations while getting, from the Exchange, any energy required to comply with bilateral contracts (Tab C.2.3).

In the field of spot trading, on the Exchange side there has been a significant rise in MI transactions (+50%), despite a still limited overall level (22 TWh); as a consequence, its growth did not cause any major impact on the overall spot volume trading, stable at around 333 TWh.

Also, given the size of its variation, it is worth recalling a significant fall of volumes in the ex ante MSD (-56%), supported by the incentive scheme envisaged by AEEG Decision ARG/elt 213/09. A bonus-based system was introduced to the benefit of Terna provided that this latter, while maintaining appropriate security standards, reduces MSD-related services volumes.

Tab C.2.2 **Volumes traded in GME's markets (TWh)**

		2011		2010	2009	2008	2007***
		TWh	delta %	TWh	TWh	TWh	TWh
	TOTAL VOLUMES (a+b+c+d+f)	**524.70**	**+15%**	**456.93**	**401.44**	**398.51**	**360.64**
	"SISTEMA ITALIA" (d+e)	**311.49**	**-2%**	**318.56**	**313.43**	**336.96**	**329.95**
	Forward trades (a+b+c)	**322.49**	**+33%**	**242.87**	**176.47**	**154.22**	**97.28**
(a)	MTE (*)	31.67	+404%	6.29	0.12	0.06	-
(b)	CDE	0.00		0.10	0.00	0.00	-
(c)	PCE (**)	290.82	+23%	236.48	176.35	154.16	97.28
	Spot trades (d+e+f)	**333.36**	**+0%**	**333.18**	**325.36**	**348.61**	**342.69**
(d)	*MGP/exchange*	180.35	-10%	199.45	213.03	232.64	221.29
(e)	*PCE/OTC*	131.15	+10%	119.11	100.39	104.32	108.66
(f)	*MA/MI (g+h+i+l+m)*	21.87	+50%	14.61	11.93	11.65	12.74
(g)	*MA*	-	-	-	9.30	11.65	12.74
(h)	*MI1*	14.47	+53%	9.47	1.68	-	-
(i)	*MI2*	5.38	+4%	5.15	0.95	-	-
(l)	*MI3*	1.22	-	-	-	-	-
(m)	*MI4*	0.80	-	-	-	-	-
	ex-ante MSD (n+p)	**9.59**	**-56%**	**21.75**	**27.16**	**22.84**	**26.60**
(n)	MSD up	4.72	-32%	6.96	12.52	11.58	14.58
(p)	MSD down	4.87	-67%	14.80	14.65	11.26	12.03

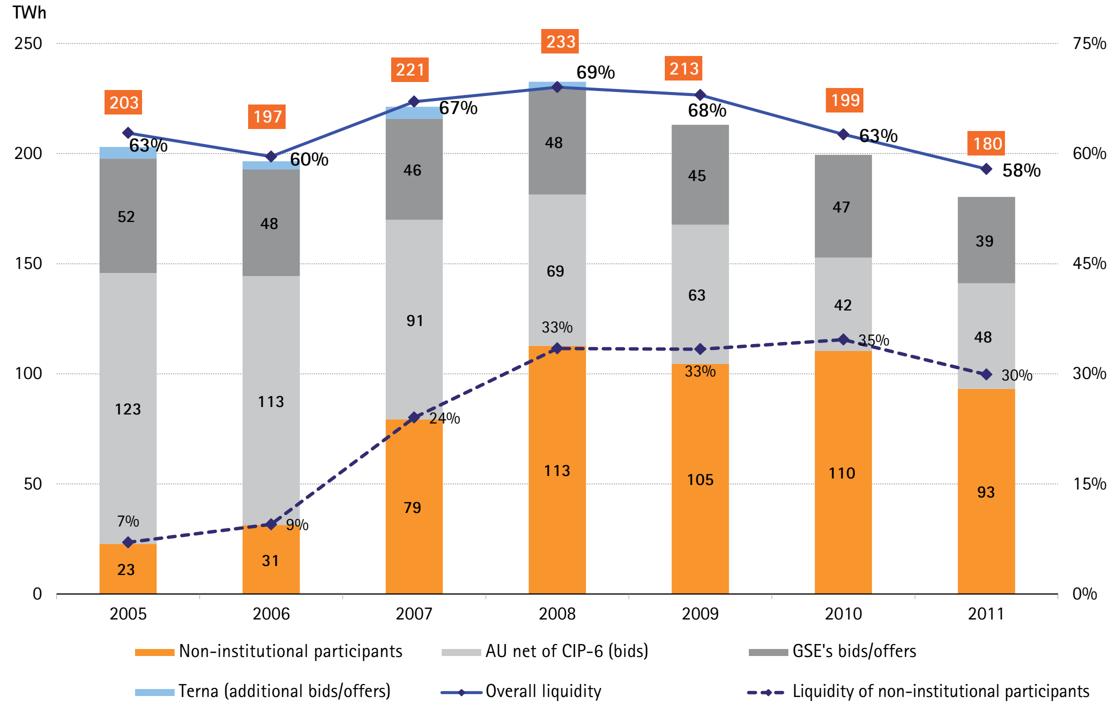
(*) Value calculated net of OTC registrations.

(**) Contracts registered on the PCE by year of trading, net of contracts pertaining to the MTE and CDE. The 2007 data refer to the April-December period

(***) Total volumes include PCE/OTC data pertaining to the January-March 2007 period

MGP liquidity (TWh)

Fig C.2.1



Demand mix in the MGP

Tab C.2.3

MWh	2011	2010	2009	2008	2007	2011-2010	2011 structure
Exchange	**180,347,000**	**199,450,149**	**213,034,688**	**232,643,731**	**221,292,184**	**-9.6%**	**57.9%**
Acquirente Unico	47,926,296	48,468,535	70,700,952	79,448,673	106,570,141	-1.1%	15.4%
Other participants	110,275,635	134,317,300	134,481,029	137,922,614	99,762,451	-17.9%	35.4%
Pumped-storage plants	945,759	2,853,292	2,891,281	5,108,149	6,334,233	-66.9%	0.3%
Foreign zones	3,102,694	3,419,627	3,825,739	6,699,056	3,057,474	-9.3%	1.0%
Balance of PCE schedules	18,096,615	10,391,394	1,135,686	91,994	161	74.2%	5.8%
Additional bids/offers	-	-	-	3,373,245	5,567,723	-	-
OTC contracts	**131,146,877**	**119,111,417**	**100,390,479**	**104,317,565**	**108,657,022**	**10.1%**	**42.1%**
Foreign OTC contracts	416,390	408,869	436,389	559,701	726,452	1.8%	0.1%
AU's national OTC contracts	36,786,812	41,846,549	24,246,640	19,502,059	16,166,432	-12.1%	11.8%
Other participants'OTC contracts	112,040,290	87,247,392	76,843,137	84,347,800	91,764,300	28.4%	36.0%
Balance of PCE schedules	(18,096,615)	(10,391,394)	(1,135,686)	(91,994)	(161)	74.2%	-5.8%
VOLUMES PURCHASED	**311,493,877**	**318,561,565**	**313,425,166**	**336,961,297**	**329,949,207**	**-2.2%**	**100.0%**
VOLUMES NOT PURCHASED	**26.716.312**	**26.491.365**	**25.790.543**	**17.357.054**	**5.475.885**	0,8%	
TOTAL DEMAND	**338.210.189**	**345.052.930**	**339.215.709**	**354.318.351**	**335.425.092**	-2,0%	

Supply mix in the MGP

Tab C.2.4

MWh	2011	2010	2009	2008	2007	2011-2010	2011 structure
Exchange	**180,347,000**	**199,450,149**	**213,034,688**	**232,643,731**	**221,292,184**	**-9.6%**	**57.9%**
Participants	108,533,768	120,956,056	131,158,116	147,438,784	142,990,379	-10.3%	34.8%
GSE	39,296,282	46,664,374	45,353,277	47,808,312	45,828,980	-15.8%	12.6%
Foreign zones	32,064,887	31,631,528	31,215,502	21,788,559	16,786,271	1.4%	10.3%
Balance of PCE schedules	452,062	198,191	5,307,793	7,985,871	12,528,950	128.1%	0.1%
Additional bids/offers	-	-	-	7,622,206	3,157,605	-	-
OTC contracts	**131,146,877**	**119,111,417**	**100,390,479**	**104,317,565**	**108,657,022**	10.1%	42.1%
Foreign OTC contracts	17,804,825	17,122,515	19,108,051	26,013,295	33,782,919	4.0%	5.7%
National OTC contracts	113,794,114	102,187,092	86,590,221	86,290,141	87,403,054	11.4%	36.5%
Balance of PCE schedules	(452,062)	(198,191)	(5,307,793)	(7,985,871)	(12,528,950)	128.1%	-0.1%
VOLUMES SOLD	**311,493,877**	**318,561,565**	**313,425,166**	**336,961,297**	**329,949,207**	-2.2%	100.0%
VOLUMES NOT SOLD	**226,643,492**	**190,934,397**	**185,806,663**	**158,390,774**	**150,274,210**	18.7%	
TOTAL SUPPLY	**538,137,369**	**509,495,962**	**499,231,829**	**495,352,071**	**480,223,417**	5.6%	

2.2 The day-ahead market (MGP)

2.2.1 The National Single Price (Pun)

During 2011, in Europe prices on the major electricity Exchanges rose moderately, reflecting the Brent and its indexed fuel increase, only partly mitigated by the persistent, generalized demand stagnation[34].

The same happened in Italy, where the wholesale price of electricity was the highest in the continent: such effect was due to the structural gap resulting from, on average, a more costly generation fleet, still heavily depending on combined cycle gas plants and, most importantly, to the higher cost of raw material (gas) vis-à-vis the rest of Europe[35].

In a time of economic crisis, then, the strong upward trend of gas prices of the last two years actually supported domestic electricity prices. More than on foreign markets, this negative pattern was paid directly by consumers in their bills and, indirectly, caused an inflationary effect on final goods.

On the other hand, in 2011 the rising trend of the Pun, while affected by the higher price of fuels, was partly neutralized by a persistent system overcapacity, exacerbated by the new capacity from renewable sources. The ensuing real price increase turned out to be quite lower than its nominal value, as pushed by an increasingly available supply. Hence, prices were down and it was not always easy for producers to recover all the variable costs they had incurred.

To be more specific, in 2011 the Pun was equal to 72.23 €/MWh, with a yearly increase actually similar to neighboring countries (+12.6%) and a significant, faster downward trend of both volatility (7.6%, -4.2 p.p.) and the peak/off-peak hourly calibration (Tab C.2.4).

This latter looks especially interesting, in that it reflects the structural transformations that are increasingly changing the national generation mix.

On a market characterized by the steady rise of the thermoelectric supply, a massive injection of energy from photovoltaic plants during peak solar irradiation hours made the peak competitiveness significantly sharper, promoting a gradual convergence of prices towards levels recorded in other hourly bands.

Tab C.2.5 **Yearly average PUN, total and by groups of hours (€/MWh)**

€/MWh	2011	Tr.change	2010	2009	2008	2007
Total	72.23	12.6%	64.12	63.72	86.99	70.99
Peak-load (a)	82.71	7.7%	76.77	83.05	114.38	104.90
Off-peak (b)	66.71	16.3%	57.34	53.41	72.53	53.00
- Working day (b1)	64.32	18.7%	54.20	48.29	67.75	48.06
- Holiday (b2)	69.37	13.8%	60.98	59.27	77.88	58.58
Volatility	7.6%	-4.2 p.p.	11.9%	13.8%	10.4%	10.3%
a/b1	1.29	-9.2%	1.42	1.72	1.69	2.18
b2/b1	1.08	-4.2%	1.13	1.23	1.15	1.22

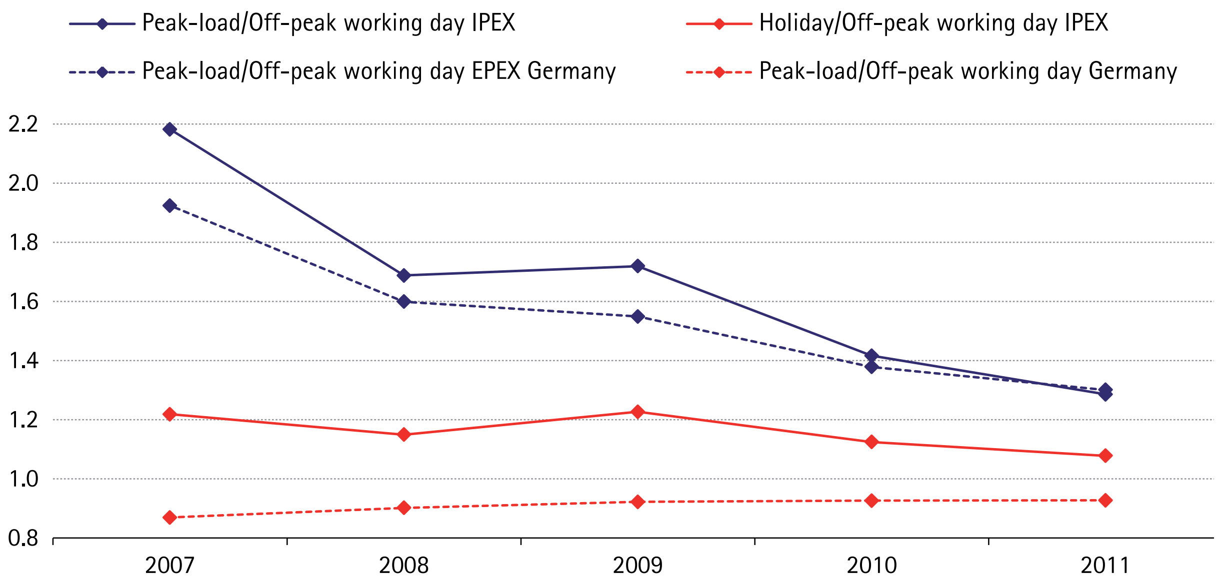
34 In 2011, according to estimates electricity consumption was quite stable (same, moderate level of the previous year in Italy and Germany); on the contrary, the demand heavily fell in France (-6.8%), where such low values had not been recorded since 2003 (Sources: Terna, BDEW, RTE).

35 Based on data collected in the major European hubs, in Italy prices were more expensive by 5.5 €/MWh than in the rest of Europe; this figure is twice as big in terms of electricity generation costs (Source: Thomson-Reuters).

By reason of this phenomenon, in 2011 the peak/off-peak price ratio dropped to 1.29 (-9.2%), in line with foreign, historically lower prices. Generally, the daily price profile was quite flattened.
Despite a mild weakening of such tendency during the first two months of 2012, this year there seems to be a stronger convergence process as the summer season approaches; in the absence of significant changes of market fundamentals, weather conditions and a large number of daylight hours could plausibly push the growing photovoltaic supply to its peak, with a possible reversal of the ratio of the two prices. A similar, although less evident trend, developed over the years in the holiday prices/off-peak ratio, which in 2011 fell down to 1.08 (-4.2%); differently from Europe, though, it is still greater than 1, by reason of a supply concentration remaining structurally higher during holidays hours (Fig. C.2.2).

International comparison of the ratio between prices in the different groups of hours[36]

Fig C.2.2

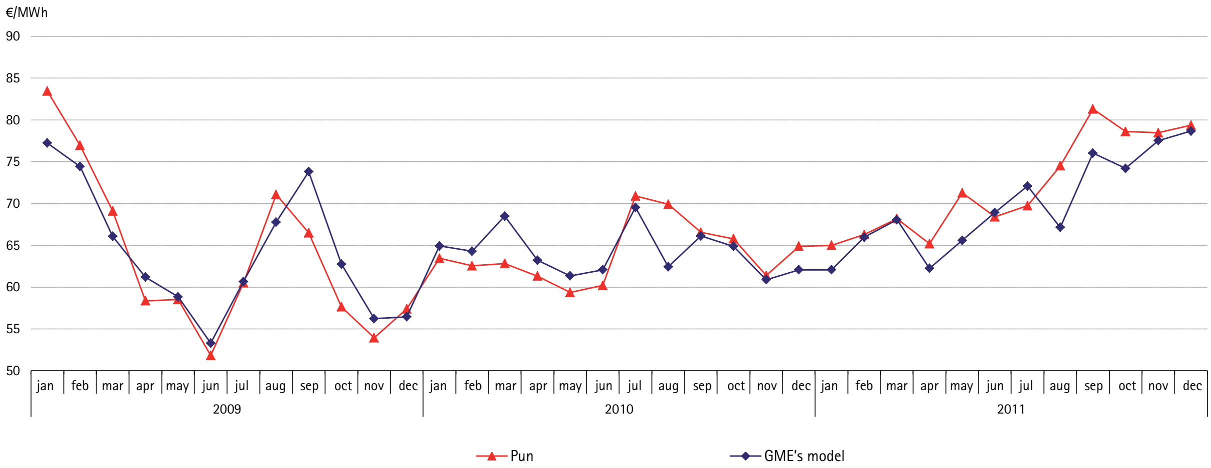


Broadly speaking, the profound change in the supply structure, with a weak, less and less variable demand[37], induced a flattening of prices in the Italian Power Exchange; this became clear with a smaller hourly variation and a weaker monthly cyclicity of the Pun in the last three years.
As a matter of fact, since 2009 Italian prices have been progressively and significantly cutting any seasonal fluctuations, to the benefit of a more direct alignment between the price dynamics and the basic trend represented by generation costs. This finding is consistent with the substantial stability of the price-setting technology in the various hours, with a progressive reduction of market power in all hourly bands.
A possible, temporarily weaker dependence of price upon the demand emerges from GME's econometric model. In 2011, while confirming the average soundness of relationships between prices and their components[38], a constant difficulty in reproducing a relative or absolute peak intensity was quite evident for the Pun during historically low consumption months, when the weight of a higher concentration (August) and the impact of

36 Fig. C.2.2 shows a comparison: these figures were calculated out of EPEX prices in the German market, a significant benchmark thanks to its traded volume.
37 The ratio between the highest and lowest value of the monthly electricity requirement, calculated by Terna, fell from 1.25, the average value in 2005-2010, to 1.16 in 2011. During the same time period, monthly purchases registered in the MGP dropped from 1.22 to 1.18. (Sources: GME, Terna)
38 For a more thorough analysis of the econometric model, please refer to Box 2 of 2009 Annual Report. The absolute mean error implied in the model is equal to 2.6 €/MWh in 2008-2011 and to 2.8 €/MWh in 2011.

local price dynamics seemed to prevail (May and, to some extent, September)[39] (Fig. C.2.3).

Fig C.2.3 **PUN estimate with GME's econometric model**



In particular, in 2011 the Pun, pushed by a greater increase in the business days off-peak price (66.71 €/MWh, +16.3%), showed a unique two-speed growth pattern: a modest, smaller growth than abroad between January and July (+8% on average) and a quite higher growth in the last four months of the year (+19% on average), when the gap with neighboring power exchanges was up to about 30 €/MWh[40]. In this respect, one should note the steep increase between July and September, bringing the price to around 80 €/MWh, kind of a break across a relatively flat tendency.

Indeed, the growth of electricity prices replicates the increase of generation costs; under the strong price rise in oil markets[41], the yearly average price increased by 19-21%[42], with a 14-21% price increase in January-July, followed by higher rises (22-33%) in the last five months of the year. The cost increase component inhibited the downward effects of overcapacity on the Pun, which reached a high level precisely between August and December (Tab C.2.6, Fig. C.2.4).

In real terms, however, the recovery of electricity prices implied a significant reduction of producers' profit margins embedded in prices, as shown by the spark spread values; despite some differences, they all tend to fall over the years, even below zero in the summer of 2011(Tab C.2.7, Fig. C.2.5).

Consistently with the growing share of sales taken up by solar energy plants in the most sunny hours of the day, with the subsequent weakening of the market power in the same hourly band[43], the narrowing of the spark spread mostly concentrated around peak hours, both during the first seven months, when Pun prices were more modest, and in the last four months of the year, when prices were higher[44]. In this perspective, the only exception to this generalized trend took place in October – December, between 6 and 8 p.m. These hours, within the peak band corresponding to medium-high consumption levels, represent the hours when

39 See Fig. C.2.7.

40 In January– July 2011, the price growth pattern was +9% in France and +24% in Germany. In August – December 2011, this value fell down to +4% in Germany, and became totally opposite in France, where prices dropped by 4% on the same period of the previous year. (Source: Thomson - Reuters).

41 For more details, please refer to par. C.1.1.

42 The variation gap reflects the lack of a sufficiently liquid spot gas market; for this reason, no univocal estimate of gas generation costs is available. This is why we estimated costs by taking as reference both the change pattern registered in prices at the PSV, a spot price reference for Italian gas, the price of Gas Release 2007, a reference for long term supply contracts, and, finally, any variation in the ITEC ccgt. All prices were appreciated and adjusted to a combined cycle plant with a 53% performance. ITEC ccgt was further reduced by 10% starting from the end of 2010, to consider the scouting practices existing in the wholesale gas market.

43 For further details, please refer to par. C.2.2.4.

44 With reference to ITEC ccgt, as defined in footnote 42, in January-July 2011 the overall fall of the spark spread was of -3.9 €/MWh (-57% versus 2010), whereas in September-December 2011 it was equal to -2.7 €/MWh (-33%).

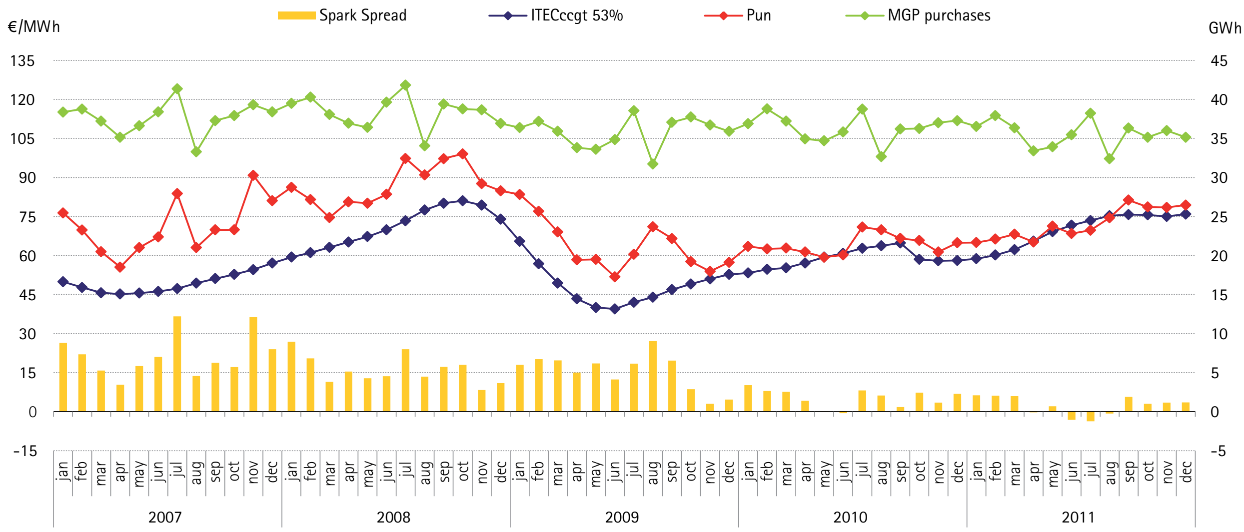
photovoltaic generation was less impactful; this suggests that participants concentrated their chances to minimize any profit losses accumulated in the remaining portion of the year within such time interval (Fig. C.2.6). Such phenomenon, with the expansion of photovoltaic generation and a persistent stagnation of consumption, could lead to a peak – off-peak price reversal, with some preliminary signals already visible in April 2012.

Yearly values of the PUN and its determinants Tab C.2.6

	2011	Tr.change	2010	2009	2008	2007
Pun (€/MWh)	72.23	+13%	64.12	63.72	86.99	70.99
Demand (MWh)	35,559	-2%	36,365	35,779	38,361	37,665
Oil prices						
Brent ($/bbl)	111.26	+40%	79.50	61.67	97.26	72.39
Brent (€/bbl)	79.92	+33%	59.95	44.22	66.11	52.82
$/€ rate	1.39	+5%	1.33	1.39	1.47	1.37
Gas cost indexes (€/MWh) [(a)]						
– Itec Ccgt	69.87	+19%	58.87	48.31	70.96	49.38
– PSV	53.26	+21%	43.95	34.74	54.83	23.22
– Gas Release 2007	63.81	+21%	52.70	46.31	59.80	42.57
Environmental charges (€/MWh)						
– GCs	5.58	+8%	5.15	4.61	3.35	4.18
– CO2 Ccgt	4.90	-9%	5.41	4.96	7.61	0.24
Combined-cycle generation cost (€/MWh)						
– Itec Ccgt	80.35	+16%	69.43	57.88	81.92	53.80
– PSV	63.74	+17%	54.51	44.31	65.79	27.64
– Gas Release 2007	74.28	+17%	63.26	55.88	70.76	47.00

(a) The gas cost reference values have been revaluated and referred to a combined-cycle plant with a 53% efficiency. The ITEC ccgt has been further reduced by 10% starting from the end of 2010 to account for the discounts applied in the wholesale gas market.

Trend of the Pun and its determinants[45] Fig. C.2.4



45 In this case, the ITEC ccgt was utilized as cost index, according to definition in footnote 42.

Tab C.2.7 **Spark spread level calculated with respect to the different gas-fired generation cost indexes**

€/MWh	2011	Tr. Change	2010	2009	2008	2007
- Spark Spread on *Itec Ccgt*	2.31	-56%	5.24	15.41	16.03	21.61
- Spark Spread on *PSV*	18.97	-6%	20.17	28.98	32.16	47.77
- Spark Spread on *Gas Release 2007*	8.42	-26%	11.42	17.41	27.20	28.41

Fig C.2.5 **Spark spread fluctuation range vs. reference cost change (€/MWh)[46]**

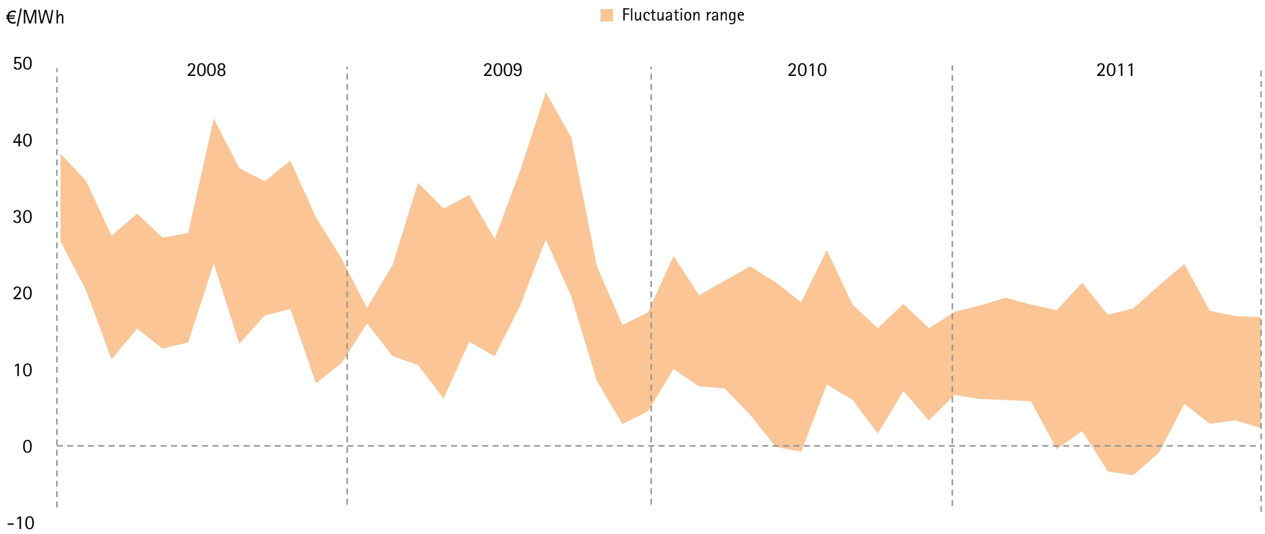


Fig C.2.6 **Hourly average spark spread level on business days (€/MWh)[47]**

46 The fluctuation range was put together by using, for each month of the years considered, the minimum and maximum values of the spark spread out of the three cost references, as under footnote 42.
47 See footnote 21.

2.2.2 Sale prices and zonal configuration

In 2011, the trend followed by zonal sale prices highlighted similar structural changes as the Pun's; amongst others, a continental alignment, the gradual convergence between the mainland and Sardinia and isolated local patterns in Sicily were confirmed.

By virtue of this development, prices were around 69-71 €/MWh in continental zones, where noteworthy differences keep occurring only in peak hours (about 5 €/MWh); on the other hand, they get close to 80 €/MWh in Sardinia, now detached from the peninsula only in times of limited availability of the interconnection cable (Sapei). As to Sicily, before evaluating any benefits resulting from the enhanced connection with Calabria due by the end of 2013, the price slightly exceeded 93 €/MWh, the highest in the System, despite the small growth propensity relative to 2010 (Tab C.2.8, Tab C.2.9).

In general terms, as with the Pun, all zonal prices showed a smaller volatility. This feature facilitated the progressive convergence of values across hourly bands. With respect to these latter, especially relevant in the Islands, the most important indications came from the South: on weekdays, the hourly calibration of prices was confirmed to be lower than elsewhere (1.22); the same pattern emerged in Sardinia, where holidays and off-peak prices are now equal (1.01) (Tab C.2.10).

Yearly average zonal prices (€/MWh) Tab C.2.8

€/MWh	2011	Tr. Change	2010	2009	2008	2007
PUN	72.23	12.6%	64.12	63.72	86.99	70.99
N Italy	70.18	13.2%	61.98	60.82	82.92	68.47
CN Italy	71.17	13.9%	62.47	62.26	84.99	72.80
CS Italy	70.86	13.2%	62.60	62.40	87.63	73.05
S Italy	69.04	17.0%	59.00	59.49	87.39	73.04
Sicily	93.11	3.8%	89.71	88.09	119.63	79.51
Sardinia	79.93	8.7%	73.51	82.01	91.84	75.00
Continental delta	2.13	-40.8%	3.60	2.91	5.07	4.75
Sardinia - Pun delta	7.70	-18.0%	9.39	18.29	4.85	4.01
Sicily - Pun delta	20.88	-18.4%	25.59	24.37	32.64	8.52

Yearly average zonal prices by groups of hours. Year 2011 (€/MWh) Tab C.2.9

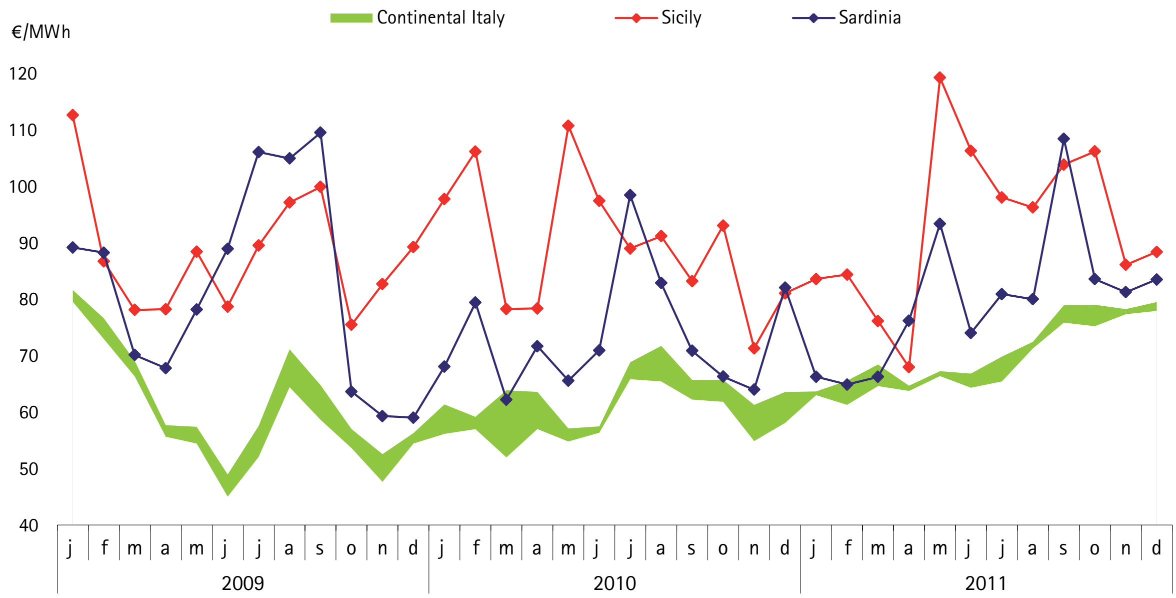
€/MWh	Total	Tr. Change	Peak-load	Tr. Change	Off-peak	Tr. Change	Off-peak work.day	Tr. Change	Holiday	Tr. Change
	72.23	12.6%	82.71	7.7%	66.71	16.3%	64.32	18.7%	69.37	13.8%
N Italy	70.18	13.2%	79.90	8.9%	65.05	16.5%	62.85	17.9%	67.51	14.8%
CN Italy	71.17	13.9%	81.96	10.3%	65.48	16.7%	63.22	18.5%	67.99	14.6%
CS Italy	70.86	13.2%	81.31	8.4%	65.36	16.8%	63.03	19.7%	67.96	13.7%
S Italy	69.04	17.0%	76.48	14.4%	65.12	18.8%	62.82	21.8%	67.68	15.6%
Sicily	93.11	3.8%	114.15	-5.0%	82.02	11.8%	77.48	17.7%	87.09	6.1%
Sardinia	79.93	8.7%	92.84	-0.6%	73.13	16.4%	72.68	21.3%	73.63	11.2%
Continental delta	2.13		5.48		0.43		0.40		0.48	
Sardinia - Pun delta	7.70		10.13		6.42		8.36		4.26	
Sicily - Pun delta	20.88		31.44		15.31		13.16		17.72	

Volatility and ratio between prices by groups of hours. Year 2011 Tab C.2.10

	PUN	N Italy	CN Italy	CS Italy	S Italy	Sicily	Sardinia
Peak/Off-peak working day	1.29 *(-9.2%)*	1.27 *(-7.6%)*	1.30 *(-6.9%)*	1.29 *(-9.4%)*	1.22 *(-6.1%)*	1.47 *(-19.3%)*	1.28 *(-18.0%)*
Holiday Off-peak working day	1.08 *(-4.2%)*	1.07 *(-2.6%)*	1.08 *(-3.3%)*	1.08 *(-5.0%)*	1.08 *(-5.1%)*	1.12 *(-9.9%)*	1.01 *(-8.3%)*
Volatility	7.6% *(-4.2 p.p.)*	7.5% *(-5.0 p.p.)*	8.9% *(-4.4 p.p.)*	9.5% *(-5.3 p.p.)*	9.4% *(-4.0 p.p.)*	15.6% *(-8.2 p.p.)*	16.5% *(-5.5 p.p.)*

trend changes between parentheses

Fig C.2.7 **Monthly trend of zonal prices. Years 2009 - 2011 (€/MWh)**



An analysis of the monthly evolution of prices in continental zones exhibits, quite similarly as with the Pun, a progressive compression of seasonal fluctuations; on the plus side, there was a reduced intra-yearly variability, totally unrelated from the typical demand pattern. Hence, unlike past observations, prices in the peninsula hit their highest in the months of August and September: right in these period, a structural leap occurred, and the reference threshold rose from 70 to 80 €/MWh in 2011.

On the other hand, in the islands prices tended to suddenly increase and right after fell down to the same levels observed on the mainland, within a framework of a gradually rising trend giving shape to specific peak price profiles. Very high values were noticed, in particular, in May and September, when connections with the mainland were reduced or inhibited (Fig. C.2.7).

Although the existing gap, in terms of price levels and variability, proves the existence of structural differences between the mainland and the islands, their convergent movement tends to confirm the positive impact of network and plant investment during the last three year period.

In the past, a historically inadequate interconnection capacity often led to use the costly local supply in the islands, causing remarkable, non sporadic price spikes.

This is happening much more rarely in Sardinia now, where the full operation of the new connection cable with the mainland (end of 2009) and its further enhancement in August 2011 paved the way to a greater integration with the mainland, with a consequent, gradually shrinking price gap. In 2011, this latter fell below 8 €/MWh (-18.0%). It should be noted that this value, slightly higher than 4 €/MWh for about 80% of the year, reached levels close to 50 €/MWh when transit was inhibited for longer than usual. At times, daily prices in the island even exceeded 200 €/MWh[48] (Fig. C.2.8 a).

Things improved in Sicily, too: here, the price gap with the mainland, still substantial and close to 21 €/MWh (-18.4%), was equal to 9 €/MWh for 70% of the hours.

As a matter of fact, the arrival of a new competitive power in 2010[49], translated into a dampening of non negligible structural differences between the Island and the rest of the country; fuel oil plants have progressively become

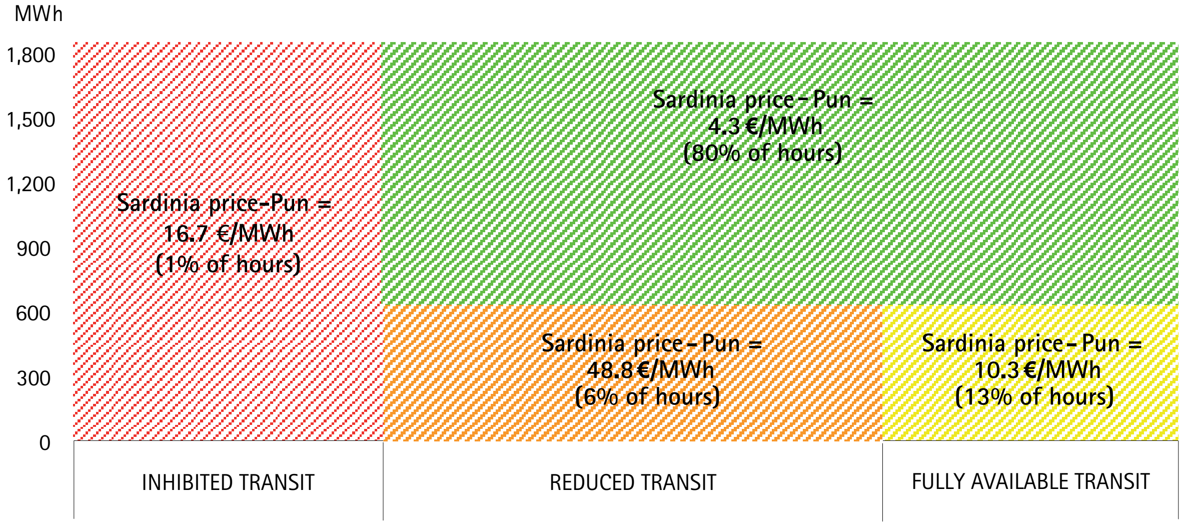
48 Reference is made to May and September 2011, characterized by bottlenecks in the CSUD-SARD transit (see Statistical Appendix).

49 In 2010, in Sicily new wind generating plants, the combined cycle plant of Nuce Nord and the second combined cycle unit of Isab Energy entered into operation, for an overall 1000 MW installed capacity.

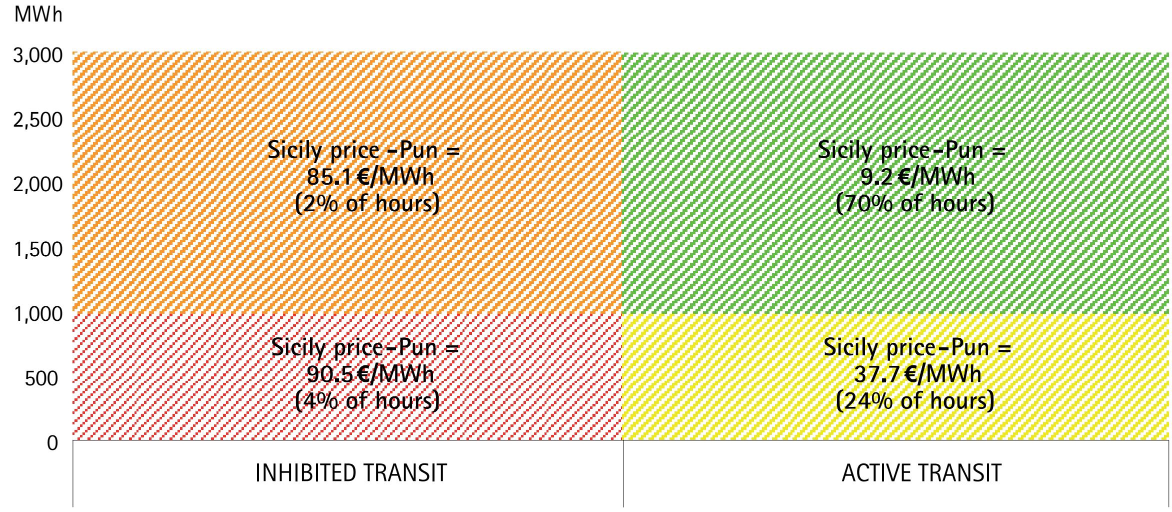
more marginal[50] and, especially during the first four months of the year, there has been a clear narrowing of the gap between zonal sale prices and Pun[51]. A broader availability of low cost energy has taken space away from more costly plants, with an immediately evident impact on both peak prices (the only ones showing a significant drop across the "Sistema Italia" (-5%), and on off-peak hours, with more hours showing prices below 10 €/MWh. Conversely, the gap with the mainland became quite large when the connection cable was unavailable or poorly available (the cable is expected to be expanded by the end of 2013) or when the available power was less: in those circumstances, Sicilian prices were on average higher than the national price by approximately 48 €/MWh[52] (Fig. C.2.8 b).

Key variables in the evolution of prices on Italian islands. Year 2011 Fig. C.2.8

a) Sardinia



b) Sicily



50 In 2011, the fuel oil ITM in Sicily went down to 19.5%, still higher than in the rest of the country (5.5%), but declining by 13.2 p.p. (trend pattern). During the same year, the combined cycle ITM made a notable leap up to 66.3%, in line with the overall value observed for the Sistema Italia, with a growth of 18.2 p.p. (see Statistical Appendix).

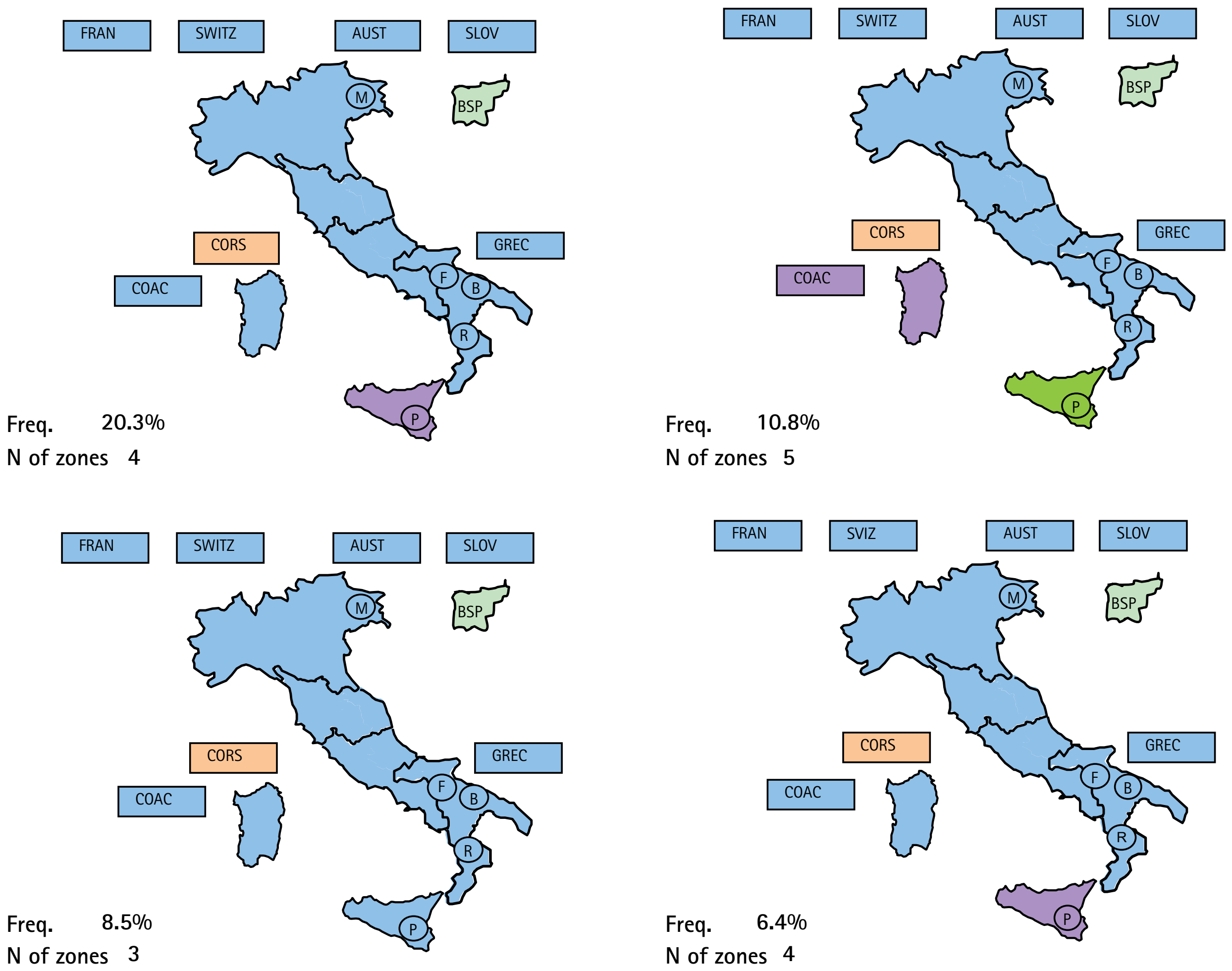
51 The differential with the Pun was of 11.7 €/MWh in the first 4 months of 2011, and 25.35 €/MWh in the rest of the year. A heavy gap was observed in May when it was equal to 47.95 €/MWh.

52 This is the average value weighted for the hours of price spread reported in Fig. C.2.8 b.

The price alignment in the mainland and the gradual integration of the islands translated into a reduced zonal fragmentation, measured by the lower average number of market zones (2.39) and by the higher number of hours during which the System was unified or split in just two zones (57.9%)[53].

Overall, the growth of zonal cohesion caused a clear-cut decline of the congestion income (coupling with Slovenia has been contributing to it since 2011), down to 177 million euro (-26%); this was especially due to a halved amount collected along the SOUTH-CSOUTH direction, less saturated than in 2010 (-7.9 p.p.).

Fig C.2.9 Most frequent market configurations. Year 2011



53 For more details, refer to the "Statistical Appendix" Italian Version only.

Box 2 THE MARKET COUPLING WITH SLOVENIA

The market coupling with Slovenia became operational on 1 January 2011. It is quite important for the future coupling processes that Italy shall implement with other borders by 2014, to fulfill the Third Package objectives and ACER Framework Guidelines on Capacity Allocation and Congestion Management for Electricity, according to the deadlines set by the European Commission. In particular, the decentralized coupling model adopted on the Slovenian border exactly replicates the so called Price Coupling of Regions (PCR): GME is developing this latter in collaboration with other major European Exchanges, as a reference model for the future European Price Coupling mentioned by ACER itself (see paragraph 1.3).

The operational kickoff of the project enables an efficient daily allocation of the interconnection capacity quota with Slovenia – previously allocated by means of daily explicit auctions. The foreign virtual zone "BSP", receiving bids/offers from the Slovenian Exchange, is now integrated with the Italian market. The capacity allocated to this zone, according to a spare reserve principle shared by national regulators, represents just a proportion of the overall interconnection capacity between Italy and Slovenia, originally set at 35 MW out of an average 460 MW available along this border: as it happened in the past, the remaining quota keeps being allocated through monthly and yearly explicit auctions and is run through the foreign virtual zone "Slovenia".

After one year of operation, the project success is confirmed by three significant aspects, as listed below.

The first one is the market coupling potential attraction of higher volumes than those initially guaranteed by clearing: in 2011, the allocated capacity grew from an average 64 MW in January to 165 MW in December; this major increase was even bigger in early 2012, when – exactly when 2011 yearly import contracts were expiring – volumes allocated to the BSP zone reached a level of 526 MW in the month of March, i.e. 97% of the overall capacity allocated to these two countries (Fig II.1). This figure reflects a clear participants' appreciation for this type of system. Indeed, they extensively opted for the "use it or sell it" covenants, a unique feature in the purchase of foreign interconnection capacity; such covenants allow participants to sell back to the TSO the forward import capacity purchased and buy it back in the spot market by placing sale offers on the Slovenian day-ahead market, while keeping the same price guarantees provided by capacity explicit auctions. An indirect proof of this success lies precisely in the liquidity growth registered by the Slovenian Exchange, with volumes rising to 1.5 TWh in 2011 versus about 0.2 TWh in 2010, with an unprecedented continuing operation. Amongst others, this confirms that it is possible to implement coupling projects with neighboring countries where wholesale markets have little liquidity, thanks to the coupling mechanism ability to extend resources from larger to smaller markets.

The second evidence of the Slovenian coupling success is its expected result: an improved efficiency in the utilization of the interconnection infrastructure between the two countries, i.e. the system ability to allocate, at all times, the transit capacity along a direction consistent with the price spread between the two borders, with a guaranteed full usage every time the differential is positive. In 2011, in fact, the flows resulting from market coupling were 100% efficient, vis-à-vis 98.2% under the previous mechanism based on explicit auctions: in absolute terms, this may seem a limited difference: the high price gap between the two borders makes it pretty simple, in most cases, to predict its pattern and consequently define coherent transit flows; still, it is a significant achievement in that a 100% allocation in the BSP zone includes 3% of export flows, whereas 98% allocated to Slovenia is always an import share.

Finally, a third reason of success is the coupling mechanism ability to promote a progressive convergence of prices between two wholesale markets.

While not reaching a full convergence of prices across the Italian and Slovenian Exchange (in 2011, 70.18 €/MWh and 57.20 €/MWh, respectively; during the first quarter of 2012, 81.24 €/MWh and 64.75 €/MWh, respectively), the progressive increase of capacity allocated through market coupling has indeed mitigated the impact of the generation costs differential between the two countries, promoting a growing equality between prices in the Northern zone and BSP prices. In particular, an hourly analysis shows that in 2011 prices were equivalent in 20% of cases, versus no equivalence at all in 2010. In the reference period, this convergence process gradually and steadily grew from 11% during the first eight months of 2011 to 37% in the last four months of 2011 and further up to 43% in the first quarter of 2012 - 73% of which in the month of February – when the wholesale price in the Italian zone has been lower than the Slovenian one for the first time ever (3% of cases) (Fig II.2).

Fig II.1 **Capacity allocation on the Italian-Slovenian border**

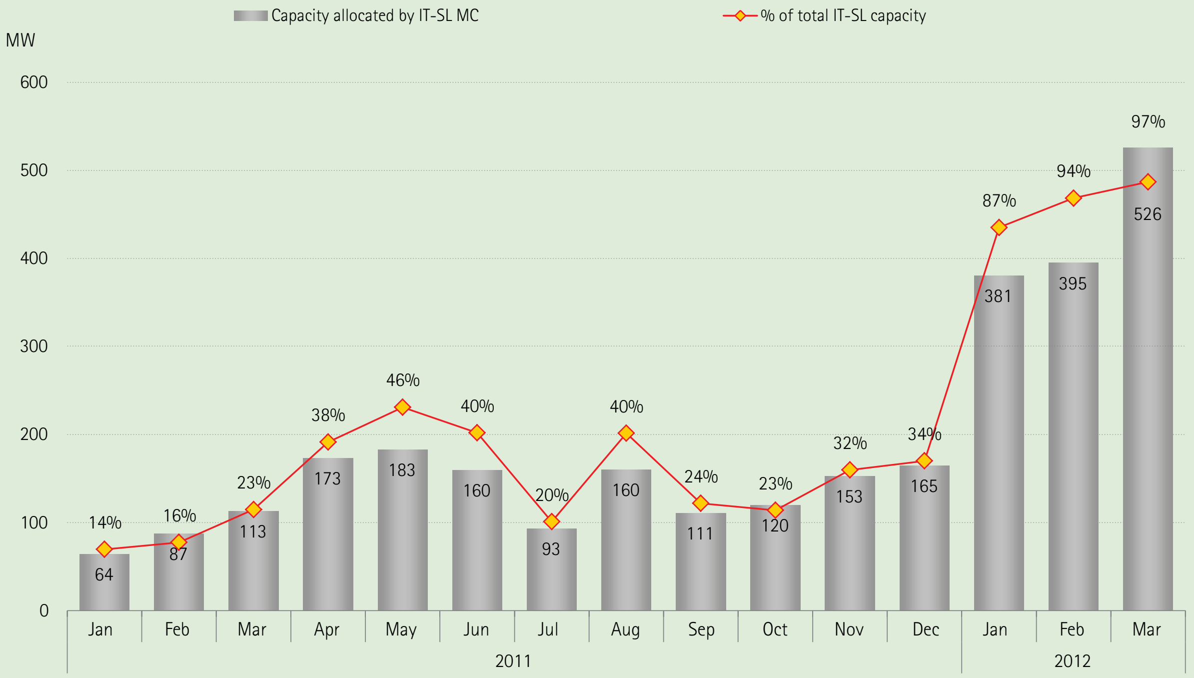
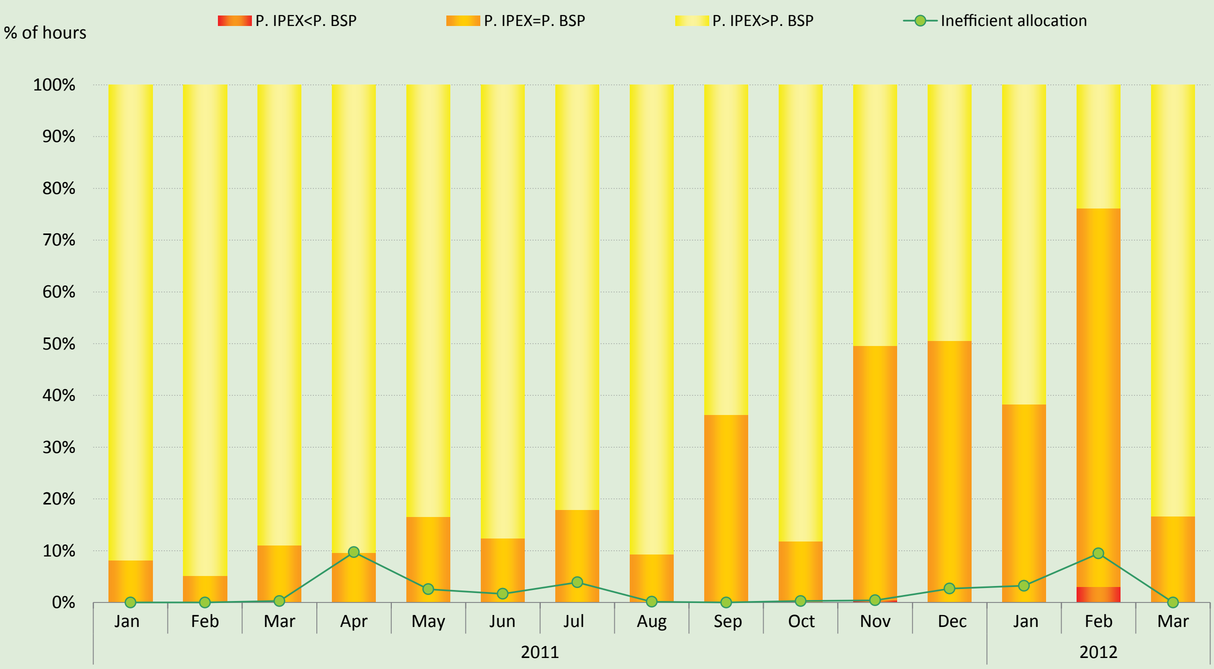


Fig II.2 **IT-SL price spread and inefficient capacity allocation**



2.2.3 Demand and supply

The year 2011 was characterized by a further narrowing of the supply and demand gap, with a net supply increase (+6%), also thanks to the growth of photovoltaic generation, and a new demand decline (-2%) after a weak recovery in 2010, hitting a historical minimum since the take-off of the Exchange (311.5 TWh). This reduction in the relative scantiness of the supply strengthened the trend heading for a gradual improvement of the main competitiveness indicators, limiting the price inflationary drive in the MGP, where the growth rate was smaller than generation costs.
However, these data underestimate the growth of the supply excess due to the changes in the Italian generation arena and, more broadly, the functioning of the electricity market and the impact of the growth of renewables, non schedulable installed capacity. As far as the demand is concerned, renewables accounted for a rise in self-consumption off the market, with artificially low volumes registered in the MGP. This is confirmed by a decline in purchases in the day-ahead market not matched by a drop in electricity requirement recorded by Terna, with 332.3 TWh, a similar level as in the previous year (+0.6%). Such difference was not observed two years ago, during the previous acute economic crisis; this pattern does confirm a trend reversal in the ratio between market and physical volumes falling down to 93.7% in 2011, for the second year in a row (Tab C.2.11).
On the other hand, the increased supply induced by renewables is underestimated by looking at bids/offers submitted in the MGP; non schedulable sources define nominations less reliable than those from conventional sources; first, forecasts are more tentative: secondly, they are subject to dispatching rules according to which the actual deviation fee is equal to the MGP price[54].

Demand in the MGP and total electricity demand on the grid (TWh) Tab C.2.11

TWh	2011	2010	2009	2008	2007
TOTAL DEMAND*	332.27	330.46	320.27	347.1	347.6
MGP VOLUMES**	311.5	318.6	313.4	337.0	329.9
MGP VOLUMES/TOTAL DEMAND*	93.7%	96.4%	97.9%	97.1%	94.9%

* including purchases by pumped-storage plants
** including OTC contracts

2.2.3.1 Demand

MGP purchases diminished across nearly all national zones, with an exceptionally high reduction of purchases from pumping units; for the first time since the market startup, they were below one TWh (-67%). This behavior reflects the sudden, accelerating downward trend, in existence since 2010, shown by the peak/off-peak price ratio. This trend seems destined to continue also this year, by virtue of the photovoltaic explosion, making the peak competitiveness significantly pronounced[55]. Both in the North and in Sicily, i.e. in zones where pumping units are in large numbers, a drop in purchases by these latter does contribute to the demand decline by 18% and 90%, respectively. Although smaller, there has also been a significant decline of purchases in foreign zones, hitting a historical minimum of 3.5 TWh. This downward pattern mostly occurred in the last quarter of the year. In 2010, trade export was still quite high by reason of the supply criticalities observed in the French plants.
In 2011, a highly anelastic demand in the national zones was confirmed, being equal to 0.2%. A slight increase

54 For this reason, producers from non schedulable renewables have no interest in offering their volumes on the market. To be precise, they might be tempted not to offer their generation on the market, making the supply scanty, so as to support a price level which, at any rate, represents the unit revenue of their actual generation.
55 For more details, please refer to par C.2.2.

was observed for pumping units (1.8%), in line with the above mentioned convergence between peak and off-peak prices, promoting the submission of bids/offers for a specified price in order to prevent a cost-ineffective usage of plants. On the contrary, at the borders the share of elastic demand, in spite of a slight decline vis-à-vis 2010, keeps accounting for the largest share of the overall demand (91.2%), with participants seeking cross-border trading opportunities. Finally, it should be noted that out of 8.3% of bids/offers for a maximum price, 7.9% of them were rejected, a further proof of stringent nature of prices (Tab C.2.13).

Tab C.2.12 **Volumes purchased in the MGP**

*Zones**	*2011*	*2010*	*2009*	*2008*	*2007*	*2011/2010 % change*	*Structure*
N Italy*	165.5	172.4	168.0	181.0	179.3	-4.0%	53.1%
CN Italy	34.0	34.5	33.7	35.9	36.5	-1.4%	10.9%
CS italy	49.6	50.4	49.7	33.3	32.7	-1.6%	15.9%
S Italy*	25.5	25.6	26.1	46.6	45.4	-0.2%	8.2%
Sicily*	19.9	20.0	19.7	20.5	19.9	-0.8%	6.4%
Sardinia	13.5	11.8	11.8	12.3	12.4	14.3%	4.3%
Italy	308.0	314.7	309.2	329.7	326.2	-2.1%	98.9%
pump.st. plants	0.9	2.9	2.9	5.1	6.3	-66.9%	0.3%
fin.customers	307.0	311.9	306.3	324.6	319.8	-1.6%	98.6%
Neigh. coun.	3.5	3.8	4.3	7.3	3.8	-8.1%	1.1%
Total	**311.5**	**318.6**	**313.4**	**337.0**	**329.9**	**-2.2%**	**100.0%**

Demand elasticity Tab C.2.13

		BIDS/OFFERS WITH SPECIFIED PRICE, SUBMITTED				
		2011	2010	2009	2008	2007
*Italy**	MWh	664,426	293,437	1,159,384	1,869,625	663,913
	% of total	*(0.2%)*	*(0.1%)*	*(0.4%)*	*(0.6%)*	*(0.2%)*
- Pump.stor.plants	MWh	16,973	30,359	78,439	171,990	142,218
	% of total	*(1.8%)*	*(1.1%)*	*(2.7%)*	*(3.3%)*	*(2.3%)*
Neighbouring countries	MWh	27,469,805	28,016,290	26,710,804	18,838,282	6,453,700
	% of total	*(91.2%)*	*(93.0%)*	*(91.8%)*	*(81.9%)*	*(73.5%)*
- France	MWh	7,779,042	8,092,780	8,737,147	6,954,190	66,915
	% of total	*(89.1%)*	*(92.1%)*	*(93.9%)*	*(85.5%)*	*(19.7%)*
- Switzerland	MWh	15,709,276	15,252,587	12,503,608	7,921,345	5,140,644
	% of total	*(92.7%)*	*(94.0%)*	*(90.9%)*	*(84.8%)*	*(93.9%)*
- Austria	MWh	1,319,998	1,013,817	1,126,975	779,224	750
	% of total	*(99.8%)*	*(99.7%)*	*(98.6%)*	*(96.6%)*	*(6.0%)*
- Slovenia	MWh	98,839	363,900	226,932	423,100	494,014
	% of total	*(99.8%)*	*(100.0%)*	*(97.0%)*	*(71.2%)*	*(73.2%)*
- Greece	MWh	2,562,650	3,293,206	4,116,142	2,760,423	751,377
	% of total	*(97.8%)*	*(98.8%)*	*(97.0%)*	*(74.2%)*	*(41.7%)*
Total	MWh	28,151,205	28,340,086	27,948,627	20,879,898	7,259,831
	% of total	*(8.3%)*	*(8.2%)*	*(8.2%)*	*(5.9%)*	*(2.2%)*

(*) Net of pumped-storage plants.

		BIDS/OFFERS WITH SPECIFIED PRICE, REJECTED				
		2011	2010	2009	2008	2007
*Italy**	MWh	110,903	165,603	938,285	1,544,786	509,529
	% of total	(0.0%)	(0.1%)	(0.3%)	(0.5%)	(0.2%)
- Pump.stor.plants	MWh	19	17,833	24,089	56,184	36,626
	% of total	(0.0%)	(0.6%)	(0.8%)	(1.1%)	(0.6%)
Neighbouring countries	MWh	26,605,316	26,303,528	24,828,168	15,755,284	4,927,730
	% of total	(88.3%)	(87.3%)	(85.4%)	(68.5%)	(56.2%)
- France	MWh	7,684,935	7,621,630	8,356,081	6,442,873	1,165
	% of total	(88.1%)	(86.8%)	(89.8%)	(79.2%)	(0.3%)
- Switzerland	MWh	15,385,893	14,322,774	11,481,491	6,447,574	4,140,683
	% of total	(90.8%)	(88.2%)	(83.5%)	(69.0%)	(75.7%)
- Austria	MWh	1,315,608	1,002,335	1,111,029	722,411	-
	% of total	(99.5%)	(98.5%)	(97.2%)	(89.5%)	(0.0%)
- Slovenia	MWh	74,822	348,489	212,225	314,765	147,603
	% of total	(75.5%)	(95.7%)	(90.7%)	(53.0%)	(21.9%)
- Greece	MWh	2,144,057	3,008,301	3,667,342	1,827,661	638,279
	% of total	(81.8%)	(90.3%)	(86.5%)	(49.1%)	(35.4%)
Total	MWh	26,716,237	26,486,965	25,790,543	17,356,254	5,473,885
	% of total	(7.9%)	(7.7%)	(7.6%)	(4.9%)	(1.6%)

(*) Net of pumped-storage plants.

2.2.3.2 Supply

In 2011, a generalized trend observed in the last eight years was confirmed: the efficient generation power rose again by 10%, up to 121,542 MW. Such increase offsets a weak recovery of thermal power which grew considerably in the past and is now quite slower (+1%), whereas renewable sources have expanded to a large extent. This is especially evident for photovoltaic plants, with a gross efficient generation power up to 12,750 MW – equal to 10% of total power – and a growth rate of nearly 270%[56].
Hence, the overcapacity becomes even more striking, with an increase of the national supply by about 30 TWh in the MGP. Conversely, in virtual foreign zones the supply slightly dropped (-3%), although this seems to affect quantities offered at relatively less competitive prices. In fact, in those zones sales recovered (2.3%), with trade export levels close to 50 TWh, to the detriment of more costly national offers, promoting a new increase of the MGP sales quota met by the foreign supply (16%; +1 p.p.).

Tab C.2.14 **Yearly volumes offered in the MGP (TWh)**

*Zones**	*2011*	*2010*	*2009*	*2008*	*2007*	*2011/2010 % change*	*Structure*
N Italy*	243.6	223.7	226.7	229.8	219.9	9%	45%
CN italy	40.4	39.4	38.2	38.4	38.2	3%	8%
CS Italy	71.4	66.8	61.6	40.7	40.1	7%	13%
S Italy*	82.0	75.7	71.1	83.9	76.6	8%	15%
Sicily*	30.0	32.4	29.2	29.7	29.6	-7%	6%
Sardinia	18.4	17.7	17.2	18.1	18.6	4%	3%
Italy	485.9	455.6	444.2	440.5	422.9	7%	90%
Neigh.countr.	52.3	53.9	55.0	52.6	55.9	-3%	10%
Total	**538.1**	**509.5**	**499.2**	**493.1**	**478.8**	*6%*	100%

Therefore, the drop in volumes sold in the MGP (-2.2%) was solely concentrated in those national zones where there was an oversupply, as proven by the level of rejected volumes, increasing by nearly 39 TWh. On a zonal level, the increase of rejected offers looks more significant in the North vs South; in those zones, on the other hand, the supply grew relatively more (+8/9%) with a decline of sales greater than (North) or aligned (South) with the average decrease observed nationwide.
In terms of structure, these zones keep covering the largest proportion of overall sales, with a 42% share in the North (-1 p.p. on 2010) and 16% in the South. Also, this latter appears to be the only net exporting zone (Tab C.2.15 and Tab C.2.16).

Tab C.2.15 **Yearly volumes sold in the MGP (TWh)**

*Zones**	*2011*	*2010*	*2009*	*2008*	*2007*	*2011/2010 % change*	*Structure*
N Italy*	129.9	137.6	136.2	154.2	148.9	*-5.6%*	42%
CN italy	20.2	22.0	20.5	22.9	24.4	*-8.4%*	6%
CS Italy	31.2	28.6	24.8	16.4	16.8	*9.1%*	10%
S Italy*	49.6	51.2	51.2	63.7	56.5	*-3.1%*	16%
Sicily*	19.2	19.3	19.0	20.1	19.8	*-0.9%*	6%
Sardinia	11.6	11.1	11.4	11.9	13.0	*4.5%*	4%
Italy	261.6	269.8	263.1	289.2	279.4	*-3.0%*	84%
Neigh.countr.	49.9	48.8	50.3	47.8	50.6	*2.3%*	16%
Total	**311.5**	**318.6**	**313.4**	**337.0**	**329.9**	***-2.2%***	**100%**

56 Source: Terna and Gse.

Yearly volumes rejected in the MGP (TWh) Tab C.2.16

Zones*	*2011*	*2010*	*2009*	*2008*	*2007*	*2011/2010 % change*	*Structure*
N Italy*	113.7	86.1	90.6	75.5	71.0	*32.1%*	50%
CN italy	20.3	17.4	17.7	15.5	13.8	*16.4%*	9%
CS Italy	40.2	38.2	36.8	24.3	23.3	*5.3%*	18%
S Italy*	32.4	24.5	20.0	20.2	20.1	*32.2%*	14%
Sicily*	10.9	13.0	10.2	9.6	9.8	*-16.5%*	5%
Sardinia	6.8	6.6	5.8	6.3	5.5	*2.0%*	3%
Italy	224.3	185.8	181.1	151.4	143.5	*20.7%*	99%
Neigh.countr.	2.4	5.1	4.7	4.7	5.3	*-53.2%*	1%
Total	**226.6**	**190.9**	**185.8**	**156.1**	**148.8**	***18.7%***	***100%***

Relative to the overall amount of registered sales, system-wide the zero price supply share slightly diminished down to 67.4%, reflecting opposite changes in the Exchange, up by approximately 2%, and in bilaterals, with a substantial decrease which brings the share of null price volumes to 78.4% (new absolute minimum). The slight increase in the Ipex is consistent with the expansion of renewable sources which are known to submit null price sale offers in the MGP. On the other hand, the downward trend observed on the PCE confirms an increasingly common use of the platform's flexibility options. Their use, especially in 2011, is the logical consequence of a proportionately higher growth of generation costs versus the Pun: participants were encouraged to submit bids/offers for a specific price in order to capitalize on arbitrage opportunities between the cost of their plants and any possibly lower prices in the market (Tab C.2.17).

Volumes sold at zero price in the MGP Tab C.2.17

	Shares of 'Sistema Italia'					Shares of IPEX					Shares of PCE				
	Total					Total					Total				
	2011	2010	2009	2008	2007	**2011**	2010	2009	2008	2007	**2011**	2010	2009	2008	2007
*N Italy**	**63.2%**	62.3%	65.3%	65.3%	66.6%	**35.5%**	32.6%	32.9%	22.8%	27.0%	**78.9%**	82.1%	93.5%	96.8%	94.2%
CN Italy	**87.5%**	88.4%	89.8%	62.4%	63.8%	**33.4%**	31.2%	32.1%	10.5%	12.6%	**92.1%**	95.6%	98.4%	100.0%	100.0%
CS Italy	**44.0%**	55.0%	70.0%	72.1%	59.8%	**39.9%**	37.9%	34.8%	8.0%	17.6%	**20.6%**	26.1%	97.0%	99.9%	99.9%
*S Italy**	**73.4%**	74.4%	80.0%	60.9%	56.8%	**31.0%**	31.6%	39.7%	32.3%	26.0%	**86.7%**	95.9%	100.0%	100.0%	98.9%
*Sicily**	**47.8%**	46.4%	39.8%	43.4%	39.8%	**19.5%**	15.3%	14.5%	13.5%	7.2%	**23.7%**	21.8%	51.4%	100.0%	100.0%
Sardinia	**87.0%**	74.7%	70.9%	73.0%	69.9%	**17.1%**	7.2%	2.7%	5.7%	9.1%	**90.0%**	70.8%	76.5%	91.9%	99.8%
Neigh.countr.	**81.9%**	86.5%	88.3%	91.2%	93.3%	**73.7%**	78.2%	80.6%	79.9%	78.8%	**100.0%**	100.0%	100.0%	100.0%	100.0%
Total	**67.4%**	68.6%	72.0%	67.2%	67.0%	**40.3%**	38.2%	38.7%	27.1%	26.2%	**74.8%**	80.0%	94.4%	97.9%	96.7%

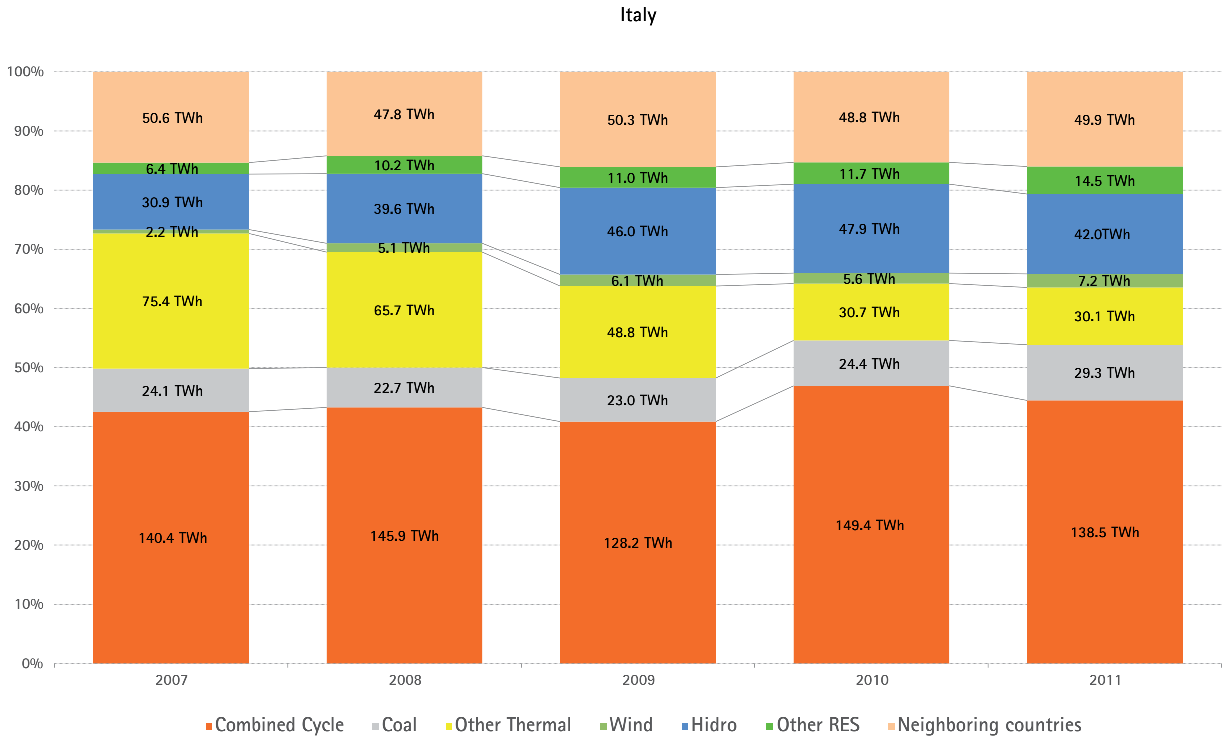
2.2.3.3 Sales and performance by source and technology

The increase of renewables installed power translated into a marked increase of the relevant sales in the MGP[57]. In greater detail, wind energy sales and those from technologies classified as 'other renewables' – including photovoltaic energy – reached a historical maximum level (7.2 and 14.5 TWh, respectively), i.e. they increased by 29% and 24%. Taken together, they accounted for 7% of total purchases. With a declining demand, the main 'victim' of this trend was combined cycle generation, with a sale drop down to 138.5 TWh (-7%). This was also due to the inflationary trend affecting gas as raw material, making the combined cycle supply less competitive, after being undermined by a larger offer of technologies characterized by zero variable costs. A strong decrease was also observed for hydroelectric sales (about -6 TWh), already suffering from smaller sales and purchases with respect to pumping units (approximately, -1 TWh). Moreover, coal plants significantly increased in terms of sales (+4.9 TWh), nearly entirely in the Center-South, where sales from this source were up to 13.2 TWh, i.e. a record growth of 214%. The same applies to zonal level, where a number of structural phenomena from past years was confirmed. The only exception is the Center-South,

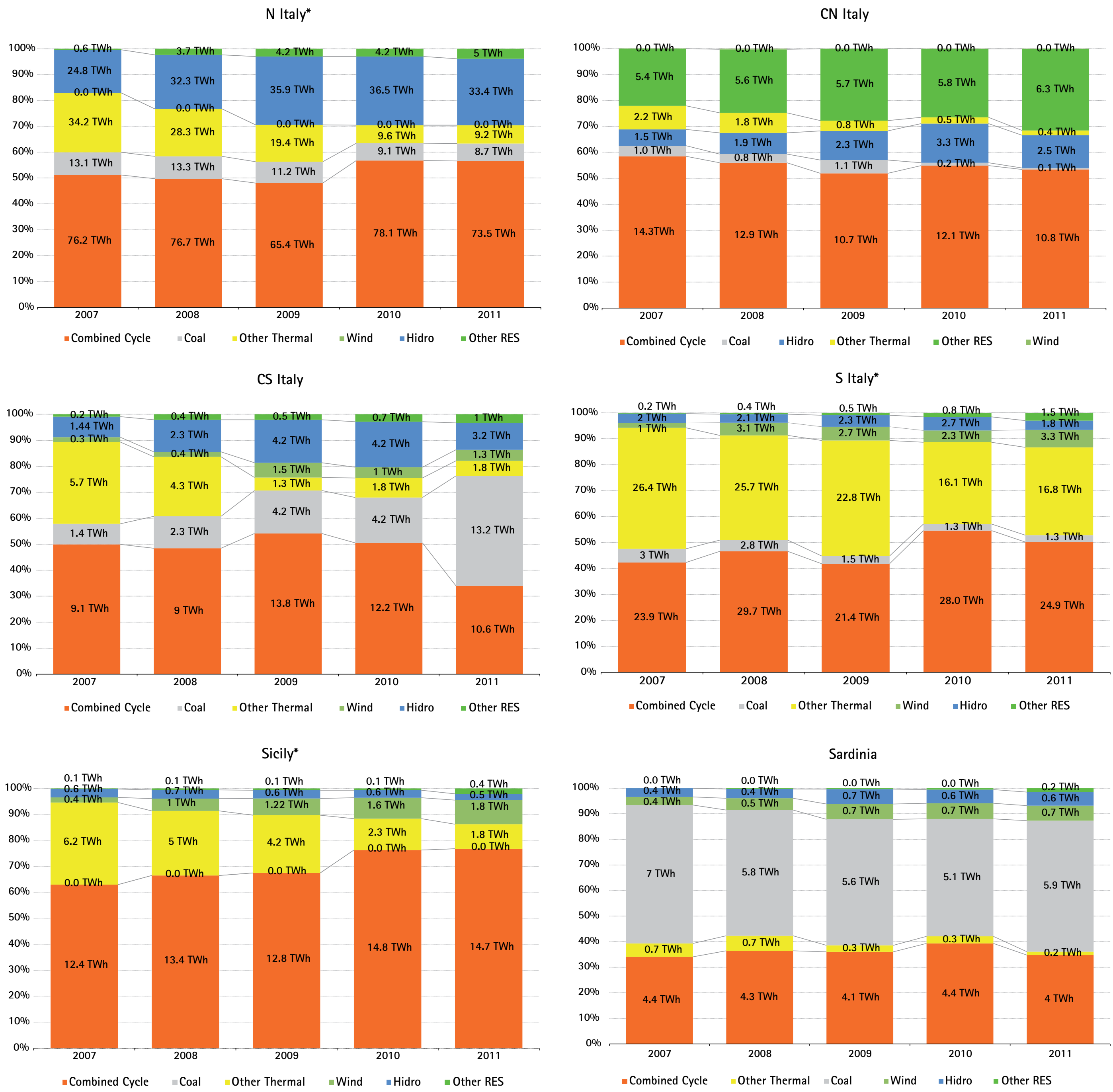
57 Nonetheless, as explained in paragraph 2.2.3.1, only a portion of energy from renewables goes through the MGP.

where the explosion of coal sales was the same as in Sardinia; generation from such source accounts for the largest sale share, i.e. 42% of total sales in the Center-South and 50% in the island.

Fig C.2.10 **Sales by technology and source**

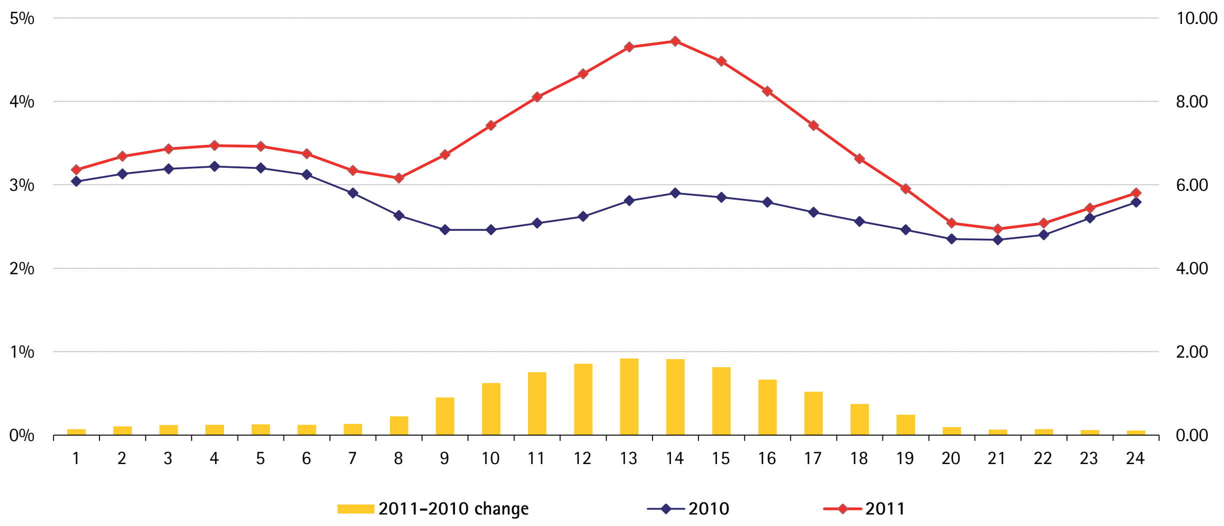


Sales by technology and source, by zone Fig C.2.11



As to sales from renewable sources, particularly from wind and photovoltaic plants, it is worth examining the hourly changing pattern of these latter, given the impact of dispatched volumes on price levels and hourly profile. In particular, during the central hours of the day, the share of sales from wind and photovoltaic generation grew from less than 3% to nearly 5%; during those hours, marginal competitiveness considerably increased and, as a consequence, the price increase was limited (to this end, see paragraph 2.2 for an analysis of the impact of such sources on the peak and off-peak price ratio). Still, this finding underestimates the impact of renewables in those hours; consideration should also be given to the extra supply not submitted in the MGP by reason of the different rules applicable to deviation charges, although active in real time (with a minimum impact on MB), and the smaller market demand due to the potential local self-consumption of photovoltaic generation.

Fig C.2.12 **Share of sales by wind and PV plants. Hourly average on business days**



The increase in marginal competition, induced by the stronger presence of renewable sources and, more broadly, by a larger overcapacity, is equally confirmed by analyzing the performance of the various technologies. Combined cycles and technologies classified under 'other thermal' – mostly including co-generation plants, self-producers and waste-to-energy facilities - were remarkably less successful, in terms of sales and offered volume ratio, or in terms of the decreasing average number of hours with accepted bids/offers. This pattern is quite meaningful with respect to combined cycles, showing a success rate down to 63% (-11 p.p.); its schedules, as defined after the MGP, covered an average number of hours equal to 4,745 (against 5,327 in 2011). The most striking phenomenon, most likely, is the spark spread trend, at 5.66 €/MWh (-3 €/MWh, approximately) despite quite different zonal values: zones more exposed to competition are around 3.78 €/MWh (North) or even below 1 €/MWh (South); the same goes for Sicily, where a greater concentration enables participants to achieve an estimated profit margin of 28 €/MWh. An analysis of the spark spread duration curve, for units belonging to continental zones, suggests that the real Pun had never been so low, with shrinking profit margins for the more efficient units, or those more open to competition, than the less competitive ones (Tab C.2.18 and Fig. C.2.13).

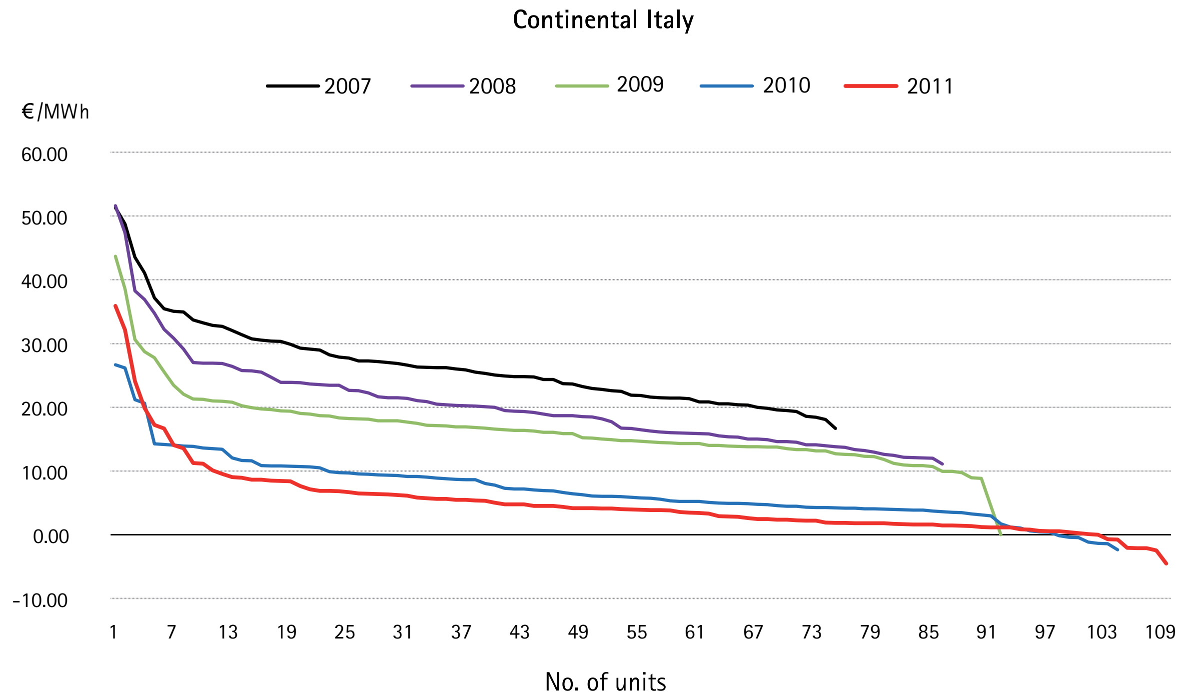
Tab C.2.18 **Performance indexes of combined cycles, by year and zone**

		No. of units						Avg no. of hours with accepted bids/offers					
		2011	2010	2009	2008	2007	Delta%	2011	2010	2009	2008	2007	Delta%
Combined Cycle (no GSE)	N Italy*	71	69	66	63	57	3%	4,871	5,283	4,875	5,715	6,324	-8%
	CN Italy	7	7	5	5	5	0%	4,290	5,659	4,451	5,125	6,598	-24%
	CS Italy	11	10	8	3	3	10%	3,432	4,570	4,422	5,644	5,766	-25%
	S Italy*	20	18	13	15	10	11%	4,418	4,295	4,785	5,284	6,409	3%
	Sicily*	5	5	4	3	4	0%	7,782	8,073	6,432	7,823	5,709	-4%
	Sardinia												
	Total	114	109	96	89	79	5%	4.745	5.206	4.868	5.678	6.300	-9%

		Success rate (sold volumes/offered volumes)						Spark Spread* (€/MWh)					
		2011	2010	2009	2008	2007	Delta%	2011	2010	2009	2008	2007	Delta%
Combined Cycle (no GSE)	N Italy*	60%	73%	70%	82%	83%	-17%	3.78	7.06	16.75	18.18	24.81	-46%
	CN Italy	41%	54%	42%	57%	74%	-25%	4.73	6.88	14.82	21.30	27.89	-31%
	CS Italy	79%	80%	86%	89%	87%	-1%	6.16	8.68	19.06	23.45	36.88	-29%
	S Italy*	68%	78%	83%	92%	95%	-13%	0.89	1.29	12.81	21.52	28.59	-31%
	Sicily*	77%	85%	90%	92%	92%	-9%	27.50	34.19	40.42	51.27	29.39	-20%
	Sardinia												
	Total	63%	74%	73%	84%	85%	-15%	5.66	8.56	18.20	21.46	26.47	-34%

(*) the index is calculated for each zone as the average, for each unit, of the difference between the zonal price and the variable cost of generation, net of environmental charges (GCs and CO2), weighted for the sales related to each unit.

Duration curve of the spark spread of combined cycles Fig C.2.13



Performance indexes by year and technology Tab C.2.19

	No. of units						Avg no. of hours with accepted bids/offers					
	2011	2010	2009	2008	2007	Delta%	**2011**	2010	2009	2008	2007	Delta%
Coal	**24**	24	23	21	21	0%	**4,366**	4,144	5,614	6,728	7,261	5%
Combined Cycle (no GSE)	**114**	105	96	89	79	9%	**4,745**	5,327	4,868	5,678	6,300	-11%
Natural gas	**6**	6	6	7	8	0%	**5**	70	160	1,083	1,832	-92%
Oil	**38**	42	43	44	44	-10%	**1,682**	1,439	1,973	2,207	2,726	17%
Gas turbine	**30**	30	29	30	29	0%	**224**	86	71	78	94	159%
Other Thermal*	**49**	46	40	34	37	7%	**5,844**	6,156	5,053	5,073	5,085	-5%
Wind	**159**	167	146	104	70	-5%	**6,457**	5,553	7,221	6,541	7,516	16%
Run-of-river hydro	**170**	170	167	167	164	0%	**7,134**	7,023	7,204	6,737	6,153	2%
Modulation hydro	**136**	137	137	140	163	-1%	**4,240**	4,862	4,612	4,053	3,560	-13%
Pumped-storage hydro	**22**	22	22	22	24	0%	**1,744**	2,219	2,180	2,132	1,567	-21%
Other RES	**35**	36	35	32	32	-3%	**8,013**	7,987	7,677	8,263	8,530	0%

	Success rate (sold volumes/offered volumes)						Average revenue(€/MWh)					
	2011	2010	2009	2008	2007	Delta%	**2011**	2010	2009	2008	2007	Delta%
Coal	**75%**	72%	81%	88%	92%	4%	**73.61**	65.74	68.56	88.07	73.54	-4%
Combined Cycle (no GSE)	**63%**	74%	73%	84%	85%	-15%	**75.23**	67.40	68.33	92.18	76.89	-1%
Natural gas	**0%**	0%	1%	10%	17%	-	**167.63**	96.23	87.07	105.10	85.75	11%
Oil	**34%**	34%	36%	39%	41%	-0%	**73.51**	65.12	65.15	95.24	81.45	-0%
Gas turbine	**1%**	0%	0%	1%	1%	47%	**106.30**	128.46	139.28	187.73	157.71	-8%
Other Thermal*	**84%**	87%	90%	87%	87%	-4%	**72.68**	67.19	70.81	97.94	76.99	-5%
Wind	**100%**	100%	100%	100%	100%	-0%	**75.10**	68.32	65.75	92.11	75.47	4%
Run-of-river hydro	**84%**	87%	90%	75%	72%	-3%	**72.76**	65.04	64.34	90.58	79.88	1%
Modulation hydro	**41%**	52%	56%	56%	57%	-22%	**75.58**	66.97	69.52	98.39	89.08	-4%
Pumped-storage hydro	**9%**	14%	14%	18%	16%	-36%	**81.90**	76.42	85.29	115.41	106.88	-10%
Other RES	**100%**	100%	100%	100%	100%	-0%	**71.09**	62.43	62.17	84.83	72.64	0%

* Other Thermal: this item includes CHP, self-generators' and waste-to-energy plants

As for other sources and technologies, the success rate of coal plants rose (75%; +3 p.p.), consistently with the increased sales of this source and a cost structure more competitive than other thermal sources. It is appropriate to highlight the strongly decreasing success rate of pumping units (-5 p.p.): alike the reduction in purchases, this reflects a rise in off-peak prices which led producers to increase sale prices to get positive margins, despite the slim likelihood that such prices are accepted.

2.2.4 Market power and concentration

Within the framework of an extremely weak electricity consumption, a larger supply from the massive increase of generation from renewable sources did ease, in 2011, a further reduction of market concentration and power, intensifying those dynamics that have characterized the start of this market.

Sistema Italia. SNationwide, all indicators point to an improved competitiveness: a downward trend for the

CR5, down to 62% because of a GSE smaller selling quota, presumably due to the expiration of CIP6 contracts and, most importantly, to a smaller sale quota with no competition (IORq), hitting a new minimum of 13% (-2 p.p. on 2010, -8 p.p. in the last five years).

An analysis of the IORq hourly movement shows an evolution affected by the growing photovoltaic supply: being this latter concentrated in the hours of highest solar irradiation, it made the peak index plummet (-5.2 p.p.), although the same did not happen in the early morning hours when a unilateral increasing market power contributed to feed a more substantial recovery of off-peak prices[58].

On the other hand, after four years of big rebates, no significant improvement was observed in the price-setting operator index (IOM), as indicated by Enel value, the major price maker, stable at 23%. Quite remarkable is the rise of E.On, up to 14% (+5 p.p.); pricing from foreign zones returned back to 2009 levels (cumulatively associated to operators following the top five price setters (38%, -7 p.p). Such phenomenon originates in the slight increase of the price differential with neighbor Exchanges and has repercussions also in the growth of marginality of combined cycle plants (66%, +10 p.p.), to the detriment of foreign countries (10%, -7 p.p.) (Fig. C.2.14, Fig. C.2.15, Fig. C.2.16, Fig. C.2.17, Fig. C.2.18, Fig. C.2.19, Statistical Appendix).

Continental zones. A progressive increase of competition was observed in continental zones, where some local specificities which emerged in the past are now more deeply rooted.

In spite of a relative stability of sales concentration, as measured by the Hirschmann-Herfindahl Index(HHI), below the non competitiveness threshold in the North and close to it in the South, the most striking patterns observed in 2011 were the drastic decline of the unilateral market power in the North and South, and the counterintuitive increased concentration in the Center-South.

In the first case, the evident drop of IOR, both in terms of frequency and quantities, seems to be mostly favored by a growing competitive supply: in the North, it brought to zero the level of guaranteed sales in many hours of the year.

On the other hand, the decreased competition in the Center-South originates from the upgrade of plants located in the region, with special reference to the Torvaldaliga plant, property of Enel. Its transformation into a coal plant sparked a significant expansion of low cost supply, actually determining a larger market share for Enel (50%, +8 p.p.) and a rise in the zonal IORq (42%, +9 p.p.), equally helped by the simultaneous decrease of volumes offered by every other participant (-5%). However, on a system level, the declining competitiveness in the Center South affected prices only minimally, being extremely sporadic the presence of the zone, traditionally a price taker, at the margin (IZM: 6%) (Fig. C.2.14, Fig. C.2.15, Fig. C.2.16, Fig. C.2.18, Fig. C.2.19, Statistical Appendix).

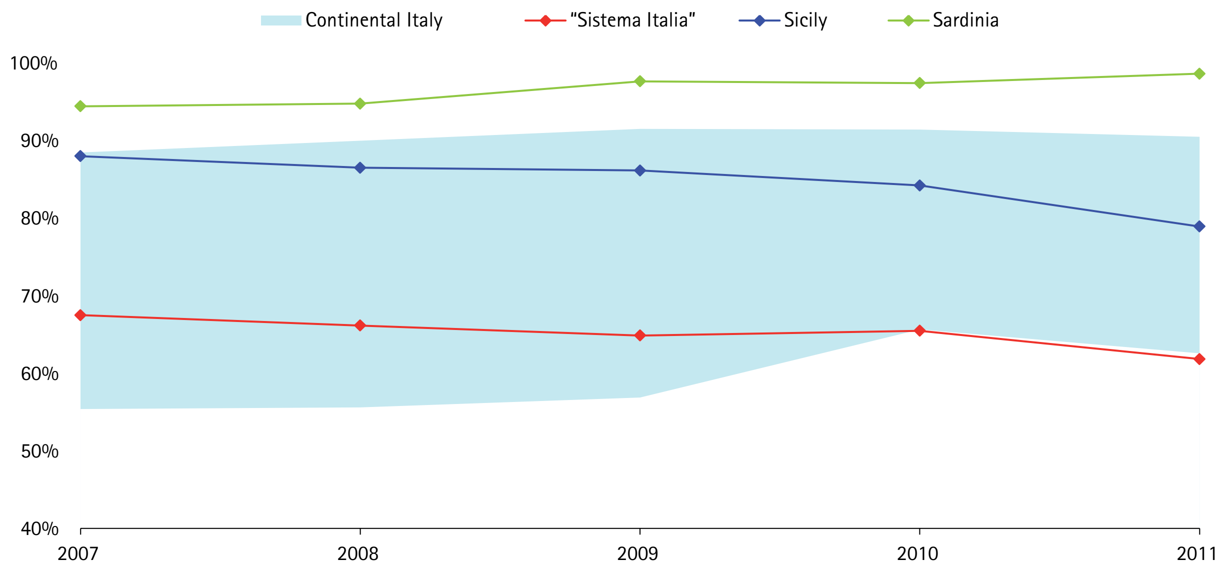
Sicily. The structural modifications which developed in the island in the last three years fully exhibited their effects on concentration indexes during 2011. A new competitive power guaranteed by the full operation of ERG combined cycle plant and by the massive availability of new renewable capacity progressively pushed traditional thermoelectric plants off merit-order; supply from market participants became less essential to fulfill the demand, which promoted a further growth of price-setting indexes. Enel's IOM and the combined cycle ITM rose up to 66%: the first to the detriment of an increasingly smaller Edipower share, also because of Edipower commitments to AGCM[59]; this latter hit an all-time record, in line with national levels and an increase of about 40 p.p. in 2009-2011.

On the other hand, while Enel supply was quite stable and Erg quantities increased in 2011, the overall volumes offered in the Island by every other operator plummeted (-29%), with direct consequences on both the concentration (bids/offers HHI: 3,475, +666) and on the unilateral market power, reaching the highest values in the last five years (27%, +12 p.p.) (Fig. C.2.14, Fig. C.2.15, Fig. C.2.16, Fig. C.2.18, Fig. C.2.19, Statistical Appendix).

58 For more details, refer to par. C.2.2.1.
59 For more information, refer to GME's 2010 Annual Report, page 84.

Sardinia. Speaking of competition, the positive effect of the Sapei cable operation was confirmed in the Island in 2011, as shown by all indexes which changed only slightly relative to the previous year.
A smaller zonal fragmentation, thanks to the new transit, caused the number of hours during which Sardinia sets the price for itself to drop down to 29% (-3 p.p.), with a further, slight convergence between its price-setting indexes and those on the mainland. Thus, while the first operator's IOM was pretty stable (39%), the combined cycle ITM reached its historical maximum (it doubled in two years) (45%, +7 p.p.).
Both CR3 and HHI remain structurally high and stable, mostly because of the small size of the local market; the IORq increased slightly (11%, +4 p.p.) and was consistent with the national figure (Fig. C.2.14, Fig. C.2.15, Fig. C.2.16, Fig. C.2.18, Fig. C.2.19, Statistical Appendix).

CR5 trend Fig C.2.14



Yearly HHIs for sales Fig C.2.15

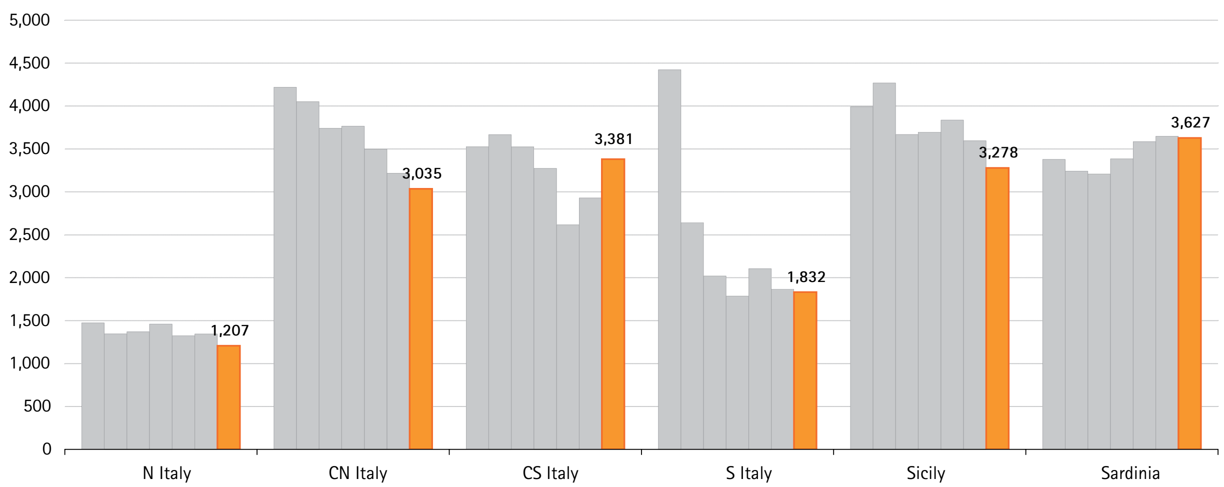


Fig C.2.16 **Share of sales without competition**

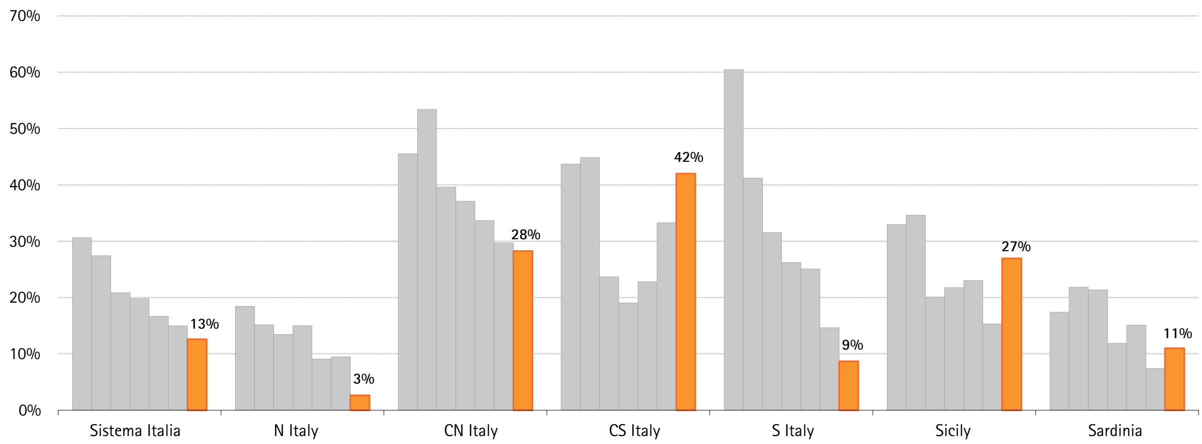


Fig C.2.17 **Hourly trend of IORq on business days. Year 2011**

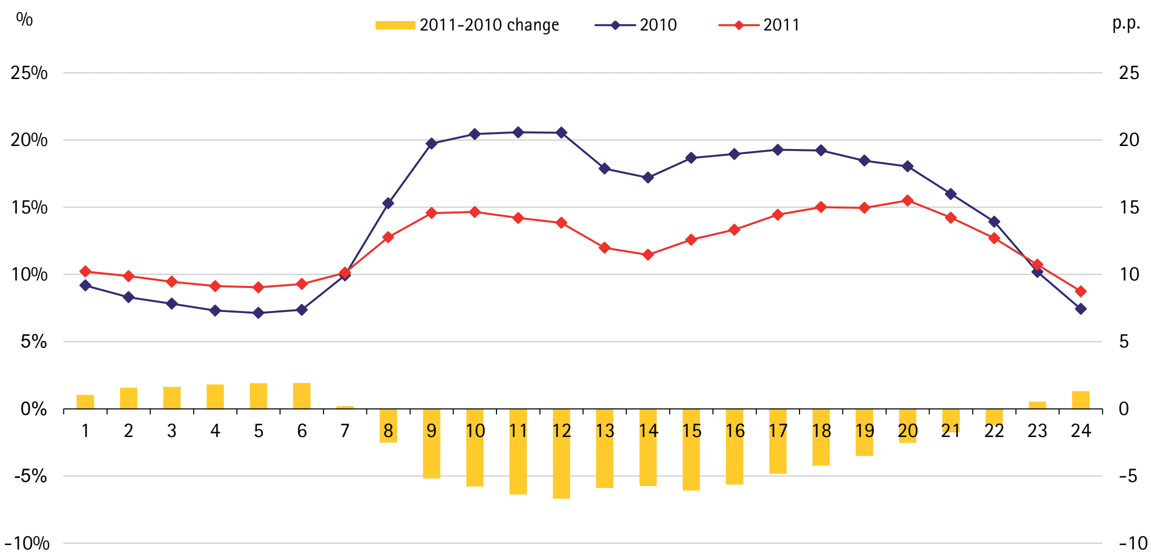
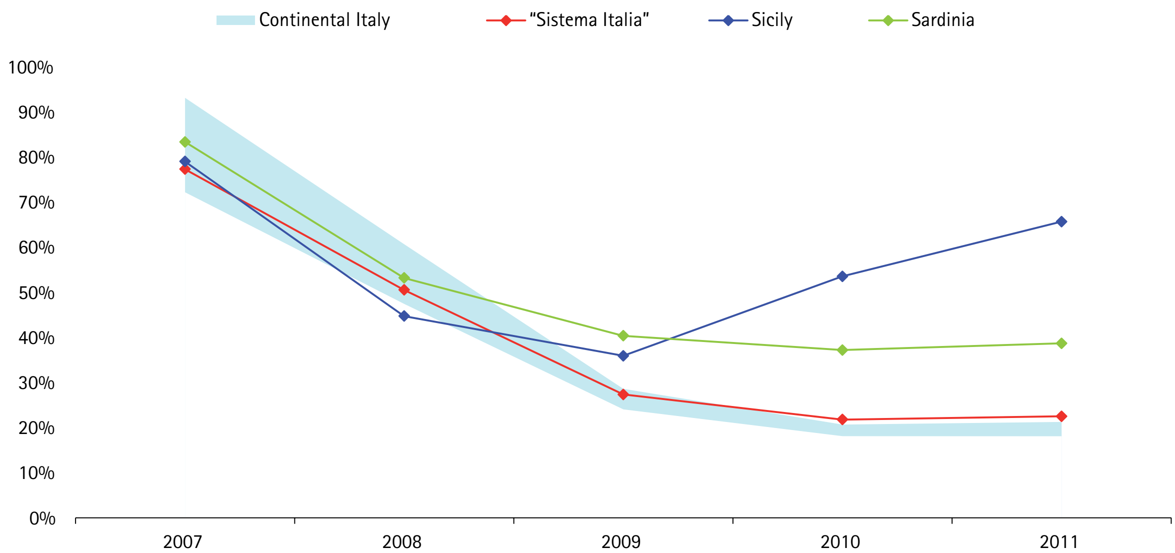
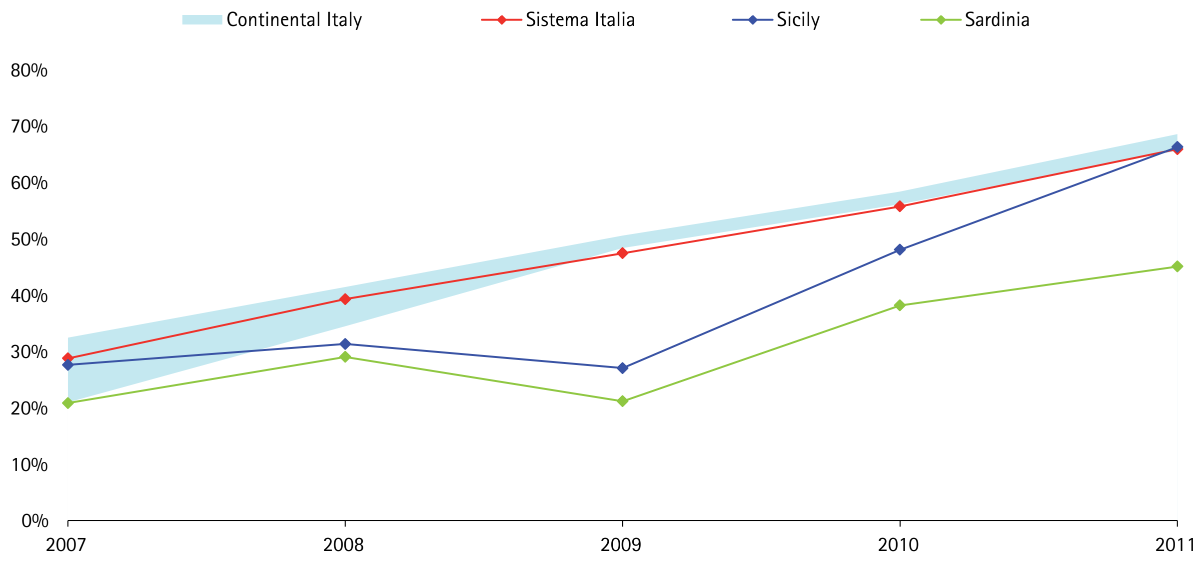


Fig C.2.18 **Trend of first operator's price-setting operator index (IOM)**



Trend of combined cycle price-setting technology index (ITM ccgt) Fig C.2.19



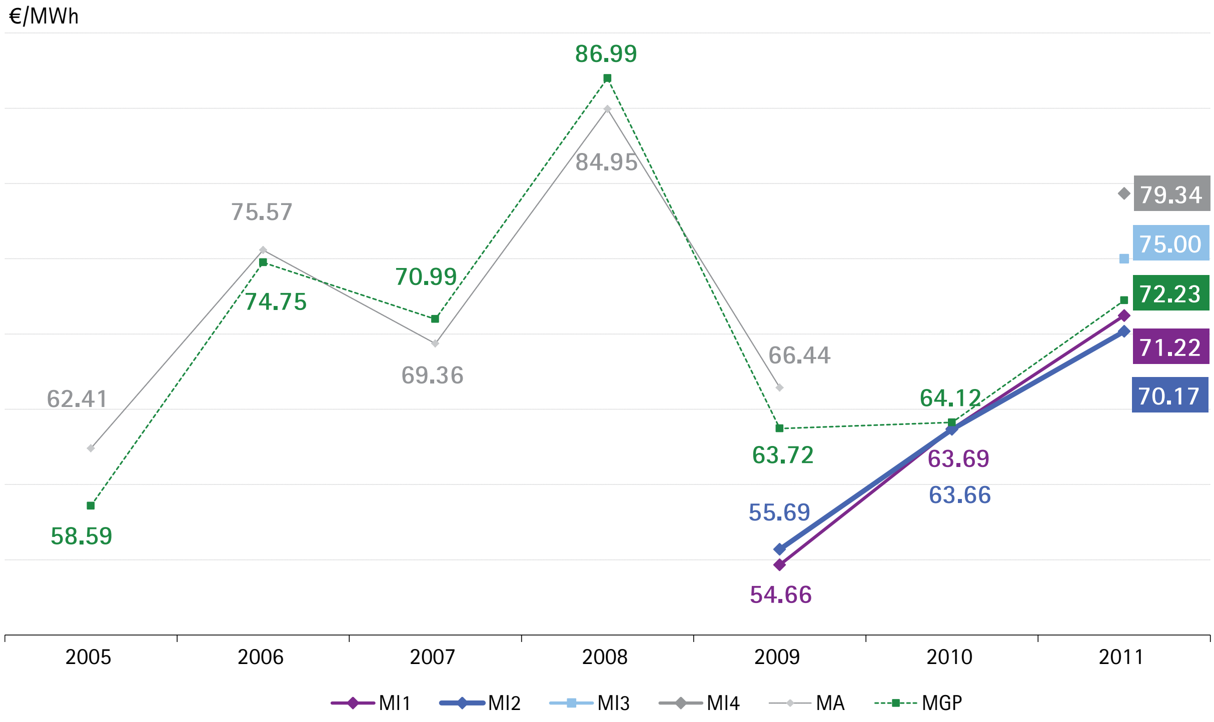
2.3 Intra-day market (MI)

The Intra-day market (MI), introduced by Law 2/09, has been replacing the Adjustment Market (MA) since 1 November 2009. Initially, it consisted of two sessions held the day before delivery with reference to the 24 hours of the subsequent day (MI1 and MI2). Since 1 January 2011, two more sessions have been added to the MI (MI3 and MI4) which close during the delivery day. During these four sessions, based on implicit auctions, participants can update their consuming unit withdrawal schedules, in the light of the latest information on the status of their plants, energy requirement and market conditions. Pricing rules are the same as in the MGP; however, the PUN is not calculated in the MI and every purchase/sale is valued at the zonal price.

2.3.1 Prices

In 2011, the average purchase-weighted price in the MI1 amounted to 71.22 €/MWh, 11.8% more than the previous year; in the MI2, the price was of 70.17 €/MWh (+10.2%). During the first two MI sessions, the average price was slightly lower than the PUN in the MGP (72.23 €/MWh); on MI3 and MI4 sessions, which started in 2011, the average price was respectively of 75.00 €/MWh and 79.34 €/MWh. In these two sessions, too, the price was lower than the MGP price, if a proper comparison is made with the bids/offers hours of both (1p.m.-midnight in MI3 and 5 p.m.-midnight in MI4) (Tab C.2.20).
MI1 and MI2 price volatility (8% and 11%, respectively), significantly declined on 2010. Moreover, MI1 volatility was the same as in the MGP, whereas MI2, MI3 and MI4 showed a greater volatility as the sessions were about to close upon the energy delivery time (Tab C.2.20).

Fig C.2.20 **Purchasing price: yearly trend**



Tab C.2.20 **Purchasing price**

	2011	"% change '11/'10"	2010	2009*	2008	2007
MI1 *(1-24 h)*	71.22 *(-1.4%)*	*11.8%*	63.69 *(-0.7%)*	54.66 *(-1.8%)*		
MI2 *(1-24 h)*	70.17 *(-2.9%)*	*10.2%*	63.66 *(-0.7%)*	55.69 *(+0.0%)*		
MI3 *(13-24 h)*	75.00 *(-4.4%)*					
MI4 *(17-24 h)*	79.34 *(-2.0%)*					
MA *(1-24 h)*				66.44 *(+1.7%)*	84.95 *(-2.4%)*	69.36 (-2.3%)

*Since November 2009, the Adjustment Market (MA) has been replaced by the two sessions (MI1 and MI2) of the Intra-Day Market; since January 2011, two sessions (MI3 and MI4) have been added.
() percentage change with MGP prices in the same applicable periods.

Tab C.2.21 **Volatility of purchasing price**

	2011	"% change '11/'10"	2010	2009*	2008	2007
MI1 *(1-24 h)*	8.1% *(+0.5 p.p.)*	-6.6 p.p.	14.7% (+2.8 p.p.)	16.6%		
MI2 *(1-24 h)*	11.3% *(+4.1 p.p.)*	-5.3 p.p.	16.6% (+6.7 p.p.)	15.9% (+1.8 p.p.)		
MI3 *(13-24 h)*	16.8% *(+9.5 p.p.)*					
MI4 *(17-24 h)*	20.2% *(+12.9 p.p.)*					
MA *(1-24 h)*				17.0% *(+3.3 p.p.)*	20.2% *(+9.7 p.p.)*	19.9% *(+9.6 p.p.)*

**Since November 2009, the Adjustment Market (MA) has been replaced by the two sessions (MI1 and MI2) of the Intra-Day Market; since January 2011, two sessions (MI3 and MI4) have been added.
() differential with MGP volatility in the same applicable periods.

In the four continental zones, average prices were similar in the four MI sessions and always 2-3% less than MGP sale zonal prices (Tab C.2.22). In all four sessions, the price volatility was not remarkably different among the various continental zones. In particular, during MI1 price volatility was quite similar as in the MGP; in MI2 and, to a larger extent, in MI3 and MI4, it turned out to be higher (Tab C.2.23). On the contrary, while the two insular zones had a smaller yearly growth than the mainland zones, prices were higher and volatility more pronounced.

Zonal prices: summary of 2011 Tab C.2.22

	N Italy		CN Italy		CS Italy		S Italy		Sicily		Sardinia	
	Price	*% change*	Price	*% change*	Price	*% change*	Price	*% change*	Price	*% change*	Price	*% change*
MI1 *(1-24 h)*	**67.97** *(-3.1%)*	*13.4%*	**68.87** *(-3.2%)*	*13.6%*	**68.71** *(-3.0%)*	*13.2%*	**67.42** *(-2.3%)*	*17.5%*	**90.16** *(-3.2%)*	*6.3%*	**80.16** *(+0.3%)*	*3.2%*
MI2 *(1-24 h)*	**67.94** *(-3.2%)*	*13.6%*	**68.91** *(-3.2%)*	*14.3%*	**68.41** *(-3.5%)*	*13.1%*	**66.76** *(-3.3%)*	*17.0%*	**80.02** *(-14.1%)*	*-2.3%*	**78.67** *(-1.6%)*	*6.2%*
MI3 *(13-24 h)*	**73.38** *(-2.6%)*		**74.88** *(-2.7%)*		**74.76** *(-2.7%)*		**72.43** *(-3.3%)*		**84.20** *(-22.9%)*		**81.30** *(-6.3%)*	
MI4 *(17-24 h)*	**75.52** *(-2.4%)*		**77.55** *(-2.1%)*		**77.49** *(-2.2%)*		**75.61** *(-2.8%)*		**88.28** *(-22.6%)*		**87.03** *(-3.2%)*	

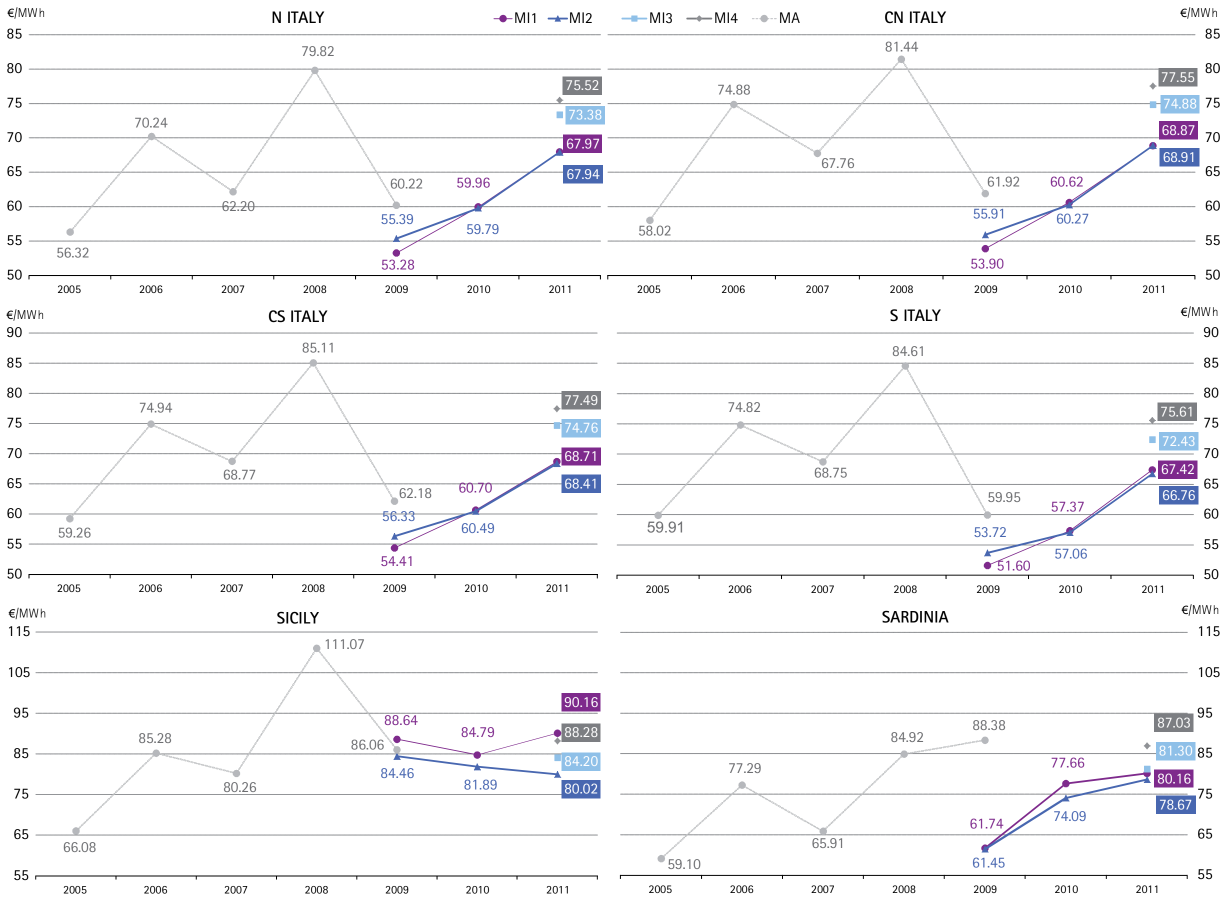
() percentage change with MGP prices in the same applicable periods.

Volatility of zonal prices: summary of 2011 Tab C.2.23

	N Italy		CN Italy		CS Italy		S Italy		Sicily		Sardinia	
	Price	change	Price	change	Price	change	Price	change	Price	change	Price	change
MI1 *(1-24 h)*	**7.8%** *(+0.3 p.p.)*	*-5.6 p.p.*	**8.9%** *(-0.0 p.p.)*	*-5.2 p.p.*	**9.4%** *(-0.1 p.p.)*	*-5.6 p.p.*	**8.8%** *(-0.7 p.p.)*	-4.0 p.p.	29.7% *(+14.1 p.p.)*	-2.7 p.p.	20.0% *(+3.5 p.p.)*	-10.4 p.p.
MI2 *(1-24 h)*	**10.2%** *(+2.6 p.p.)*	*-4.3 p.p.*	**11.4%** *(+2.5 p.p.)*	*-3.0 p.p.*	**11.4%** *(+1.8 p.p.)*	*-4.1 p.p.*	**10.8%** *(+1.3 p.p.)*	-2.9 p.p.	28.1% *(+12.5 p.p.)*	-3.6 p.p.	20.0% *(+3.5 p.p.)*	-1.3 p.p.
MI3 *(13-24 h)*	**15.9%** *(+8.8 p.p.)*		**16.8%** *(+7.6 p.p.)*		**16.6%** *(+7.1 p.p.)*		**16.1%** *(+6.2 p.p.)*		**55.2%** *(+39.4 p.p.)*		**23.1%** *(+6.4 p.p.)*	
MI4 *(17-24 h)*	**16.4%** *(+9.4 p.p.)*		**18.5%** *(+9.3 p.p.)*		**18.5%** *(+9.2 p.p.)*		**18.2%** *(+8.5 p.p.)*		**41.6%** *(+26.4 p.p.)*		**26.0%** *(+9.7 p.p.)*	

() differential with MGP prices in the same applicable periods.

Fig C.2.21 **Zonal prices in the MI**



2.3.2 Volumes

The new Intra-day market had a significant impact on traded volumes. Between 2005 and 2009, energy trading in the Adjustment Market was quite fluctuating, with a peak value of 12.7 million MWh in 2007. In 2010, with a two-session Intra-day market, traded volumes rose to 14.6 million MWh (+22.5% on the previous year); in 2011, after introducing two more sessions, the traded energy went up to 21.9 million MWh with a 49.6% increase on the previous year's record figure (Fig C.2.22).

Both volumes and the overall MI growth are mostly concentrated in the MI1, the most important of the four sessions, with volumes rising from 9.5 million MWh in 2010 to 14.5 in 2011 (+52.8%) (Tab C.2.24, Tab C.2.26). MI1 was the session with the highest ratio between submitted and accepted bids/offers (above 30% both on the sale and purchase side) (Tab C.2.25, Tab C.2.27).

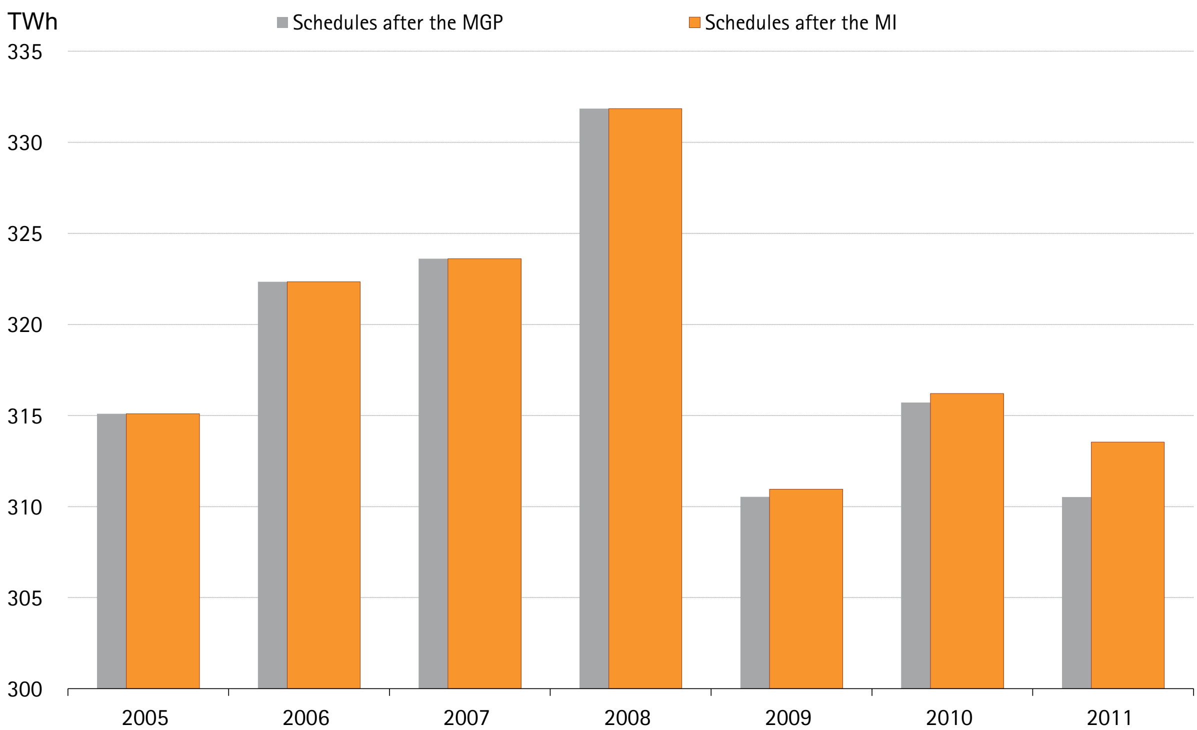
In MI2, 5.4 million MWh (+4.5%) were traded; in MI3 and MI4, 1.2 and 0.8 million MWh were traded, respectively.

As to national zones, the Northern and Southern zones were most dynamic both in terms of sales and purchases, the Central-Southern zone was quite active in terms of purchases only.

In 2011, participants' activity in MI sessions led to more schedules (injection/withdrawal) than those resulting from the MGP (+1.0%), with an increase higher than in the previous two years. Market participants who hold injection points have been admitted to the intra-day market since 2009.

Volumes traded Fig C.2.22

Fig C.2.23 Scheduled injection after the MGP and the MI Fig C.2.23



Tab C.2.24

Tab C.2.24 Volumes sold: summary of 2011

MWh		N Italy	CN Italy	CS Italy	S Italy	Sicily	Sardinia	National total	Neigh. countries	Total
MI1 (1-24 h)	Total	8,879,106	857,277	1,023,462	1,824,204	1,375,320	346,543	14,305,913	160,044	14,465,957
	Average	1,014	98	117	208	157	40	1,633	18	1,651
	%change	*63.9%*	*15.9%*	*7.8%*	*105.1%*	*29.3%*	*-11.1%*	*51.4%*	*913.9%*	*52.8%*
MI2 (1-24 h)	Total	3,327,679	266,500	525,956	776,541	324,137	119,380	5,340,191	40,460	5,380,651
	Average	380	30	60	89	37	14	610	5	614
	%change	*11.9%*	*-29.4%*	*-14.9%*	*22.6%*	*-11.5%*	*-31.0%*	*3.9%*	*451.9%*	*4.5%*
MI3 (13-24 h)	Total	629,025	86,159	156,025	238,606	55,931	52,969	1,218,715	0	1,218,715
	Average	144	20	36	54	13	12	278	0	278
MI4 (17-24 h)	Total	411,795	73,691	105,956	143,299	42,563	24,694	801,999	0	801,999
	Average	141	25	36	49	15	8	275	0	275

Tab C.2.25

Success rate of volumes sold: summary of 2011

		N Italy	CN Italy	CS Italy	S Italy	Sicily	Sardinia	National total	Neigh. countries	Total
MI1 (1-24 h)	success rate	36.2%	38.9%	10.6%	26.0%	67.2%	28.9%	30.6%	38.1%	30.7%
	change	*+6.1 p.p.*	*-18.4 p.p.*	*-29.7 p.p.*	*+12.0 p.p.*	*+13.1 p.p.*	*-10.4 p.p.*	*+0.1 p.p.*	*-46.8 p.p.*	*+0.1 p.p.*
MI2 (1-24 h)	success rate	20.4%	17.8%	5.8%	13.7%	37.0%	14.5%	15.6%	94.1%	15.7%
	change	*+0.3 p.p.*	*-21.3 p.p.*	*-21.4 p.p.*	*+2.4 p.p.*	*+3.9 p.p.*	*-6.9 p.p.*	*-4.5 p.p.*	*+14.5 p.p.*	*-4.5 p.p.*
MI3 (13-24 h)	success rate	12.6%	13.4%	3.4%	11.2%	62.3%	24.0%	9.6%	-	9.6%
MI4 (17-24 h)	success rate	13.6%	17.0%	3.7%	11.8%	71.7%	17.9%	10.4%	-	10.4%

Tab C.2.26

Volumes purchased: summary of 2011

		N Italy	CN Italy	CS Italy	S Italy	Sicily	Sardinia	National total	Neigh. countries	Total
MI1 (1-24 h)	Total	7,985,589	801,651	1,199,635	2,996,340	647,011	365,505	13,995,731	470,223	14,465,954
	Average	912	92	137	342	74	42	1,598	54	1,651
	%change	70.4%	13.2%	53.9%	45.7%	8.1%	-22.4%	50.5%	184.8%	52.8%
MI2 (1-24 h)	Total	3,374,162	346,740	553,888	546,994	262,079	138,495	5,222,358	158,292	5,380,650
	Average	385	40	63	62	30	16	596	18	614
	%change	19.9%	7.5%	-20.7%	-21.3%	-27.3%	-28.2%	2.7%	142.4%	4.5%
MI3 (13-24 h)	Total	616,961	90,382	196,192	201,447	49,432	64,301	1,218,715	0	1,218,715
	Average	141	21	45	46	11	15	278	0	278
MI4 (17-24 h)	Total	385,674	68,840	152,669	124,631	40,396	29,788	801,999	0	801,999
	Average	132	24	52	43	14	10	275	0	275

Tab C.2.27

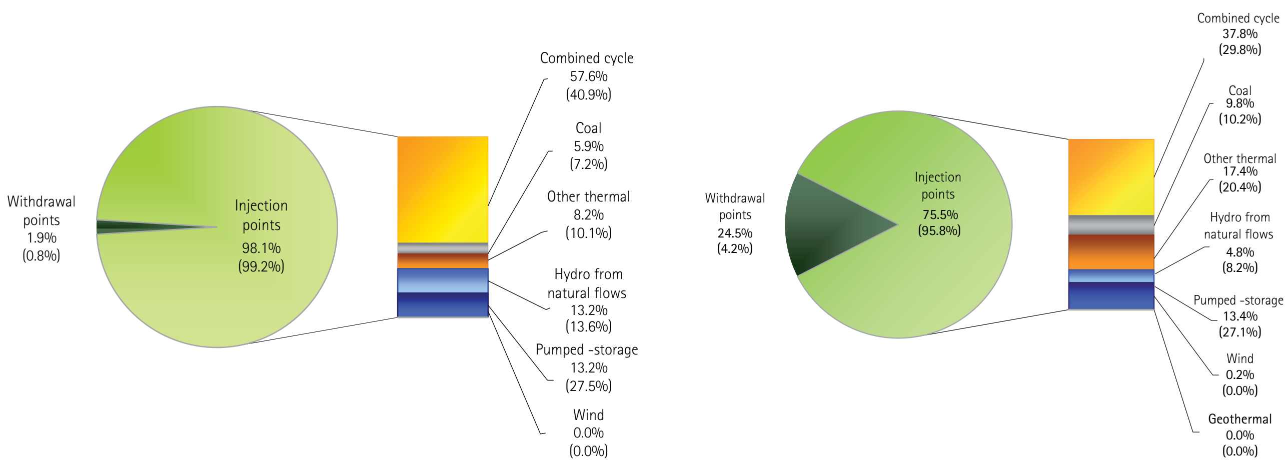
Success rate of volumes purchased: summary of 2011

		N Italy	CN Italy	CS Italy	S Italy	Sicily	Sardinia	National total	Neigh. countries	Total
MI1 (1-24 h)	success rate	38.9%	33.3%	16.8%	44.6%	79.1%	72.9%	36.7%	22.0%	36.0%
	change	+9.5 p.p.	-19.8 p.p.	-33.4 p.p.	+6.2 p.p.	+20.3 p.p.	+2.8 p.p.	+0.7 p.p.	-77.5 p.p.	-0.4 p.p.
MI2 (1-24 h)	success rate	19.7%	23.0%	8.4%	10.8%	68.3%	48.7%	16.9%	99.2%	17.3%
	change	-0.2 p.p.	-12.1 p.p.	-36.6 p.p.	-6.1 p.p.	+17.7 p.p.	+0.1 p.p.	-6.4 p.p.	-0.7 p.p.	-6.2 p.p.
MI3 (13-24 h)	success rate	9.0%	11.8%	5.4%	8.2%	44.7%	35.8%	8.7%	-	8.7%
MI4 (17-24 h)	success rate	8.6%	13.7%	6.6%	7.0%	43.0%	31.4%	8.7%	-	8.7%

In 2011, during the four intra-day market sessions, most trading was conducted by participants who hold injection points, in order to modify generation schedules after the MGP. However, purchases by holders of withdrawal points (wholesalers), amounting to 3.2 million MWh, grew five-fold on 2010 (+467.8%) and account for 24.5% of the total figure (versus 4.2% in 2010). On the sale front, holders of injections points (producers and importers) prevail, with a 98.1% share of overall sold energy (99.2% in 2010) (Fig C.2.24).

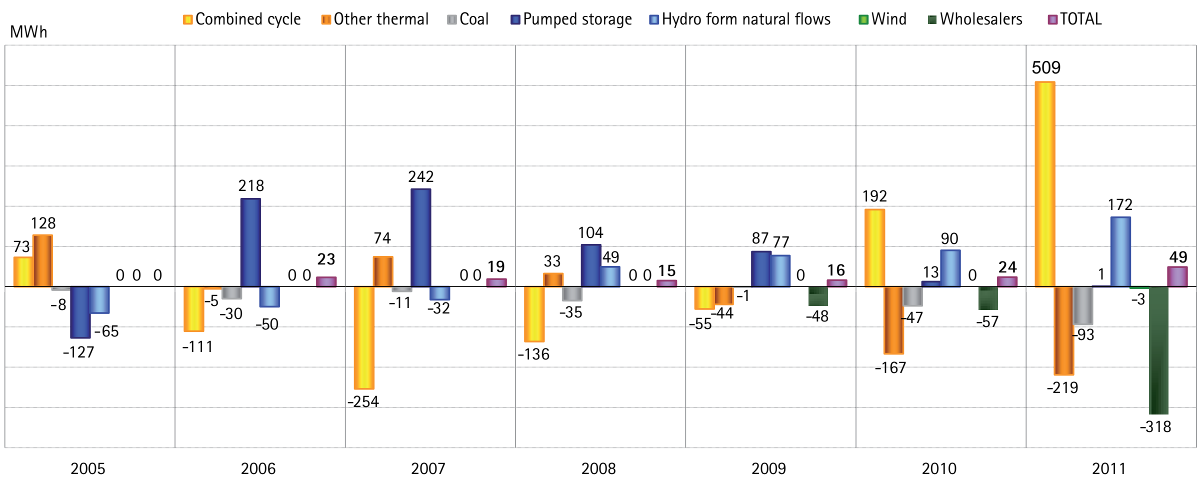
In 2011, electricity trading in the MI determined, on one hand, an increase of sales from combined cycle plants (hourly average, +509 MWh) and natural hydro plants (+172 MWh) and, on the other, a reduction of sales from coal plants (-93MWh) and other thermal plants (-219 MWh) (Fig C.2.25).

Purchases and sales by type of plant Fig C.2.24



The values of the previous year are shown between parentheses.

Balance of sales/purchases by type of plant. Hourly average Fig C.2.25



2.4 Ancillary Services Market (MSD)

As it is well known, the Ancillary Services Market is the instrument employed by the Transmission System Operator, Terna S.p.A., to procure any resources required to manage and control the system.
The MSD is comprised of a scheduling stage (*Ex-ante MSD*) and of the Balancing Market (MB).
In the *Ex-ante MSD*, purchase and sale bids/offers referred to the relevant periods of the solar day after the day the session ends are selected. Terna accepts bids/offers to purchase and sale energy to create a reserve, solve any residual congestion and keep balancing between energy injections and withdrawals into/from the grid.
The Balancing Market (MB) is the venue where purchase and sale bids/offers referred to the relevant periods of the MB day are selected. At present, it consists of several sessions, where Terna accepts purchase and sale bids/offers to perform the secondary clearance service and keep a real time balancing of energy injections and withdrawals.

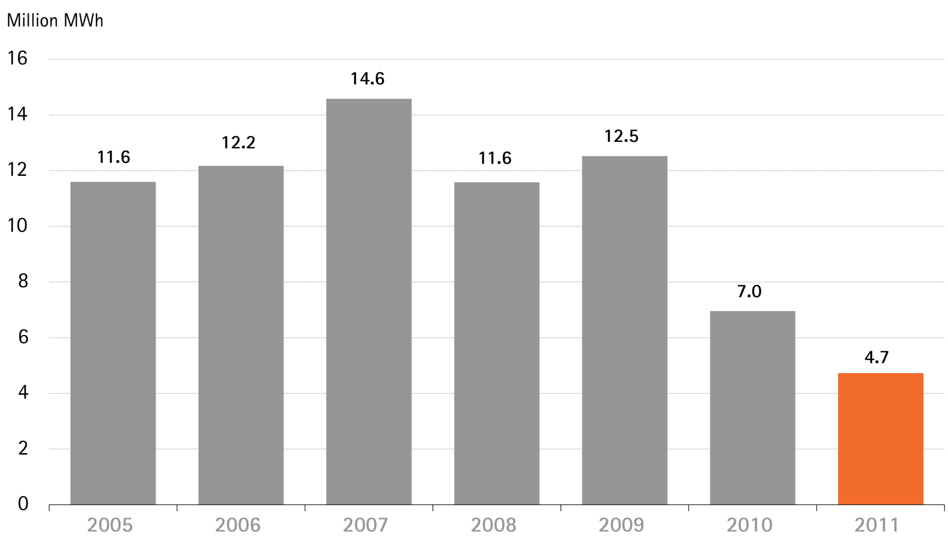
2.4.1 EX-ANTE MSD

In 2011, in the Ex ante MSD up, volumes purchased by Italy's TSO fell (4.7 million MWh) with a 32.1% drop on the previous year, after a 44.4% decline in 2010 (Fig C.2.26).
Terna's decline in purchasing occurred in every geographical zone, although it was less evident in the Southern and Central-Southern zones (Tab C.2.28).

Tab C.2.28 **Volumes traded in the Ex ante MSD up**

	2011	11/'10 %	2010	2009	2008	2007
MWh	*Total*	*change*	*Total*	*Total*	*Total*	*Total*
N Italy	2,943,354	*-66.0%*	8,663,769	8,581,229	6,642,370	6,838,047
CN Italy	124,833	*-69.5%*	408,683	334,422	317,195	395,315
CS Italy	308,736	*-70.7%*	1,053,568	1,141,573	453,535	754,675
S Italy	1,131,259	*-63.5%*	3,099,246	2,146,715	2,000,315	2,330,881
Sicily	351,503	*-72.2%*	1,262,157	1,288,017	863,997	705,755
Sardinia	10,879	*-96.5%*	310,611	1,153,305	981,396	1,000,571
Italy	**4,870,564**	***-67.1%***	**14,798,034**	**14,645,260**	**11,258,809**	**12,025,243**

Fig C.2.26a **Fig C.2.26 Volumes traded in the Ex ante MSD up**

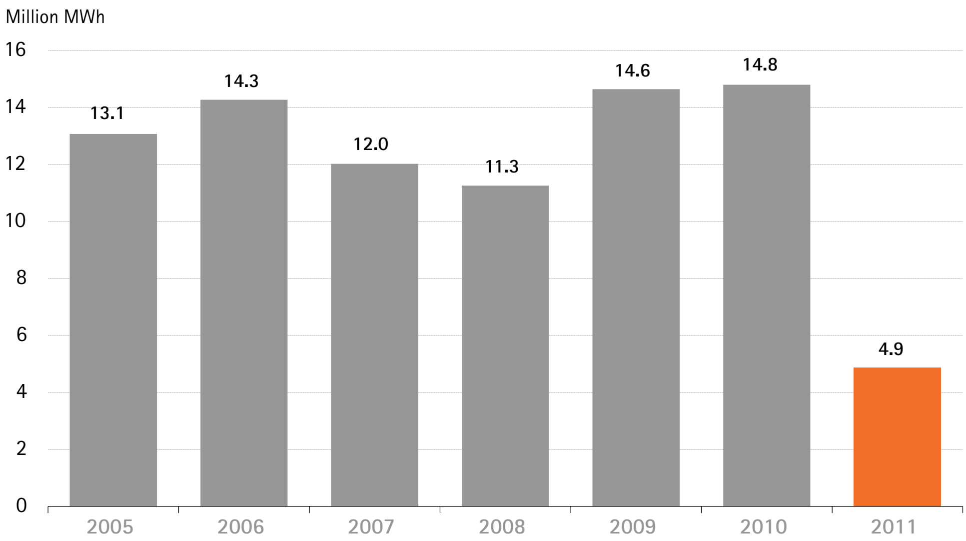


In the Ex ante MSD down, too, Terna's sales decreased from 14.8 million MWh in 2010 to 4.9 million MWh in 2011 (-67.1%), the lowest level since the market startup (Fig C.2.26 b). The TSO's declining sales covered all zones, ranging between 63.5% in the Southern zone to 96.5% in Sardinia (Tab C.2.29).

Volumes traded in the Ex ante MSD down Tab C.2.29

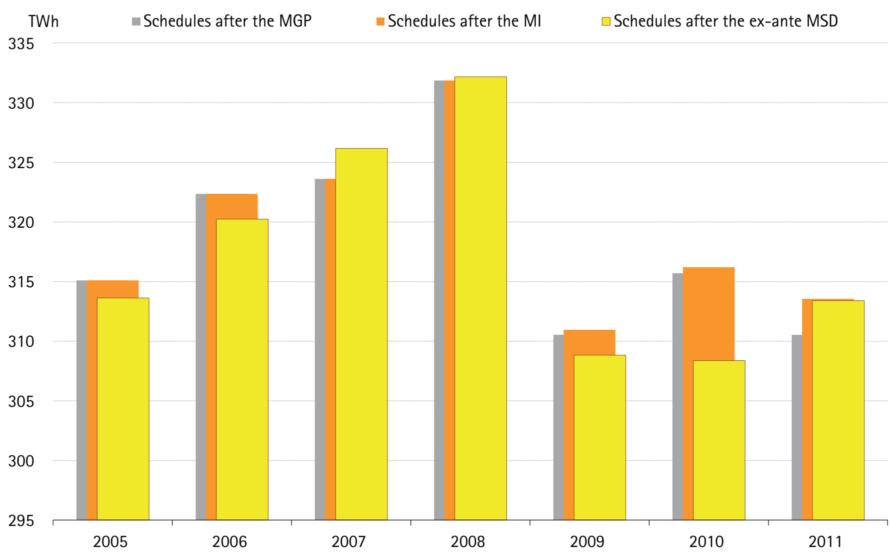
	2011	11/'10 %	2010	2009	2008	2007
MWh	*Total*	*change*	*Total*	*Total*	*Total*	*Total*
N Italy	1,077,124	*-45.1%*	1,962,572	3,210,126	2,621,252	3,643,421
CN Italy	356,720	*-48.7%*	695,620	1,335,907	1,947,977	1,686,068
CS Italy	897,353	*-5.0%*	944,125	2,655,547	2,331,165	4,327,170
S Italy	1,156,164	*-2.6%*	1,186,942	1,896,181	1,206,938	2,073,960
Sicily	881,970	*-30.7%*	1,273,152	1,692,832	1,990,109	1,898,347
Sardinia	352,151	*-60.6%*	893,473	1,728,430	1,482,378	947,331
Italy	**4,721,483**	***-32.1%***	**6,955,884**	**12,519,023**	**11,579,819**	**14,576,298**

Volumes traded in the Ex ante MSD down Fig C.2.26b



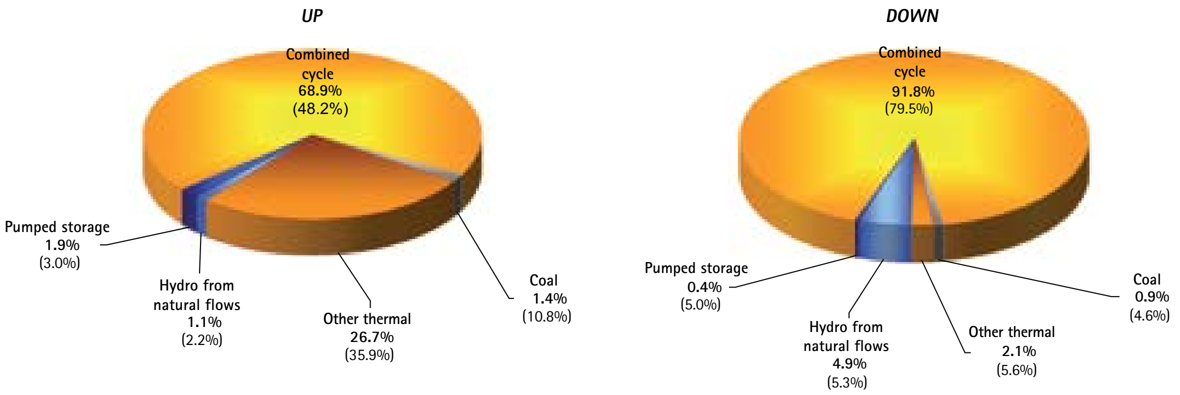
In 2011, differently from the past years, Terna's activity in the two Ex ante MSD up and down markets caused only a minimal change to the overall value of scheduled injections after the MI (Fig C.2.27).

Scheduled injections after the MGP, MI and Ex ante MSD Fig C.2.27



As to the type of plants, Terna's purchasing from combined cycle plants rose from 48.2% in 2010 to 68.9% in 2011. Conversely, the share for every other type of plant, coal plants in particular, fell down to 1.4% (10.8% in 2010).
As to Terna's selling, causing a reduction of generation schedules, the share from combined cycle plants increased considerably to 91.8% (79.5% in 2010), with a decline of shares for every other type of plants (Fig C.2.28).

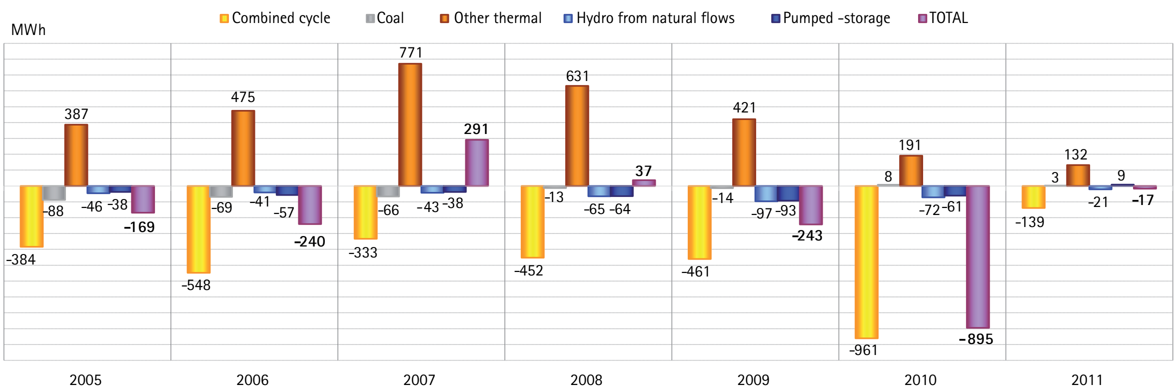
Fig C.2.28 **Volumes traded in the Ex ante MSD, by type of plant**



The values of the previous year are shown between parentheses.

As a whole, Terna's sales in the Ex ante MSD surpassed purchasing, on an hourly average basis, by just 17 MWh: generation from combined cycle plants declined (-139 MWh, on average, each hour) whereas generation from other thermal plants rose (+132 MWh) (Fig C.2.29).

Fig C.2.29 **Balance of Terna's purchases/sales in the Ex ante MSD, by type of plant. Hourly average**



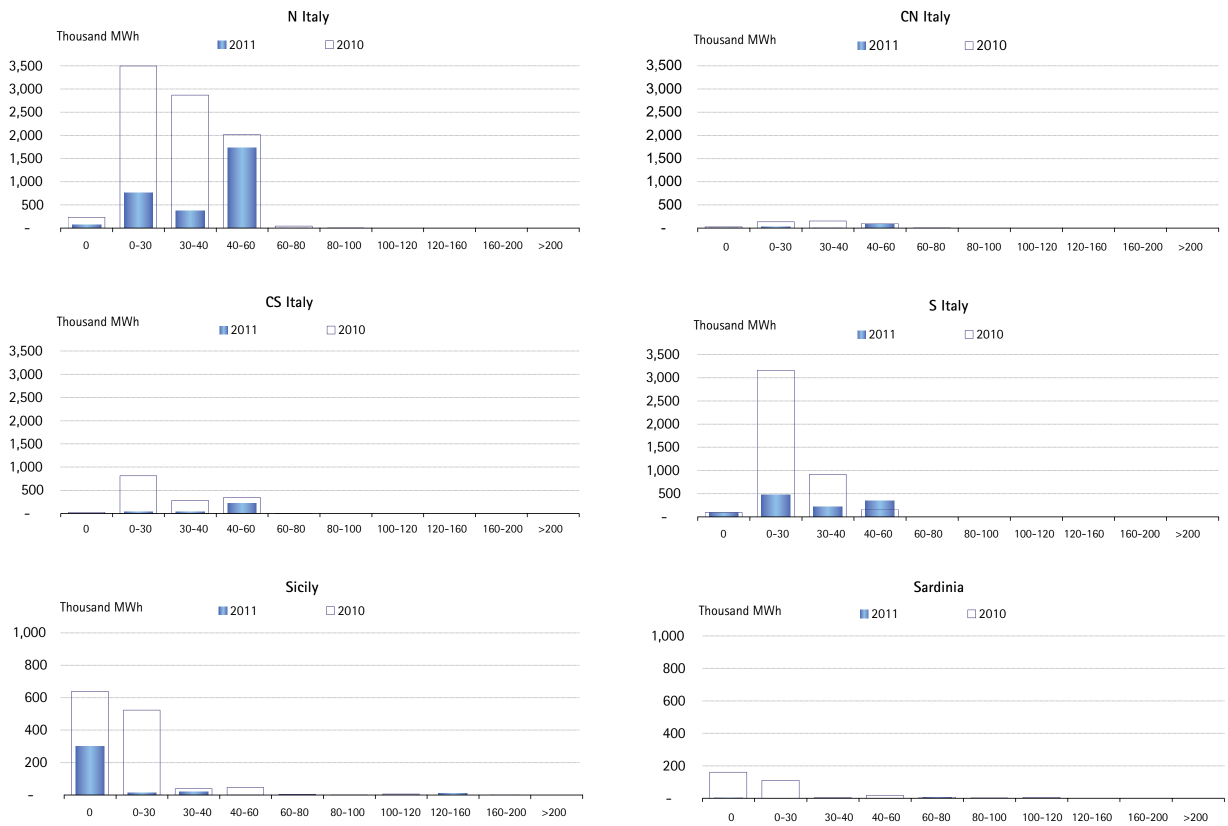
The remuneration rules for bids/offers in the MSD do not allow to calculate a summary price as it happens with other markets managed by GME. However, in order to provide a summary illustration of the price structure, the distribution function of volumes accepted in the ex-ante MSD by price class offered is reported below (Fig C.2.30, Fig C.2.31).

Volumes on the ex ante MSD up, by price class

Fig C.2.30

Volumes on the Ex ante MSD down, by price class

Fig C.2.31



2.5 OTC Registration Platform (PCE)

The startup of the OTC Registration Platform (PCE) has been a milestone in the evolution of the electricity market; most importantly, this market has opened up a new flexible option for participants, who can sell or purchase back (according to their own needs) any product previously purchased/sold on the PCE itself. Buy and sell transactions concluded outside the bids/offers system (the so called bilateral contracts), volumes from the Forward Electricity Market (MTE) and from the Electricity Derivatives Platform (CDE) with any related physical injection and withdrawal schedules are registered on this platform. On the PCE, the registration obligation applies to the two month period prior to delivery only; hence, any data registered on the PCE and trading activities represent only a proportion of the Italian Forward Market (see paragraph C.2.6).

Transactions registered on the PCE, with delivery/withdrawal in 2011, had an overall value of 296.1 million MWh, 25.3% more than the previous year. Its growth rate, although smaller than the whopping 36.5% of 2010, does confirm the success of PCE commercial transactions from the very beginning, even during the low electricity demand periods of recent years (Fig C.2.32).

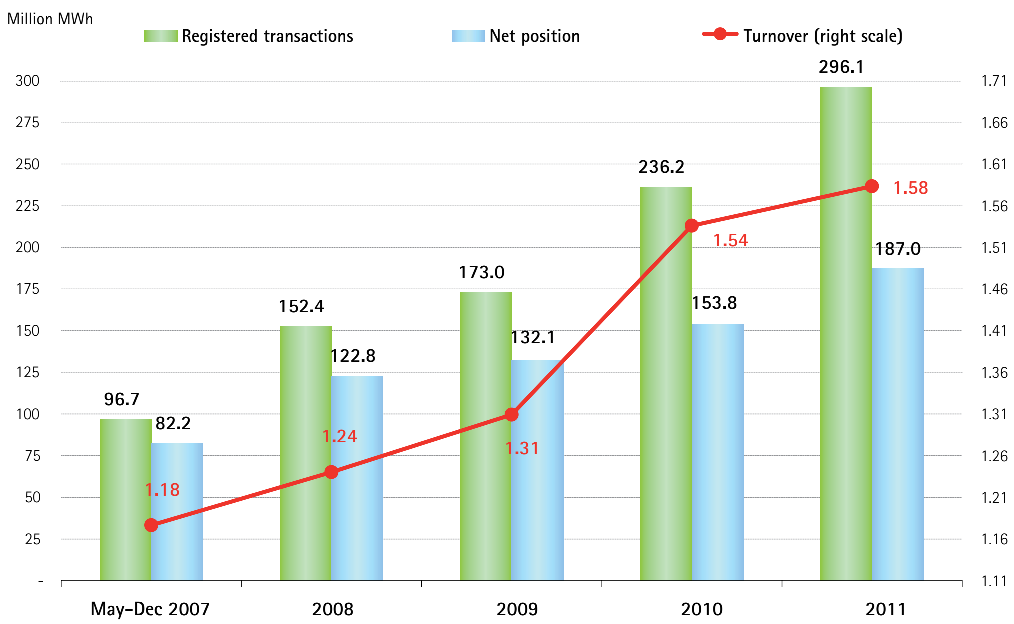
Most transactions registered on the PCE have to do with contracts entered by participants outside the regulated market (bilateral contracts). However, in 2011 transactions from contracts concluded on the forward electricity market (MTE) did increase up to 7.9 million MWh, i.e. 2.7% of total registrations (versus 0.5% in 2010). Conversely, no transaction resulted from the CDE platform (Tab C.2.30).[60]

In 2011, like in previous years, the most common type of contract was the non-standard one. In terms of registered volumes, it accounted for 60.3% of the total. Among standard contracts, baseload (29.6% of the total) contracts are by far those preferred by participants, stressing the tendency to adopt the same types of contracts that are most popular abroad (Tab C.2.30, Fig C.2.33).

Moreover, the net position of electricity accounts, resulting from the whole of registered transactions, reached a record level of 187.0 million MWh, with a 21.6% increase on the previous year (+16.4% in 2010).

Therefore, also the turnover, i.e. the ratio between registered transactions and net position, rose to 1.58, the highest since 2007 (Fig C.2.32).

Fig C.2.32 **Registered transactions, net position and turnover**



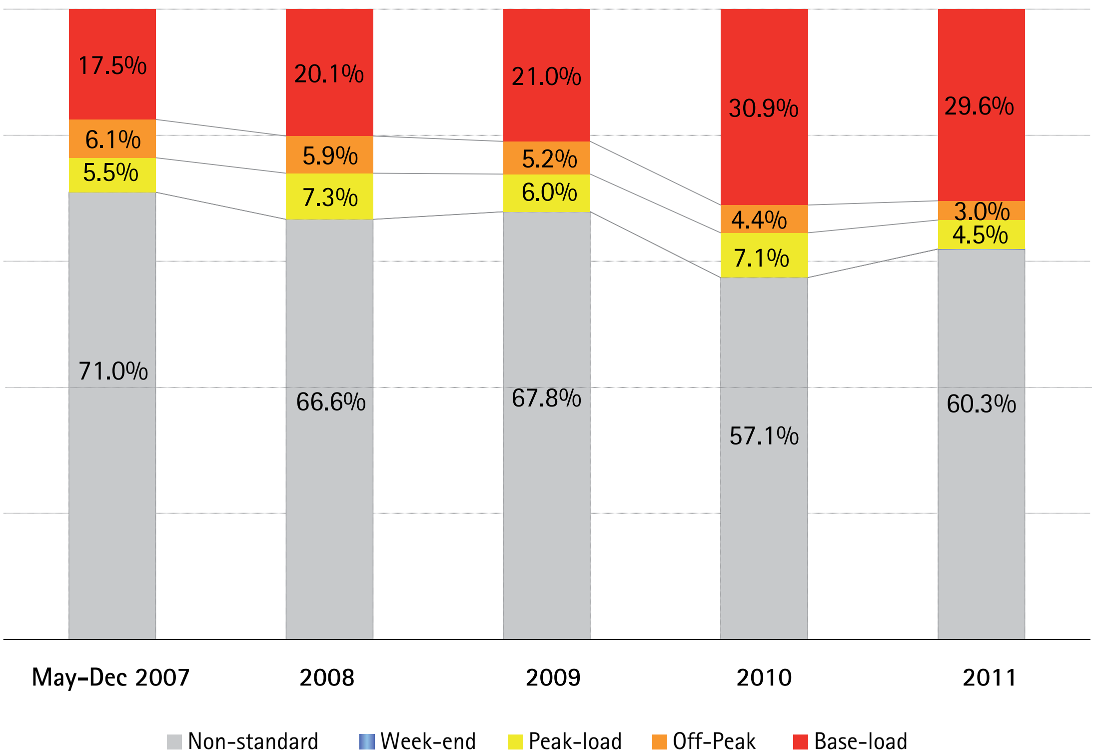
60 Data on the MTE refer to quotas registered and delivered in 2011. Most volumes traded in the MTE in 2011, however, are referred to 2012: this is why they are not included into volumes registered on the PCE to be delivered in 2011.

Registered transactions by type and net position Tab C.2.30

Total. MWh

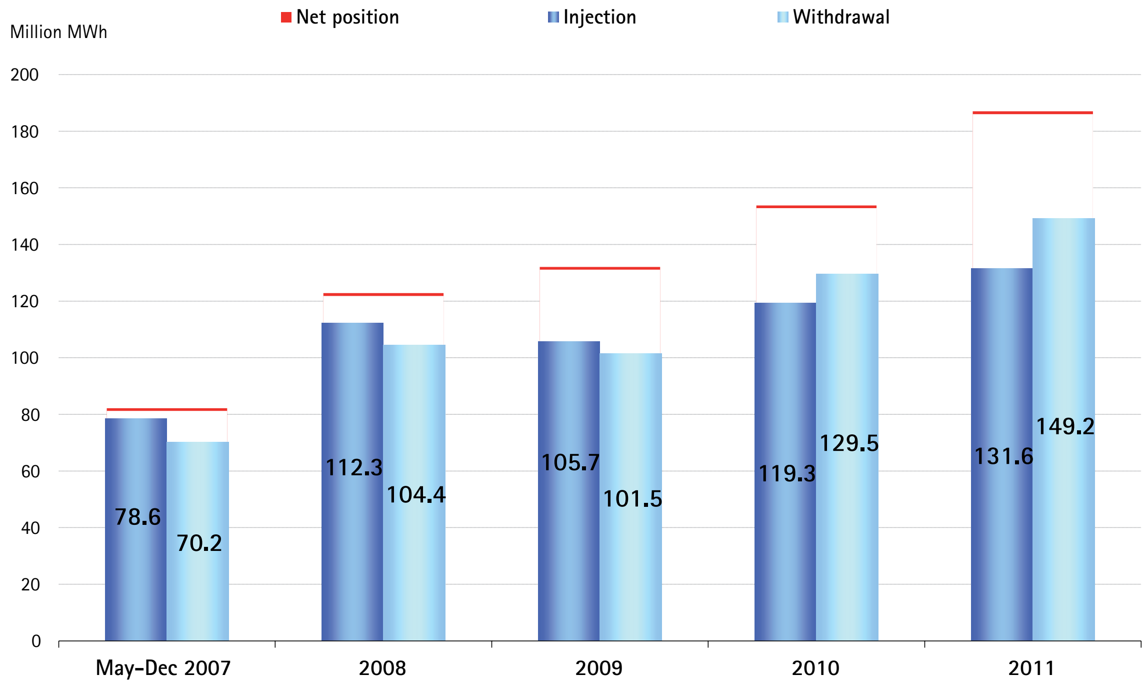
Profile	2011	11/'10 % change	2010	2009	2008	2007
Base-load	87,578,438	20.0%	72,977,500	36,257,105	30,680,745	16,918,893
Off-Peak	8,858,792	-14.6%	10,376,043	9,010,700	8,946,983	5,858,379
Peak-load	13,203,103	-21.0%	16,718,071	10,297,008	11,187,852	5,297,652
Week-end	19,591	60.1%	12,240	12,960	13,200	1,200
Total Standard	109,659,924	9.6%	100,083,855	55,577,773	50,828,780	28,076,124
Non-Standard	178,482,075	32.3%	134,920,843	117,347,359	101,533,152	68,619,843
PCE/OTC contracts	288,141,999	22.6%	235,004,697	172,925,132	152,361,932	96,695,967
MTE	7,924,827	613.1%	1,111,303	80,999	57,600	-
CDE	-	-100.0%	97,392	-	-	-
Total PCE	296,066,826	25.3%	236,213,392	173,006,131	152,419,532	96,695,967
Net position	187,008,644	21.6%	153,805,704	132,088,821	122,842,343	82,187,562

Structure of registered transactions by type of contract Fig C.2.33



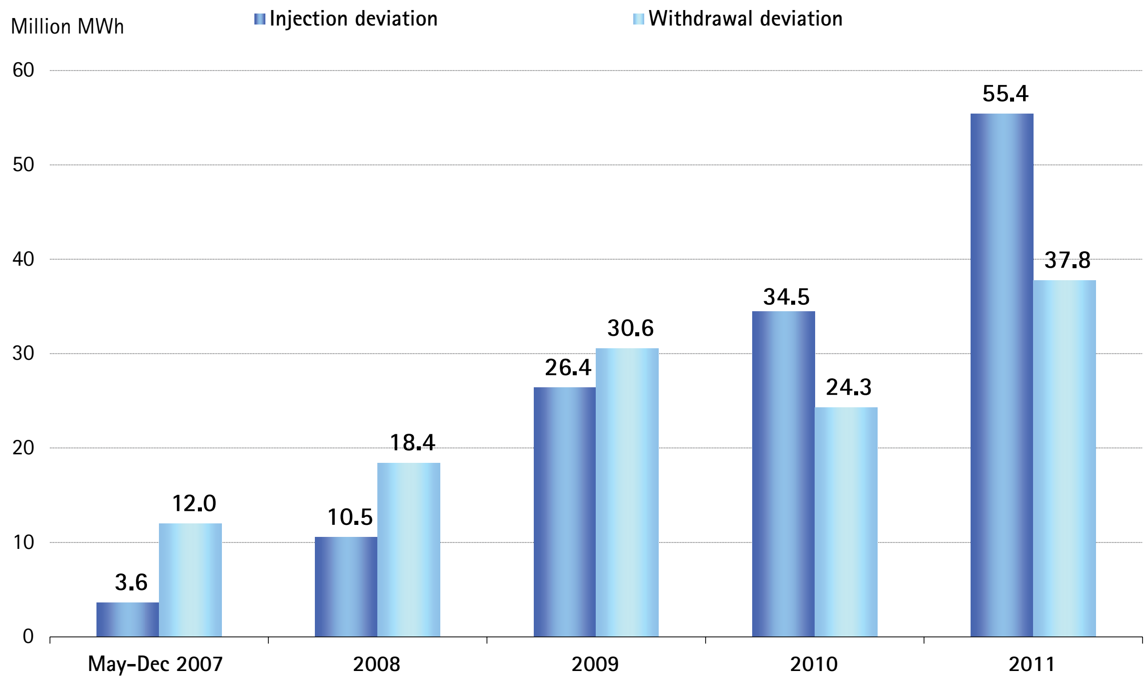
The year 2011 was a record year also for physical schedules registered on the PCE. To be specific, physical schedules registered in injection accounts climbed up to 131.6 million MWh (33.1 million MWh of which with a price indication), showing a 10.3% increase on the previous year. Physical schedules registered in withdrawal accounts amounted to 149.2 million MWh (all of them with no price indication), with a 15.2% growth (Fig C.2.34).

Fig C.2.34 **Registered physical schedules**



The growing utilization of the Electricity Account from participants as a major flexible instrument in their portfolio management is also proven by the yearly evolution of on schedule deviations (Fig. C.2.35). In particular, in 2011 on schedule deviations on the injection side (i.e. purchase back in the Exchange of a share of energy sold over the counter) reached 55.4 million MWh, way above on schedule deviations on the withdrawal side.

Fig C.2.35 **On schedule deviations**



We report below an analysis of the time evolution of contracts registered on the PCE and their characteristics, such as: duration, advance to delivery and type of electricity accounts.
As to the first aspect, weekly contracts were most used, with a volume share above 40%. In 2007, daily contracts accounted for 25.9% to gradually decrease down to around 12% in the last two years. On the contrary, monthly contracts kept growing from 22.0% in 2007 to 36.0% in 2011 (Tab C.2.31).

Registered contracts by contract duration (%) Tab C.2.31

Duration	2011	2010	2009	2008	2007
1 Day	12.5%	11.7%	17.7%	19.5%	25.9%
>1 Day	7.8%	7.3%	8.7%	9.8%	11.0%
1 Week	40.6%	41.3%	42.1%	40.0%	36.7%
>1 Week	3.2%	2.6%	6.0%	6.1%	3.8%
1 Month	36.0%	34.0%	24.8%	24.2%	22.0%
>1 Month	-	3.2%	0.7%	0.6%	0.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

As to the advance to delivery, over the years fewer contracts were registered on the last accepted day (2 days); in recent years, their share was halved relative to 34.9% in 2007. An opposite trend was observed for contracts registered 3-5 days prior to their deadline: in 2011, they accounted for 59.1% in terms of volumes, against 44.1% in 2007. Finally, contracts registered long before the deadline (> 5 days) kept growing until reaching 30.9% in 2010 to then fall down to 24.3% in 2011.

Registered contracts by days ahead of delivery (%) Tab C.2.32

Ahead of delivery	2011	2010	2009	2008	2007
2 days	16.6%	15.2%	19.2%	24.0%	34.9%
3 – 5 days	59.1%	53.9%	52.4%	49.8%	44.1%
> 5 days	24.3%	30.9%	28.4%	26.2%	21.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Finally, with regard to the type of Electricity Accounts, "classical" transactions aimed at a physical trade of energy, where sales are registered in an injection account and purchases in a withdrawal account, were the highest in terms of volumes. Yet, their proportional weight has considerably fallen over the years, from 86.2% in 2007 to 65.8% in 2011. Conversely, transactions where both sale and purchase are registered in a withdrawal account have grown in importance. The proportion of these latter has more than doubled, rising from 11.7% in 2007 to 27.5% in 2011 (Tab C.2.33)

Registered contracts by type of electricity accounts (%) Tab C.2.33

ELECTRICITY ACCOUNTS: sells → buys	2011	2010	2009	2008	2007
Injection → Withdrawal	65.8%	67.9%	78.6%	82.0%	86.2%
Injection → Injection	3.8%	4.7%	1.2%	1.4%	0.8%
Withdrawal → Injection	2.8%	2.7%	2.2%	1.4%	1.2%
Withdrawal → Withdrawal	27.5%	24.7%	18.0%	15.2%	11.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

2.6 The Forward Electricity Market (MTE) and the Electricity Derivatives Platform

In the last two years, the size of Italy's Forward Electricity Market expanded considerably, with a trading volume exceeding 520 TWh in 2011, equal to a 37% increase and a ratio of nearly 1.6 to 1 with the physical underlying (Tab C.2.34 a).

The largest share of such volumes is still focused on OTC trading, for the same reasons applicable to every international market: easy establishment of non regulated commercial channels, enjoying the typical competitive edge of first comers; possibility to trade non-standardized and/or indexed products: especially after the opening up of markets, these raised much interest on the part of participants in that they allow to replicate and postpone more conventional supply contracts; less importance given to financial guarantee systems: counterparties and terms of payment can be freely chosen, with an evident cost saving and no need to have a dedicated trading facility; no daily monitoring of positions to possibly adjust margins (in cash) in case of adverse price movements. Obviously, with special reference to the last aspect, this approach has a cost in terms of transparency, security and solvency of transactions: in the medium run, liquidity tends to partially pour into regulated markets, as one can infer by looking at the more mature markets of central-northern Europe[61].

A similar process is now developing also in Italy; in 2009, two regulated markets where set up. One of them is run by GME and offers monthly, quarterly and yearly contracts with physical delivery (MTE); the second one is managed by Borsa Italiana, offering similar products with financial delivery (Idex).[62] (Tab C.2.34a).

Tab C.2.34 a **Forward volumes traded yearly, by year of trading (TWh)**

	2012 (Q1)	2011	2010	2009
Physical Market (Terna)	83.05	332.27	330.46	320.27
Spot Market (IPEX)(*)	44.52	202.21	214.07	224.97
Forward Market	67.74	523.35	381.69	255.95
MTE(**)	4.30	31.70	6.29	0.12
IDEX	3.44	11.65	15.41	15.82
OTC (***)	60.00	480.00	360.00	240.00

Source: processing of data of GME, Borsa Italiana and European brokers

(*) including the volumes traded on the exchange in the MGP and the volumes of the MI
(**) net of OTC clearing
(***) estimate based on data from the main European brokers

61 In this respect, however, it should be noted that more and more participants are using the so called OTC clearing; through this latter, those who have entered standard OTC contracts request to have them registered in regulated markets in order to access the guarantee system of such markets and get a counterparty. This approach is quite popular abroad (it accounts for about 60% of volumes registered on the EEX) and is gaining popularity in Italy, too, as detailed in the paragraph.

62 Since 26/09/2009, Borsa Italiana has been offering a physical delivery option in the MTE for contracts registered in the Idex, although this option has never been used to this date. In 2011, no physical delivery option for Idex contracts in the MTE through CDE registration was reported.

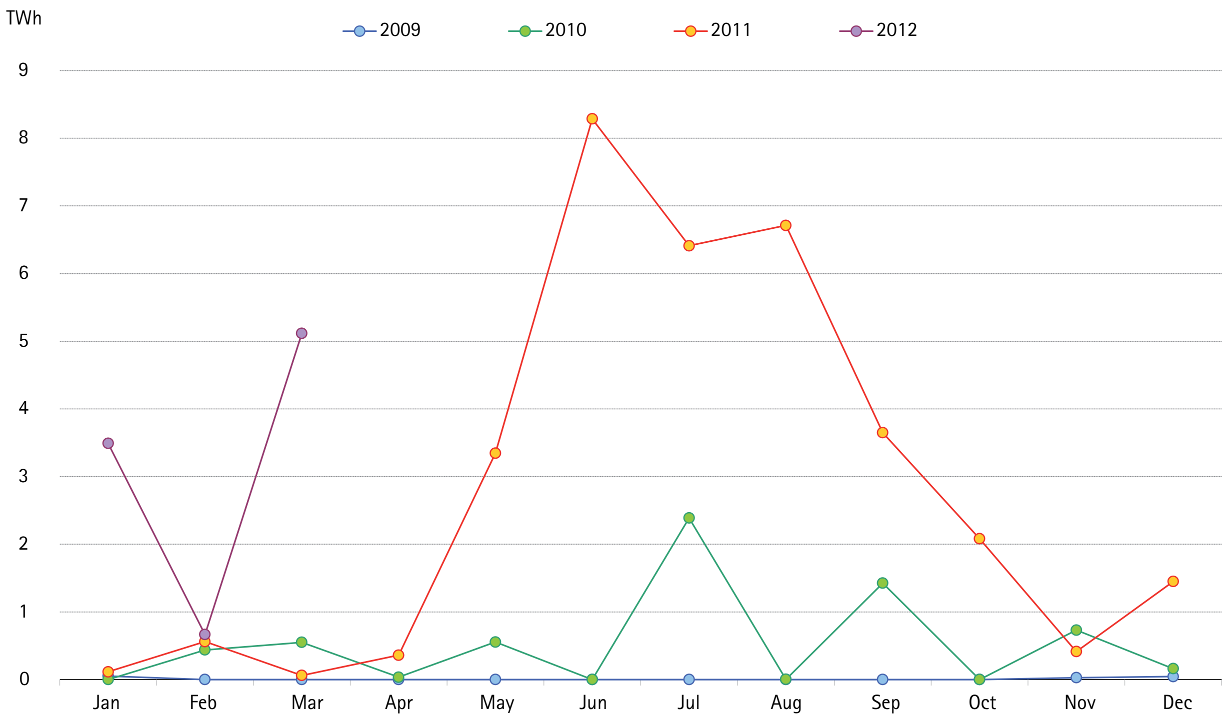
2.6.1 MTE volumes

While Idex has been relatively stable from the very beginning and was worth about 12 TWh in 2011 (-24%), the MTE is displaying a major growth rate. After a weak start in 2009, due to a different definition of products[63] and a more costly system of financial guarantees, volumes went up to 6 TWh in 2010 and 33 TWh in 2011 (+430%); in 2012, it is expected to grow again, as proven by the aggregate rate for the first quarter of this year, with MTE volumes above 9 TWh. Amongst others, OTC contracts are being registered in the MTE more and more often: from 0 TWh in 2010 to 1.8 TWh in 2011 and as much as 5 TWh during the first quarter of 2012 (Tab.C.2.33).

The structural growth of MTE liquidity is also displayed by the distribution of traded volumes, with trades exceeding 2 TWh in six out of twelve months (just one month in 2010), and always above 0.3 TWh in four out of the remaining six months: a confirmation of the high minimum guaranteed liquidity (Fig.C.2.36).

In spite of such very visible growth signals, the MTE market is close to maturity. In 2011, its absolute size accounted for 13.9% of the day-ahead market trading ; trading activities grew in frequency but there were fewer sittings with matching. This was also confirmed in the first months of 2012); large concentration of trades both on the demand side (in 2011, one participant alone covered 94% of purchases) and on the supply side, where active market participants were 10, the largest of whom sold 57% of volumes (Tab C.2.38).

Volumes traded in the MTE (including OTC), by month of trading and by year (TWh) Fig C.2.36



63 In 2009, traded products were daily, weekly and monthly.

A closer look at the 16 products which are listed daily in the MTE (incoming yearly contracts, four incoming quarterly and three incoming monthly contracts, each one with a baseload and peakload profile) suggests that baseload products are more liquid. They account for 89% of volumes, 73% of quantities expressed in MW and 72% of matchings. Lengthwise, the baseload yearly contract is the most liquid one (82%, 46% and 48% of the same variables), followed by baseload quarterly and monthly contracts. Since the yearly baseload contract is the most important product, liquidity goes up between May and October, when the commercial campaign to renew yearly supply contracts for the subsequent year is held. Once again, with every other product trades tend to focus on closer maturity products (Tab C.2.34b , 35; Fig. C.2.37-38).

It should be noticed that despite the increasing popularity of the MTE, the ratio between traded volumes and net positions is nearly always equal to one. This suggests that the MTE is still underutilized for trading and largely used to enter supply contracts. The only, partial exception is the yearly baseload contract boasting a 108% churn ratio (Tab C.2.40-41).

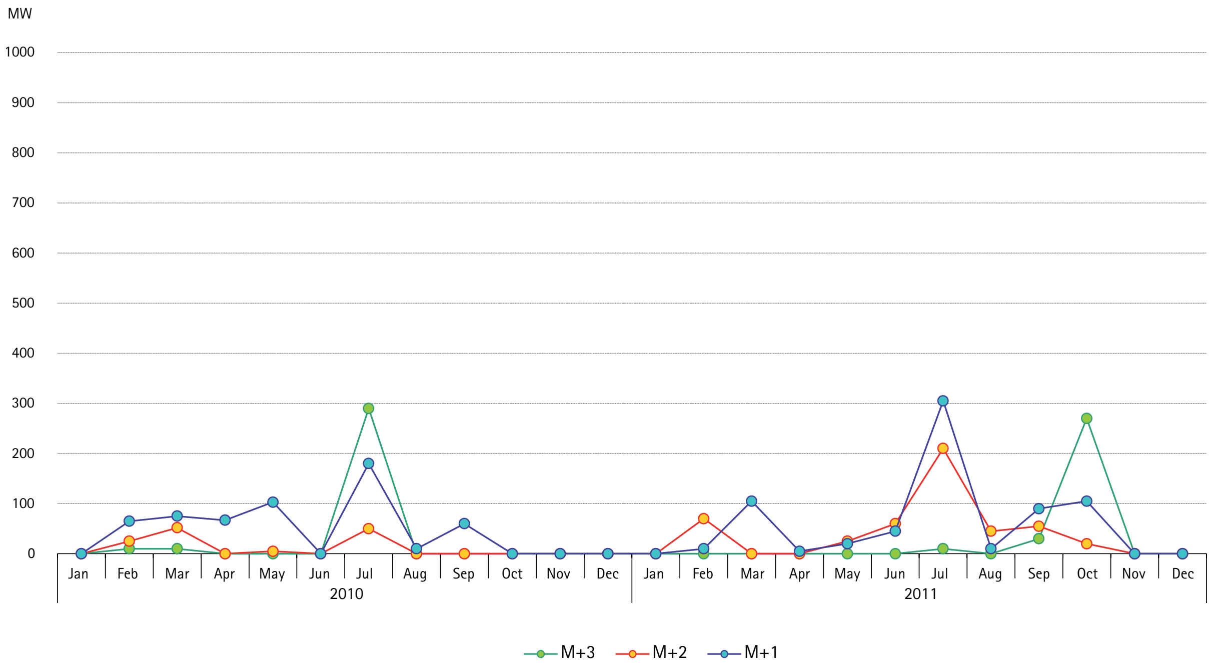
Tab C.2.34 b **Volumes traded in the MTE, by year of delivery**

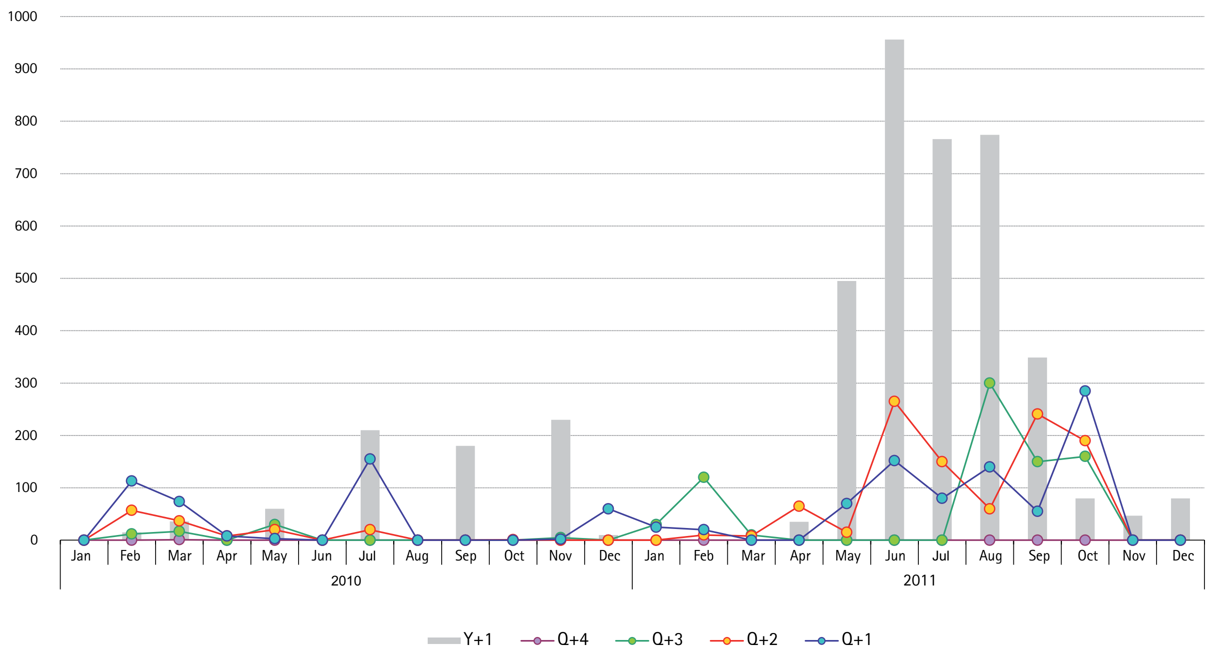
Total	2012 (Q1)	2011	2010	2009	2011/2010 Δ%
Contracts (MW)	1,885	8,228	2,366	219	248%
Volumes (MWh)	9,271,185	33,440,130	6,285,444	124,799	432%
No. of matchings	172	681	360	18	89%
OTC share	54%	5%	0%	0%	+ 5 p.p.
Base-load					
Contracts (MW)	1,825	6,018	1,146	175	425%
Volumes (MWh)	9,250,665	29,752,242	5,010,660	112,655	494%
No. of matchings	167	493	177	11	179%
OTC share	54%	6%	0%	0%	+ 6 p.p.
Peak-load					
Contracts (MW)	60	2,210	1,220	44	81%
Volumes (MWh)	20,520	3,687,888	1,274,784	12,144	189%
No. of matchings	5	188	183	7	3%
OTC share	88%	1%	0%	0%	+ 1 p.p.

Tab C.2.35 **Liquidity of trades in the MTE, by time ahead of delivery (2011)**

Ahead of delivery	M+1	M+2	M+3	M	Q+1	Q+2	Q+3	Q+4	Q	Y+1	Total
Contracts (MW)	1,075	485	310	**1,870**	827	1,004	770	-	**2,601**	3,757	8,228
Volumes (MWh)	618,265	268,365	225,850	**1,112,480**	1,641,796	1,825,204	1,279,430	-	**4,746,430**	27,581,220	33,440,130
No. of matchings	77	40	20	**137**	69	79	67	-	**215**	329	681
OTC share	38%	0%	0%	**21%**	0%	0%	0%	-	**0%**	6%	5%

Volumes traded, by month of trading and by type of product (MW) Fig C.2.37





A liquidity measure more significant than the amount of volumes and matchings, at least in terms of outlooks, is the growth of the trading book depth. According to indicators, the higher liquidity of baseload products not only regards volumes but also the book depth. In particular, with yearly contracts the percentage of successful sessions (i.e. with at least one matching) exceeds 27%; the percentage of hours during which a bid ask is created (i.e. purchase and sale bids/offers are simultaneously available, although their prices do not match) reaches 22%. However, the most interesting finding is another one: despite a number of participants with a small number of matchings (6 on purchase, 9 on sale) – including the AU which plays a crucial role with respect to purchases – on average, more participants (10-11) are active and express a relatively narrow average bid ask (1.46 €/MWh). The above variables are of interest but less significant in the case of quarterly contracts (on average, 8% of successful sessions, 11% of time with a bid ask and a mean value of 2.24 €/MWh) and monthly contracts (6%, 8%, 2.40 €/MWh, respectively). The same variables are lower with respect to peakload products (Tab C.2.36-37). This could easily translate into a larger number of trades, a larger number of participants and, therefore, into a diluted market concentration. A positive aspect may result from GME's recent decision to make the MTE available on the Trayport platform, too. Such platform is generally used by participants seeking arbitrage opportunities from different market platforms and OTC.

Tab C.2.36 **Liquidity of the order book of baseload products traded in 2011**

BASE-LOAD PRODUCTS

Delivery		Full book	Useful sessions	Matching time	Avg Bid-Ask*	Offered volumes*		Active participants		Participants with matchings	
Year	Period	% of hours	% of sessions	(mm:ss)	(€/MWh)	Bid (MW)	Ask (MW)	Bid	Ask	Bid	Ask
2011	Feb	1%			1.01	10	3	2	2		
2011	Mar	2%	2%	30:36	3.83	24	7	4	3	1	1
2011	Apr	4%	5%	62:10	1.77	36	7	4	4	1	3
2011	May	4%	2%	9:8	1.35	10	5	1	2	1	1
2011	Jun	4%			1.57	10	5	3	1		
2011	Jul	5%	8%	55:18	3.52	10	5	3	5	2	2
2011	Aug	12%	11%	36:2	3.55	29	7	4	5	3	3
2011	Sep	12%	6%	6:19	2.67	26	10	6	5	1	2
2011	Oct	13%	14%	41:42	2.60	25	12	6	6	1	4
2011	Nov	20%	9%	41:10	3.60	16	7	5	6	1	4
2011	Dec	14%	5%	78:52	3.39	19	8	4	5	1	4
2012	Jan	9%	14%	34:6	1.99	16	13	5	4	2	3
2012	Feb	3%	2%	245:10	0.79	5	5	2	1	1	1
2012	Mar	6%	5%	14:45	1.95	9	5	4	3	1	3
2011	Q2	4%	1%	5:17	2.81	10	8	6	4	1	1
2011	Q3	10%	5%	11:27	4.33	17	7	7	5	4	4
2011	Q4	14%	11%	31:29	2.71	19	7	6	8	4	5
2012	Q1	7%	9%	21:30	1.67	22	8	6	8	1	5
2012	Q2	14%	10%	37:2	1.35	14	6	4	7	2	6
2012	Q3	14%	11%	26:6	1.46	11	6	6	5	2	4
2012	Q4	15%	9%	45:23	1.34	11	5	3	4	1	3
2012	Y	22%	27%	27:43	1.46	37	8	10	11	6	9

* the indicators pertain to the first bids/offers which may be matched on the two sides of the order book and to the time interval in which both are simultaneously present

Liquidity of the order book of peakload products traded in 2011 Tab C.2.37

PEAK-LOAD PRODUCTS

Delivery		Full book	Useful sessions	Matching time	Avg Bid-Ask*	Volumes offered*		Active participants		Participants with matchings	
Year	Period	% of hours	% of sessions	avg (mm:ss)	(€/MWh)	Bid (MW)	Ask (MW)	Bid	Ask	Bid	Ask
2011	Feb							3			
2011	Mar	6%			3.44	43	16	3	3		
2011	Apr	1%	3%	19:4	2.02	32	19	1	5	1	3
2011	May		2%	8:22				1	1	1	1
2011	Jun		3%	17:48				3	3	1	3
2011	Jul	3%			6.97	31	5	3	3		
2011	Aug	11%	8%	46:52	5.49	24	8	4	5	2	3
2011	Sep	10%	9%	70:17	3.64	24	12	5	6	1	3
2011	Oct	7%	3%	78:49	4.51	17	12	3	6	2	2
2011	Nov	11%	2%	150:46	3.96	16	7	6	4	2	1
2011	Dec	8%	2%	149:52	4.04	14	6	3	4	2	1
2012	Jan	1%			2.88	24	5	1	2		
2012	Feb							1			
2012	Mar	1%			0.75	5	5	1	2		
2011	Q2	2%	1%	1:14	5.30	14	15	4	4	2	2
2011	Q3	5%	2%	12:19	4.67	16	7	5	5	2	3
2011	Q4	9%	4%	24:50	4.13	16	8	6	4	1	3
2012	Q1	3%	1%	31:40	2.18	16	6	4	4	1	2
2012	Q2	5%	4%	35:17	2.49	12	7	7	7	2	5
2012	Q3	2%	1%	34:38	3.34	12	6	3	2	1	2
2012	Q4	1%			4.69	5	5	1	2		
2012	Y	17%	13%	31:18	2.69	25	9	10	9	1	6

* the indicators pertain to the first bids/offers which may be matched on the two sides of the order book and to the time interval in which both are simultaneously present

Market shares Tab C.2.38

Market participant	Purchases M	Purchases Q	Purchases Y	Purchases Total	Sales M	Sales Q	Sales Y	Sales Total
ACQUIRENTE UNICO S.P.A.	97.1%	97.5%	93.5%	94.2%				
GDF SUEZ S.P.A.	0.7%	0.8%	0.5%	0.5%	9.1%	13.9%	7.3%	8.3%
EGL-ITALIA S.P.A.					2.0%		0.6%	0.6%
ENI SPA					12.5%	9.2%	6.5%	7.1%
EDF TRADING LIMITED			5.3%	4.4%	5.6%	2.5%	11.9%	10.3%
EDISON TRADING S.P.A.	0.7%	0.2%	0.2%	0.2%	23.8%	25.3%	13.2%	15.3%
ENEL TRADE S.P.A.	0.7%	0.5%	0.3%	0.3%	33.2%	47.7%	59.6%	57.0%
Other	0.9%	0.9%	0.3%	0.4%	13.8%	1.4%	0.9%	1.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

2.6.2 MTE prices

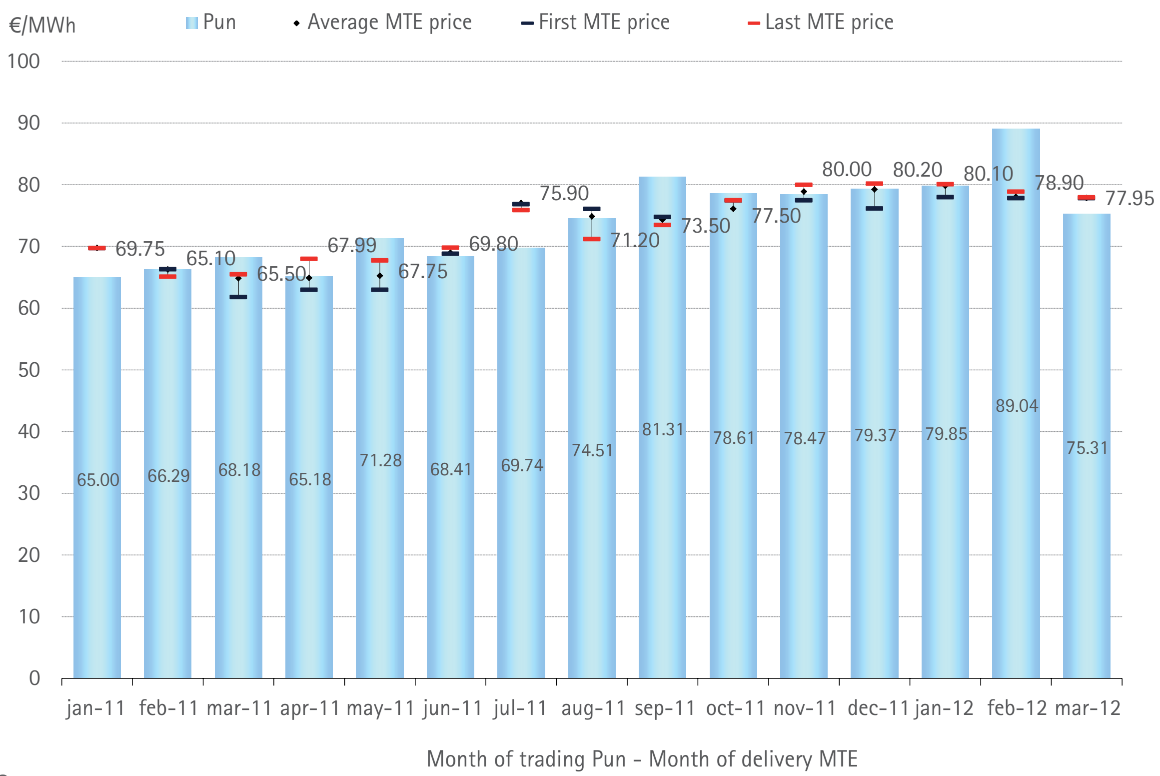
The market liquidity can be expressed also by the quality of prices. This latter is measured, for example, by the absolute differential with prices of similar products on other platforms and by the relative or high correlation with the value of the underlying. A similar analysis of the MTE can prove to be quite difficult. First of all, despite a major growth of volumes and trades frequency, the MTE overall liquidity is still quite volatile: intensive negotiation periods alternate with more or less long static periods. This is why the analysis of price trends was not based upon reference prices – equal to the mean value of matchings concluded during each session; hence, they are calculated for trading sessions only. Therefore, check prices were taken as a reference: such prices are calculated when each session opens and closes, to allow calculating the size of financial guarantees even in the absence of concluded trades. Although this has an influence on the analytical outcome, with reference to the value of reported prices and their volatility, MTE seems to send out rather reassuring signals.

First of all, MTE quotes are consistent with those of similar products in other markets (Idex, Tfs), both in terms of prices and mean value of the absolute gap. As to the correlation, it looks very good with respect to yearly and quarterly products listed in the three markets. When it drops down to 50% with reference to monthly products, this is due to a low, if not negative, correlation of M1 M2 and M3 products offsetting higher values in the other months (Tab.C.2.39). Finally, the relationship between the value of energy, expressed by its products, and the corresponding value of the underlying – measured by comparing the last quote of monthly products on delivery and the monthly values expressed by the MGP for the same month – seems to have an excellent predictive value, with a less than 1% difference in six out of twelve months, and 5-10% in the other six months (comprising the months of January, May, July and September). Furthermore, the difference between the MTE first and last quote, relative to the Pun, was less than 8% in absolute terms (Fig.C.2.38).

Tab C.2.39 **Correlation of check prices of baseload products traded in the MTE, Idex and Tfs in 2011**

	Correlation			Average absolute deviation (€/MWh)		
	M	Q	Y	M	Q	Y
MTE vs IDEX	55%	89%	85%	0.9	1.1	0.7
MTE vs TFS	50%	88%	89%	0.4	0.3	0.4

Fig C.2.38 **Ratio of spot prices (MGP) to forward prices (MTE)**



A closer look at the trend of the check price of the various products listed in 2011, suggests a modest growth of all products during the trading period; the percentage difference between the first and last check price quote varies between 0 and 25%, depending on the different products. This figure reflects the progressive appreciation of 2012 calendar Brent during the year, rising from 95 to 105 $/bbl (+10%). Some summer, monthly products represent an exception: their liquidity was low and the first three quarterly peakloads showed a value reflecting a remarkable leap between 2010 (beginning year of the trading period, with zero trades) and closing values near the end of 2011 (by way of further confirmation, the same figure if calculated relative to the reference price provides an opposite finding) (Tab C.2.40-41).

Prices of baseload products traded in 2011[64] Tab C.2.40

BASE-LOAD PRODUCTS

Delivery		Trading		Volumes			Open position	Churn ratio*	Check price (€/MWh)						Matching price €/MWh)				
Year	Period	Start	End	MW	MWh	OTC share (%)	MW	%	First	Last	Min	Max	Avg	Vol.	First	Last	Min	Max	Avg
2011	Feb	29/10/10	28/01/11				531		66.32	65.10	65.10	66.32	66.26	1.8%					
2011	Mar	30/11/10	25/02/11	290	215,470	97%	811	100%	61.81	65.50	61.81	65.50	64.82	0.9%	65.00	65.00	65.00	65.00	65.00
2011	Apr	30/12/10	30/03/11	70	50,400		571	100%	63.00	67.99	63.00	67.99	64.90	0.7%	63.90	64.60	63.70	64.60	64.04
2011	Mag	31/01/11	28/04/11	5	3,720		506	100%	63.00	67.75	63.00	67.80	65.24	1.2%	67.75	67.75	67.75	67.75	67.75
2011	Giu	28/02/11	30/05/11				501		68.83	69.80	68.83	69.80	68.99	0.6%					
2011	Lug	31/03/11	29/06/11	70	52,080		689	108%	76.85	75.90	75.50	78.25	77.00	0.4%	78.32	75.50	75.50	78.40	77.08
2011	Ago	29/04/11	28/07/11	200	148,800		816	103%	76.10	71.20	71.20	76.10	74.86	1.0%	74.50	71.35	71.20	74.50	72.90
2011	Set	31/05/11	30/08/11	75	54,000		699	100%	74.80	73.50	73.20	75.60	74.31	1.3%	74.85	73.20	73.20	75.40	74.53
2011	Ott	30/06/11	29/09/11	130	96,850		1,186	100%	77.45	77.50	74.40	78.50	76.09	0.8%	75.45	77.45	74.40	78.50	76.83
2011	Nov	29/07/11	28/10/11	140	100,800		1,196	100%	77.49	80.00	77.49	80.70	78.89	0.6%	80.46	80.00	79.60	80.70	80.15
2011	Dic	31/08/11	29/11/11	50	37,200		1,106	100%	76.16	80.20	76.16	80.20	79.24	0.6%	78.85	80.20	78.70	80.20	79.47
2012	Gen	30/09/11	29/12/11	270	200,880		3,470	104%	78.00	80.10	78.00	81.00	79.79	0.5%	81.00	79.80	79.80	81.00	79.95
2012	Feb	31/10/11	30/01/12	5	3,480		3,215	100%	77.83	78.90	77.83	79.65	78.03	1.4%	79.30	79.30	79.30	79.30	79.30
2012	Mar	30/11/11	28/02/12	40	29,720		3,250	100%	77.83	77.95	77.70	78.20	77.84	0.3%	78.20	77.64	77.60	78.20	77.81
2011	Q2	30/03/10	29/03/11	40	87,360		501	100%	65.50	68.19	63.00	68.19	65.00	1.5%	63.40	64.00	63.40	64.00	63.70
2011	Q3	29/06/10	28/06/11	170	375,360		624	101%	74.00	75.07	63.50	76.85	72.51	0.9%	63.50	75.30	63.50	76.85	74.79
2011	Q4	29/09/10	28/09/11	625	1,380,625		1,056	105%	67.00	78.64	67.00	80.90	74.63	1.0%	70.50	78.65	70.20	79.75	76.51
2012	Q1	29/12/10	28/12/11	615	1,342,545		615	100%	67.01	78.60	67.01	79.10	76.23	1.2%	76.10	78.50	75.80	79.10	77.99
2012	Q2	30/03/11	28/03/12	570	1,244,880		3,150	103%	69.00	75.81	68.83	77.25	71.90	1.1%	71.73	75.45	68.70	77.25	72.81
2012	Q3	29/06/11	31/03/12	395	872,160		2,985	101%	72.21	80.10	72.21	82.00	76.35	0.8%	73.23	80.10	73.20	81.60	79.08
2012	Q4	29/09/11	31/03/12	145	320,305	3%	2,740	100%	73.81	81.90	73.81	83.10	78.80	0.9%	81.90	81.90	81.15	83.00	82.10
2012	Y	29/12/10	28/12/11	2,798	24,577,632	6%	2,595	108%	67.42	76.64	67.42	76.64	73.71	1.2%	75.50	76.66	72.00	77.15	74.42

* the indicator is calculated in terms of volumes/open position net of cascading

Prices of peakload products traded in 2011 Tab C.2.41

PEAK-LOAD PRODUCTS

Delivery		Trading		Volumes			Open position	Churn ratio*	Check price (€/MWh)						Matching price (€/MWh)				
Year	Period	Start	End	MW	MWh	OTC share (%)	MW	%	First	Last	Min	Max	Avg	Vol,	First	Last	Min	Max	Avg
2011	Feb	29/10/10	28/01/11				320		76.93	76.93	76.93	76.93	76.93	0.0%					
2011	Mar	30/11/10	25/02/11	100	27,600	100%	420	100%	78.22	75.70	74.00	78.22	75.15	2.0%					
2011	Apr	30/12/10	30/03/11	100	25,200		385	100%	73.00	75.75	73.00	78.87	74.76	1.9%	76.02	75.75	75.60	76.48	75.99
2011	May	31/01/11	28/04/11	5	1,320		290	100%	73.08	77.28	73.08	77.28	75.15	0.8%	77.28	77.28	77.28	77.28	77.28
2011	Jun	28/02/11	30/05/11	20	5,280		305	100%	74.71	79.30	74.71	79.50	77.61	0.7%	79.61	80.20	79.30	80.25	79.91
2011	Jul	31/03/11	29/06/11				345		89.15	90.50	89.15	91.00	90.37	0.7%					
2011	Aug	29/04/11	28/07/11	165	45,540		510	100%	88.28	78.40	78.40	88.28	85.75	1.6%	83.50	78.44	78.40	83.50	81.37
2011	Sep	31/05/11	30/08/11	145	38,280		490	100%	80.34	82.75	80.34	84.80	82.20	1.1%	84.85	83.35	83.35	85.00	84.23
2011	Oct	30/06/11	29/09/11	15	3,780		450	100%	89.84	86.00	84.90	89.84	87.35	1.0%	84.85	86.00	84.85	86.00	85.23
2011	Nov	29/07/11	28/10/11	10	2,640		445	100%	89.89	93.22	82.10	93.57	89.21	2.0%	82.00	82.00	82.00	82.00	82.00
2011	Dec	31/08/11	29/11/11	10	2,640		445	100%	87.48	91.64	81.20	91.64	90.03	1.8%	81.00	81.00	81.00	81.00	81.00
2012	Jan	30/09/11	29/12/11				1,039		86.68	90.54	86.68	90.54	89.20	0.8%					
2012	Feb	31/10/11	30/01/12	25	6,300	100%	1,039	100%	89.33	92.87	89.33	92.87	90.89	1.6%					
2012	Mar	30/11/11	28/02/12				1,039		89.47	91.01	88.00	91.01	90.44	1.1%					
2011	Q2	30/03/10	29/03/11	6	4,680		285	120%	85.15	76.96	73.00	85.15	77.85	1.6%	74.60	73.80	73.80	74.60	73.93
2011	Q3	29/06/10	28/06/11	70	55,440		345	108%	96.20	84.67	77.35	96.20	84.14	0.9%	86.90	86.05	86.05	87.15	86.69
2011	Q4	29/09/10	28/09/11	160	124,800		440	100%	85.42	83.06	80.30	90.85	85.34	0.8%	80.30	89.30	80.30	91.15	87.55
2012	Q1	29/12/10	28/12/11	80	62,400		80	100%	77.73	90.49	77.73	90.49	87.84	0.6%	89.30	87.77	87.60	89.30	88.33
2012	Q2	30/03/11	28/03/12	296	230,880		1,254	100%	80.04	83.64	74.97	87.85	80.92	1.3%	80.30	79.00	77.75	80.40	79.39
2012	Q3	29/06/11	31/03/12	70	54,600		1,029	100%	83.76	92.33	80.21	94.23	86.29	1.3%	82.20	82.40	82.20	82.40	82.37
2012	Q4	29/09/11	31/03/12	10	7,920	100%	959	100%	78.47	98.12	78.47	99.25	91.43	1.8%					
2012	Y	29/12/10	28/12/11	959	3,003,588		959	100%	78.21	86.70	78.21	86.70	84.00	0.6%	86.23	83.10	82.49	86.30	84.18

* the indicator is calculated in terms of volumes/open position net of cascading

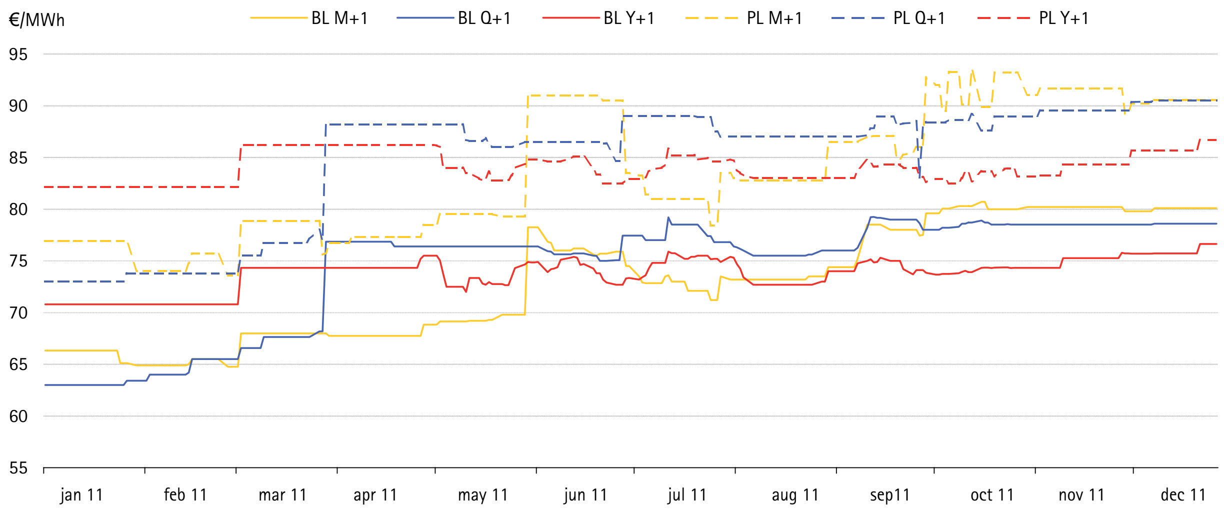
64 The value of the check price shown in the "first" column represents the check price upon opening of the product trading session. The value shown in the "last" column represents the closing value reported in the last session or, in the case of products still being traded at the end of March, the closing value of the last session of April.

A second, clear observation is the lack of seasonality in prices. These latter were actually flat during the year, net of the oil-induced trend; the only exception was the evident change in the price level of front month (M+1) and front quarter products (Q+1) when the summer season was approaching (Fig.C.2.39). A partially related aspect is the volatility of prices, generally very small (0-2%) and by way smaller than in the MGP (9%); such limited volatility was due to the low liquidity of trades and to the different nature of spot and forward products. Still, it suddenly grew between May and October, i.e. when trades featured a higher liquidity and the prices of the underlying were more volatile. Broadly speaking, volatility was higher for monthly and peakload products (Fig.C.2.39, Tab C.2.40-41).

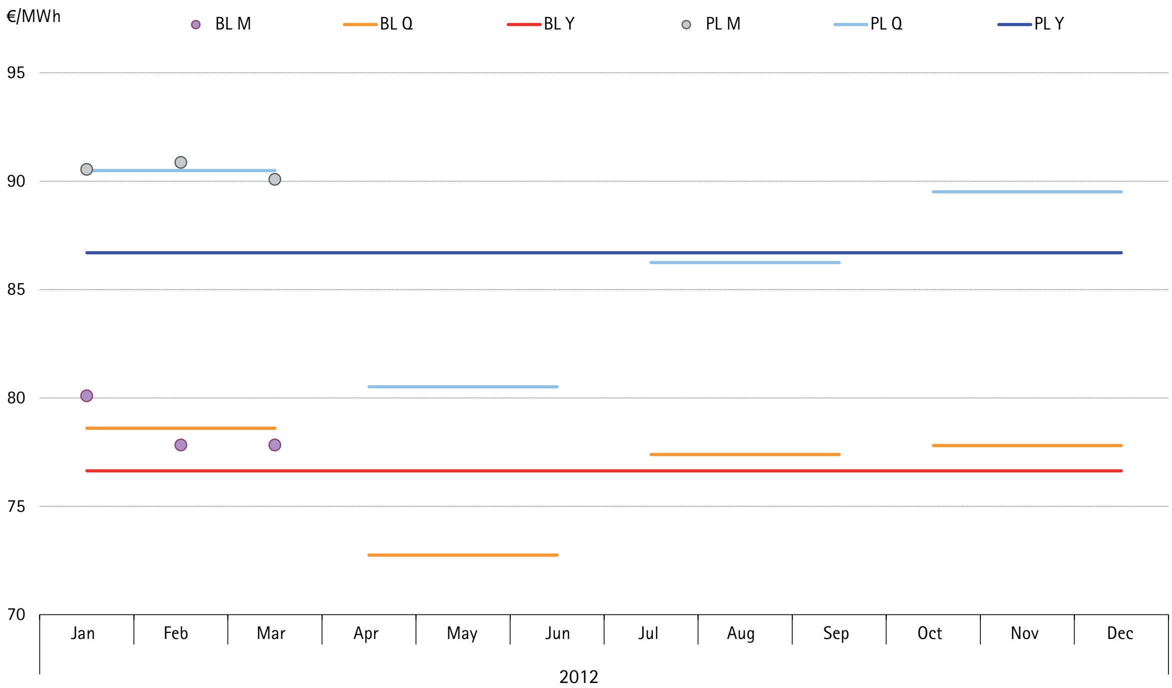
A progressively smaller spread was confirmed between base and peak prices which average-wise, across-products fell from 1.17 to 1.14 in 2011; this phenomenon is by now characterizing the MGP daily prices. On a yearly basis, the same parameter turned out to be 1.15. Over the years, this trend has become more and more pronounced and is clearly reflected by MTE prices as well (Fig C.2.39).

Finally, in 2012 the forward curve expressed by the MTE displays a 6% expected increase on the 2011 spot price (76.64 €/MWh is the latest figure available for the check price, versus an average yearly value of Pun 2011 equal to 72.23 €/MWh). Similar increases were observed also for the yearly leading product (86.70 €/MWh versus a Pun value of 82.71 €/MWh), thus confirming a further narrowing of the peak/base ratio from 1.15 to 1.13 (Fig. C.2.40).

Fig C.2.39 **Evolution of prices of front products based on check prices**



Forward curves expressed by the MTE for the year 2012 Fig C.2.40



2.7 International comparisons

After a timid initial recovery during 2010, the drop of electricity markets trading in Europe caused by the economic crisis continued also in 2011 (Fig. C.2.41).

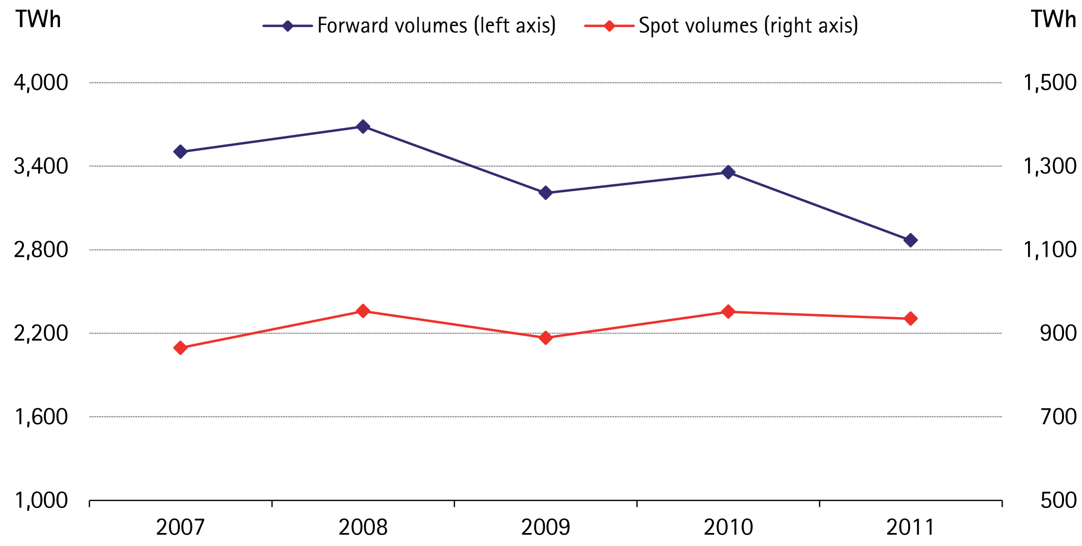
In line with the current uncertainty about the unpredictable length of the crisis, the most significant effects were observed on forward traded volumes which hit their minimum in five years, after a dramatic decline suffered in 2009 (-15%). Such fall reflects a drastic decrease in quantities as observed in more mature markets in the German-Scandinavian region (-14/-17%); the evolution of these latter generally and deeply affects the rest of Europe, since those markets alone account for over 90% of forward traded electricity across the Continent (Fig. C.2.42, Tab C.2.42).

On the other hand, reassuring signals are sent by the younger Mediterranean markets: while having a smaller size than central-northern European markets, their operations are well developing with a growth rate that at least in Italy is a triple digit one (+108%).

After a rather weak beginning, in Italy the physical market of electricity drives up forward operations; in one year, volumes grew from 6 to 33 TWh. Further, encouraging growth outlooks are characterizing the first quarter of 2012, too, possibly thanks to the platform being used for clearing purposes[65] (Fig. C.2.42 Tab C.2.42).

65 For more information, please refer to par. C.2.6.

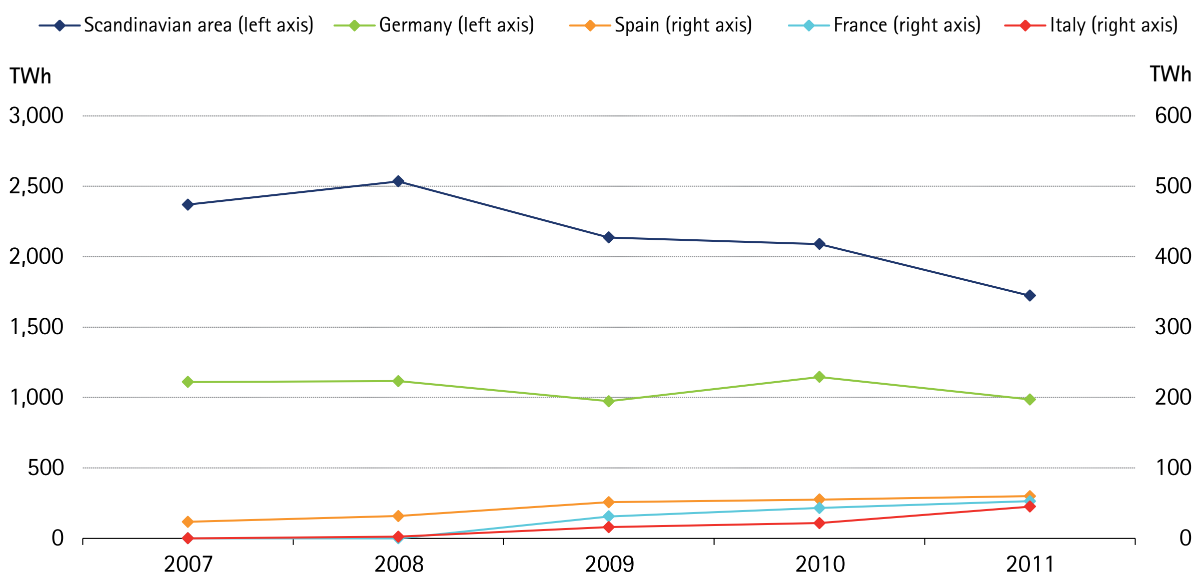
Fig C.2.41 **Trend of spot and forward volumes in Europe (TWh)**



Tab C.2.42 **Yearly volumes in the main European forward markets (€/MWh)**

Reference Area	2011	Tr. Change	2010	2009	2008	2007
Italy	*45.1*	*107.8%*	*21.7*	*15.9*	*2.3*	-
- physical market (GME)	*33.4*	*430.8%*	*6.3*	*0.1*	-	-
- financial market (Borsa Italiana)	*11.7*	*-24.4%*	*15.4*	*15.8*	*2.3*	-
Germany (EEX)	986.2	*-13.9%*	1,145.8	973.4	1,116.1	1,110.3
France (EEX)	52.7	*22.3%*	43.1	31.1	-	-
Spain (OMIP)	59.9	*8.7%*	55.2	51.4	31.6	23.4
Scandinavian Area (NASDAQ OMX)	1,723.3	*-17.5%*	2,089.8	2,136.3	2,534.9	2,369.2

Fig C.2.42 **Volumes traded in the forward markets of the main European exchanges**



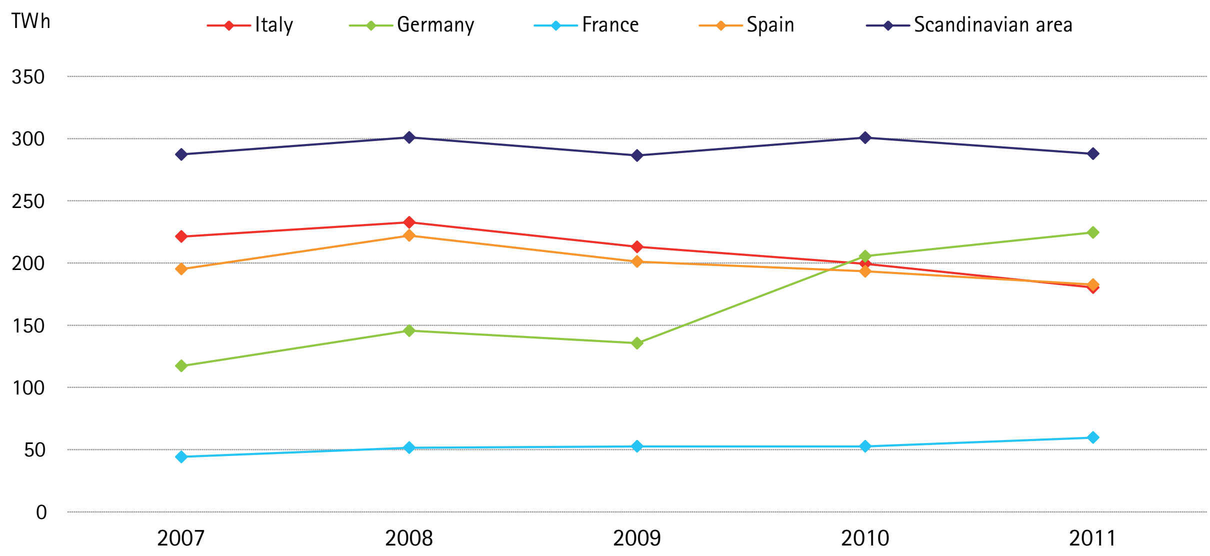
The generalized fall of electricity demand in Europe, however, seems to have just partially affected spot transactions which, on the whole, are close to last year's levels (Fig. C.2.41).

Yet, this finding is heavily influenced by the further rise of trades in the German sot market (+9%): this latter can well offset the volume decline in historically larger exchanges. Even the Scandinavian exchange declined (-4%), although its quantities slightly fluctuated around the average level of the last five years. Conversely, Mediterranean exchanges have been characterized by a downward trend since 2009, with a 6-10% reduction of trades. In Italy, the amount of spot traded electricity has been reaching its minimum value since the market startup[66] (Tab C.2.43).

Yearly volumes in the main European spot markets (€/MWh) Tab C.2.43

Reference Area	2011	*Tr.change*	2010	2009	2008	2007
Italy (GME)	180.3	*-10%*	199.5	213.0	232.6	221.3
Germany (EPEX)	224.6	*9%*	205.5	135.6	145.6	117.3
France (EPEX)	59.7	*13%*	52.6	52.6	51.6	44.2
Spain (OMIE)	182.6	*-6%*	193.3	201.2	222.1	195.2
Scandinavian Area (NORDPOOL)	287.8	*-4%*	300.7	286.4	300.9	287.2

Volumes traded in the day-ahead markets of the main European exchanges Fig C.2.43



66 For a more exhaustive analysis of Italy, refer to par. C.2.1.

In the face of some conflicting volume movements, at times reflecting local demand peculiarities, the prices expressed by the major European exchanges are virtually homogeneous over time. While replicating the structural differences existing among the electricity systems of each country, a growing interaction among exchanges, and a high propensity by derivatives markets to generate appropriate forward-looking price signals were confirmed in 2011 (Fig. C.2.44, Fig. C.2.45).

As to these latter, one should notice the partial disagreement about 2012 price expectations. These are supposed to be quite stable vis-à-vis 2011 in the French-German region, after an initial steep rise in the aftermath of the Fukushima catastrophic incident; on the opposite, a price increase is expected in Italy, where the international dynamics of the Brent and gas prices seem to play a heavier role (Tab C.2.44, Fig. C.2.45, Fig. C.2.46).

Fig C.2.44 **Historical trend of spot prices on European power exchanges (€/MWh)**

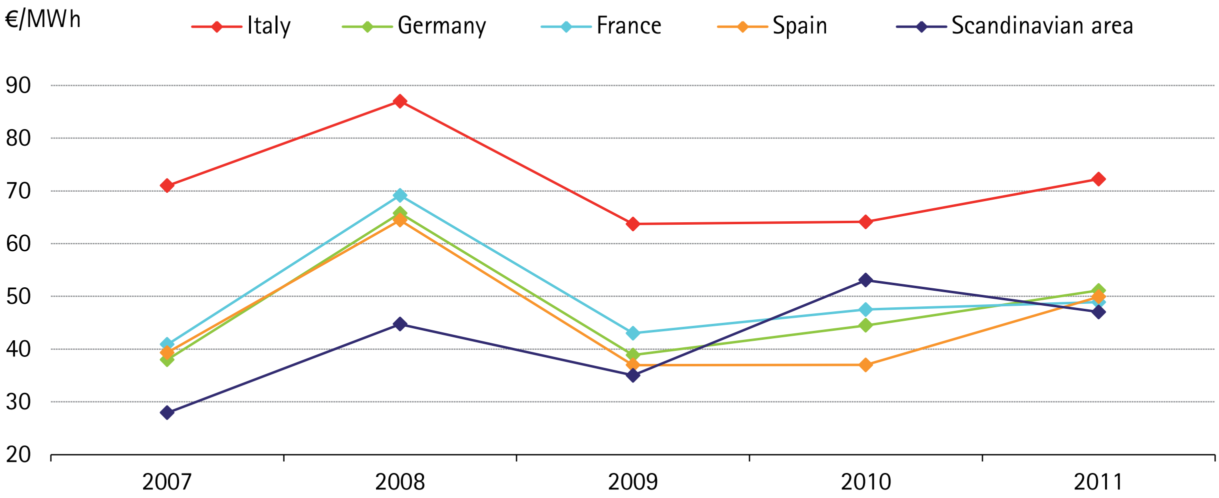
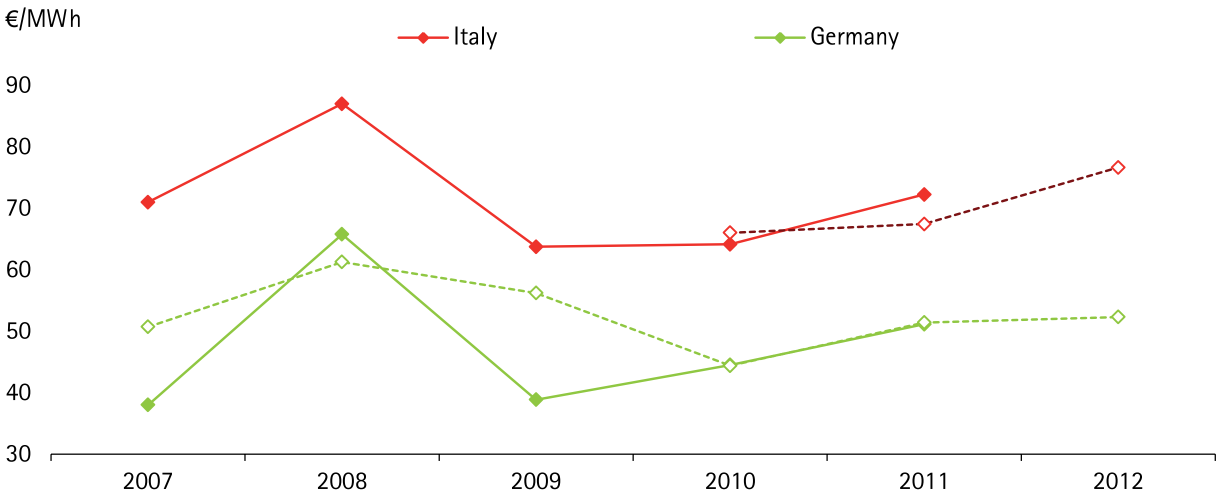
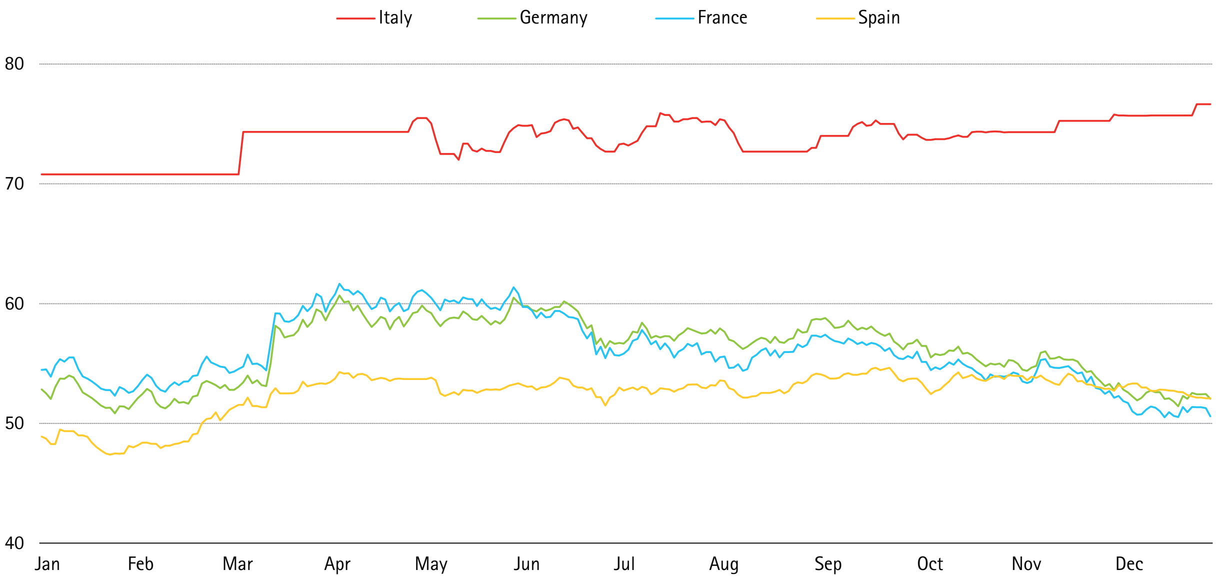


Fig C.2.45 **Average level of the spot price and of the Calendar product to be delivered in the same year (€/MWh)**[67]



67 Reference is made to the settlement price for the Calendar product on its last trading day. For the sake of simplicity, the diagram illustrates the series of Italian and German spot and futures prices only.

Monthly trend of the settlement price for yearly product 2012 (€/MWh) Fig C.2.46



At any rate, these dynamics only partially affected consolidated spot prices in 2011; these latter moderately went up from the low levels of the previous two year period. Non negligible price increases mainly emerged during the first months of the year in Central European exchanges and in the last four months of the year in Italy, in line with the national gas price trend[68].

To be specific, in the major continental power exchanges prices were consistently around 49-56 €/MWh, with a trend rise between 3% in France and 35% in Spain. Such convergence is more evident in the Exchange prices of France and Germany, which were identical in 16% of hours (2% in 2010, 0% in 2009), as a consequence of market coupling in CWE[69].

Conversely, the only price decrease was observed in Scandinavia, where prices followed a slightly opposite trajectory without returning to the level existing prior to the 2010 booming pattern (-11.3%).

In this context, the Italian price of electricity was of 72.23 €/MWh, in line with the rest of Europe in terms of growth trend (+12.6%) and, in particular, of peak/off-peak hourly calibration (1.29)[70].

With an eye to a growing integration between the Italian and neighboring markets, it should be noted that the coupling project with Slovenia became operational in 2011. Thanks to this project, cross-border capacity was allocated more efficiently vis-à-vis explicit auctions; also, it was constantly consistent with the price spread developing along the border. Despite an incomplete convergence of prices in the Italian and Slovenian (BSP) power exchanges, the progressive increase of capacity allocated through implicit auctions (during the year, it increate from an average 64 MW in January to 165 MW in December) did mitigate the effect of the generation cost gap between the two countries; on the opposite, it did promote equal prices in the Northern zone and in the neighboring BSP for about 20% of hours.

68 For more specific information, refer to Cap.3.
69 CWE was started on 9 November 2010. For more details, refer to Box 1 of GME's 2010 Annual Report.
70 For a more comprehensive analysis of Italian patterns, refer to par. C.2.2.

In spite of this clear convergence with foreign movements, in 2011 Italian prices were still the highest across the continent: the generation fleet is more costly and structurally depending upon gas fuelled combined cycle plants. The different structure of the fleet and a different pattern followed by the reference fuel, then, did promote a new broadening of the gap between Italian and foreign prices which in 2011 went back to slightly over 20 €/MWh (Tab C.2.44, Tab C.2.45, Tab C.2.46).

Tab C.2.44 **Yearly average prices in the main European spot markets (€/MWh)**

	2011		2010	2009	2008	2007
Reference Area	Average	*Tr.change*	Average	Average	Average	Average
Italy (GME)	72.23	*12.6%*	64.12	63.72	86.99	70.99
Germany (EPEX)	51.12	*14.9%*	44.49	38.85	65.76	37.99
France (EPEX)	48.89	*2.9%*	47.50	43.01	69.15	40.88
Slovenia (BSP)	57.20	-	-	-	-	-
Spain (OMIE)	49.93	*34.9%*	37.01	36.96	64.44	39.35
Scandinavian Area (NordPool)	47.05	*-11.3%*	53.06	35.02	44.73	27.93
PUN-PME	21.60	13%	19.03	23.85	20.38	32.24

Tab C.2.45 **Average prices by groups of hours on the main European exchanges**

Year 2011	Total		Peak-load		Off-peak		Off-peak working day		Holiday	
Reference Area	Average	*Tr.change*	Average	*Tr.change*	Average	*Tr.change*	Average	*Tr.change*	Average	*Tr.change*
Italy (GME)	72.23	*12.6%*	82.71	*7.7%*	66.71	*16.3%*	64.32	*18.7%*	69.37	*13.8%*
Germany (EPEX)	51.12	*14.9%*	61.51	*11.3%*	45.65	*17.9%*	47.27	*17.9%*	43.84	*18.0%*
France (EPEX)	48.89	*2.9%*	61.17	*3.2%*	42.42	*3.0%*	44.02	*4.6%*	40.64	*1.3%*
Slovenia (BSP)	57.20	-	69.79	-	50.56	-	52.58	-	48.31	-
Spain (OMIE)	49.93	*34.9%*	54.54	*29.6%*	47.50	*38.5%*	47.30	*38.4%*	47.72	*38.7%*
Scandinavian Area (NordPool)	47.05	*-11.3%*	50.50	*-14.4%*	45.23	*-9.3%*	45.56	*-10.1%*	44.85	*-8.3%*
PUN-PME										

Tab C.2.46 **Volatility and ratio between prices by groups of hours. Year 2011**

	Italy	Germany	France	Slovenia	Spain	Scandinavian Area
Peak-load/Off-peak working day	1.29	1.30	1.39	1.38	1.15	1.11
	(-9.2%)	*(-12.5%)*	*(-1.3%)*	-	*(-6.3%)*	*(5.9%)*
Holiday/Off-peak working day	1.08	0.93	0.92	0.92	1.01	0.98
	(-4.2%)	*(0.1%)*	*(-3.1%)*	-	*(0.2%)*	*(2.1%)*
Volatility	7.6%	10.4%	12.9%	11.0%	9.1%	7.7%
	(-4.2 p.p.)	*(-0.3 p.p.)*	*(0.4 p.p.)*	-	*(-9.9 p.p.)*	*(0.8 p.p.)*

() trend changes between parentheses

Box 3 THE RELATIONSHIP BETWEEN WHOLESALE AND RETAIL PRICE IN THE ITALIAN MARKET THROUGH AU'S ROLE

Edited by Acquirente Unico (AU)

The relationship existing between the wholesale and retail price in the Italian electricity market depends on several factors, including the activities performed by the Acquirente Unico (AU, Single Buyer) with respect to the purchasing portfolio (raw material); it also depends on AEEG regulatory role with respect to regulated cost components (transmission, distribution, system charges etc.).
The weight of raw material (electricity), while varying from one customer to another according to the type and power, accounts for about 60% of the final cost. In other words, the relationship between any change in the cost of raw material and the cost paid by final customers is increased or reduced according to the variation of the other regulated cost components.
This relationship is explored further below by analyzing the AU's role.

Acquirente Unico and the standard offer service

Acquirente Unico S.p.A. is a share company established under Legislative Decree 16 March 1999 n. 79, to guarantee the supply of electricity to customer of the then constrained market. On 1° July 2007, the liberalization process for the retail sale of electricity was completed. The constrained market became history, allowing every end customer, including households, to choose their supplier on the open market.
Within the present liberalized market, now open to small consumers, too, the simultaneous presence of a number of larger operators both during the generation and distribution stages, has justified the definition of a price protection system. Here, Acquirente Unico is vested with the procurement of electricity to end customers who do not avail themselves of the open market whereas AEEG defines prices for the same customers, according to the procurement costs incurred by AU. In fact, Law n. 125/2007, in accordance with Community measures on the liberalization of electricity markets and public and universal service duties, the so called "standard offer" service was introduced. It is based on standard economic conditions for the retail sale of electricity, defined by the Regulator according to the purchasing portfolio of Acquirente Unico. The standard offer service can be offered to every households and small businesses with less than 50 employees and a maximum yearly sales volume of 10 million euro.
The standard offer service is directly provided by distributors provided that they have less than 100,000 customers. Otherwise, the service is provided by special selling companies which deliver their service according to the "economic conditions" established by the Electricity and Gas Regulator, subject to a quarterly adjustment.
In compliance with the rules established by the Regulator, Acquirente Unico sells electricity to standard offer retailers at a selling price which covers any procurement cost incurred and allows to balance its accounts, in accordance with article 4 para 6 of Legislative Decree n. 79/99.

Procurement for the standard offer service

The activities and procurement strategies pursued by Acquirente Unico are based on the projected requirement of the standard offer market and on price trend of energy raw materials.
By means of public tenders to select contracts with domestic and foreign producers and by simultaneously taking part in regulated markets, Acquirente Unico seeks the best buy opportunities on the market to minimize the procurement cost and its volatility.
The factors that most affect the electricity demand on the standard offer market include: the number of customers on that market, which varies according to the proportion of customers switching from the standard

offer to the open market; how power devices and equipment are used by end customers for their own needs, determining the hourly/seasonal trend of the electricity load.
In December 2011, customers under the standard offer market accounted for 25.4% of total energy, amounting to about 28.6 million customers, comprising of 23.8 million household consumers and 4.8 million customers other than households.
During 2011, by reason of their switching decision, approximately 105,000 customers/month were lost by the standard offer market; as for other BT uses and public lighting, such decrease was equal to approximately 11,400 customers/month.
In the last three years, the effect of macro-economic variables on the electricity demand pattern among standard offer customers, although existing, was little evident. This depends on the consumption structure on the standard offer market, characterized by households' needs and habits. The standard offer perimeter, in fact, mostly consists of household customers exhibiting a rigid demand, and of uses different from households which are only partly affected by the economic crisis. The business segment, on the other hand, operates within an environment characterized by a small GDP growth which in turn accounts for a a modest domestic demand and a modest export growth: hence, it heavily suffered the economic crisis and remarkably reduced the electricity demand.
One further factor having a major impact on the standard offer demand is electricity generated by photovoltaic plants. Their continuous expansion caused photovoltaic plants to constantly grow in number and installed power. At the end of 2011, there were about 330,000 plants for a total of 12,7 GW installed power, according to estimates.
With special reference to customers who follow the "net metering" approach, for the purpose of an accurate requirement estimate, it is important to monitor actually generated electricity to evaluate the effect of the smaller amount of electricity withdrawn from the grid. By consuming a portion of self-generated electricity, they reduce the share of electricity taken from the grid and procured by Acquirente Unico. As a consequence, electricity self-consumption causes a lowering of withdrawal curves, especially during the central hours of the day, when solar irradiation is at its peak.

Analysis of purchases and selling prices

During 2011, the requirement of the standard offer market fell by 5.3% on 2010, especially because of those switching to the open market. The overall requirement was 84.33 TWh. The following table illustrate AU's procurement volumes in 2011:

Type of procurement	Electricity (TWh)				%
	Fixed price	Indexed price	Variables	Total	
Yearly imports	5.1	-	-	5.1	6.1%
Multi-year imports	-	5.3	-	5.3	6.2%
National physical OTC contracts + MTE	26.4	-	-	26.4	31.3%
Contracts for difference and VPPs	2.0	0.1	-	2.1	2.5%
Total contracts (hedging)	*33.5*	*5.4*	-	*38.8*	*46.0%*
MGP without hedging	-	-	45.9	45.9	54.4%
Deviation	-	-	-0.4	-0.4	-0.5%
Total	33.5	5.4	45.5	84.3	100.0%
%	39.7%	6.4%	54.0%	100.0%	

AU has a balanced portfolio: purchase of fixed price forward electricity and exposure in the wholesale market (MGP). The ultimate goal is to minimize purchase costs and charge final customers with a price consistent with wholesale market, partly offsetting the price volatility. AU's exposure at the Exchange price covered 54.4% of total purchases. On the contrary, purchased made outside the bids/offers system included contracts with the physical delivery of electricity as well as different contracts to hedge against the market price volatility.

In particular, yearly imports, equal to 5.1 TWh, were covered through yearly baseload products at a price of 71.67 €/MWh. In addition, 5.3 TWh cover the multiyear import contract at an average price of 71.00 €/MWh. As to domestic physical bilateral contracts, 18.8 TWh were purchased through yearly baseload products at an average price of 71.02 €/MWh. Another 8 TWh were purchased through quarterly and monthly baseload products either on AU auctions and through purchases in the MTE. Finally, the overall coverage was completed through 2.1 TWh of differential contracts.

Considering the deviation share allocated to Acquirente Unico as a user for the dispatching service, equal to 0.4% of requirement, an overall 84.33 TWh of electricity was purchased. During a year on which the Exchange price was 72.23 €/MWh, 12.6% more than in 2010, the average purchase price of the electricity portfolio was 74.61 €/MWh, 4.5 % more than in 2010. Dispatching charges increased by +16.6% on the previous year, and amounted to 8.82 €/MWh. Considering fee-related charges and AU's operating costs, in 2011 the selling price was 83.57 €/MWh, 5.7 % more than in 2010.

Sale of electricity to standard offer retailers

The price of electricity, for final customers, is set on the basis of all costs incurred along the value chain ranging from generation through consumption.

For both customers on the open and standard offer markets, the final price can be broken down into two parts: one is formed on the market according to the supply and demand law and a second one is defined in a regulated manner.

The share of the final price being formed on the market represents the costs incurred to generate, market and sell electricity.

The regulated share of the final price, on the other hand, represents any cost incurred for grid services, including dispatching, system charges and taxes.

As to the standard offer perimeter, the integrated sale text (TIV), approved by AEEG Decision n. 156/07, defines fees for the sale of electricity to customers on the standard offer market. In accordance with such regulation, procurement and dispatching are remunerated through a fee called PED, defined as the sum of the electricity price item (PE) and the dispatching price item (PD).

The PED fee is calculated on a quarterly basis by the Regulator according to the selling price paid by standard offer retailers to cover the purchasing, dispatching and operation costs incurred by Acquirente Unico.

According to the costs incurred by Acquirente Unico in 2011, the Regulator set a PED fee of 91.05 €/MWh, 3.2% up on 2010. Considering the other tariff components and the offsetting effect of the cost equalization system, final customers on the standard offer market, with a household contract and a yearly consumption of 2700 kWh, were charged a tariff of 161.84 €/MWh, 2.3% more than the previous year.

During 2011, therefore, Acquirente Unico procurement activities helped mitigating the increasing prices of raw materials underlying electricity. This enabled standard offer customers, i.e. those customers who did not switch to the open market, to benefit from a limited rise of the final price, at least in respect of the electricity component of AEEG tariff.

3. GAS MARKETS

In 2011, the market and registration platforms started by GME during 2010, began their full operation. At first, P-GAS and M-GAS later, from December 2011, the Gas Balancing Platform (PB-GAS).
The sectors making up the P-GAS (Royalties' segment, Import and ex Legislative Decree 130/10[71]) were created to allow operators to fulfill their obligation to sell to third parties shares of their national production and import, respectively; these translate into explicit supply obligations and price constraints, as well as gas quantities made available by the relevant matched virtual storage operators, within the framework of the virtual storage service.
The M-GAS, consisting of the MGP-GAS and MI-GAS is not subject to any participation and/or supply constraint; still, it suffered the lack of a balancing market. This latter (PB-GAS) was started in December 2011: the initial transient system provided for the mandatory participation of holders of storage quotas, limiting trades to the quantities required by SRG to balance the system with respect to flows registered one day before. As established by AEEG Decision ARG/gas 45/11, on 1 April 2012 the second, simplified stage of the gas balancing system has officially started. Results are defined on the basis of all bids/offers submitted by participants (purchase and sale side, too).
Overall, volumes traded on such platforms are still small, equal to approximately 5 TWh/year, i.e. 452 million cubic meters and 0.6% of the gas domestic demand. PB-GAS is the most important platform. In just one month of operations on daily products, it collected 1.71 TWh (Tab C.3.1)[72].

Tab C.3.1 **Volumes traded by market platform (TWh)**

	2011		2010
	TWh	delta %	TWh
TOTAL VOLUMES (a+b+c+d+e+f)	4.78	123%	2.14
P-Gas (a+b)	2.91	*36%*	2.14
Imports	*0.00*	–	*0.00*
Royalties	*2.91*	*36%*	*2.14*
M-Gas (c+d+e)	0.16	-	0.00
MGP continuous-trading stage	*0.15*	-	*0.00*
MGP auction stage	*0.00*	-	*0.00*
MI	*0.01*	-	*0.00*
PB-Gas	1.71	-	-

* for the M-GAS, given the different number of days of trading, changes are not reported

3.1 Gas Platform (P-GAS)

The P-GAS Import Segment, operational since 10 May 2010, allows to sell gas import quotas of obliged subjects pursuant to Law Decree 7/07 and decree of the Ministry of Economic Development 18 March 2010. This platform – for all operators eligible to perform transactions at the Virtual Trading Point, either obliged or not– allows to trade under the continuous trading mechanism, fixed or indexed priced products, non standardized, with monthly and yearly delivery.
In 2011, this segment was poorly active. Participation of obliged participants was higher on the sale side: they submitted bids/offers in 44% of sessions. (Tab C.3.2.).

71 Investors can fulfill their supply obligation either cumulatively or alternatively within the MGP-GAS on the terms provided by AEEG Decision 67/2012/R/GAS.
72 This figure refers to volumes traded in 2011, regardless of the delivery period. In this particular case, 65% of volumes were delivered during the same year.

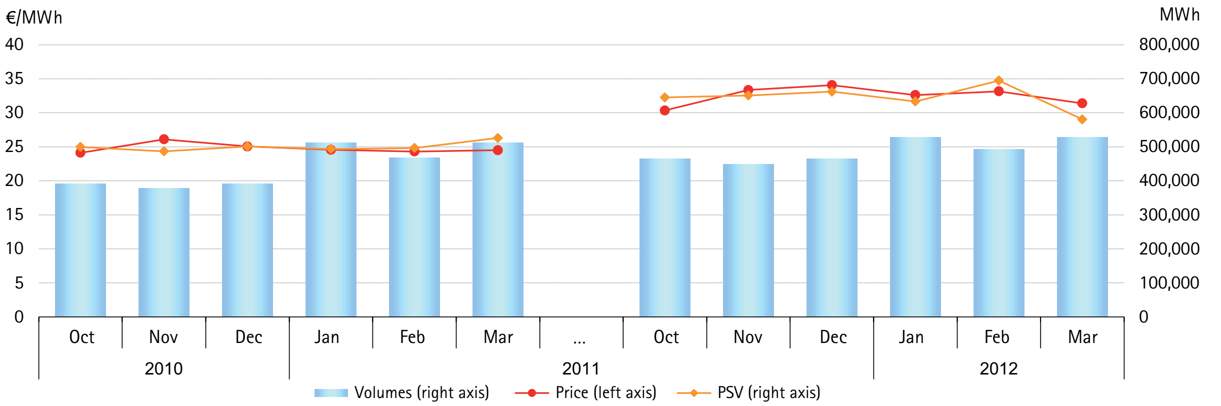
Participation in the P-Gas Tab C.3.2

	Year of trading	Sittings				Participants			No. of matchings	Volumes (MWh)	
		with matchings	with buy orders	with sell orders	with both buy and sell orders	with purchases	with sales	with trades		total	average
Import	2011	-	0%	44%	0%	-	-	-	-	-	-
	2010	0%	3%	47%	1%	1	1	2	1	365	1
Royalties	2011	6%	13%	6%	6%	15	3	17	-	2,910,718	15,906
	2010	6%	11%	6%	6%	14	3	17	-	2,140,810	14,178
Total	2011	-	-	-	-	-	-	-	-	2,910,718	15,906
	2010	-	-	-	-	-	-	-	-	2,141,175	14,179

The Royalties' Segment, in operation since 11 August 2010, looks different. Pursuant to Law 2 April 2007, n. 40, national gas production royalties owed to the State are offered on this segment. Here, non standard products with monthly delivery are offered through the auction trading mechanism (one per each trading book). Operators subject to the obligation to bid are constrained not only in the quantities offered, but also in their prices, which need to be equal to the QE index. As a matter of fact, it is the demand to set the price. Consequences on liquidity and trading participation are evident: the most active participants are on the purchase side, submitting bids/offers in 13% of sessions against 6% of participants on the sale side; sale offers were nearly always matched during the first trading day, a proof of the attractive price offered. There has been 6% of sittings with matchings, involving 3 sellers and 14 buyers for an overall 2.9 TWh (equal to 275 million cubic meters, approximately). On this platform, only winter products (October through March) are listed: this means that volumes accounted for a delivery over a time horizon of 183 days, i.e. a mean daily volume of approximately 16 GWh.

On average, the price of these products depended upon trades registered at the PSV, with a 94% correlation and a mean deviation of slightly more than 1 €/MWh. However, it would make little sense to report an overall yearly average value of trades, as long as listed products are referred only to the first and last three months of the year. (Fig. C.3.1)

Clearing volumes and prices in the P-Gas Royalties' Segment Fig C.3.1



Source: GME's processing of Thomson Reuters data (PSV)

Segment as per Legislative Decree 130/10, where investors can bid/offer quantities of gas made available by the relevant matched virtual storage units, within the framework of the virtual storage service, on the terms established by AEEG Decision AEEG 67/2012/R/GAS, officially started in May 2012.

3.2 Spot Gas Market (M-GAS)

The spot gas market, in operation since 13 December 2010, has been consisting of two sessions: the day-ahead market (MGP-GAS), organized as a continuous trading session opening three days ahead of the gas day bids/offers are referred to, followed by an auction-based session which is held on the day prior to delivery and the Intra-day market (MI-GAS), organized as a continuous trading in the time period between the day ahead and the day bids/offers are referred to.

Although participation in the market is voluntary, with no price or quantity constraints, the M-GAS liquidity seems to be quite higher than the P-GAS. The MGP continuous trading session is more active, with bids/offers on both sides of the order book in 56% of sessions, matchings in 21% of sessions, with 16 operators involved in trades, for a total of 148 GWh (equal to 14 million cubic meters). Such values are quite lower in the MI (15%, 5%, 7 operators and 13 GWh, respectively) and even more so in the MGP auction-based session (5%, 1%, 3 operators, 1 GWh) (Tab C.3.3).

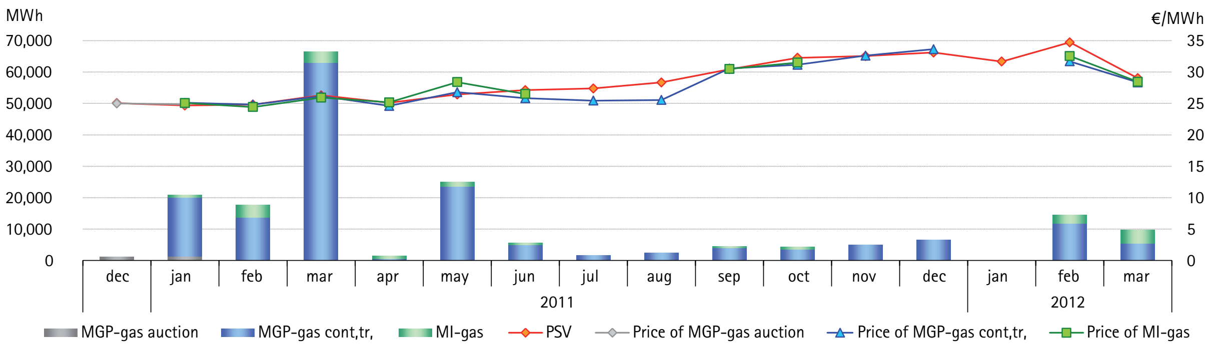
Tab C.3.3 **Participation in the M-Gas**

	Sittings				Participants			No. of matchings	Volumes (MWh)	
	with matchings	with buy orders	with sell orders	with both buy and sell orders	with matchings	with purchases	with sales		total	average
MGP continuous-trading stage	21%	65%	73%	56%	16	15	9	125	148,028	406
MGP auction stage	1%	48%	9%	5%	3	2	2	-	1,350	4
MI-continuous trading	5%	51%	19%	15%	7	3	6	22	12,616	35
Total	-	-	-		-	-	-	**147**	**161,994**	**444**

Unlike the P-GAS royalties' segment, in the MGP-GAS there have been trades in every month (except for January 2012), with remarkable spikes in March, when trades exceeded 60 GWh, and to a lesser extent in January February and May, on the occasion of the Greenstream supply problems caused by the Libyan crisis. During the same months, fewer, occasional trades were recorded in the MI-GAS. A similar, sudden rise of MGP volumes happened again in February 2012, during the European gas crisis due to the extreme cold weather, with its related consumption peaks and supply problems in Ukraine. This trend suggests that the M-GAS liquidity, still small, gets bigger especially in times of crisis, when the search for additional volumes turns it into kind of a balancing market for participants.

Again, as already mentioned for the P-GAS, prices are very close to the value of trades registered at the PSV, with a 94% correlation and a mean deviation of slightly less than 1 €/MWh.

Fig C.3.2 **Clearing volumes and prices in the M-Gas**



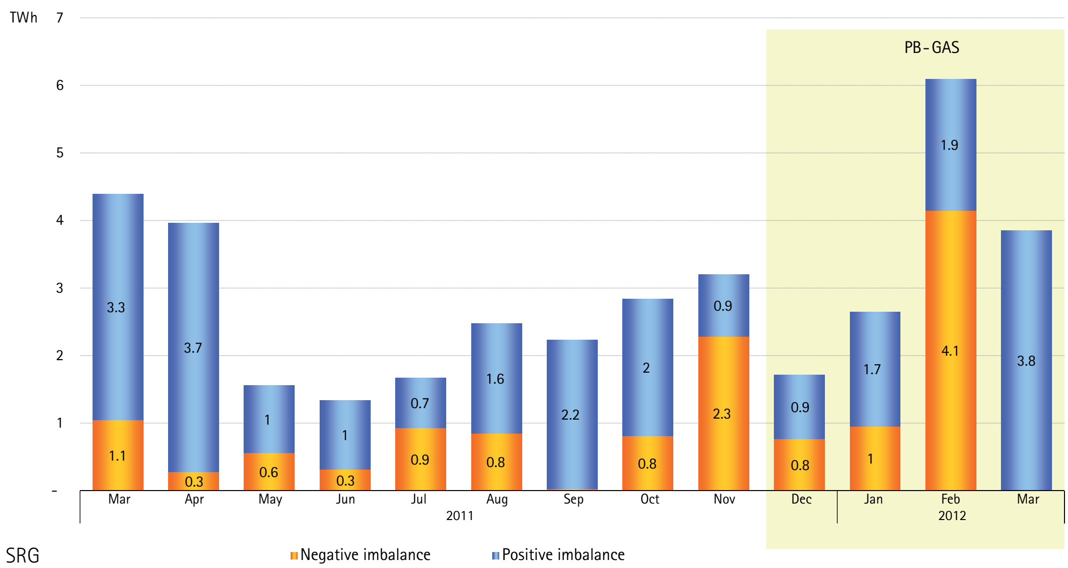
3.3 Gas Balancing Platform (PB-GAS)

The greatest novelty of 2011 was the start up of the PB-GAS on 1 December 2011, in accordance with Decision 45/11 on the rules of gas balancing. The aim of this measure is to start a stepwise transition from the old "storage-based balancing" system, revolving around a tariff scheme, to a new "market-based balancing", based on prices resulting from the intersection of stored gas demand and supply. The start up of the PB-GAS constitutes the first step in this transition, as long as every storage capacity holder are bound to participate. During the preliminary, transient stage, only volumes requested from SRG to balance the system were accepted; starting from 1 April, this constraint has been lifted and the market matches all offered quantities according to their specified prices. Moreover – differently from the Balancing Market in the electricity sector, where Terna procures volumes required for a real time system balancing – in this case Snam Rete Gas procures the balancing requirement referred to the previous gas day: in other words, this is a market trading accounting energy balances to complete the balance equation of each participant and value the relevant physical imbalance. Finally, it should be observed that mandatory participation is nothing but a constraint on offered quantities, which must fall between the minimum and maximum quantities which holders can handle in their own storage space; yet, this does not affect prices, which are free up to the ceiling of 82.80 €/MWh[73]. Mandatory participation in the market and a guaranteed trade quota on the part of SRG, according to the system physical needs, translated into a trading volume of 1.7 TWh of gas in December. This value grew, during the first four months of operation, until 14.3 TWh, i.e. approximately 1.35 billion cubic meters and 3.7% of the domestic demand. Such volume reflects the impact of seasonality; consumption and imbalances are both very high; most notably, the gas crisis of February pushed up the volume of imbalances, reaching the highest level of the last 12 months. At any rate, taking as a reference the overall value of imbalances recorded by SRG in the last twelve months, a yearly value of reference for the PB-Gas liquidity could be around 34 TWh, i.e. approximately 3.2 billion cubic meters and 4.1% of the domestic demand (Tab C.3.4, Fig.C.3.3).

Activity on the PB-Gas Tab C.3.4

		Participants			Volumes (MWh)		Prices (€/MWh)			
		with purchases	with sales	with trades	total	average	average	min	max	Vol.
2010	December	31	31	38	1,711,574	55,212	33.1	31.9	34.7	1.7%
	January	32	25	38	2,647,584	85,406	31.5	30.5	32.8	1.5%
2011	February	31	43	47	6,095,524	210,190	32.8	30.5	39.4	5.5%
	March	36	4	36	3,851,277	124,235	28.9	27.9	30.7	0.9%
	Total	48	46	53	14,305,959	117,262	31.5	27.9	39.4	2.4%

Monthly imbalances in the past year Fig C.3.3



Source: SRG

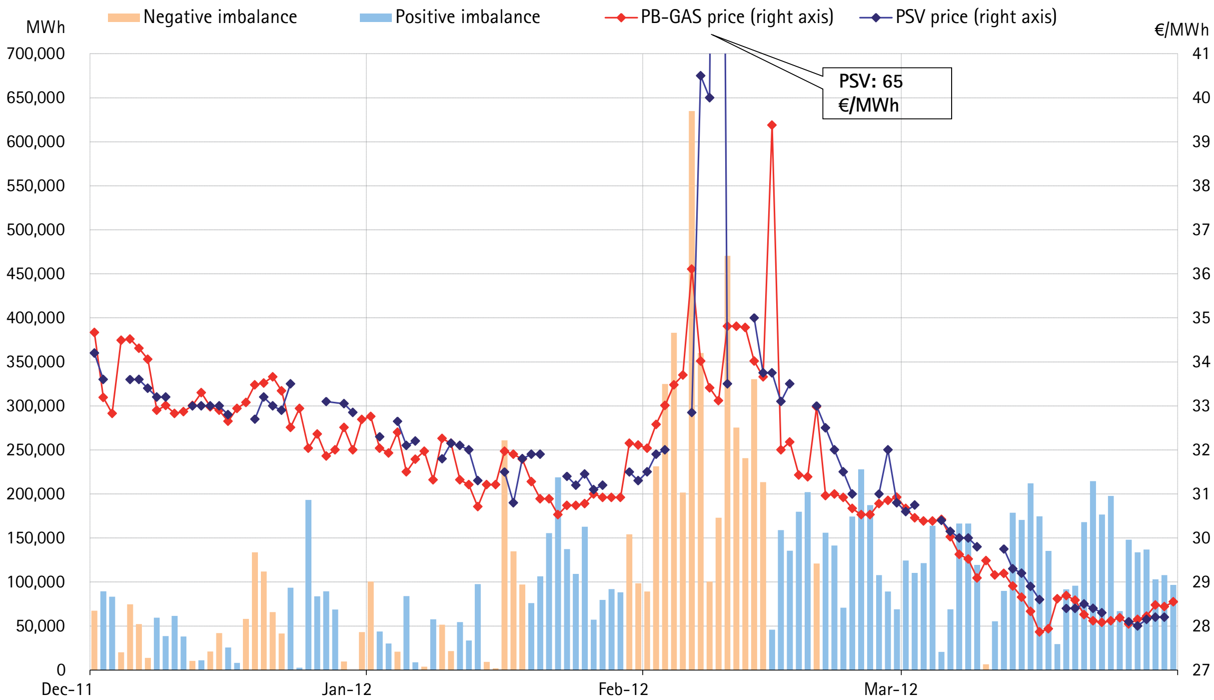
73 Equal to the cost of access to strategic storage, as per para 15.10 of Decision n. 119/05, increased by 3.5 euro/GJ.

In this case, trading liquidity enables a preliminary analysis of prices. Obviously, it ends the first quarter of 2012, given the lack of 2011 historical series (Tab C.3.4).

Interestingly, the average price level seems to be consistent with values reported at the PSV, with a 54%[74]correlation and an average difference below 1 €/MWh. While this applies to every platform, in this case it looks more striking since the PB-GAS is referred to the previous gas day, i.e. prices registered at the PSV are already known. This factor could explain the rather limited volatility of prices (nearly 1-2%, to the exception of 5% in February) and the difference between monthly minimum and maximum prices (nearly 2/3 €/MWh, excluding 9 €/MWh in February).

However, these two markets are held on different days, with a potentially very different information set and expectations. The consequences were quite evident during the gas crisis, when the PB-GAS immediately responded to the demand shock with a peak of 36 €MWh, followed by a downward phase and by another peak at 39 €/MWh, whereas the PSV reacted one day after the PB-GAS, by aligning two peaks at 40 €/MWh and then a third one at 65 €/MWh; these figures, however, are still below the regulatory ceiling of 82.80 €/MWh. The clear correlation between the price registered in the PB-GAS and in the PSV could be confirmed in a medium-term perspective; or it could dramatically change with the full opening up of the PB-GAS to offered volumes. (Fig C. 3.4).

Fig C.3.4 **Daily prices and volumes on the PB Gas**



74 The correlation is lower than in other markets because it is calculated daily instead of monthly; without considering the month of February, it would be 97%.

So far, the low price volatility seems to reflect very flat demand and supply curves, near the clearing price, with a supply pattern very similar, for many participants, to the one observed at the PSV: this is shown by ICM values, according to which the price fluctuation induced by a change in volumes of ±5% would be lower than 0.3%, with 26% of obliged participants submitting offers within a ±5% range of the clearing price (Tab C.3.5).

These patterns are also promoted by a structurally high concentration of trades on the market, given the low, somewhat predictable liquidity of this latter: during the first four months of trading, the PB-GAS produced a HHI of 3.364 and a cumulative share for the first three participants (CR3) equal to 37.6%, with a maximum price-setting percentage from the same participant (IOM) of 34.4% (Tab C.3.5). However, since in this period volumes offered on the PB-GAS on average were two-three fold higher than those accepted, the impact on liquidity resulting from the adoption of the definitive scheme could be considerable. Of course, this would also affect concentration and marginal behavior indexes, supply behaviors and, therefore, prices and volatilities.

Concentration and price-setting behavior (ICM) indexes Tab C.3.5

					Number of participants (1)				Price elasticity (2)			
					Demand curve		Supply curve		Demand curve		Supply curve	
		HHI	CR3	IOMq	left	right	left	right	left	right	left	right
2010	December	4.017	57.1%	44.8%	9	22	25	8	-0.0%	0.0%	0.1%	-0.0%
2011	January	3.098	54.7%	49.0%	6	22	28	10	-0.0%	0.0%	0.1%	-0.1%
	February	3.369	43.4%	33.4%	15	17	25	11	-0.1%	0.2%	0.1%	-1.1%
	March	2.973	43.2%	41.9%	3	8	26	12	0.0%	0.0%	0.1%	-0.0%
	Total	3.364	37.6%	34.4%	8	17	26	10	-0.0%	0.1%	0.1%	-0.3%

1) equal to ±5% of the price determined in each session
2) equal to ±5% of the volumes traded in each session

Market shares of top 10 participants Tab C.3.6

	Total	Purchases	Sales
E.ON ENERGY TRADING	16.9%	12.8%	4.1%
SHELL ITALIA	13.2%	8.2%	5.0%
GDF SUEZ ENERGIA ITALIA	7.5%	7.0%	0.5%
ENEL TRADE	7.3%	0.1%	7.2%
BP ITALIA	6.5%	5.5%	1.0%
ENI	5.9%	1.7%	4.2%
EDISON	5.0%	0.0%	5.0%
GUNVOR INTERNATIONAL	3.3%	2.9%	0.4%
HERA TRADING	2.8%	0.8%	2.0%
ELETTROGAS	2.6%	2.4%	0.1%
Other	28.9%	17.5%	11.5%

3.4 International comparisons

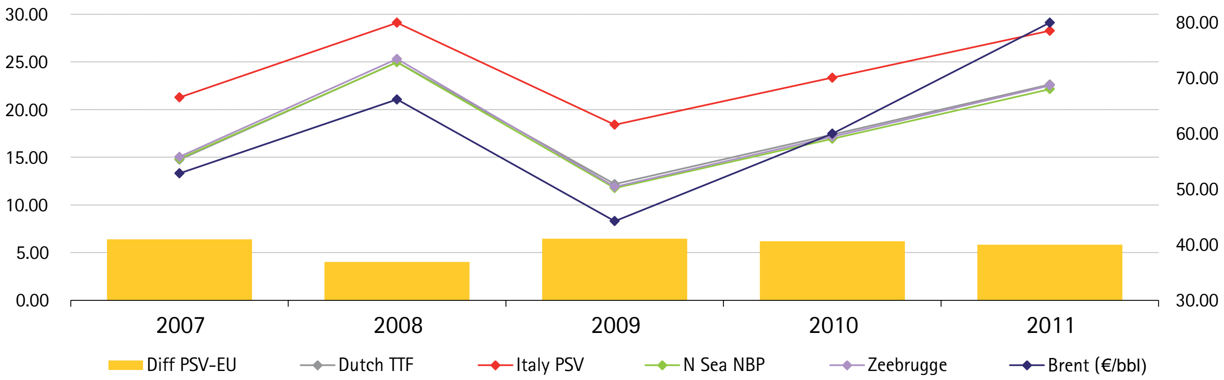
Data listed in Italy in the M-GAS and PB-GAS cannot be compared yet with other European hubs, due to the limited liquidity of the first and the recent birth of the second. To this end, PSV data still represent a reference parameter. This is also justified by the generalized alignment between market prices and prices reported at the PSV.

At first sight, such comparison immediately highlights one point. In spite of an absolute liquidity lower than in other major European hubs at the crossroads of the wealthiest European generation and trading areas – spot volumes in Italy have been growing at a fast and long-lasting pace for several years. This has happened not just in Italy but also elsewhere. However, it seems to be stronger in Italy, also by virtue of the recent opening of the national spot market. With 600 TWh of yearly volumes, the PSV ranks low among the major European hubs along with Zeebrugge and Cegh, quite distant from the 1,700 TWh of the Dutch TTF and 19,000 TWh of the British NBP. In terms of growth, though, the PSV is one of the most vital ones, both yearly (+34%) and on a multi-year perspective, growing +270% on 2008, way more than NBP's +76%, Cegh's +128% and even TTF's +170%. This finding is especially interesting given a stagnating industrial demand and a displacement of thermoelectric demand caused by renewables. Once again, it confirms a large, increasing short-term flexibility demand from our system, in times of long market (Tab C.3.7).

Tab C.3.7 **Volumes of gas traded on European hubs**

European hubs (data in GWh)	Reference	2011	2010	2009	2008	Δ% 2011/2010
Zeebrugge	Belgium	765,091	724,008	723,082	505,588	+6%
PSV	Italy	641,137	479,151	260,591	173,742	+34%
CEGH	Austria	435,019	378,662	253,336	166,018	+15%
NBP	United Kingdom	19,079,080	13,733,843	11,627,961	10,844,971	+39%
TTF	Netherlands	1,731,034	1,122,150	801,593	639,038	+54%

Fig C.3.5 **Prices at European hubs**



As to prices, the Brent increase (+33%, considering the exchange rate) led every European Exchange to rise for the second year in a row: prices reached the same levels of 2008, with the PSV at 28.27 €/MWh (+21%) in the face of a mean European value of nearly 22-23 €/MWh (+30%). These figures along with the analysis of monthly series confirm some basic features of the national gas market.

On one hand, there exists a 5-6 €/MWh difference between Italian and European prices, accounting for nearly half the wholesale price spread of electricity between Italy and cross-border market – a multi-year trend – net of some short-lived fluctuations. It should be noted that after its substantial elimination during the first five months of the year, such price spread broadened again and nearly doubled in the second six-month period, bringing the yearly mean back to the figure observed in recent years (Fig.C.3.7).

On the other hand, the spread trend seems to reflect a different behavior of gas prices, more closely related to oil prices in Italy than in continental platforms. The so called decoupling of gas and oil prices is by now quite common across the most important European markets; they keep reflecting the mean change of oil prices on a yearly basis only and increasingly less; conversely, they display short-term autonomous, independent dynamics which are heavily based on the demand and supply. As already hinted in chapter C.1.2, in Italy the monthly trend of prices is still heavily influenced by the QE index (the regulated component of gas price, linked to covering raw material costs). By nature, the index faithfully reflects the Brent price in euro, with a 6 month delay (Fig.C.3.7). Such pattern reflects the lack of liquid spot markets; in our system, pre-existing contract formats – generally regulated and indexed – are still playing the lion's share, with price signals which are strongly related to the Brent, quite incapable of reflecting any scarcity or abundant supply. In such context, the same values reported at the PSV, more volatile and independent in some market stages, respond to short term demand and supply variations; on average, they seem to follow quite faithfully the above references (Fig. C.3.7, Tab.C.3.8).

In Italy, too, the supply excess induced by the consumption crisis and the increasing liquidity of platforms point to an evident weakening of the link between spot price and indexed price. Recently, in fact, AEEG decided to modify QE calculation criteria to include a share indexed to the spot value of the main European prices. The effect of such decision will presumably show up in the next future.[75]

75 Decision 30 March 2012 116/2012/R/gas.

Fig C.3.6 **Monthly prices on the main European hubs (€/MWh)**

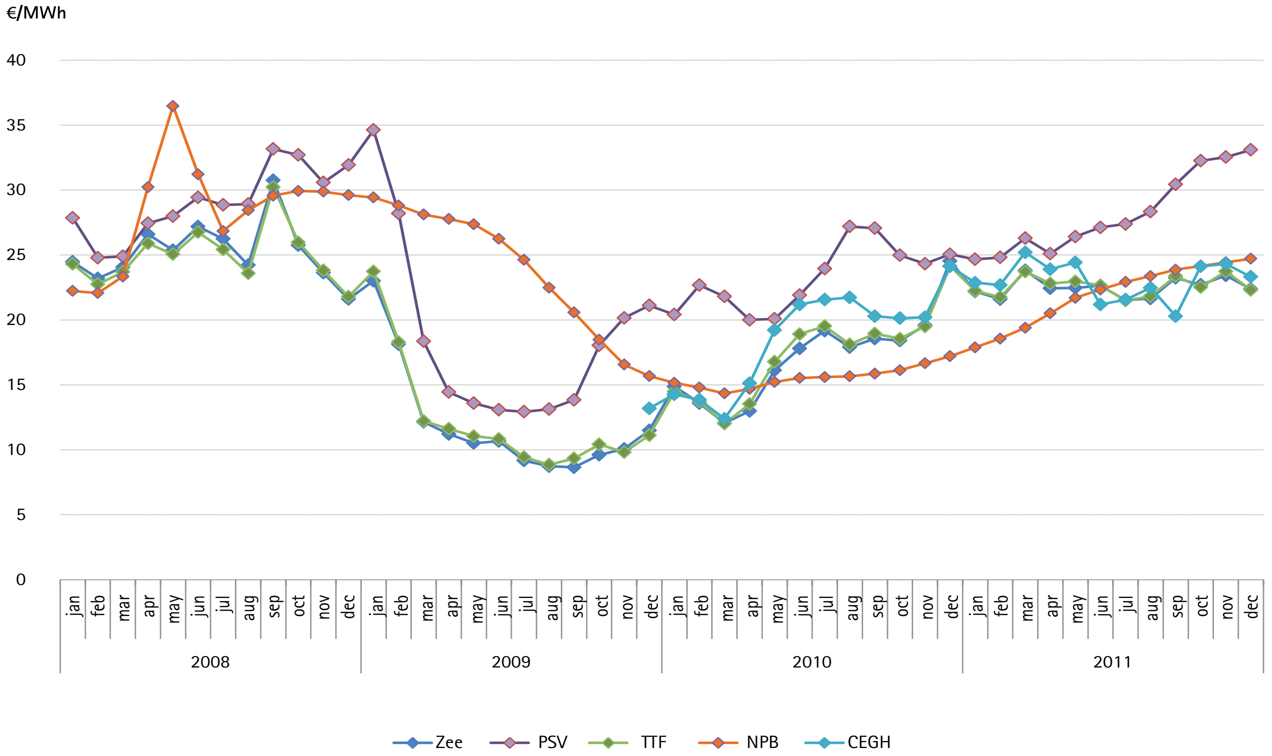
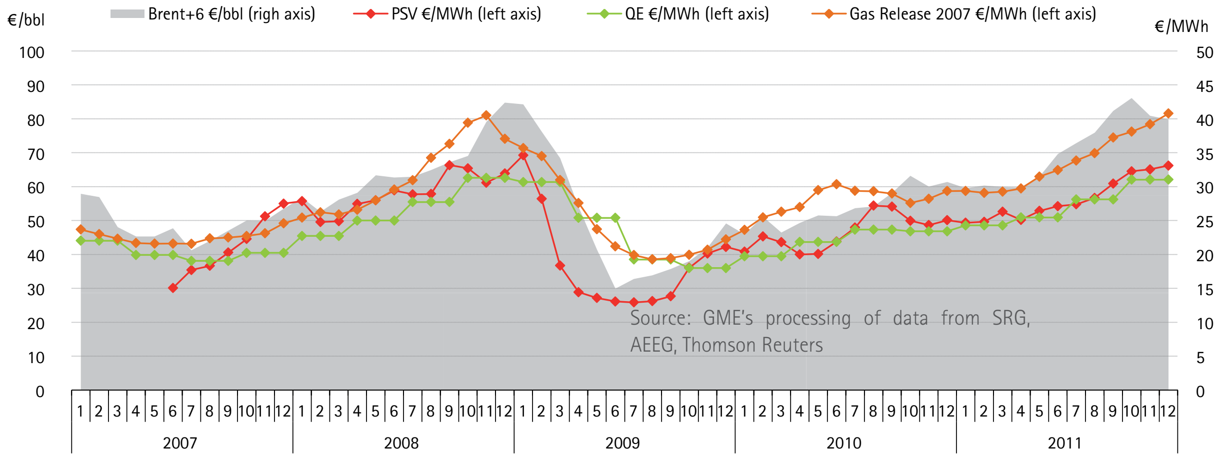


Fig C.3.7 **PSV price, QE, Gas Release 2007 (€/MWh), Brent delayed by 6 months(€/bbl)**



Source: GME's processing of Thomson Reuters data (PSV)

Tab C.3.8 **Main indicators of wholesale gas cost**

€/MWh	2011	2010	2009	2008	**Δ% 2011/2010**
Gas Release 2007	33.79	27.92	24.60	31.68	21.0%
QE	27.23	22.17	23.33	26.68	22.8%
PSV	28.27	23.34	18.41	29.11	21.1%

Source: GME's processing of Thomson Reuters data (PSV)

4. ENVIRONMENTAL MARKETS

4.1 Green Certificates Market

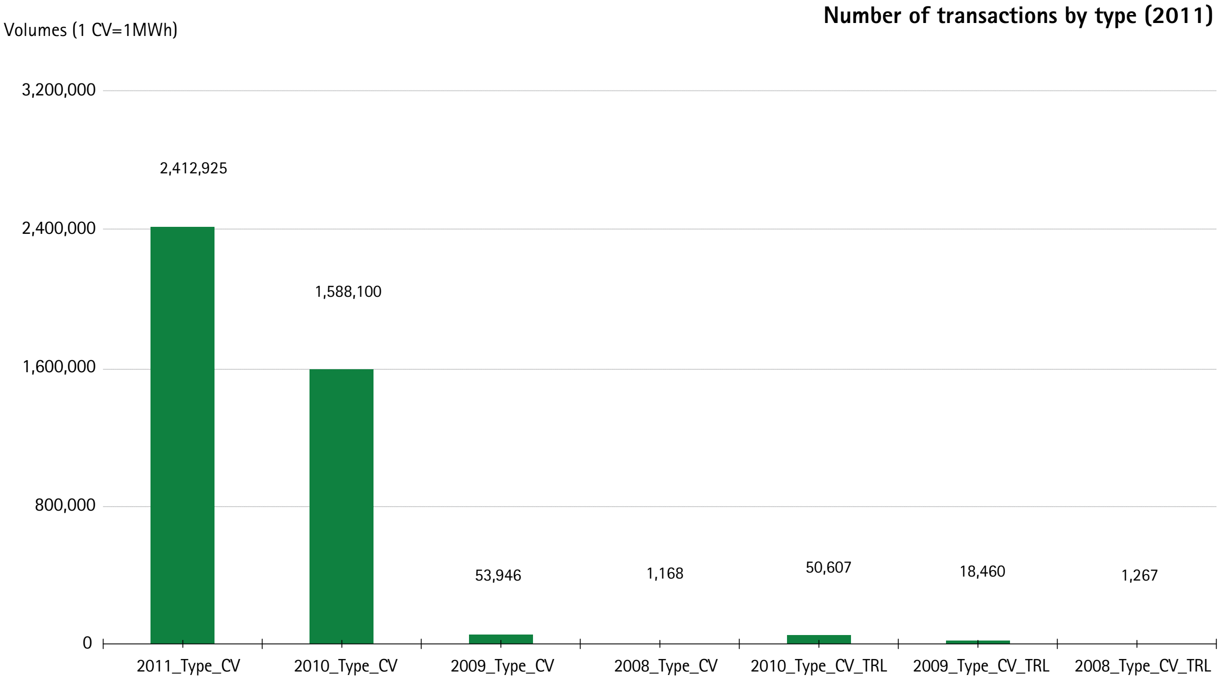
In 2011, too, the number of participants in the Green Certificates Market (MCV) kept increasing up to 55 vis-à-vis the end of 2010.
In 2011, the MCV operational management organized and managed 47 regulated market sessions, on which participants traded 4,126,473 GCs, worth over 339 million euro.
The mean weighted prices of GCs traded in the above market sessions, whatever their type, was 82.25 €/MWh.
GCs with reference year 2011 were most traded during the year and accounted for about 58.47 % of the total number of GCs traded in the regulated market, followed by GCs with reference year 2010, which accounted for 38.49 % of the total.
Table C.4.1 summarizes the main statistics about trades in the regulated market during 2011:

Trades in the MCV – 2011 Tab C.4.1

	Type of GCs ("CV")				Type CV TRL		
Reference Year	2011_Type_CV	2010_Type_CV	2009_Type_CV	2008_Type_CV	2010_Type_CV_TRL	2009_Type_CV_TRL	2008_Type_CV_TRL
GCs traded in the MCV	2,412,925	1,588,100	53,946	1,168	50,607	18,460	1,267
Total value	€ 193,816,232.91	€ 135,166,943.45	€ 4,577,279.49	€ 98,384.40	€ 4,072,927.83	€ 1,549,152.41	€ 105,107.50
Min price	€ 78.92	€ 79.99	€ 79.95	€ 84.00	€ 79.00	€ 79.05	€ 80.00
Max price	€ 86.10	€ 92.50	€ 87.15	€ 84.60	€ 85.00	€ 84.90	€ 87.15
Avg price of GCs (2010)	€ 80.32	€ 85.11	€ 84.85	€ 84.23	€ 80.48	€ 83.92	€ 82.96

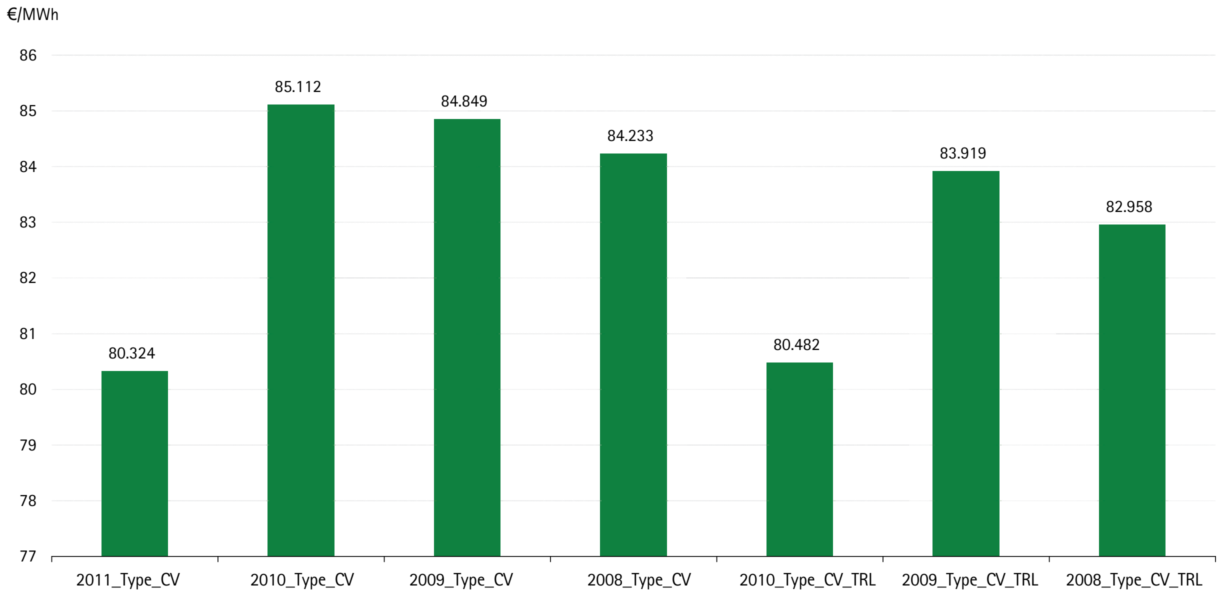
The following diagram reports volumes traded in 2011, grouped by type:

Number of transactions by type (2011) Fig C.4.1



Finally, the next diagram depicts the mean weighted prices across all 2011 sessions, by each type of certificate:

Fig C.4.2 **Average prices weighted for volumes, by type (2011)**



During the analysis of the series of mean weighted prices in the GC market in 2011, a volatility index was calculated. Such index is based on the standard deviation of log returns of weekly prices versus the yearly average of weekly log returns. In particular, attention was paid to the series of GC close prices with reference year 2011 during the market sessions held in April 2011 – March 2012.

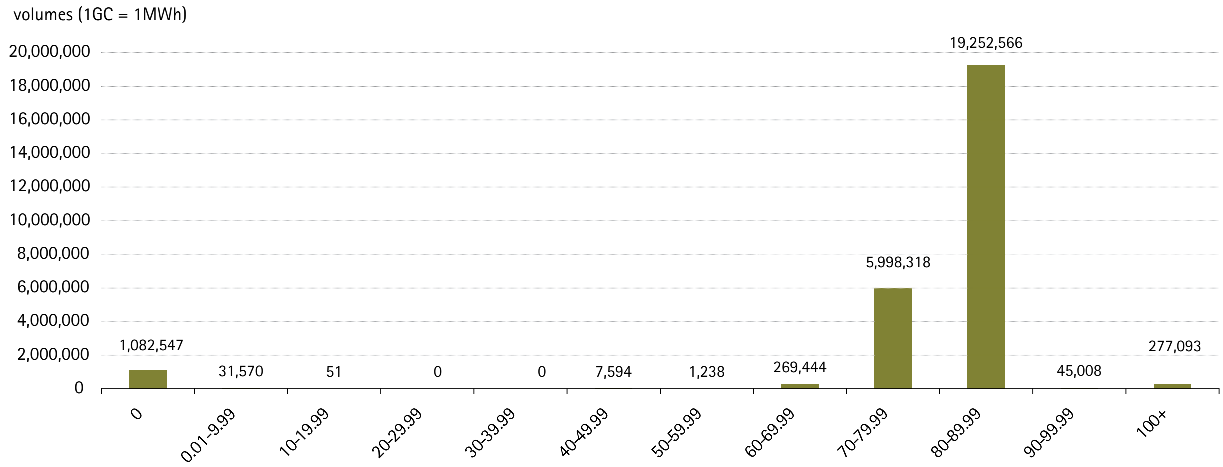
The volatility index was shown to be equal to 0.48.

Other than trading in the regulated market, GCs were traded through bilateral contracts. Since 2009, every bilateral trading, with price indication, must be registered in the GC Bilateral Platform (PBCV) .

During 2011, contracts registered through the PBCV achieved a total volume of certificates equal to 26,965,429. The total number of GCs traded in the regulated market and on the PBCV was 31,091,902.

Table C.4.2 reports volumes by price class:

Fig C.4.3 **GCs traded over the counter, by price range, in 2011 (€/MWh)**

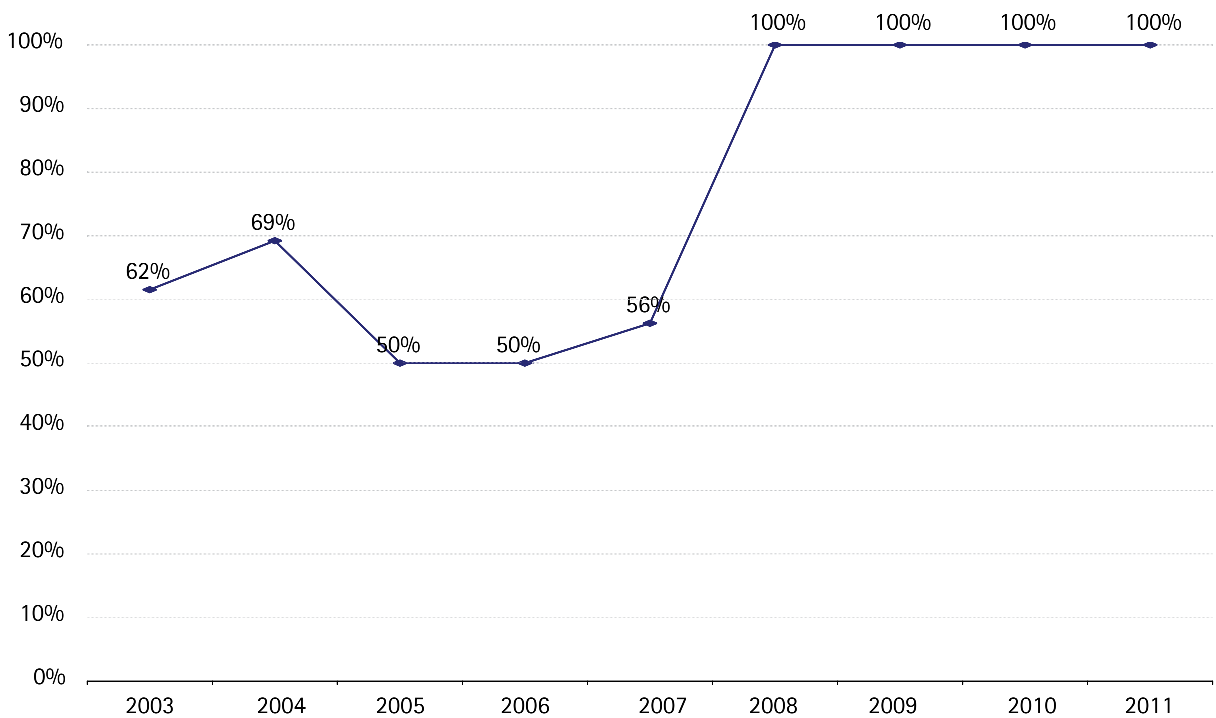


Over time, the GC market has slowly grown. In the last couple of year, trades have been concluded in every regulated market session, proving the increasing involvement of participants and the significant effects in terms of pricing.

To prove this point, an analysis was conducted in order to verify the proportion of successful sessions (i.e. with at least one trade) out of the total sessions in a given year. This proportion gradually grew over the years and, starting from 2008, has been equal to 100%. While in the past most trading was concluded during sessions near the deadline for fulfilling the relevant obligation, participants are now involved in every session organized in the course of the year. This new practice has been heavily determined by GME's role as central counterparty in the regulated market, since November 2008.

The diagram shown in Fig.C.4.3 illustrates the proportion of successful sessions a year, starting from 2003:

Percentage of useful MCV sessions in total session Fig C.4.4



With reference to the GCs demand and supply concentration, the proportion of trades for the first 3 and 10 participants has been calculated. With respect to the demand, the first 3 participants accounted for about 54% of the overall demand in the regulated market; the first 10 participants accounted for nearly 81%. On the supply side, the first 3 participants accounted for close to 26%, the first 10 participants for 52%. The smaller concentration of the supply vs demand, reflects a market situation where the supply consists of a plurality of producers from renewable sources whereas the demand is mostly represented by the leading obliged producers from conventional sources, with a significant share in the electricity market as well.

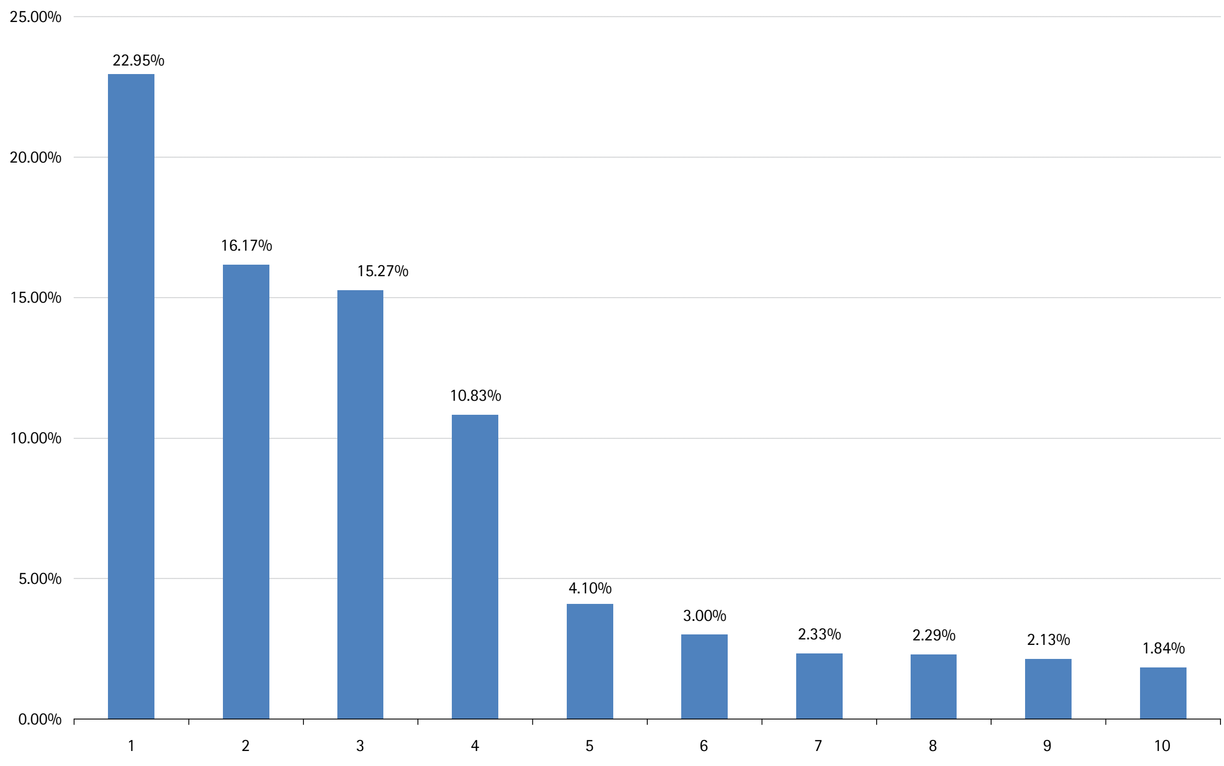
Tab C.4.2 reports the participants' rates on both the GCs demand and supply side:

Tab C.4.2 **Market shares of MCV participants**

	Market shares of MCV participants	
	demand side	supply side
Top 3	54.39%	25.69%
Top 10	80.90%	52.49%

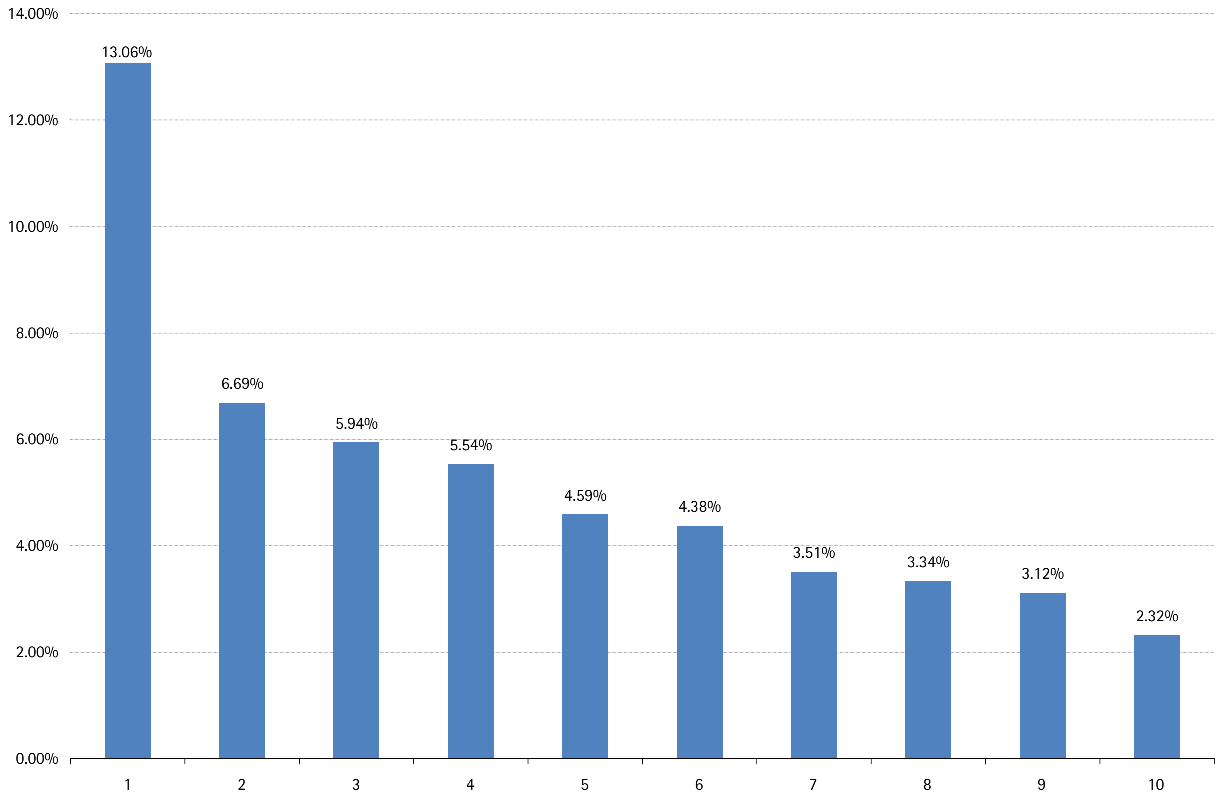
The following diagrams show the various market shares for the first 10 participants, on both the demand and supply side:

Fig C.4.5 **Percentage of top 10 MVC participants – demand side**



Percentage of top 10 MVC participants – offer side

Fig C.4.6



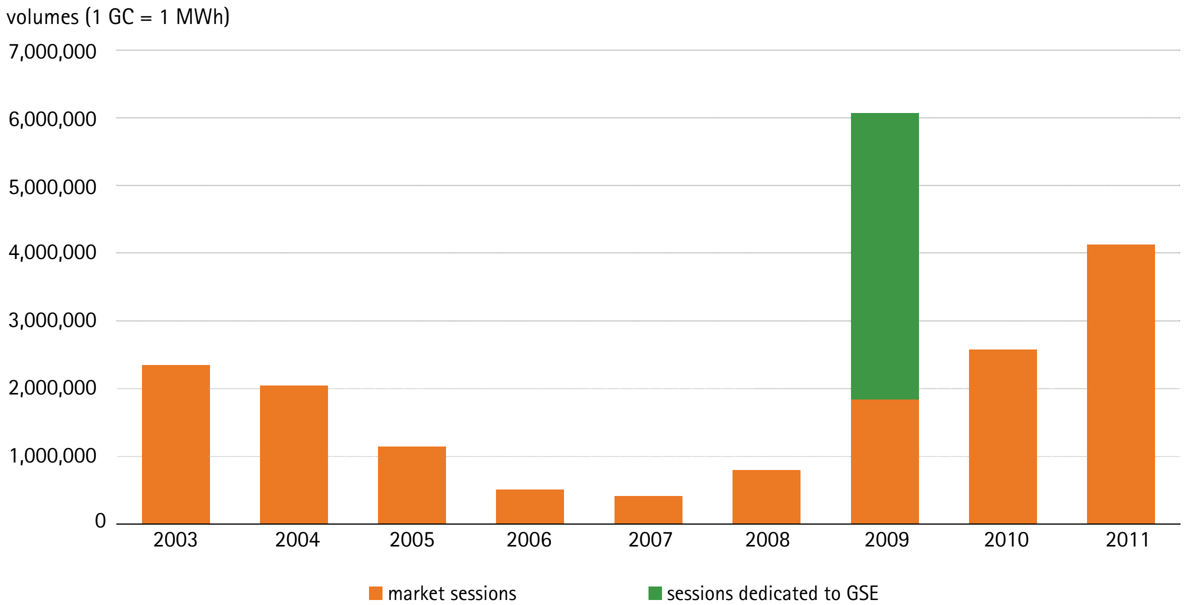
Historical volume analysis

As to the historical trend of Green Certificates traded in the regulated market, they were steadily dropping in 2003-2006, mostly because of a reduced market participation on the part of GSE, given the increasing supply of certificates from new producers from renewable sources; since 2007 onwards, volumes began to grow again, in line with the increasing maturity of the market itself.

The diagram below shows volumes traded in the regulated market over the years.

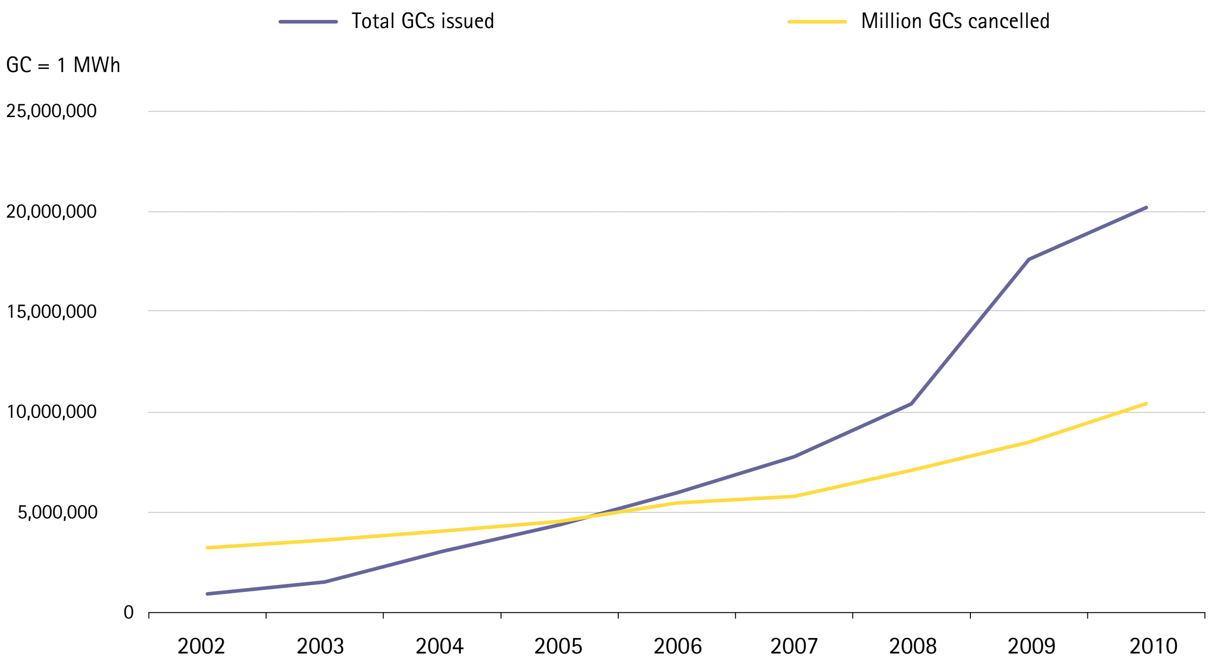
Number of GCs traded in GME's regulated market

Fig C.4.7



Volumes traded on the platform increased on the previous year, from 2,578,638 GCs in 2010 to 4,126,473 GCs in 2011 (+60.02%): this increase reflects a larger obligation, from 6.05% to 6.80% (+12.4%) as well as participants' preference for trading on GME's trading venue (platform).
The next diagram highlights the rise of GCs issued with respect to those required to fulfill the obligation:

Fig C.4.8 **GCs issued and GCs cancelled (2002-2010)**



By comparing issued and cancelled GCs, some indications on GCs price change over the years can be identified. In particular, three distinct stages emerge with respect to price volatility:

- stage a), during the 2003-2006 period, when prices kept increasing. The demand from obliged subjects was higher than the supply from "private" producers from renewable sources;
- stage b), during the 2007-2008 period, when prices drastically dropped from the levels reached in the previous four years;
- stage c), in 2009, when prices rose again to average levels across the whole period considered.

During stage a), GCs price increase was mostly due to two reasons. First, the demand from obliged subjects was higher than the supply from "private" producers from renewable sources (thus, aside from GCs offered by GSE, holder of GCs for CIP6[76] plants, under contract with GSE itself). Within that framework, producers who had GCs to sell were well aware of the demand surplus; they knew that GSE would not "crowd out" the private supply, allowing the market placement of every other GCs. This is why they set a sale price very close to GSE's reference price. Such price did represent and still remains a ceiling to market values.
Secondly, GSE's reference price increased every year in 2003-2006, except for one year during which it did

76 After the effective date of legislative decree 16 March 1999, n. 79, known as "Bersani decree", ENEL stopped being the entity in charge of every CIP6 agreement which had been employed to incentivize generation of electricity from renewables. The Gestore della Rete di Trasmissione Nazionale (GRTN, now GSE) took over ENEL's duties in this respect. With sole reference to electricity generated from renewables, and not from related sources, purchased through said agreements, GSE issues GCs to itself and sells them on the market at a statutory price.

not change. Such price was calculated every year as the difference between the mean cost incurred by GSE to buy electricity generated by CIP6 plants and revenues from selling the same electricity on the market[77]. With time, plants close to the expiration of CIP6 agreements tended to be less expensive than plants entering into operation upon receiving the support (incentive) tariff, with a consequent net increase of GSE costs. While the price of electricity remained quite stable over the period, the price of GCs held by GSE was rising from one year to another. In the light of the demand excess previously described, GCs reached increasing record level every year, and even exceeded a price of 120 €/MWh relative to 82-84 €/MWh at the beginning of the period. We report below a graph on GSE's reference price over the years:

Reference price of GSE's GCs Fig C.4.9

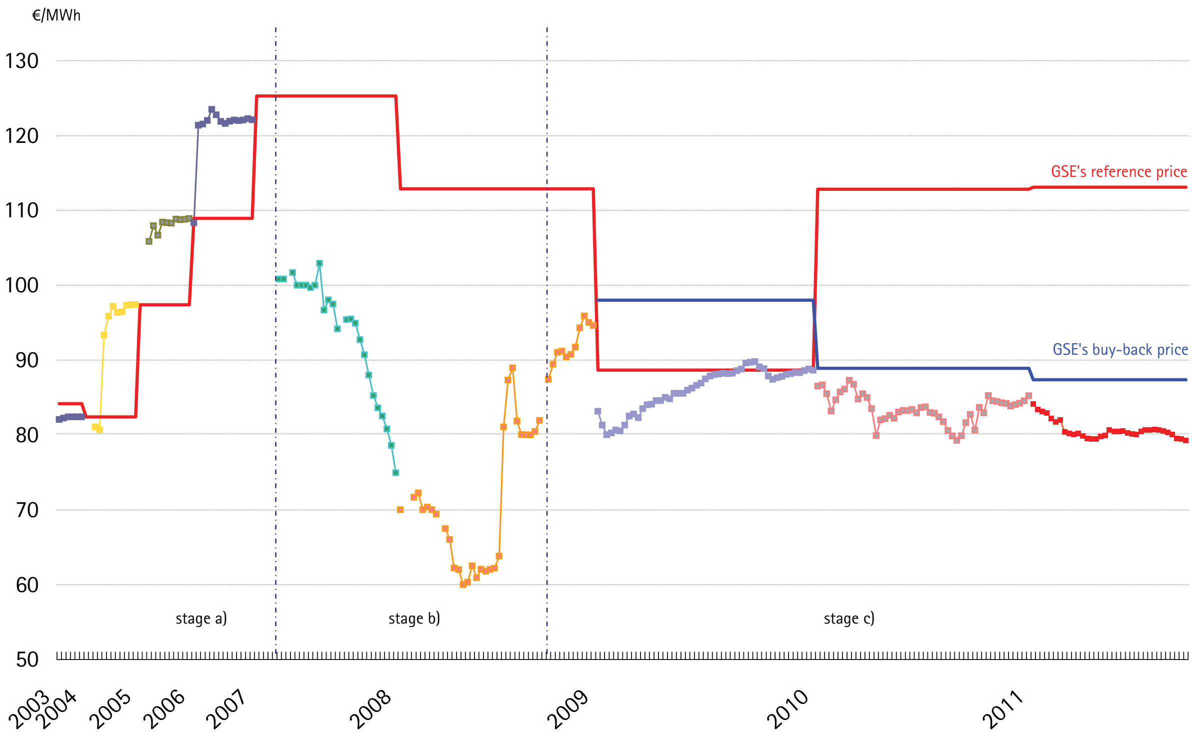
Source: GME's processing of GSE data

The price increase during stage a), however, did foster investment in new plants fed by renewables. As a matter of fact, the installed capacity and the number of private GCs offered have risen. In stage b), the ratio of obliged demand and private supply was reverted, bringing about an excessive supply. GSE ceased stepping in by selling its own GCs, since the private supply was more than sufficient to meet the demand. For the first time, private producers had to compete with one another to sell GCs on the market, pushing the price downward. Such situation continued for the most part of 2008, when prices went below 60 €/MWh. The projected demand growth, resulting from the extended obligation, showed a structural excess on the supply side, with the danger of an insufficient return on the investment. This is why law-makers decided to introduce, through decree 18 December 2008, a transient rule whereby GSE has to take back from obliged

77 Law n. 244 of 24 December 2007 modified GSE's reference price calculation method, setting a ceiling to the maximum price increase. According to the new mechanism, the price is calculated as the difference between 180 € and the average price of electricity calculated by AEEG for the previous year GCs are referred to.

subjects any excess GCs for every year in the 2009-2011 period.
Stage c) began with the introduction of decree 18 December 2008 and the above mentioned transient rule. It is characterized by relatively stable prices, thanks to the new automatic mechanism. GSE, as a buyer of last resort, can fully take up any excess in supply, so as to guarantee a perfect balancing of the market. Lately, legislative decree 3 March 2011, n. 28, established that the buy-back price for GCs in excess during the years 2011-2015 shall no longer be equal to the average of GCs market price in the three years prior to buy-back; it shall be equal to 78% of GSE's GCs reference price, i.e. to the difference between 180 € and the mean price of electricity in the year preceding the buy-back, as calculated by AEEG.
The next diagram reports GCs price over the years[78], starting from 2003, compared with GSE reference prices and GSE's buy-back prices (from 2009 onwards):

Fig C.4.10 **Trend of GC prices vs. GSE buy-back price**



78 For each period falling between 1 April of a given year and 31 March of the subsequent year, the price is referred to GCs with a reference year falling during the period being examined.

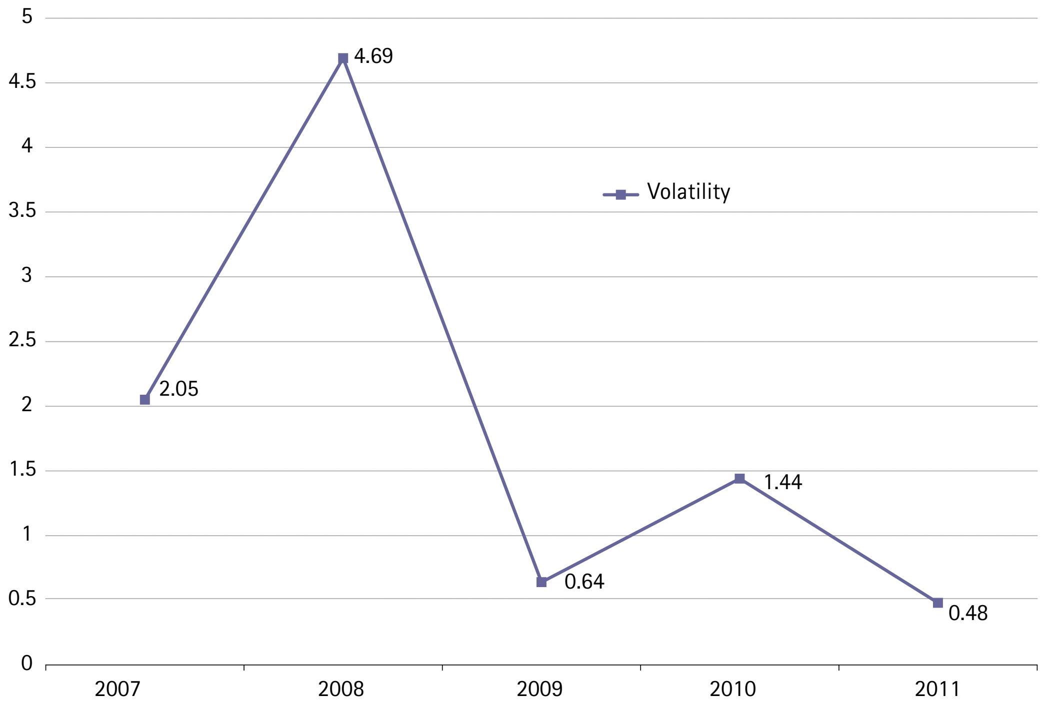
An analysis of volatility in 2007-2011, based on the standard deviation of log returns of weekly prices versus the yearly average of weekly log returns, expressed the following results:

Volatility analysis Tab C.4.3

Year	2007	2008	2009	2010	2011
Volatility	2.05	4.69	0.64	1.44	0.48

One-year volatility was calculated by considering the average weighted prices in regulated market sessions during the period between April of the year being examined and March of the subsequent year.
The graph below reports the values illustrated in the previous table:

Volatility analysis Fig C.4.11

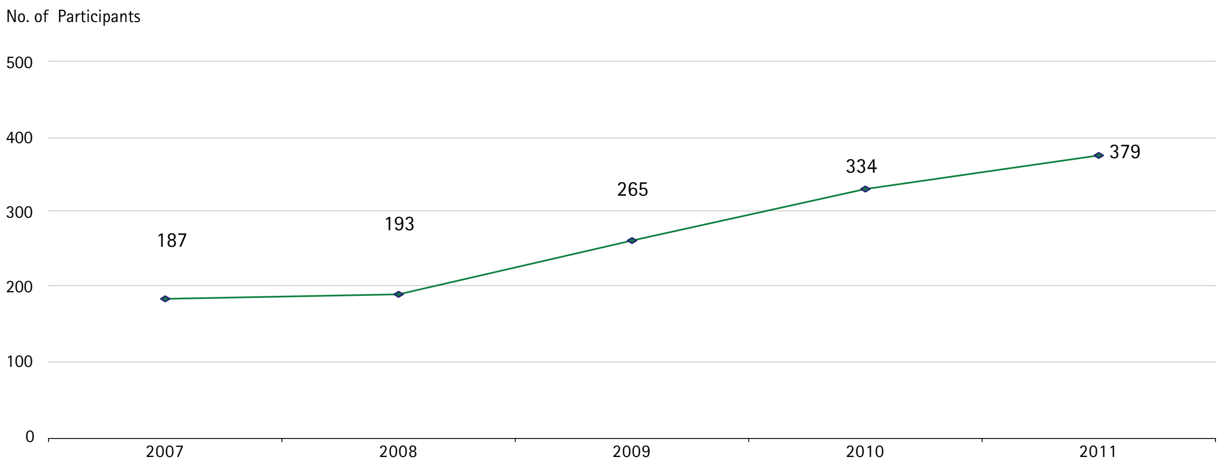


These data confirm that in 2007-2008, when GCs prices suddenly fell because of an excessive supply vis-à-vis the demand from obliged subjects, volatility was high. On the opposite, when GCs in excess began being taken up by GSE, prices became stable and volatility decreased considerably.

4.2 Energy Efficiency Certificates (TEE)

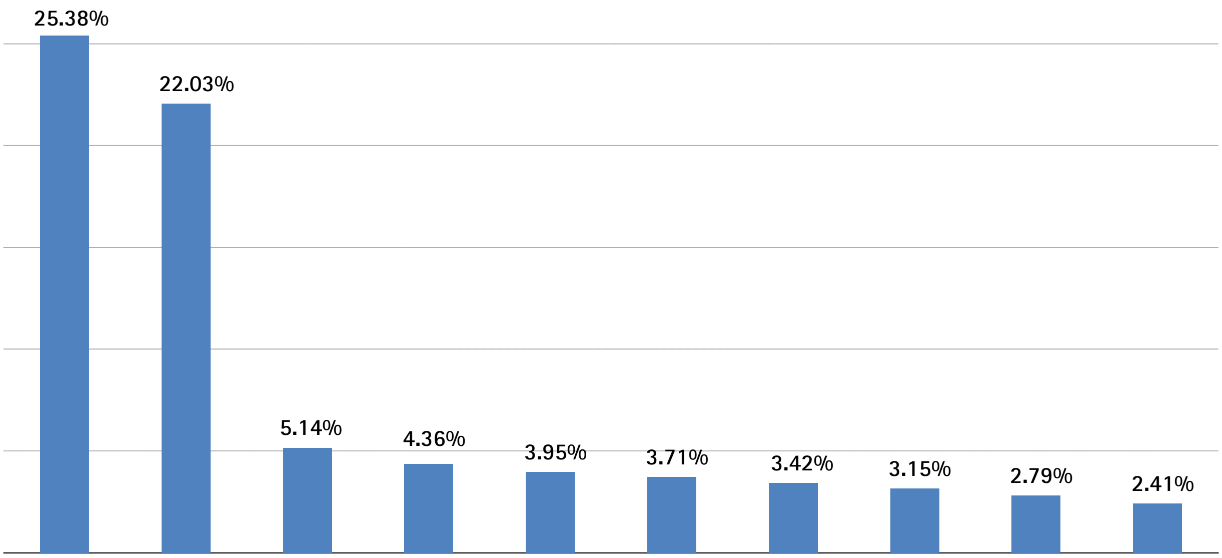
During 2011, the Energy Efficiency Certificates (TEE) market was characterized by a larger number of both participants and TEE volumes traded, either on the market or bilaterally.
As of 31 December 2011, participants registered under the TEE Register were 512, 379 of which applied and qualified as market participants.

Fig C.4.12 **Number of MTEE participants**



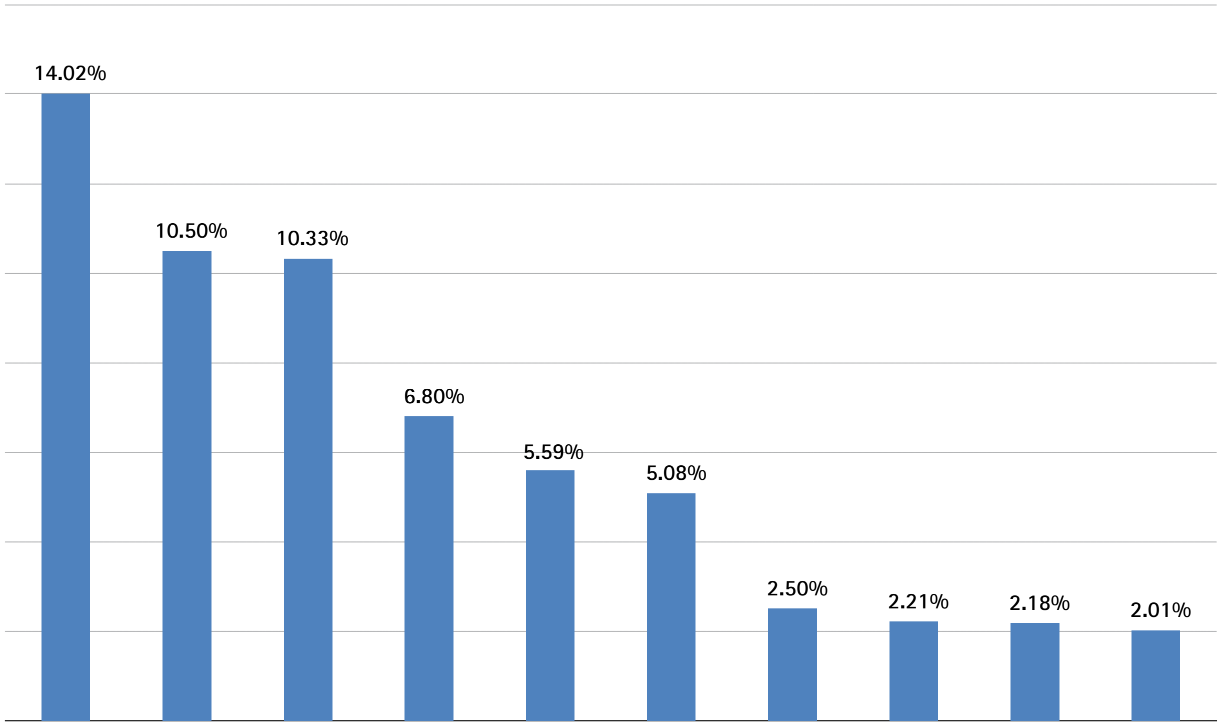
The following diagrams report the different market shares of the top 10 participants, on both the demand and supply side.

Fig C.4.13 **Market shares of top 10 MTEE participants – demand side – 2011**



Participants' market shares, demand side, reflect a certain concentration due to large-sized obliged distributors; the larger fragmentation of participants' market shares, supply side, reflects a larger number of selling participants on the market platform.

Market shares of top 10 MTEE participants – supply side – 2011 Fig C.4.14

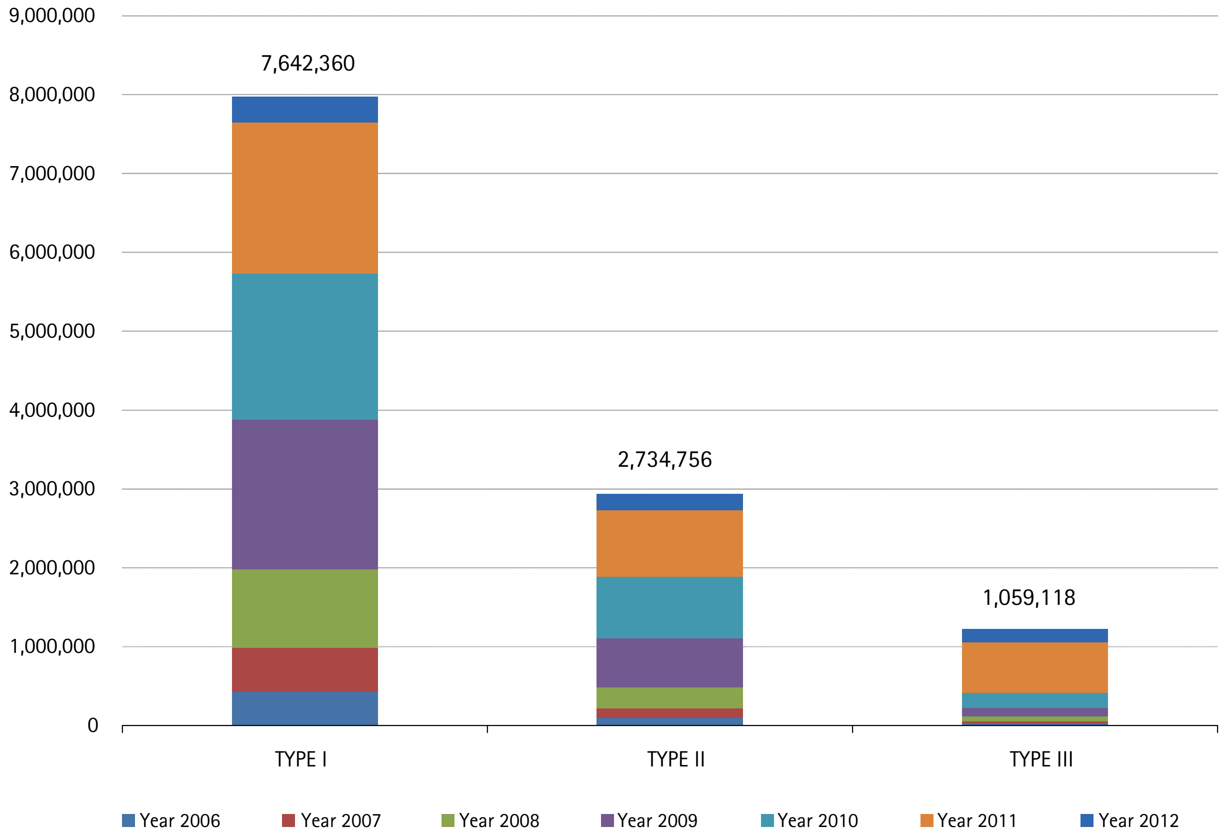


In 2011, upon the Electricity and Gas Regulator's approval GME issued 3,411,591 TEEs, of which:
- 1,917,593 of type I (certifying electricity saving);
- 848,564 of type II (certifying gas saving);
- 645,434 of type III (certifying primary energy saving).

Between the start date of this mechanism and 31 December 2011, 11,436,234 certificates were issued, of which:
- 7,642,360 of type I (electricity);
- 2,734,756 of type II (gas);
- 1,059,118 of type III (primary energy).

The following picture shows the number of issued TEEs, by type, during the various years (from 2006 onwards) covered by the support mechanism:

Fig C.4.15 **Number of TEE issued as of 31 December 2011, by type**



As to trades in the regulated market, during 2011 1,276.797 TEEs were traded. The most traded certificates were type I (732,603), followed by type II (414,728) and type III (129,466).

The volume weighted average prices were respectively equal to 93,00 €/TEE, 93,20 €/TEE, 93,00 €/TEE for type I, II and III.

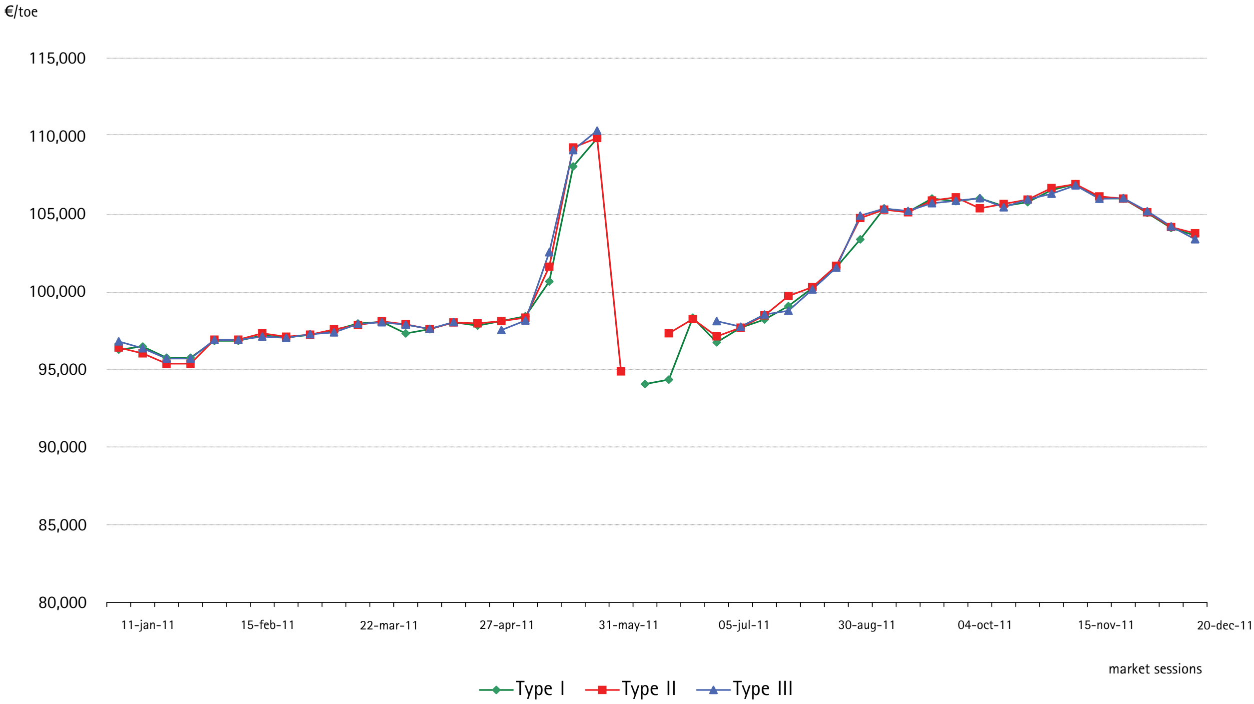
The table reports the main statistics on 2011 regulated market sessions:

Tab C.4.4 **Volumes and prices of TEE, by type (2011)**

	Type I	Type II	Type III
Volume of TEE traded (no. of TEE)	732,603	414,728	129,466
Minimum price (€/TEE)	93.00	92.30	93.00
Maximum price (€/TEE)	111.00	114.50	112.00
Weighted average price (€/TEE)	100.13	101.16	103.12

The diagram below illustrates the trend of average weighted prices for each session held during 2011:

TEE prices in GME's market – sessions of January-December 2011 Fig C.4.16

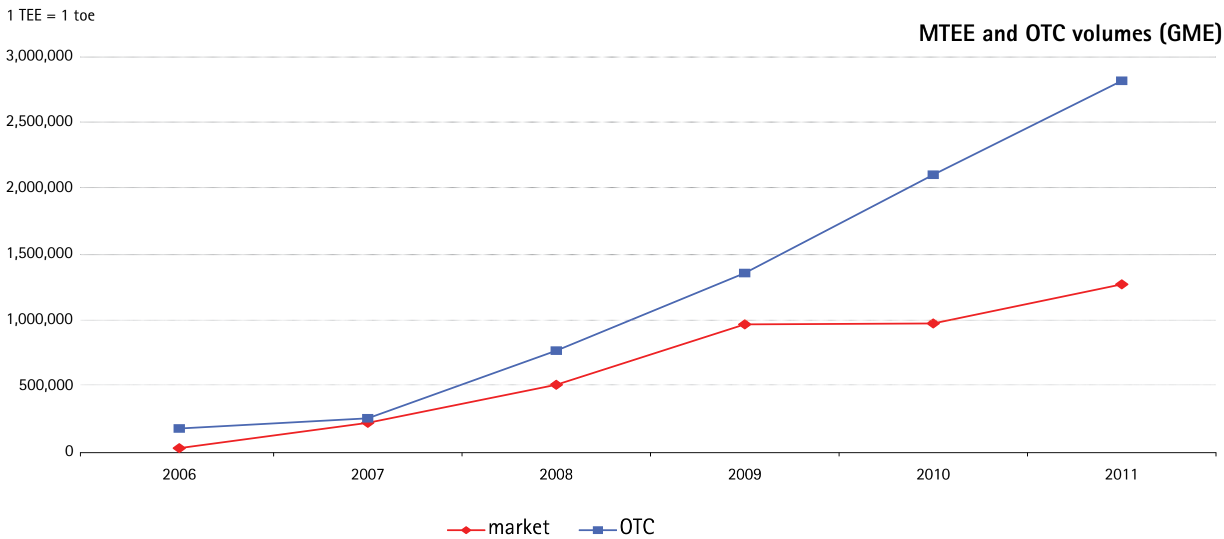


In 2011, TEE's market prices tended to grow, because of a demand excess from obliged distributors. Actually, relative to certificates requested by these latter, the number of issued certificates was insufficient to cover the demand; this pushed prices up as the deadline to comply with the obligation was approaching. After 31 May, prices fell by over 10%, in just one trading sitting, with a corresponding volume decrease; however, during the subsequent sessions, prices rose again bringing back TEEs close to the maximum levels of the year.

Historical analysis of volumes

TEEs volumes traded in the market followed a positive trend, although, as the diagram highlights, the growth of OTC volumes was larger than trades in the regulated market:

MTEE and OTC volumes (GME) Fig C.4.17



The tendency to conclude bilateral contracts rather than trading TEEs through the regulated market can probably be explained by the need, for large obliged distributors, to get considerable numbers of certificates with the smallest number of transactions. In the regulated market, the supply is quite fragmented and mostly consists of ESCOs holding a limited number of TEEs. This is why the large distributors seek to enter into bilateral contracts, including multi-year contracts, with participants who can sell a sufficiently large number of TEEs. On the contrary, they trade residual quantities in the regulated market.
With the increase of yearly obligations, this pattern has become more common. More certificates are required to comply with the obligation; plus, in this market GME does not act as a central counterparty.

Historical analysis of prices

From the market take-off, prices were driven by the tariff reimbursement granted to obliged distributors for each TEE cancelled for obligation purposes, to partially cover costs.
This amount is set by AEEG; until 2008, it amounted to 100 €/toe, subject to an adjustment in the subsequent years (see diagram C.4.18.).
During the first years of enforcement, when there was an excess supply of TEEs versus the obliged subjects' demand, the market price of certificates was constantly below the tariff contribution. As soon as an excess demand emerged, with fewer TEEs than those requested by obliged subjects, their price exceeded the tariff reimbursement set for that year. In particular, this situation began in early 2010 and continued until the end of 2011.
By comparing the cumulative number of TEEs issued as against the cumulative level of targets for each year, it becomes clear that since 2008 the total number of issued certificates has been lower than the cumulative target[79].
The following table reports a detailed comparison of certificates required to fulfill the obligation and the cumulative number of certificates issued by the end of each year:

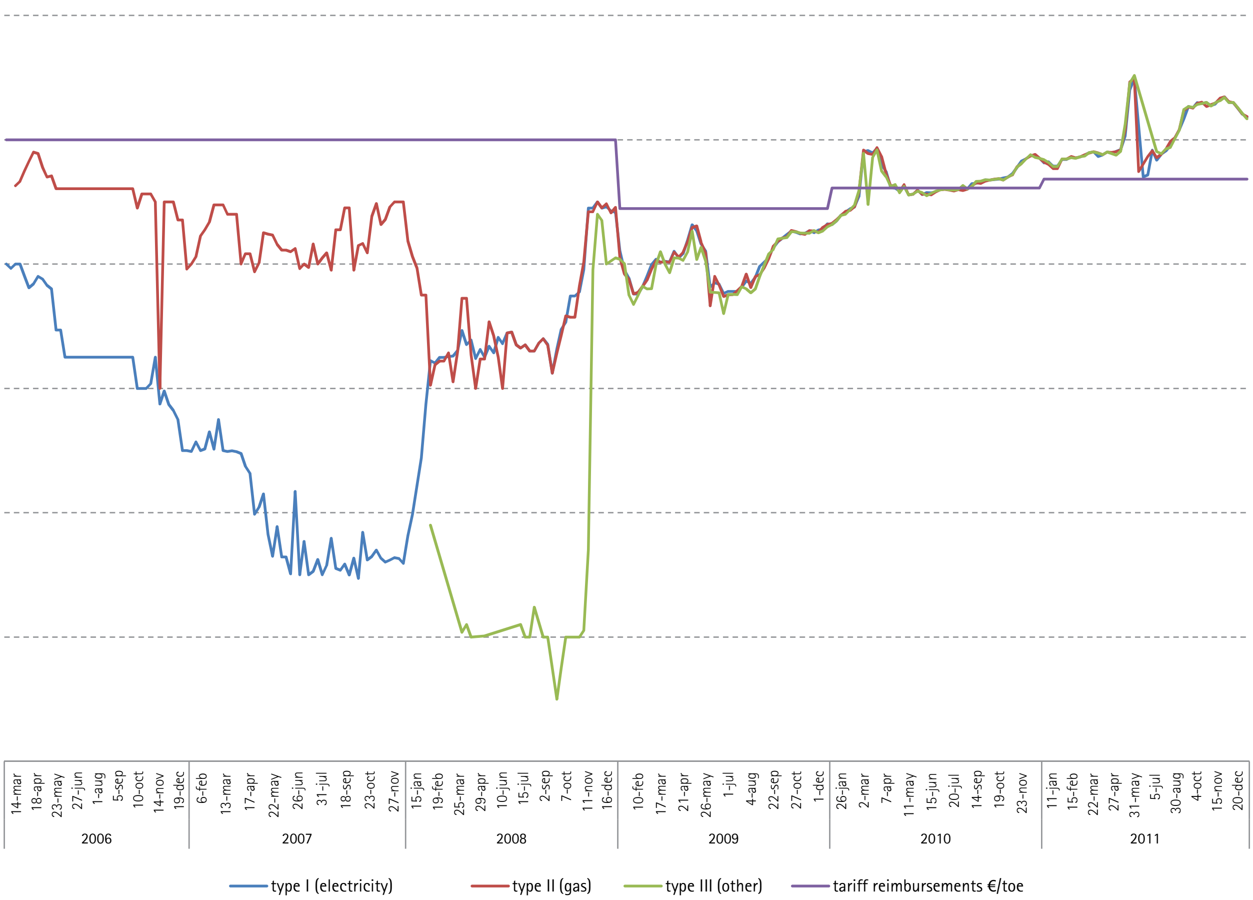
Tab C.4.5 **Mtoe/y needed for compliance with obligation**

Year of obligation	Actual obligations – electricity disributors (Mtoe/yr)	Actual obligations – gas distributors (Mtoe/yr)	Cumulative total of TEE needed for compliance (Mtoe/yr)	Certificates issued from the start of the scheme (Mtoe)
2005	0.1	0.06	0.16	
2006	0.19	0.12	0.47	
2007	0.39	0.25	1.11	1.26
2008	1.2	1	3.31	2.6
2009	1.8	1.4	6.51	5.23
2010	2.4	1.9	10.81	8.02
2011	3.1	2.2	16.11	11.44

79 However, the obligation for any given year expires on 31 May of the subsequent year. Hence, participants may acquire a proportion of certificates issued in the first half of the subsequent year to comply with the obligation.

Market prices were influenced by the new demand and supply equilibrium. They were always below the tariff contribution until 2009, to then exceed this cutoff from 2010 onwards:

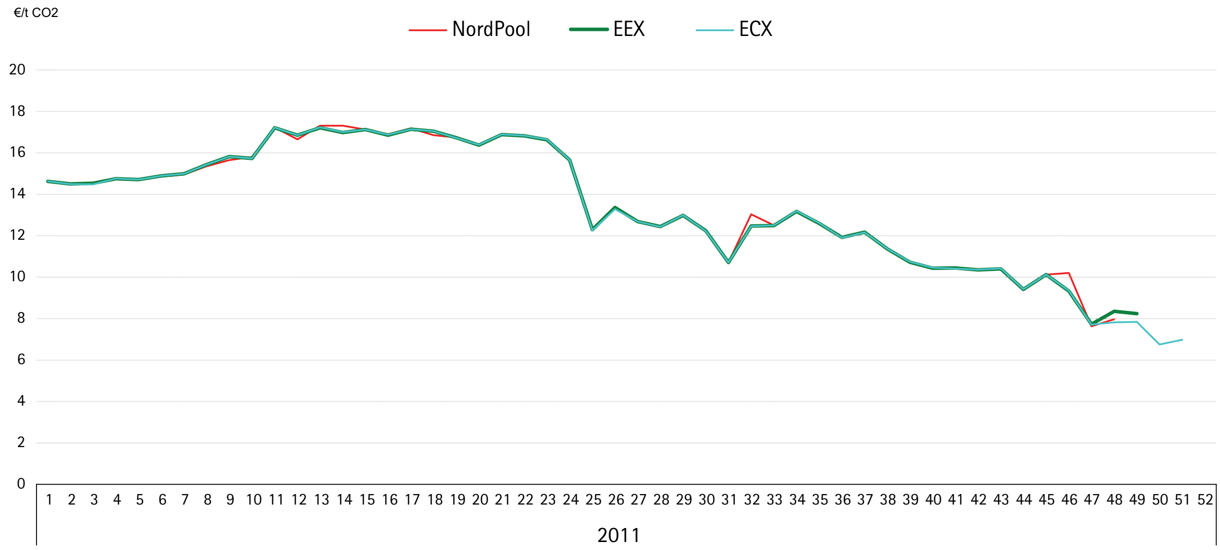
Comparison of TEE prices and tariff reimbursement - 2006-2011 Fig C.4.18



4.3 Emission Allowances (EUA)

In 2011, 6.1 billion EUAs were traded, versus 5.12 billion in 2010. Overall, carbon credits (EUAs, CERs and ERUs) traded in 2011 equaled 7.6 billion units[80].
In the face of an increase of volumes on the market, the price of Emission Allowances sharply fell.
Fig. C.4.19 below illustrates the price trend of weekly trades of Emission Allowances in 2010 (EUA expiring in December 2011), in the three largest European forward markets (Nord Pool, EEX, ECX).

Fig C.4.19 **EUA prices on Nord Pool, EEX, ECX (2011)**



The forward prices of Emission Allowances expiring in December 2011 ranged between a minimum of 6.45 €/t CO2 and a maximum of 17.42 €/t CO2.
Given the excessive liquidity and poorly competitive prices, a number of major proposals for the emission allowances market were made. Amongst others, they aim at protecting the mechanism efficiency and incentivizing new investment to limit emissions from industrial plants.
The Environment Commission of the European Parliament, in its Report on the 2050 Roadmap asked the EU Commission to 'set-aside' emission allowance phase III 2013/2020 to fix the system scarcity and propose, by the end of 2013, legislative measures sending out a clear, long term indication to investors.
Furthermore, in order to raise the security of National Registers, in the light of the theft of allowances which happened in the past, the European Commission initiated a procedure to set up a European Single Register, providing for the gradual move of accounts held in national Registers to the Single Register. At the same time, the Directive on financial instruments markets (MiFID) is being revised, with an eye to considering emission allowances as a financial instrument as well as preventing market turbulence.
Such proposal, comprised of a directive and a Regulation (COM_2011_656, COM_2011_652), aims at raising the efficiency, oversight and transparency of markets as well as strengthening investors' protection. In particular, the MiFID should be covering the spot market of EUAs (see COM_2011_656 - 3.4.15. Emission allowances - Article Annex I, Section C).

80 http://www.pointcarbon.com/news/1.1710408.

As a first step toward the full operation of the EU Single Register, airlines have been able to apply for an account with the Single Register and receive allowances from their own member state, since 30 January 2012. In Italy, the Interministerial Committee for ETS, which is in charge of the National Register, is the organization responsible for checking the documents requested in order to open an account with the EU Single Register, in operation since 20 June 2012.

The EU Commission has communicated that National Registers stopped their activities on 3 June, in view of the upcoming operation of the Single Register starting from 20 June. The functions of the Single Register will be further developed in order to fulfill requirements set out by ETS Phase 3.

4.4 The CO2 international market

At the end of 2011, delegates from 194 Countries met in Durban (South Africa) on the occasion of the 17th meeting of the Conference of the Parties (COP). They reached a climate agreement whereby they shall begin talks to sign a global treaty by 2020. However, such agreement is not binding for signatories and does not set any emission reduction target, although several countries accepted to curb emissions on a voluntary basis in the next few years.

The weakness of said agreement lies in the fact that no binding agreement will become effective by 2020; hence, emissions from the most polluting countries may be reduced thanks to voluntary initiatives only, and no control or inspection can be performed.

To this date, the lack of an agreement on the second enforcement period of the Kyoto Protocol or another binding agreement raises a large degree of uncertainty and slows down the investment level.

Both because of Kyoto and of the growing environmental awareness of several countries, a number of CO2 emission reduction schemes have been introduced in various countries. In particular, aside from Europe where the European Directive 2003/87 establishes an Emission Trading System, in the USA, Asia and Australia independent initiatives were taken with the goal of limiting atmospheric pollution.

The figure below shows the main schemes introduced worldwide:

Main emission reduction schemes in the world Fig C.4.20

Beside the various local initiatives, the Kyoto Protocol, through its flexible mechanisms (in particular, the Clean Development Mechanism - CDM) facilitated the creation of a credit market (Certified Emission Reductions - CERs) related to the implementation of emission reduction projects in developing countries. In a number of countries, the existing schemes acknowledge CERs, creating kind of a "bridge" with local schemes and an international market of emission reduction allowances.

Without a new international binding agreement, in a time of global economic crisis, the investment flow created by the CDM is slowly coming to an end. On the horizon, it is unlikely that the market demand can guarantee the sale of credits with a consequent economic return on the investment. Moreover, any initiative aimed at standardizing the various types of credits acknowledged by each emission reduction scheme has been stopped. This leads to a fragmented market which, on the opposite, need to be global in order to fully unfold its action.

The current and the next year will be crucial for the future of the carbon market: a joint effort by the top countries seems to fundamental in order to reach a global, binding agreement, attract economic resources and standardize products traded under the various schemes.

Box 4 THE IMPACT OF RENEWABLE SOURCES SUPPORT SYSTEM

Edited by Gestore dei Servizi Energetici (GSE)

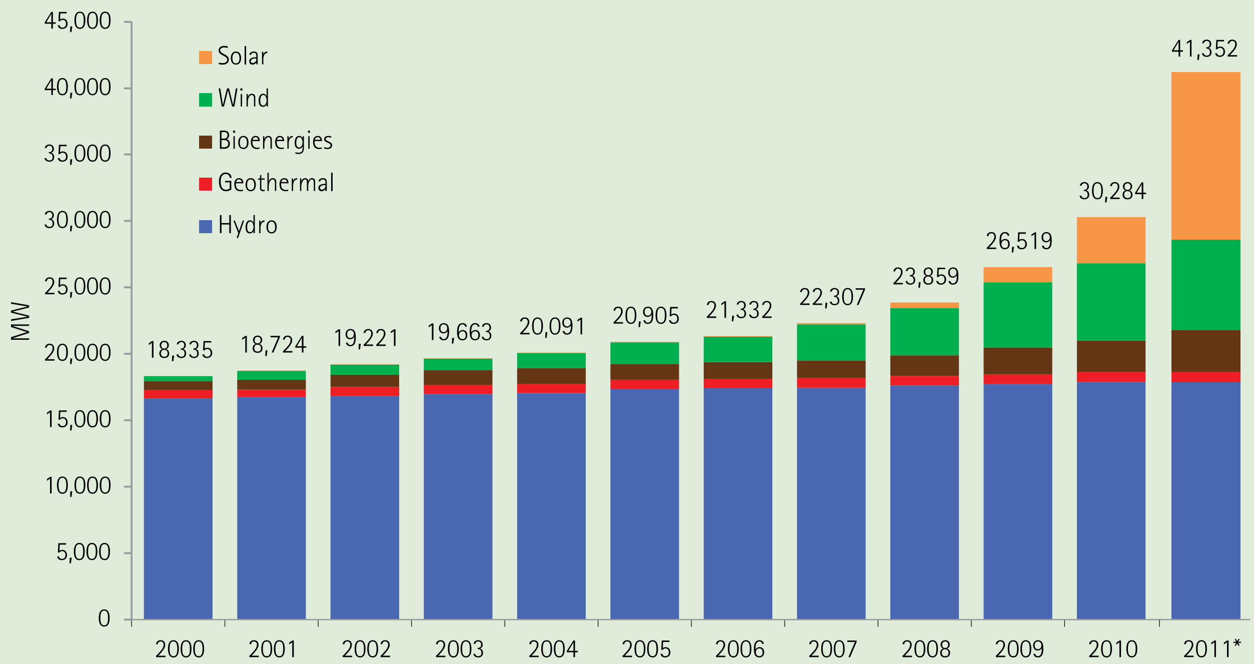
In 2011, too, the national electricity system was characterized by a large development of renewable-fed plants. According to the preliminary estimates provided by Gestore dei Servizi Energetici, electricity generated from renewable sources in Italy, in 2011, exceeded 84 TWh, covering about 24.5% of Italy's gross domestic electricity consumption, i.e. 344 TWh[1].

In order to compare this figure with the National Action Plan for Renewable Sources (NAP), forwarded to the European Commission in 2010, it is necessary to keep into account fluctuations of hydro and wind generation, caused by changing wind and precipitations, after applying the normalization formulas set by Directive 2009/28/EC. According to such calculation, in 2011 the consumption level covered by renewable would be equal to 23.7%, way above 19.6%, as envisaged by NAP for such year, and close to the figure envisaged for 2017.

In summary, in the last couple of years the growth of renewables, particularly photovoltaic energy, is estimated to easily exceed the 26.4% share envisaged by the NAP for 2020.

However, to fully understand this result and the resulting medium and long term perspectives, it is necessary to analyze the development trend, with some detailed remarks on each type of renewable source and their related technologies.

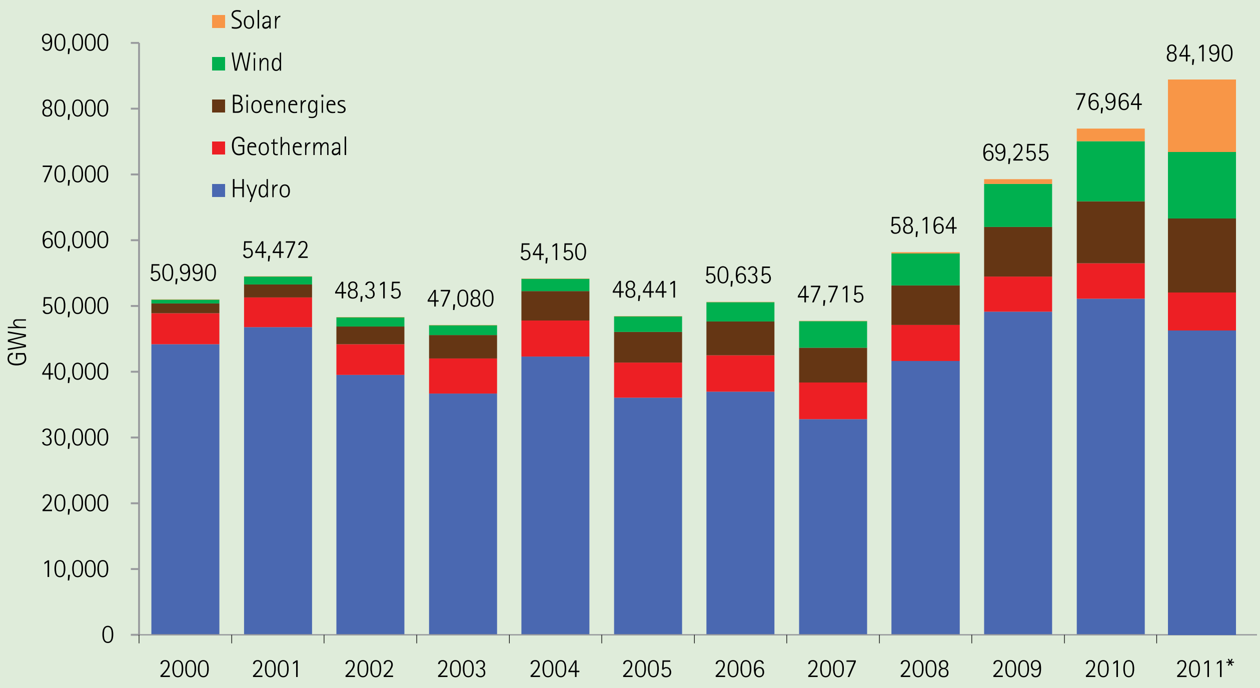
Gross maximum capacity of renewable power plants Fig IV.1



* Provisional data of TERNA/GSE

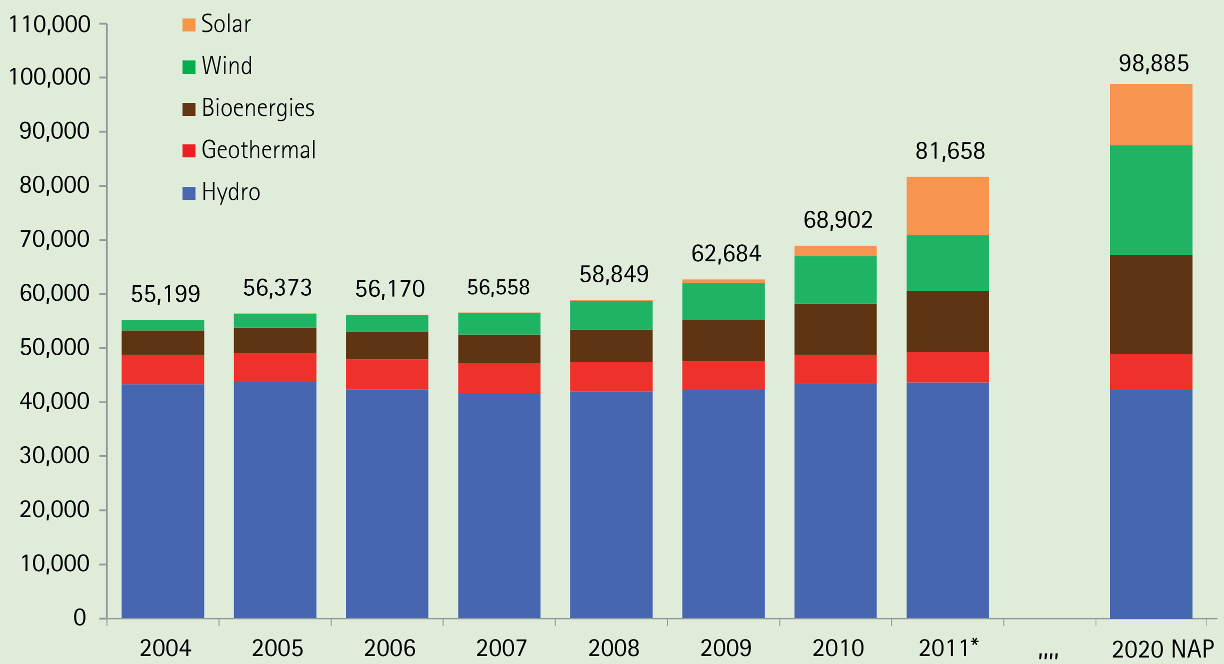
1 It should be noted that inside the box a comparison was made between results achieved in 2011 in terms of FER generation and 2020 European targets, calculated relative to gross consumption, i.e. to CIL in the electricity sector.

Fig IV.2 **Gross generation of renewable power plans**



* Provisional data of TERNA/GSE

Fig IV.3 **Normalised gross generation of renewable power plants and comparison with NAP projections by 2020**



* Provisional date of TERNA/GSE

Hydroelectric generation

Historically, hydraulic sources have been the main component of the renewable fleet in Italy.

The most productive sites have been exploited since the beginning of the last century; in the last couple of years, small-sized fluent water plants have been installed. Hence, in Italy the installed power grew very little and was equal to 17,950 MW in 2011 (+0.5% on 2010).

Hydroelectric generation is characterized by continuous fluctuations due to more or less favorable hydraulic conditions (precipitations, temperature). After two record years, in 2011 the generating capacity of hydroelectric plants was 46,350 GWh (-9% on 2010).

On the other hand, the National Action Plan estimates did reflect these typical factors. For 2015, as well as for 2020, no major change in terms of generation or installed power is expected.

Geothermal energy

LThe geothermal power installed in Italy, equal to 772 MW and limited to Tuscany only, did not vary in the recent past. Generation, too, did not show any significant change and was equal to 5.650 GWh in 2011 (+5% on 2010).

The excellent performance of such plants do justify the explicit pledge, as stated in the NAP, to expand the geothermal-electrical generation up to 920 MW by 2020, in order to guarantee a generation of 6,750 GWh.

Solar energy

The exploitation of solar energy through photovoltaic plants has had an unprecedented development in the last five years. At the end of 2011, the installed photovoltaic power was higher than 12.5 GW, i.e. nearly three hundred fold more than at the end of 2006.

In particular, with over 9 GW in operation in 2011 (3.7 of which, however, had been completed as the connection was awaited by 2010), Italy covered about one third of the new installed power worldwide.

As a consequence, solar energy generation exceeded 10.5 TWh in 2011. A true turning point after the marginal role solar energy had played in the past.

This result has contributed to surpass, nine years ahead of time, the NAP's target of a photovoltaic generation of 9.65 TWh by 2020.

Clearly, such a growth rate cannot continue forever; in 2012, also because of less cost-effective support measures, fewer installations will be put in place, according to estimates.

Wind power

Generation of electricity from wind grew remarkably in Italy in recent years. As a matter of fact, this trend was confirmed in 2011. The installed power increased by approximately 1 GW, raising the total power of the Italian wind generation above 6.8 GW, with a generation level slightly greater than 10 GWh during the year.

Looking at the development trajectories drawn by the NAP, it can be seen that the wind sector is heading toward the 2020 national target nearly one year ahead. Indeed, figures referred to 2011 are very close to those set for the following year.

In the light of such success, although the 2020 target (exceeding 12.5 GW of installed power, with a yearly generation of 20 TWh (2 TWh of which from off-shore wind energy) remains ambitions, it is within reach, irrespective of a possible slower rate of installation.

Bioenergy

The bioenergy sector (solid biomass, biogas and bioliquids) in the last decade had ups and downs, although it kept growing. The yearly average increase, in terms of productivity, was slightly less than 1 TWh. Again, at the end of 2011 the installed power was equal to 3 GW and the yearly generation to about 11.3 TWh. These figures reflect a significantly better result than the NAP.

As to the future development, this sector is characterized by an undisputed primary of biogas plants. To achieve 18.8 TWh (the target set for 2020), the same comments made on the wind energy sector can apply to bioenergy, too.

Conclusions

In the reorganization of the European system of electricity generation, where low environmental impact technologies are playing an increasingly crucial role, Italy, at the beginning of 2012, is well off. With special regard to the electricity sector, Italy is ahead of any Community planned targets and roadmap.

The ongoing, substantial development of renewable sources was largely accounted for by the introduction of significant support and incentivizing measures on a domestic level. Now, the real challenge is to achieve a long term economic sustainability allowing this sector to keep growing on its own legs in order to accomplish its ambitious goals and targets.

LIST OF ACRONYMS

ACER	Agency for the Cooperation of Energy Regulators
AEEG	Autorità per l'Energia Elettrica e il Gas (Electricity and Gas Regulator)
AGCM	Autorità Garante per la Concorrenza ed il Mercato (Competition Regulator)
AHAG	Ad Hoc Advisory Group
AIEE	Associazione Italiana Economisti dell'Energia
AU	Acquirente Unico (Single Buyer)
BBL	Barrel of Oil
BEN	Bilancio Energetico Nazionale (National Energy Balance)
BP	British Petroleum
CACM	Capacity Allocation and Congestion Management
CC&G	Cassa di Compensazione e Garanzia
CCT	Fee for assignment of rights of use of transmission capacity
CDE	Electricity Derivatives Delivery Platform
EC	European Commission
CEGH	Central European Gas Hub
CER	Certified Emission Reduction
CFD	Contract for Differences
CH	Clearing House
CIP6	Provision 6/1992, Interministerial Price Committee
CV	Green Certificates (GCs)
ECC	European Commodity Clearing
EEX	European Energy Exchange
EFET	European Federation of Energy Traders
EIA	Energy Information Administration
ENTSO-E	European Network Transmission System Operators for Electricity
ENTSO-G	European Network Transmission System Operators for Gas
EPEX	European Power Exchange
ERGEG	European Regulators' Group for electricity and gas
ERIs	Electricity Regional Initiatives
ESCO	Energy Service Company (Società di Servizi Energetici)
ETS	Emission Trading Scheme
EUA	Emission Unit Allowance
Eurelectric	Association of the Electricity Industry in Europe
EUROPEX	Association of European Energy Exchanges
EXAA	Energy Exchange Austria
IMF	International Monetary Fund
GJ	Gigajoule
GME	Gestore dei Mercati Energetici
GNL	Liquefied Natural Gas
GRIs	Gas Regional Initiatives
GSE	Gestore dei Servizi Energetici
GW	Gigawatt
GWh	Gigawatthour
HHI	Hirschmann Herfindal Index
IDEX	Italian Derivatives Energy Exchange

IEA	International Energy Agency
IFIEC	International Federation of Industrial Energy Consumers
IOM	Price-setting Operator Index
IOR	Residual Supply Index
IPEX	Italian Power Exchange
ISPRA	Istituto Superiore per la Protezione and la Ricerca Ambientale (Environmental Protection and Research Institute)
ISTAT	Istituto di Statistica (Italian National Institute of Statistics)
ITEC®	Italian Thermoelectric Cost
ITM	Price-setting Technology Index
IZM	Price-setting percentage, by zone and by year
LCH	London Clearing House
MA	Adjustment Market
MB	Balancing Market
MCP	Market Clearing Price
MCV	Green Certificates Market
MEF	Ministry of Economy and Finance
MGP	Day-ahead Market
MGP-GAS	Day-ahead Gas Market
MI	Intra-day Market
MI-GAS	Intra-day Gas Market
MOL	EBITDA
MPE	Spot Electricity Market
MSD	Ancillary Services Market
MISE	Ministry of Economic Development
MTE	Forward Electricity Market
MW	Megawatt
MWh	Megawatthour
MZ	Zonal Market
NBP	National Balancing Point
OECD	Organization for Economic Cooperation and Development
OMEL	Operador del mercado iberico de energia
OMIP	Iberian Power Derivatives Exchange
OPEC	Organization of Petroleum Exporting Countries
OTC	Over The Counter
PAB	Bilaterals Adjustment Platform
PBCV	Green Certificates Bilaterals Registration Platform
PCE	OTC Registration Platform
PCG	Project Coordination Group
PCR	Price Coupling of Regions
PEG	Point d'Echange de Gaz
P-GAS	Gas Trading Platform
GDP	Gross Domestic Product
PSV	Virtual Trading Point
PUN	National Single Price
PX	Power Exchange
PZ	Zonal Price

RO	EBIT
ROE	Return on Equity
ROI	Return on Investment
RTN	National Transmission Grid
TEE	Energy Efficiency Certificates
TOE	Ton of Oil-Equivalent
TSO	Transmission System Operator
TTF	Title Transfer Facility
TW	Terawatt
TWh	Terawatthour
EU	European Union
UIC	Ufficio Italiano Cambi (Italian Foreign Exchange Office)
UNEP	United Nations Environment Program
UNFCCC	United Nations Framework Convention on Climate Change
UNMIG	Ufficio Nazionale Minerario per gli Idrocarburi and la Geotermia (National Office for Mining, Hydrocarbons and Geothermal Resources)

GLOSSARY

Acquirente Unico (AU – Single Buyer)

Company created by "Gestore della Rete di Trasmissione Nazionale" (now "Gestore dei Servizi Energetici – GSE") with the task of guaranteeing the availability of electricity to cover the demand of all captive customers. AU operates by purchasing the required electrical capacity and reselling it to distributors on non-discriminatory terms in order to allow the application of a single national tariff to final customers. To this end, AU may purchase electricity on the power exchange or through bilateral contracts.

Agency for Cooperation of Energy Regulators (ACER)

A European Union body set up in 2010 pursuant to Regulation No 713/2009 (Third Energy Package). At EU level, its mission consists in assisting national regulators in performing their regulatory functions and, where necessary, in coordinating their actions.

Ancillary Services Market (MSD)

Venue for trading supply offers and demand bids in respect of ancillary services. Terna S.p.A. uses this market to relieve intra-zonal congestions, procure reserve and balance injections and withdrawals in real time. Participation in the MSD is restricted to units authorized to supply ancillary services and bids/offers may be submitted only by their dispatching users. Participation in the MSD is mandatory. The MSD produces two separate results: 1) the first result (ex-ante MSD) concerns bids/offers that Terna S.p.A. has accepted on a scheduled basis for relieving congestion and creating an adequate reserve margin; 2) the second result (ex-post MSD) concerns bids/offers that Terna S.p.A. has accepted in real time for balancing injections and withdrawals (by sending balancing commands). Bids/offers accepted in the MSD determine the final injection and withdrawal schedules of each offer point. In the MSD, bids/offers are accepted by economic merit order, taking into account the need for ensuring the correct operation of the system. Bids/offers accepted in the MSD are valued at the offered price (pay as bid).

Arbitrage

Financial transaction consisting in purchasing goods or securities by capitalizing on market inefficiencies to obtain a sure profit. Arbitrageurs perform an essential function in ensuring a proper pricing mechanism, since their activity helps redress any misalignment of prices as soon as it arises.

Autorità Garante per la Concorrenza ed il Mercato (AGCM – competition or antitrust regulator)

Independent regulator set up by Law no. 287 of 10/10/1990 ("Rules on the protection of markets and competition"). It also has responsibilities in the field of misleading advertising and comparative advertising, as established by Title III, Chapter II of Legislative Decree no. 206 of 06/09/2005, and in the field of conflicts of interest, as established by Law no. 215 of 20/07/2004.

Autorità per l'Energia Elettrica e il Gas (AEEG – electricity & gas regulator)

Independent regulator with the task of guaranteeing the promotion of competition and efficiency in the electricity and gas sectors, established by Law no. 481 of 14 November 1995. With regard to GME's activity, AEEG is in charge, amongst others, of defining rules on merit-order dispatch and market power control mechanisms.

Bilateral (or OTC) Contract

Contract for supply of electricity concluded off the power exchange between a producer/wholesaler and an eligible customer. The price for the supply as well as the injection and withdrawal profiles are freely agreed by the parties. However, transactions and related injection or withdrawal schedules must be reported to Terna S.p.A., which will verify their consistency with the transmission constraints on the national transmission grid.

Cascading

Procedure under which quarterly and yearly forward contracts (futures, forwards and Contracts for Difference) are replaced upon maturity with an equivalent number of contracts with a shorter maturity. The new positions are opened at a price equal to the final settlement price of the original contracts.

Churn Ratio

Indicator measuring the liquidity of gas hubs and calculated as the ratio of the gas volume traded to the gas volume delivered.

CIP 6

Resolution no. 6 adopted in 1992 by "Comitato Interministeriale Prezzi" (CIP - Interministerial Committee on Prices). The resolution promotes the construction of plants for generation of electricity from renewable and/or so-called "assimilated" sources, as per Law 9/91. GSE purchases the electricity generated by such plants under art. 3.12 of Legislative Decree 79/99, and sells it in the power exchange under art. 3.13 thereof. In the years elapsing between the approval of Legislative Decree 79/99 and the start of the power exchange, GSE sold such electricity to final customers by selling yearly and monthly electricity bands (similar to bilateral contracts). Since 1 January 2005, GSE has offered CIP-6 electricity directly in the power exchange: market participants with CIP-6 allocations are required to enter into a Contract for Difference with GSE, under which they undertake to procure the volumes of electricity corresponding to their allocations in the Electricity Market.

Clean Development Mechanism (CDM)

One of the flexible mechanisms identified in the Kyoto Protocol to help developing countries to move from their present development model to a less carbon-intensive one. Through the CDM, a developed country invests in a project of emission reduction or greenhouse gas capture in a developing country. In this way, the developing country may have access to a less polluting technology, while the industrialized country and/or its companies may reduce their cost of compliance with emission reduction constraints.

Clearing House

A Stock Exchange mechanism ensuring the fulfillment of the obligations underlying the transactions concluded by operators. It acts as a central counterparty, replacing the original parties to a contract.

Clearing Price

It generally identifies the price of electricity, as determined in the MGP and MI in each hour, at the point of intersection of demand and supply curves, so as to ensure that they are equal. In case of market splitting in two or more zones, both in the MGP and MI, the clearing price may be different in each market zone (see zonal price). In the MGP, the zonal clearing price may be applied to all supply offers, to demand bids pertaining to mixed units and to demand bids pertaining to consuming units belonging to virtual zones. Demand bids pertaining to consuming units belonging to geographical zones are valued, in any case, at the national single price (PUN). In the MI, in case of market splitting in two or more zones, the zonal clearing price is applied to all supply offers and demand bids.

Coefficient of Variation

Price volatility index, expressed as a percentage. It is calculated as the ratio of the standard deviation to the average price value.

Contract for Difference (CfD)

In this type of contract, two parties exchange financial flows on the basis of the spread between a price defined in the same contract (strike price) and the price set in the underlying market on given maturity dates and for pre-established quantities. The portfolio of AU includes two-way CfDs for hedging purposes. Similarly, GSE has a CfD for the electricity volumes that it purchases from CIP-6 plants. In this case, the buying counterparties are - on a pro quota basis - AU and a group of operators. In each applicable period, GSE pays the difference (multiplied by the underlying volume of electricity) between the market price and the strike price defined in the contract, if positive, and receives such difference, if negative. There also exist one-way CfDs, actually representing call options. In this case, the buyer pays an advance premium; if the market price of the underlying is higher than the strike price defined in the contract, the buyer receives the difference from the counterparty; in the opposite case, no financial flows arise.

Constrained zone (or point or pole of limited production)
Set of generating units connected to a portion of the national electricity transmission grid (RTN) without withdrawal points; its maximum generation exportable to the rest of the grid is smaller than its maximum possible generation owing to insufficient transmission capacity. In the Italian market, it is defined as a national virtual zone.

Day-Ahead Market (MGP)
Venue where participants enter electricity supply offers and demand bids for each hour of the next day. All electricity operators may participate in the MGP. In this market, supply offers may only refer to injection and/or mixed points and demand bids may only refer to withdrawal and/or mixed points. Bids/offers are accepted by merit order, taking into account the transmission limits notified by Terna S.p.A. Accepted supply offers are remunerated at the zonal clearing price. Accepted demand bids are remunerated at the National Single Price (PUN). Accepted bids/offers determine the preliminary injection and withdrawal schedules of each offer point for the next day. Participation in this market is optional.

Day-Ahead Gas Market (MGP-GAS)
Venue where participants enter gas supply offers and demand bids in respect of the applicable period following the one in which the auction-trading sitting of the MGP-GAS ends. All operators authorized to carry out transactions at the Virtual Trading Point (PSV) may participate in the MGP-GAS. The MGP-GAS consists of two successive stages: in the first one, transactions take place under the continuous-trading mechanism; in the second one, they take place under the auction-trading mechanism. In the MGP-GAS, gas demand bids and supply offers for the gas-day following the one on which the auction-trading session ends are selected.

Derivative Contract
Financial instrument whose price and value depend on the value of another asset, defined as underlying instrument. This category includes options and futures.

Electricity Derivatives Platform (CDE)
Platform organized by GME to allow participants to exercise the physical delivery option for electricity futures traded on IDEX.

Emission Allowance
Certificate worth 1 tonne of CO2 emissions, which may be traded and used to demonstrate compliance with the obligation to hold down greenhouse gas emissions, as defined in the Emission Trading Scheme.

Emission Trading Scheme (ETS)
Scheme of greenhouse gas emission allowance trading among EU Member States. Emissions trading is one of the mechanisms identified under the Kyoto Protocol.

Energy Efficiency Certificates (TEE or White Certificates)
Energy Efficiency Certificates (TEE) were established by the Decrees adopted by the Ministry of Productive Activities in agreement with the Minister of the Environment and Land Protection on 20 July 2004 (Ministerial Decrees 20/7/04). TEE give evidence of the energy savings that electricity and gas distributors with over 50,000 customers are required to achieve. TEE are valid for five years starting from the year of reference and are issued by GME.

Ex-ante MSD
It consists of three scheduling sub-stages: MSD1, MSD2 and MSD3. In the ex-ante MSD, there is only one session for bid/offer submission, which starts at 3.30 p.m. the day before the day of delivery and ends at 5 p.m. of the day before the day of delivery. The results of the ex-ante MSD are made known by 2 p.m. of the day of delivery. In the ex-ante MSD, Terna accepts energy demand bids and supply offers to relieve any residual congestions and create reserve margins.

Fee for Assignment of Rights of Use of Transmission Capacity (CCT)
Hourly fee, as defined in article 43 of AEEG Decision 111/06, as subsequently amended and supplemented. For injection schedules and withdrawal schedules (only if the withdrawal schedules refer to mixed points or withdrawal points belonging to foreign virtual zones registered in accordance with the PCE Rules), this fee is equal, for each hour, to the product between: 1) the difference between the National Single Price (PUN) and the zonal price of the zone where dispatching points are located; 2) the forward electricity account schedule resulting from the MGP. Both in the MGP and in the MI, the fee for GME in each hour amounts to the difference between the purchasing value and the selling value of power exchange volumes.

Forward Contract
Contract of sale/purchase of an asset where price and volume terms are set upon concluding the contract. The contract will be executed on a future pre-set date. Hence, it is a deferred delivery sale/purchase contract.

Forward Electricity Market (MTE)
Venue where forward electricity contracts with delivery and withdrawal obligation are traded.

Future Contract
Forward contract different from a conventional forward contract, because its main clauses are standardized and it is traded on a regulated market.

Gestore dei Mercati Energetici (GME)
Publicly-owned company established in 2001 pursuant to art. 5 of Legislative Decree 79/99 (the so-called "Bersani Decree"). GME is vested with the organization and economic management of the Electricity Market and of the natural Gas Market under principles of neutrality, transparency, objectivity and competition. GME is also vested with the management of the OTC Registration Platform (PCE), where forward electricity purchase/sale contracts concluded off the exchange are registered.
GME also manages Environmental Markets, i.e. venues where Green Certificates, Energy Efficiency Certificates (the so-called "white certificates") and emission allowances are traded.

Gestore dei Servizi Energetici (GSE)
Publicly-owned company playing a central role in the promotion, support and development of renewable sources in Italy. GSE's sole shareholder is the Ministry of Economy and Finance, which exercises its shareholder rights together with the Ministry of Economic Development. GSE controls the following subsidiaries: Acquirente Unico (AU), Gestore dei Mercati Energetici (GME) and RSE (Ricerca Sistema Energetico).

Green Certificates (GCs)

Certificates giving evidence of generation of electricity from renewables (RES-E), in compliance with art. 5 of the Ministerial Decree of 24 Oct. 2005, as subsequently amended and supplemented. Producers and importers of electricity from non-renewable sources exceeding 100 GWh/year must inject a given quota of RES-E into the power grid (renewable quota obligation). Green Certificates are issued by GSE for the first 12 years of operation of RES-E plants. Conversely, the electricity generated by RES-E plants commissioned or repowered after 1 January 2008 is certified as RES-E for the first 15 years of operation of the same plants. Green Certificates, each of which is worth 1 MWh, may be purchased or sold in the Green Certificates Market by parties with a deficit or surplus of generation from renewables.

Green Certificates Bilaterals Registration Platform (PBCV)

Electronic platform enabling the registration and settlement of bilateral transactions covering green certificates, in accordance with the provisions laid down in the PBCV Rules.

Greenhouse Gases (GHGs)

See Kyoto Protocol.

Hirschmann-Herfindahl Index (HHI)

Aggregate market index measuring the degree of concentration and dispersion of volumes offered and/or sold by market participants. The value of the HHI may range from 0 (perfect competition) to 10,000 points (monopoly). If the value is below 1,200, the market is competitive; if it is above 1,800, it is poorly competitive. The HHI is calculated by aggregating the volumes sold and/or offered (including those covered by bilateral contracts) by individual market participants on the basis of their belonging group. CIP-6 volumes are included in this calculation and allocated to market participant GSE.

IDEX

Segment of the financial derivatives market – IDEM – organized and managed by "Borsa Italiana S.p.A.", where financial electricity derivatives are traded.

Intra-Day Market (MI)

Venue for trading electricity supply offers and demand bids for each hour of the next day, with a view to modifying the injection and withdrawal schedules defined in the MGP. GME accepts bids/offers by merit order, taking into account any transmission limits remaining after the MGP. If accepted, bids/offers are remunerated at the zonal clearing price. Accepted offers modify any preliminary schedules and determine the updated injection and withdrawal schedules of each offer point for the next day. Participation in the MI is optional.

Intra-Day Gas Market (MI-GAS)

Venue for trading gas demand bids and supply offers for the gas-day corresponding to the one on which the session ends. The MI-GAS takes place in a single session under the continuous-trading mechanism.

IPEX

Name under which the Italian power exchange is known abroad.

Kyoto Protocol

International environmental treaty signed in the Japanese city from which it takes its name. The treaty was signed on 11 December 1997 by over 160 countries on the occasion of the Conference of the Parties (COP3) to the United Nations Framework Convention on Climate Change (UNFCCC) and global warming. The treaty entered into force on 16 February 2005, after its ratification by Russia. The treaty requires industrialized countries to sharply cut down their emissions of pollutants (carbon dioxide and five other greenhouse gases, i.e. methane, nitrogen oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride) by at least 5.2% from their 1990 (base-year) levels in the 2008-2012 period. The protocol also covers the trading (purchase and sale) of greenhouse gas emission units.

Liquefied Natural Gas (LNG)
Natural gas being liquefied to allow sea transportation through LNG carriers. Upon destination, special facilities called regasification units are employed to return LNG to its original state.

Liquidity
Ratio of volumes traded on the exchange (MGP) to total volumes (including bilateral contracts) traded in the "Sistema Italia".

Margin
In derivatives or financial instruments transactions, it expresses the percentage value of securities in position (purchased or sold) to be held in cash or cash equivalents by market participants as a guarantee of any possible change in the investment value.

Mark to Market
Procedure of daily revaluation of a portfolio of derivatives on the basis of market prices; it is employed in forward exchanges to manage margins paid in by market participants as a guarantee of their positions.

Market Clearing Price (MCP)
Equilibrium price. By extension, it identifies the rule for remunerating bids/offers accepted in the MGP and MI on the basis of the price of the marginal offer/bid.

Market Coupling
Mechanism of coordination of regulated electricity markets in different national states, having the purpose of managing congestions on interconnected grids (cross-border trade). The goal of market coupling is to maximize the use of interconnection capacity under cost-effectiveness criteria (ensuring that electricity flows are directed from markets with lower prices towards those with relatively higher prices).

Market Splitting
Mechanism used to manage grid congestions, quite similar to market coupling; however, unlike under market coupling, the market zones are managed by a single entity (as in the case of the Italian market managed by GME, which has a zonal configuration).

Merit-Order Dispatch (or Economic Dispatch)
Activity carried out by GME on behalf of Terna S.p.A. It consists in determining the hourly injection and withdrawal schedules of the units associated with offer points on the basis of the offer price and, if this price is equal, on the basis of priorities specifically assigned to the different types of units by Terna S.p.A. In particular, supply offers are accepted – and injection schedules are determined accordingly – by increasing offer price order, whereas demand bids are accepted – and withdrawal schedules are determined accordingly – by decreasing offer price order. Furthermore, bids/offers are accepted consistently with the transmission limits between pairs of zones, defined daily by Terna S.p.A. Merit-order dispatch covers electricity volumes directly offered in the market, those generated by plants with a capacity of less than 10 MVA, by CIP-6 plants, by plants selling electricity under bilateral contracts, as well as imported electricity volumes.

National Single Price (PUN)
Average of zonal prices in the MGP weighted for total purchases and net of purchases for pumped-storage units and of purchases by foreign/neighboring countries' zones.

National Transmission Grid (RTN)
In Italy, the set of lines being part of the grid used to transmit electricity from production centers to distribution and consumption areas.

Nomination
Procedure through which each market participant notifies electricity injection (withdrawal) schedules into (from) the transmission grid.

Offset
Procedure typical of forward markets, under which a position may be closed before maturity by concluding a contract of a sign opposite to the original one. This mechanism is made possible by standardized contracts.

Option
Contract whereby the buyer is given the option to buy (call option) or sell (put option) a given real or financial asset at a pre-set price (strike price) on a given date (European option) or by a given date (American option). This right is granted by the seller (writer) to the buyer against the concurrent payment of a premium, the option price.

OTC (Over-the-Counter) Markets
Unregulated markets, i.e. markets where financial assets are traded off the official stock exchanges. Generally, trading terms are not standardized and "atypical" contracts can be entered. Broadly speaking, contracts traded in such markets are characterized by lower liquidity than contracts traded in regulated markets.

OTC Registration Platform (PCE)
Platform for registration of bilateral contracts, introducing significant flexibility with respect to the previous Bilaterals Platform. The provisions governing the operation of the PCE are covered by AEEG Decision 111/06 and by GME's PCE Rules. The PCE allows to register five types of contracts, including four standard ones (baseload, peak load, off peak, weekend) and one non-standard contract. Participants may register forward electricity volumes and delivery length two months (maximum) ahead of the physical delivery date.

Pay-as-Bid
Valuation rule adopted in the MSD, whereby each offer is valued at its offer price.

Peak capacity
The highest electrical capacity supplied or used at any point of the grid in a given time interval.

P-GAS
Trading platform organized and managed by GME for the bidding of natural gas.

Price Coupling of Regions (PCR)
Cooperation agreement among the six leading European power exchanges (APX/ENDEX, Belpex, EPEX, GME, OMEL, NordPool). It aims at identifying a coordinated mechanism to set the price of electricity in such markets. The project is intended to lay the foundations of a true European energy market.

Price-Setting Operator Index (IOM)

Index referred to individual market participants who have set the selling price at least once. For each market participant, in each macro-zone and in a given time period, it is defined as the share of volumes on which the market participant has set the price, i.e. the ratio of the sum of the volumes sold (including bilateral contracts) in the geographical zones (included in the macro-zone) where the market participant has set the price to the sum of the total volumes sold in the macro-zone.

Price-setting Technology Index (ITM)

Similar to IOM (see Price-setting Operator Index), this index considers the production technology in lieu of the market participant.

PSV

"Sistema per Scambi/Cessioni di Gas al Punto di Scambio Virtuale – Modulo PSV" (gas trading system at the Virtual Trading Point), referred to in AEEG Decision 22/04 and organized and managed by Snam Rete Gas.

Renewable Energy Sources (RES)

This category includes sun, wind, water resources, geothermal resources, tides, wave motion and the transformation of vegetables or organic and inorganic waste into electricity.

Residual Supply Index (IOR)

Index referred to individual market participants submitting offers into the market. It measures the presence of residual market participants, i.e. those that are necessary to cover demand. For each market participant, it is defined as the ratio of the overall volumes offered by competitors to the overall volumes sold. The index is < 1 when one residual participant is present; the closer is the index to 0, the higher will be the share of the market participant's offer that can be sold, regardless of its offer price. The IOR is calculated by aggregating the volumes offered by individual market participants on the basis of their belonging group, including the volumes covered by bilateral contracts. Also the volumes pertaining to CIP-6 contracts are included in this calculation and allocated to market participant GSE. The use of the accepted volume in the denominator makes it possible to discount the effect of transits with neighboring zones on the internal demand of each zone. For each macro-zone, the following data are published at regular intervals: percentage of hours during which at least one participant has been necessary; percentage of electricity sold under residual supply conditions in overall electricity sold, equal to the simple average of the residual hourly volumes of the macro-zone (which in turn are defined as the sum, for all participants, of the volumes offered by each participant less the overall volume offered plus the overall volume sold); number of necessary participants and percentage of hours during which they have been necessary.

Shale Gas

Special and very common type of unconventional gas obtained from shale formations. It is becoming increasingly important, especially in the United States, thanks to new drilling techniques making its extraction cost-effective.

Spot price

Current price expressing the present "market value" of a given good or financial asset.

Terna - Rete Elettrica Nazionale S.p.A.

Company in charge of electricity transmission and dispatching over the high-voltage and extra-high voltage grid throughout Italy. Terna is a listed company. Its shares were first traded in June 2004. At present, its relative majority shareholder is "Cassa Depositi e Prestiti".

TOE (Tonnes of Oil Equivalent)
Conventional unit used in energy accounting to express all energy sources (taking into account their calorific value) in a common unit of measurement.

Transmission Limits (or Transit Limits)
Maximum electricity transmission capacity between a pair of zones, expressed in MWh. Transmission limits are part of the preliminary information that Terna S.p.A. daily notifies to GME and that GME posts on its website. Such limits are utilized by GME to identify clearing prices in both the MGP and MI.

Transmission System Operator (TSO)
Entity in charge of managing the electricity and gas transmission grid.

Unconstrained
In the MGP, virtual prices or volume which would arise if there were no transmission constraints.

Volatility
The indicator evaluating volatility is calculated monthly as the standard deviation of the logarithmic returns of daily prices, subsequently aggregated on a yearly basis through an arithmetic mean calculation.
In the Green Certificates Market (MCV), characterized by a single weekly session, the volatility indicator is instead calculated on a yearly basis as a standard deviation of logarithmic returns of weekly sessions.

White Certificates
See Energy efficiency certificates

Zonal price (Pz)
Clearing price characterizing each geographical and virtual zone in the MGP.

Zone
Portion of the power grid where, for system security purposes, there are physical limits to transfers of electricity to/from other geographical zones. The zones are defined by Terna SpA and approved by AEEG. At present, the zones are as follows:
- Geographical Zone: representing a portion of the national grid; geographical zones are: northern Italy (NORD), central-northern Italy (CNOR), central-southern Italy (CSUD), southern Italy (SUD), Sicily (SICI) and Sardinia (SARD).
- National Virtual Zone: constrained zone ("point or pole of limited production"); it includes: Monfalcone (MFTV), Rossano (ROSN), Brindisi (BRNN), Priolo (PRGP) and Foggia
- Foreign Virtual Zone (or Neighboring Country's Virtual Zone): point of interconnection with neighboring countries; it includes: France (FRAN), Switzerland (SVIZ), Austria (AUST), Slovenia (SLOV), BSP (zone representing the Slovenian Electricity Market managed by BSP and connected to IPEX via market coupling mechanism), Corsica (CORS), Corsica AC (COAC) and Greece (GREC).
Moreover, AEEG Decision ARG/elt 243/10 of 16 December 2010 (approving the Pentalateral Agreement on operational procedures aimed at implementing market coupling with Slovenia) introduced, amongst others, the BSP foreign virtual zone representing the Slovenian electricity market managed by the BSP exchange.
Unless otherwise specified, the volumes (purchases/sales) indicated under the "Foreign/neighboring countries" heading represent the sum of the volumes of the foreign virtual zones (France, Switzerland, Austria, Slovenia, Corsica, Corsica AC and Greece) and of the electricity flows resulting from market coupling; more specifically, the flow outgoing towards the BSP zone is included in the purchases, whereas the flow incoming from the BSP zone is included in the sales.

– Market Zone: aggregation of geographical and/or virtual zones such that the flows between the same zones are lower than the transmission limits notified by Terna SpA. This aggregation is defined on an hourly basis as a result of the resolution of the MGP and MI. In the same hour, different market zones may have non-different zonal prices.

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