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The impact of the Italian-Slovenian market coupling on the risk of price spikes in the Italian day-ahead electricity market

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Abstract

In this thesis the impact of the Italian-Slovenian market coupling on the risk of price spikes in the Italian day-ahead electricity market is examined through the use of a regime-switching model. Such models allow to distinguish between two regimes: one characterized by normal market conditions and the other characterized by non-normal market conditions under which price spikes happen. In addition to model specification which has been widely used in literature, a new alternate model specification is introduced, with the goal of capturing the full effect of the market coupling. The changes in the values of the parameters of both models are analyzed in order to assess the changes in the risk of price spikes and volatility. The introduction of the market coupling mechanism is expected to decrease the risk of price spikes and the volatility in both the two regimes, because of the increased supply and connectivity. The results show that indeed the risk of price spikes and volatility have decreased after the introduction of the market coupling, however the price changes have not become more random, therefore the market has not become more efficient. Also, differently from what observed in other markets, there is no evidence of convergence between the Italian and Slovenian markets. This can be explained by various motives: the short amount of data available (the market coupling mechanism started only in January 2011) the fairly limited capacity allocated for the mechanism and the profound dissimilar characteristics, both in structure and in size of the two markets. The alternate model specification gives more statistically significant results and indeed allows to fully capture the market coupling effect.

Keywords: electricity day-ahead prices; switching regimes model; price spikes; market coupling; Italian power pool

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1. Introduction

Until the first years of the 1990s, the electricity sector has been a vertically integrated industry where there was little or no uncertainty in price. Prices were set, in fact, by state regulators as a function of the various costs (generation, transmission and distribution). On the wake of similar reforms, the electricity market underwent a liberalization and deregulation process, with the goal of achieving similar benefits to those achieved in other sectors. The idea was that through the introduction of competition in generation and supply activities, many perceived benefits such as a greater supply security, lower retail prices for the consumers and a more efficient and streamlined use of resources without the overproduction typical of vertical integrated systems, would have been obtained.

The most evident effect of liberalization is that prices are not set any more by the regulator but are determined by the market, more precisely by the interaction between the supply side (generators and, in some markets, the traders) and the demand side (distribution companies who sell energy to consumers, large clients and other traders). A crucial characteristic of these deregulated prices is their high volatility. The main reason behind this is that the shocks affecting supply and demand cannot be immediately smoothed out and therefore directly affect market-clearing prices, and this, in turn, is due to some peculiar characteristics of electricity: its non-storability, the seasonality of demand and the effect of severe weather conditions on demand and production which causes sudden price spikes.

In all of the liberalized markets prices have shown a more complex and volatile behavior than other commodities or financial instruments. However, it has been observed that different markets can show very different price behaviors. Wolak (1997) analyzed different markets and illustrated that market structure and market rules are important drivers of the behavior of prices in a competitive electricity market. His findings can be summarized as follows: there is a greater price volatility in markets where a higher percentage of electricity is obtained from fossil fuels; supply industries with a larger component of private participation in the generation market tend to have more volatile prices but lower mean electricity prices; electricity spot markets with mandatory participation have more volatile prices than the ones with voluntary participation. In order to deal with this newly introduced uncertainty in the behavior of prices, hedging instruments, such as derivative contracts taking place both in OTC and in regulated markets, has been introduced in the electricity market.

The European Union promoted the process of liberalization of the electricity market in the member countries with the aim of building a single internal electricity market since the 1990s. In 1996, in fact, the European Parliament approved the Directive 96/92/EC "concerning common rules for the internal market in electricity”**.** The creation of the internal energy market was already considered the key aspect necessary to reach those policy goals which can promote and sustain the growth of the European Union economy, such as competiveness, sustainability and security of supply. The main idea behind this Directive was that electricity had to be considered just like any other commodity and, therefore, it had to be able to flow freely. The Directive contained obligations and guidelines for the member states regarding the increase of efficiency of transmission, distribution, production, security of supply and the interconnection of the various national networks but has been implemented in different ways in the different member States and this has resulted in very different market structures which still depend on the previous regulatory and technical structure of the markets.

The Italian electricity market presents some characteristics which differentiate it from the other main electricity markets of the European Union. The first steps preliminary steps in the liberalization process of the electric market sector started in 1992, with the monopolist company, ENEL, becoming a limited company, and in 1995, when an independent energy regulator, AEEG, was established. Despite these initial steps, it took the Italian legislator almost three years from the approval of the EU Directive 96/92/EC to draw up an execution law: the liberalization project, in fact, required both a modification and an enrichment of the regulatory framework of the national market.

Liberalization in Italy started with the ratification of the Legislative Decree 16th March 1999, n. 79 (D. Lgs. n. 79/99) which transposed the EU Directive 96/92/EC. The first phase, until April 2004, consisted in a period of transition and adjustment where different structural and legislative distortions still affected the functioning of the market. The second period started in April 2004, when the Italian power exchange (IPEX) finally started operating (though it became fully operational only from January 2005) and ended with the complete liberalization of supply and demand on the 1st of July 2007, when all typologies of consumers became eligible to choose a supplier. However the reform of the market continued in the following years: a forward market (MTE) was introduced in November 2008 and restructured one year later along with the other markets and the rules for the integration with foreign markets, and a market coupling mechanism with Slovenia began operating in 2011. Market coupling allows to allocate daily physical cross-border interconnection rights between the two countries according to an implicit scheme, through the resolution of the respective day-ahead markets operated by GME and BSP and is therefore able to eliminate the imperfect arbitrage that may arise under the previous mechanism of explicit auctions.

The distinctiveness of the Italian market does not pertain only to the market reform process and its delays, but regards also aspects of the production of electricity, with the two most evident anomalies being the absence of mutual exclusivity between different types of market players (Grilli, 2011) and the wholesale day-ahead price level which has been consistently higher than that of the major European power exchanges (see Figure 1-1). This high price level can be mostly attributed to the insufficient generation and interconnection capacity and the unique generation composition which is, for the larger part, still fossil-fuel based.

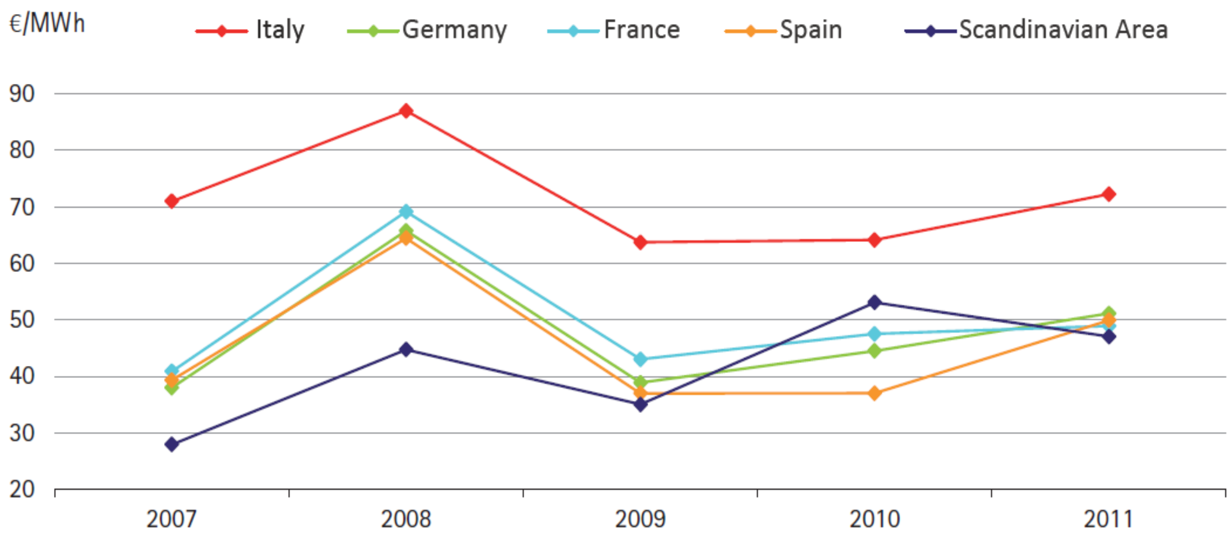

Figure 1-1 Historical trend of day-ahead electricity prices for the major European power exchanges (2007-2011). Source: GME

In this thesis the history of the day-ahead prices in the Italian market is examined. The period of analysis ranges from 1st January 2005, when the Italian power exchange became fully operational, until 30th September 2012. The focus is however set on the years following the introduction of the market coupling mechanism, in order to assess what is the effect on the risk of price spikes and on volatility.

On the basis of previous literature, a two state regime-switching model is applied on the average daily prices of the Italian day-ahead market in order to establish patterns for the model parameters and examine the behavior of market prices both in normal market conditions and in the non-normal market conditions which exhibit extreme price spikes. An alternate specification of this model is developed and employed in order to capture the full effect of the market coupling mechanism without the arbitrary division of data in years.

This work provides added value to the existing literature for a few reasons. First of all, it analyzes the Italian electricity market for which there has not been particularly extensive research. Secondly, most of the existing research is limited to the first years after the introduction of the Italian Power Exchange. Thirdly, this work analyzes the effects of the Italian-Slovenian market coupling which has been introduced only in January 2011, therefore gives statistical validation of the positive effects of this mechanism on the Italian market. Lastly, in addition to the common model specification used in literature, a new and different model specification which gives clearer results is introduced.

The remainder of the thesis is organized as follows: chapter 2 presents a literature review concerning analysis of the Italian electricity market, regime-switching models and cross-border trading. Chapter 3 outlines the characteristics of the electricity markets and focuses the Italian electricity market and its liberalization process. Chapter 4 describes the dynamics of the day-ahead prices. Chapter 5 discusses the performance of the Italian electricity market in 2011 and 2012. In Chapter 6 the methodology used for the research is discussed, while chapter 7 presents the data and the descriptive statistics. Chapter 8 presents results obtained from the application of the regime-switching model and chapter 9 concludes.

2. Literature review

Directive 96/92/EC was the first attempt of the European Community to establish a legislative framework which would have led to the liberalization of the electricity market. At that time, in fact, the electricity market was heavily regulated in almost all the European Union countries: the scene was dominated by national or sometimes regional state-owned companies which had a substantial monopoly in vertically integrated market, by providing generation, transportation and retail sales. As this and the subsequent legislative attempts did not achieve the expected results, it took various legislative interventions, both at the European and national levels, to overcome the bigger market distortions and create national competitive markets. At the time of writing the process of liberalization is still at different stages throughout the different EU countries; some market imperfections are still present, preventing the realization of the goal of creating a European internal market. As this is still an ongoing process which has seen radical changes in the last decade, it is important to consider the time period in which analysis has been conducted when evaluating the existing literature.

So far, the literature analyzing the liberalized Italian day-ahead market has not been as extensive as for other European markets. The first attempt is from **Bosco et al. (2007)** who analyze the time series of daily mean prices in order to *characterize the high degree of autocorrelation and multiple seasonalities in the electricity prices*. The authors carry out a comparison between the performance of periodic models with GARCH disturbances and leptokurtic distribution and ARMA-GARCH processes. They find that periodic AR-GARCH models perform more than adequately in modeling the stochastic component of the price process and that a major part of the variability of prices is explained by deterministic multiple price seasonalities interacting with each other. The analysis is done on the first 21 months of operations of the Italian power exchange (April 1st 2004 to January 15th 2006). The prices present a strong weekly seasonality due to the seasonality present in the electricity consumption. It is interesting to note that the volatility of the day-ahead prices is much higher in the first year, 2004, than in the following. This can be explained by hypothesizing a learning phase for the traders and by the regulatory changes concerning the power exchange which took place from January 1st 2005. Data shows a slow increasing trend in the prices, which could be explained by the growth in the prices of fossil-based energy sources. The electricity demand series point out the presence of higher than average consumption in winter and summer with the exception of the two respective holiday periods: Christmas vacation (December 24th to January 6th) and summer vacation (typically the entire month of August). This characteristic was accounted for by using a low-pass filter with a lower cut-off frequency for normal periods and a higher one for the Christmas and summer vacations.

The authors estimate three nested regressions of the prices on the deterministic components which differ on the form and the influence of the within-year seasonality on the within-week seasonality. The models are estimated on the full sample and on a subsample (Feb 1st 2005 to Jan 15th 2006). These allows to see that all the models perform much worse on the full sample period, resulting in a R^2 value of 20% and a standard error of regression whose value is more than the double of the one estimated on the subsample. The best performing model is then enhanced by shifting to a PARMA-GARCH model. It is interesting to note that the authors observe different linear memory changes for the ACF and PACF functions according to each different day of the week. Although the models used perform well on the subsample analyzed the authors stress that the stability of the model must be tested on more extensive data sets.

Petrella and Sapio (2010) focus on the relation between changes in the market architecture and the dynamic of prices in the Italian day-ahead market, using data consisting in the daily average day-ahead price (PUN) from April 2004 to December 2008. The price series is positively sloped and the price increases by circa 50% in in the period considered (4 years and three quarters of year). Regular patterns can be observed at a high weekly frequency and within year fluctuations are present, as in Bosco et Al. (2007). Short and extreme spikes are present, but their occurrence is less frequent than in other European power exchanges. The authors include various factors in the estimation of the price dynamic: natural gas prices, impact of perceived temperatures, seasonality, persistence in conditional volatility and the inverse leverage effect. The authors consider different models including one or more of the aforementioned factors and look at their forecasting performance based on rolling regressions of 1370 observations (two samples: April 1st, 2004 to December 12th, 2007 and September 30th, 2004 to June 30th, 2008). The result is that models including deterministic weekly patterns, non-linear weather and volatility effects capture the essential drivers of the IPEX price dynamics. The authors also account for changes in the market architecture by inserting dummy variables for the three main changes in the architecture of the Italian power exchange: demand-side liberalization, contracts for differences (CfDs) for renewable energies support and white certificates. The outcome of the analysis is that market architecture changes do not affect the conditional mean of prices but only the conditional volatility and with mixed effects: while CfDs mitigated price volatility, demand-side liberalization and white certificates increased it. The net effect seems to be a small increase of volatility. Also, the inverse leverage affects disappears after taking into account market architecture changes. However the authors stress that this outcome is strictly dependent on the characteristics of the Italian electricity market: Robinson and Baniak (2002) suggest that CfDs would increase volatility, demand-side liberalization has been weak because of lack of information on switching opportunities and the weak competitive pressure of the Italian market might be the cause of the low effects of white certificates.

Gianfreda and Grossi (2009) focus their attention on extreme spiky behavior and, differently from common practice in literature where arithmetic mean of the hourly prices is used, decide to use median daily prices to reduce the impact of intra-daily spikes. In addition, they consider network congestions which induce non-linearity of the underlying stochastic process. Since the market is segmented into different zones, congestions between two zones can be identified every time different zonal prices are observed: therefore if no congestion occurs, then all the zonal prices are equal to the PUN price. The difference between zonal prices and the PUN is then the marginal congestion cost and gives indications about the market efficiency. The authors' contribution consists then in a price dynamics which takes into account simultaneously long memory, congestion costs and technologies. The zonal structure of the market must be taken into account when modeling prices because all the zonal series influence the determination of the single price. The authors propose evidence that congestions occur among all seven zones and both in peak and off-peak periods. No evidence is found about the degree and sign of evidence of electricity price dependency on prices of the sources of generation. Weekly and seasonal adjustment is incorporated using dummy variables. The adjusted series present an autocorrelation structure with long memory which tends to decrease slowly. In a follow-up study from 2010, Gianfreda and Grossi include market power into the analysis and find out that not all of the examined factors affect the zonal prices.

Boffa et al. (2010) simulate a fully interconnected market and estimate a lower spot price level which would reduce substantially the spot market total expenditure. Since the market is currently divided in several zones, with limited amounts of electricity which can flow from one zone to the other due to insufficient transmission capacity, a fully interconnected market would cause a cost reduction of 6% of the spot market expenditure, for a total amount of more than 120mn euro. The analysis is limited to the month of May 2004, weekends excluded, because saturation of transmission capacity occurred for 46% of the time, very close to the average yearly value of 48%. The reduction in production costs would lead to welfare improvement in the medium and the long run.

Huisman and Kilic (2012) examine day-ahead prices in the Belgian, Dutch, French, German and Nordic electricity markets between 2003 and 2010, to assess the impact of liberalization policies on the occurrence of price spikes. The methodology adopted consists in the estimation of the parameters of a two parameters regime-switching model for every year and every market. Such models have already been successfully used to model the spikes (Huisman and Mahieu, 2003; Mount et al., 2006; Huisman, 2008). The central question of the authors concerns whether the risk of price spikes has declined over time due to the liberalization process and the further interconnection with other markets. The increased interconnection would shift the supply curve to the right. A shift of the demand curve would lead to a lower increase of the market clearing price, therefore the probability of price spikes would be lower under the new conditions. The authors find evidence that the variation, as measured by standard deviation, decreased over the sample period in all the markets, as well as the interval between maximum and minimum prices. Measures as skewness and kurtosis also declined, therefore confirming that high price uncertainty reduced. The correlation between the markets increased; therefore the integration between the markets increased over the years as it could have been expected as a result of measures such as the Trilateral Market Coupling between France, Belgium and the Netherlands. The application of the regime-switching model results in comparable parameters for the Dutch, German, French and Belgian markets. In each of these countries the mean log price level increases over the period of analysis and the price level in the non-normal regime (the spike price) declines. Probability of occurrence of a spike declines for the Dutch, Belgian and French markets and increases for the Nordic and German ones. The impact of the spikes is therefore reduced over time. The authors find that the markets become more efficient: due to a decline in the mean reversion speed, the influence of stochastic component of the price on the stochastic price change declines and price changes behave more randomly. The level of expected price spikes becomes more predictable because of the decline in volatility in the non-normal regime and, together with the lower mean price spike level, suggests that prices have become more stable. Overall, there is a convergence between volatilities in the two regimes: this can be attributed to increased liquidity and connectivity. The impact of weekend seasonality becomes smaller over the sample period. Only the Nordic market shows a complete different behavior, with an increasing mean reversion speed, mean price spike level and volatility in the normal regime. This last parameter is increasing and in 2010 is higher than volatility in the non-normal regime (which, instead, shows a declining trend). Tests show that all parameters are converging between the markets, with the exception of the Nordic market.

Parisio and Bosco (2008) analyze the welfare effects obtained by the introduction of cross-border trading between two isolated countries with the allocation of transmission rights done through the use of an implicit auction mechanism. The authors show that cross-border trade may lead to price convergence between countries and that welfare gains and losses across countries are determined by both a volume and a strategic effect of the interconnection. In detail, the volume effect causes the consumers' surplus to increase and producers' rent to decrease in the importing country, while in the exporting country the opposite occurs. The strategic effect causes the reduced demand in the importing country to flatten the supply curve in the market. This effect can further increase consumers' surplus in the importing country, but can also lead to a further reduction of the consumers' surplus in the exporting country.

Boffa and Scarpa (2009) point out that integration can facilitate collusion between market operators and reduce the overall welfare of the new integrated markets. The authors model the case of two markets, one with a situation of monopoly price collusion and another where excess capacity exists. When markets are integrated, excess capacity in the second market can be used to meet demand in the first market. However, if the first market is able to absorb the new capacity without any price reduction, and if in the second market an increase in prices as a result of the reduction in the level of reserve capacity occurs, it is possible that the cross-border interconnection leads to a reduction in overall social welfare.

Pellini (2011) evaluates the welfare effects (as measured with respect to the change in the productive efficiency of the electricity market) of introducing market coupling for the allocation of cross-border interconnection capacity between Italy and its neighboring countries. Two alternative market scenarios, with four alternative cases each, are simulated for the year 2012 using the optimal dispatch model ELFO++. The four alternative cases use alternative models to allocate cross-border transmission capacity, namely explicit auctions, market coupling, perfect and imperfect competition. The simulations support the theoretical expectation that market coupling would determine a net welfare gain for market participants. The increase in social surplus brought by the introduction of market coupling is particularly evident when market fundamentals are tight.

3. The Italian electricity market

The electricity supply industry has traditionally followed a centralized regulation, because of the widespread idea that this was the best way to achieve a satisfying level of security of supply and efficient production. Therefore, the whole electricity sector was characterized by economics of scale achieved through a highly vertically integrated market structure with little or no competition (Weron, 2006) where regulators fixed the price as a function of generation, transmission and distribution costs.

The last three decades saw a complete overhaul in the sector all around the world. Deregulated and competitive markets superseded the previous monopolistic arrangements. This was due to the idea that the success achieved by liberalizations in other sectors could be obtained in the power sector as well. The general idea was that competition would have brought perceived benefits and that liberalization would have promoted efficiency gains and technical innovation and would have allowed doing efficient investments. The restructuring process of liberalization has opened the generation and supply activities to competition, while other areas such as transmission and distribution activities have been considered natural monopolies and therefore have been regulated with models of competition for the market (Escribano et Al, 2002).

Exchanges and pools for electricity have been organized to facilitate trading in these new markets. Though they are not necessary for the existence of a deregulated market (since in many markets a lot of deals take place on the OTC market), their introduction has promoted competition and speeded up the process of liberalization of the electricity sector. Exchanges and pools can be considered as a tool to foster creation of efficient clearing prices which can guarantee the purchase and sale of electricity where there is a greater economic benefit. It is a centralized mechanism for the management of electricity hourly trading and secondary services (reserves, capacity, balancing) which aims to ensure equal treatment for all operators, clarity of the participation rules and price definition, impartiality of the network management operator, reduction of counterparty risk. The main advantages resulting from their introduction are the following:

a) The price formation process better reflects the state of supply and demand of energy.

b) The market-place motivates competition between the market's actors, promoting the emergence of more convenient prices for the purchase of electricity.

c) Equilibrium prices and quantities are always known to all the actors, ensuring higher transparency and better conditions of symmetric information.

d) Sudden peaks of load due to unexpected fluctuations of the demand can be satisfied by the operators thanks to a higher flexibility of the market.

e) The total cost of energy transaction is minimized through an efficient order of dispatchment.

f) Greater protection of the consumers' interests.

It is possible to make a first classification of electricity markets based on the nature of the contracts which can be stipulated by the operators: contracts can in fact have physical or financial nature. Therefore it is possible to distinguish between electricity markets based on the exchange of physical contracts (Power Pools) and markets based on the stipulation of financial contracts (Power Exchanges). These two models can take different forms and can also be combined together.

Power Pools are usually set in place by governments interested in facilitate competition in the market. Their goal is the definition of schedules of injection and withdrawal of electricity. Suppliers and buyers present their offers for the following calendar day to the one of current session. In the case of generators, their offers are the prices at which they are willing to run their power plants. The Market Clearing Price (MCP) is obtained through a one-sided auction given from the intersection of the supply curve and the estimated demand. Offers are selected on the base of an increasing prices rule, following a merit order mechanism, until the entire demand is satisfied. Participation to the market is not mandatory: market actors can stipulate bilateral contracts outside of this market. Physical contracts can also be stipulated on the adjustment market. As the moment when the effective supply takes place comes closer, the available data on the demand becomes more precise: the adjustment market allows the market operators to adjust their supply on the base of the better information on the final demand of electricity. Power pools also include a market for ancillary services, such as congestion management and dispatching. Examples of power pools are the Italian IPEX, the Spanish OMEL and the three U.S. power pools. Similarities among these pools are underlined by these characteristics:

a) They are managed directly from the network operator or from companies strictly related to it

b) Volumes traded in the day-ahead market represent a very relevant quote of the total physical volumes traded.

c) Prices volatility is similar in all of the aforementioned power pools and it is generally lower than in power exchanges. Volumes of trades which take place on the adjustment and ancillary markets are much lower.

Power Exchanges are usually the result of a private initiative (for example by one or more generators, distributors and traders) and are a centralized trading platform which guarantees transparency for the negotiation process and for the prices resulting from these trades. Typically, financial products derived from the underlying physical contracts of sale are traded. Market participants can be power-generating companies, distribution companies, traders and large clients.

The goal of the pool is to promote the matching of the demand and the supply in order to determine the market clearing price, which is usually established on the basis of a daily two-sided auction. Market actors submit their bids and offers for each hour of the following day, determining a different MCP for every hour which matches demand and supply. Some examples of power exchanges are the French Powernext, the German EEX and the Dutch APX. The Nord Pool market presents characteristics of both power pools and power exchanges.

Some of the common characteristics of power exchanges are the following:

a) Management and planning are carried out autonomously by the local network operators.

b) They provide products which reflect the trading methods of the market.

c) They provide contracts for base and load provision, juxtaposed by a market for hourly trading with balancing purposes.

d) They provide different price indices used for valuation of the market state.

The success of power exchanges is connected to the credibility which these markets can have towards the operators and to their capacity to supply different and alternative contracting method from bilateral contracts. The more a power exchange attracts clients, the more liquid it becomes and the resulting prices become reference prices for the whole system. Therefore the success indicators of these markets are the traded volumes and the products volatility.

In respect to power pools, in the power exchanges less volumes are traded and there is higher market volatility. Since they instruments are financial contracts it is not possible to talk of production capacity conveyed on the power exchange but rather of electricity negotiated and traded in various market forms.

3.1 Liberalization of the Italian electricity market

The creation of an internal energy market within which effective competition can be fostered is one of the priority objectives of the European Union. Its characteristics include the absence of trading barriers and the efficient use of available generation capacity and transport infrastructure, in order to maximize cross-border trade in accordance with the general criterion of minimization of the total costs of generation.

The liberalized electricity market originates in Italy as effect of the Legislative Decree 16th March 1999, n. 79 (D.lgs. n. 79/99), as part of the transposition of the EU directive concerning common rules for the internal market in electricity (96/92/EC). This directive is part of the European Union aim to implement a comprehensive process of markets liberalization, in order to achieve important results of energy and environmental policy, such as:

a) A greater quality and efficiency of services.
b) Prices restraint.
c) A greater integration of energy networks.
d) A greater security supply.
e) A Greater technological development.
f) Environmental protection.

The two goals of the directive, limited to the electricity market, are:

a) The creation of a market platform in order to encourage competition in production and wholesale of electricity.
b) The promotion of maximum efficiency and transparency in the activities of production and consumption of electricity, through the creation of a market for the purchase of resources for dispatching services.

The Decree of transposition of the EU directive 96/92/EC has revolutionized the Italian electricity sector which was previously configured in a monopoly with only one national-level producer, ENEL, and a few other local dimension producers forced to sell to ENEL, to which the activities of import and export, production, transportation, processing and distribution and sale of electricity were reserved by law.

As a result of the liberalization process of production, purchase and sale, import and export of electricity, on March 31st 2004 the first organized electricity market has been launched in experimental form in Italy. From January 1st 2005, with the introduction of the active participation of the demand side, the marketplace has become fully operational. The Power pool is an essential tool for the creation of a competitive market for electricity in Italy and it is born with the aim of encouraging the emergence of transparent equilibrium prices, allowing consumers and producers to buy and sell energy where it is more cost-effective.

This market is commonly referred to as "Borsa Elettrica Italiana" (or IPEX, Italian Power Exchange). IPEX is an electronic marketplace for the trading of wholesale electricity in which the price reflects the equilibrium price obtained from the meeting of demand and supply of the market participants. It is a real physical market where the schedules of injection and withdrawal of the electrical energy into (and from) the network are defined according to criteria of economic merit. It is not a mandatory market: operators, in fact, can conclude sale contracts (bilateral contracts) outside of the IPEX.

The organization and management of the electricity market is entrusted to the electricity market operator (GME, Gestore del Mercato Elettrico SpA) which ensures management according to principles of neutrality, transparency, objectivity and competition between producers and ensures the management of an adequate availability of power reserve.

3.2 Organization of the Italian electricity market

The Italian electricity market is divided into:

- **A spot electricity market** (MPE, Mercato Elettrico a Pronti) composed by:
  - A day-ahead market (MGP, Mercato del Giorno Prima)
  - An intraday market (MI, Mercato Infragiornaliero)
  - A market for ancillary services (MSD, Mercato del Servizio di Dispacciamento), divided into a planning phase (MSD ex-ante) and a balancing market (MB, Mercato del Bilanciamento).
- **A forward electricity market with obligation of delivery/collection (**MTE, Mercato a Termine dell'Energia) introduced since November 2008 to allow trading of electricity on longer-term horizon than the one offered by the day-ahead market.
- **A platform for the delivery of the financial contracts traded on IDEX** (CDE, Piattaforma per la Consegna Derivati Energia). IDEX (Italian Derivatives Energy Exchange) is the segment of the Italian Derivatives Markets (IDEM) dedicated to trading of derivatives based on commodities and related indices. IDEX is managed by Borsa Italiana SpA.

3.2.1 The Day-ahead market (MGP)

The Day-Ahead Market (MGP) is organized following a model of implicit auction and hosts the majority of the transactions of purchase and sale of electricity. MGP is in fact a market for the wholesale exchange of energy where hourly blocks of electricity are negotiated for the next day and in which not only the prices and the traded quantities are defined, but also the schedules of injection and withdrawal for the next day. The MGP qualifies as a physical market for three reasons:

1) The only allowed participants are electricity network operators with the obligation to present sale offers on injection point and purchase bids on withdrawal points: therefore on MGP it is not possible to carry out trading activities.
2) Offers must refer to specific points of entry, and, if accepted, result in planned injection / withdrawal (*unit bids*)
3) Bids are accepted in order of economic merit consistent with the constraints of transit between areas (so-called zonal market).

MGP is characterized by an auction mechanism for the attribution of the right to withdraw and inject electricity: namely the dispatching priority. The MGP session opens at 8:00 of the ninth day before the day of delivery and closes at 9:00 on the day before the day of delivery. The central counterparty for transactions involving the purchase and sale of the MGP is GME.

During the opening time of the MGP session, operators may submit the bids (offers) in which they indicate the amount and the maximum (minimum) price at which they are willing to buy (sell) according to a logic of auction negotiation. Each sale offer and purchase bid must be consistent with the limits of injection or withdrawal of the supply point to which it refers and, above all, it must correspond to the actual intention to inject or withdraw the mentioned amount of electricity in a given relevant period. The process of acceptance of the bids and offers can be schematically summarized as follows:

- All valid and appropriate received sale offers are sorted by ascending price on an aggregate supply curve and all valid and adequate demand bids received are sorted by decreasing price on an aggregate demand curve. The intersection of the two curves determines the total quantity traded, the equilibrium price, the accepted offers and bids and the schedules of injection and withdrawal obtained as the sum of the accepted offers and bids which refer, on the same hour, at the same point of offer.

- If the flows on the network resulting from the schedules do not violate any limit transit, the equilibrium price is unique in all areas and is equal to P^*. The accepted offers shall be those with a sale price up to P^* and the accepted bids those with a purchase price of not less than P^*.
- If at least one limit is violated, the algorithm "splits" the market in two market zones (one export zone, which includes all the zones upstream of the bond, and one import zone, which includes all areas downstream of the bond) and repeats in each of them the crossing process described above, constructing, for each market zone, a supply curve (which includes all the sale offers presented in the same zone as well as the maximum quantity imported) and a demand curve (which includes all bids submitted in the same zone, as well as a quantity equal to the maximum quantity exported). The outcome is an equilibrium price zone (P_Z) which differs in each market zone. In particular, P_Z is greater in the importing market area and is lower in the exporting one. If as a result of this solution further constraints within each market area have been violated, the process of "market splitting" is repeated within this area until a result compatible with the constraints of the network is obtained.
- With regard to the price of electricity for consumption GME has implemented an algorithm that provides a single price of purchase on a national basis (PUN, Prezzo Unico Nazionale), equal to the average selling prices zonal weighted for the zonal consumption. The PUN applies only to the offer points for withdrawal belonging to national geographical areas, while the zonal price is applied to all the other offer points (injection, mixed and withdrawal belonging to foreign virtual zones).
- The mechanism of "market splitting" described above constitutes an implicit non-discriminatory auction for the allocation of transit rights.

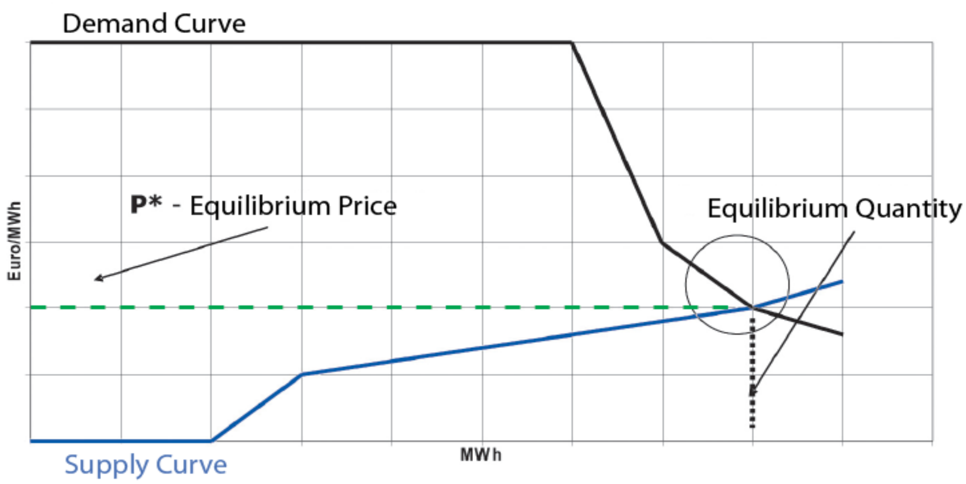

Figure 3-1 Determination of the equilibrium allocation for price and quantity

The energy exchanged as a result of **bilateral contracts** recorded on PCE participates in the process described above, both because it contributes to seize a share of the transmission capacity available on transits and both because it helps to determine the weights used for the PUN. The recorded programs on the PCE are sent on the MGP in the form of gifts and contribute to the determination of the outcome of the MGP itself.

Market zones are aggregates of geographical and/or virtual areas characterized by the same zonal price of energy. The electrical network is, in fact, divided into portions of the transmission network - defined as zones - for which there are, for the purpose of the safety of the electrical system, physical limits to the available energy transit towards the corresponding confining zones. These limits are determined on the basis of a model calculation based on the balance between generation and consumption. Zones may correspond to geographical areas, virtual areas (that is, without a direct physical correspondence), or be limited production poles, namely the virtual zones whose production is subject to constraints for the safe management the electrical system and which consist exclusively of production units whose capacity for interconnection with the network is inferior to the installed power of the units themselves. For the purpose of verification and removal of congestions eventually determined by the schedules of withdrawal and injection GME uses a simplified representation of the network, which only highlights the most important limits of transit or the limits of transit between the national geographical zones, foreign zones and poles of limited production. The shape of these zones is functional to the management mode of transit along the peninsula adopted by Terna[1] and they can be summarized as follows:

- 6 geographical zones (Centre - North, North, Central - South, South, Sicily, Sardinia).
- 8 foreign virtual zones (France, Switzerland, Austria, Slovenia, BSP, Corsica, Corsica AC, Greece).
- 4 national virtual zones which represent poles of limited production (Rossano, Foggia, Brindisi, Priolo).

[1] Terna Rete Elettrica Nazionale S.p.A. is a state-owned network operator for the transmission of energy, which provides its services under concession. In Italy it is responsible, throughout the national territory, of the transmission and dispatching of electricity on the high and very high voltage network. It is the both the manager and the main owner of the electricity transmission network in Italy, owning more than 98% of the electrical infrastructure in the country.

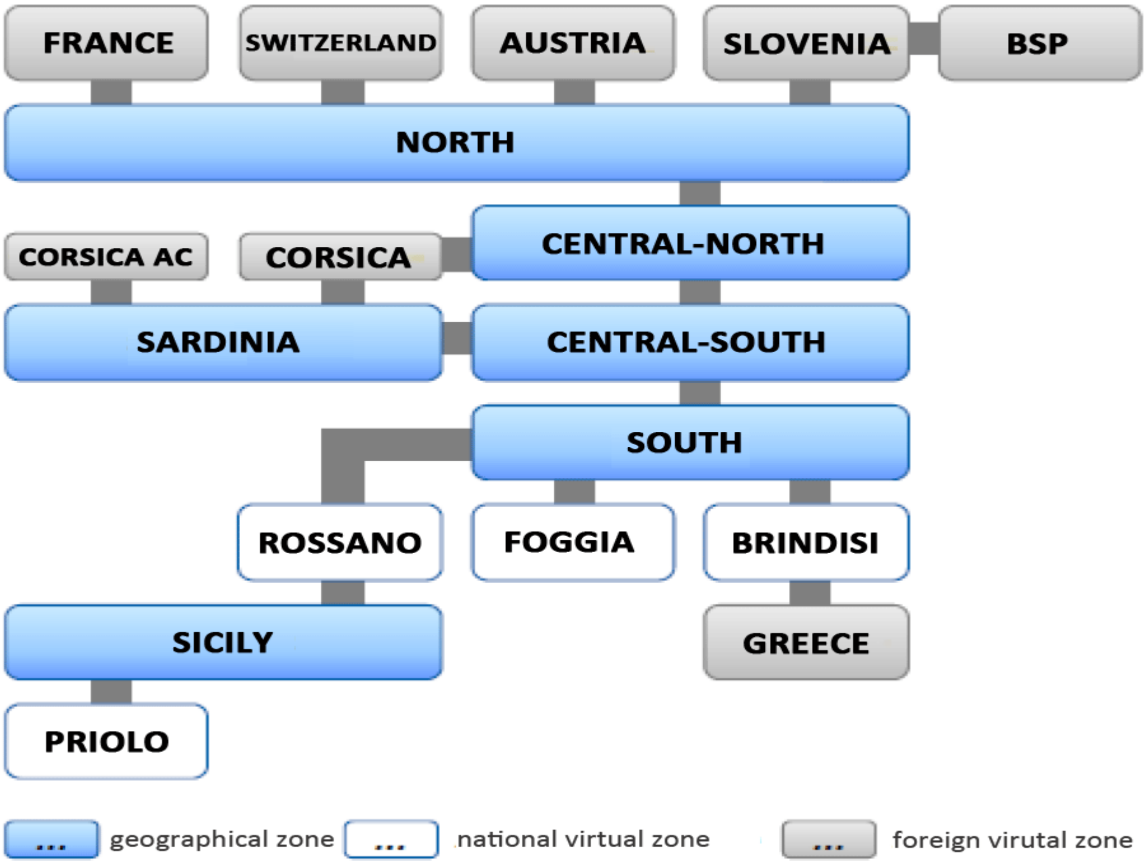

Figure 3-2 Virtual and geographical zones of the Italian transmission network (source: GME)

From the 1st January 2011 the zonal structure includes an area named BSP relative to the interconnection capacity between Italy and Slovenia allocated through daily implicit auctioning (the so-called market coupling). Conversely, the foreign Slovenia virtual zone is used for the amount of interconnection capacity allocated through explicit periodic (monthly and annual) auctions.

3.2.2 The Intraday market (MI)

The Intraday market (MI) allows operators to update their sale offers and purchase bids defined in the MGP and their trading positions with a frequency similar to that of continuous trading with respect to changes in information about the state of the production facilities and the consumption needs. Continuous trading is a method of trading based on an automatic combination of sale offers and purchase bids with the possibility of incorporation on a continuous basis of new proposals during the trading sessions. The contracts traded on the MI are those for the purchase and sale of electricity for which GME stands as counterpart of the operators.

It takes place on the calendar day preceding that to which offers and bids relate to and in the period between the closure of MGP and the deadline for submission of bids at the opening of MSD. It is divided into four sessions, organized in the form of implicit auctions of energy, through which the operators can perform a better control of the state of the production facilities, and update the withdrawal schedules for consumption units, taking into account the latest information about the status of production facilities, the need for energy for the next day and the market conditions. MI sessions are based on pricing rules which are homogenous to those of the MGP. However, unlike the MGP, in the MI the PUN is not calculated and all purchases and sales are valued at the zonal price.

In order to replicate on the MI the effect of the application of PUN to the withdrawal offer points belonging to the geographical zones, the GME applies a compensation of non-arbitrage to all the accepted offers which refer to those said points. In particular, for each purchase transaction completed on the MI and referred to a withdrawal offer point belonging to a geographical zone, if on the previous session of the MGP the PUN was greater (smaller) than the relative zonal price, the operator must pay (receive) a compensation of no-arbitrage, equal to the difference between the PUN and the zonal price applied to each MWh of the purchase transaction.

Conversely, for each sales transaction concluded on the MI and referred to a withdrawal offer point belonging to a geographical zone, if on the previous session of the MGP the PUN was lower (higher) than the relative zonal price, the operator has to pay (receive a) a compensation of no-arbitrage, equal the difference between the zonal price and the PUN, applied to each MWh of the sale transaction.

3.2.3 The market for ancillary services (MSD)

The market for ancillary services (MSD) is the tool through which Terna SpA procures the resources necessary for the system management and control (intra-zonal congestion management, creation of energy reserve, real time balancing). On the MSD Terna stipulates contracts of purchase and sale for the provision of resources for the dispatching service. Participation is compulsory for and limited to the dispatching users only on the “production side”. Dispatching users are required to offer all the available capacity from their units to which TERNA has authorized to provide dispatching services. They must submit incremental bids (to increase injections) and decremental bids (to decrease them).

The availability of an adequate amount of reserves is guaranteed by Terna through the selection of bids for changes in the schedules presented by operators on the ancillary market where the activities of collection of bids and communication of the results with regard to the acceptance of offers are carried out. The reserve may be used as tool for real-time balancing by Terna which acts as the central counterparty. For each accepted purchase bid on the MSD, GME determines the amount of non-arbitrage compensation that the operator is required to pay (if negative) or to receive (if positive). The accepted bids are paid for at the presented price (*pay-as-bid*).The MSD consists of a planning phase (MSD ex-ante) and a balancing market (MB, Mercato del Bilanciamento).

On the **MSD ex-ante**, the purchase bids and sale offers, relative to the calendar days following the one in which the session ends, are selected. Here Terna accepts purchase bids and sale offers in order to supply reserves, resolve congestions and maintain the balance between injection and withdrawal on the network. The MSD ex-ante takes place in one session the day before the day of delivery.

The **balancing market (MB)** is the place where the purchase bids and sale offers relative to the periods of the calendar day of the MB sessions are selected. The MB is divided into several sessions in which Terna selects the offers related to group of hours of the same day in which the relative session of the MB takes place. On the MB Terna accepts purchase offers and sale bids in order to perform the service of secondary control and to maintain the real time balance between withdrawal and injection of electricity on the network.

3.2.4 The forward electricity market (MTE)

The MTE is the market-place for the trading of electricity forward contracts with delivery obligation and withdrawal thereof. On this market, GME acts as central counterparty and, being a qualified market operator, holds an energy account on the PCE[2] on which it records the net position over the corresponding purchase and sale transactions concluded by the operator in the MTE.

Two types of contracts, for which the underlying amount of energy is fixed by GME in an amount equal to 1 MW, multiplied by the relevant periods of the underlying contract, exist:

1. **Base-load**, whose underlying is the electricity to deliver in all the relevant periods of the days belonging to the period of delivery.
2. **Peak-load**, whose underlying is the electricity to deliver during the relevant periods from the 9th to the 20th day belonging to the period of delivery, Saturdays and Sundays excluded. These contracts can be traded with the following delivery periods: monthly, quarterly and yearly.

[2] Electronic platform for registering Bilateral Contracts. Five types of contracts may be registered on the PCE: four contracts of standard type (base-load, peak-load, off-peak, week-end) and one contract of non-standard type.

GME organizes a trading book for each type of contract and for each delivery period. On this book, bids are ordered based on the price: in descending order for purchase bids in ascending order for sale offers. In case of two bids with the same price, the time submission of the bid has higher priority. Bids with no price limit have maximum priority of price.

Trading on the market is done through continuous negotiations during which the contracts conclusion is done with the automatic matching of bids of opposite sign on the book and ranked according to priority criteria. Forward contracts with a horizon longer than one month, at the end of the relevant trading period, are regulated through the cascading mechanism.

The cascading mechanism provides that, at the end of the session of the last day of trading, positions on an annual contract are split into equivalent positions on contracts with a lower maturity (monthly and quarterly). Similarly, a position on a quarterly contract is converted into equivalent positions on the corresponding monthly contracts. This mechanism is applied separately for contracts with base-load and peak-load profile. For these contracts, at the end of the last trading session of the monthly contracts, GME determines for each operator the net delivery position corresponding to the sum of the purchase and sale transactions, concluded on the MTE for all hours of the month included in the period of delivery of such contracts. The net position is then recorded on the energy accounts of the PCE in the availability of the operator.

3.2.5 The platform for the physical delivery of the financial contracts concluded on IDEX (CDE)

GME cooperates with Borsa Italiana SpA (Italian Stock Exchange), which manages the market for energy derivatives (IDEX), in order to allow, through the electricity market managed by GME, the operators involved in both markets to adjust through physical delivery the financial contracts with electric power as underlying, concluded on IDEX.

The agreement between GME and the Italian Stock Exchange for the integration of the derivatives market operated by the Stock Exchange and the electricity market managed by GME provides that operators with an open position on IDEX may exercise on this market an option of physical delivery, requiring in this way that their position is adjusted by physical delivery through the market GME.
The exercise of the option of physical delivery implies for the operator, as a consequence of the transfer of its position to GME, the conclusion on the CDE platform of a purchase/sale transaction of the underlying energy, with GME as its counterpart.

3.3 The Italian-Slovenian border market coupling

The allocation of daily capacity on the Italian-Slovenian border is managed through the Italian-Slovenian Market Coupling mechanism which simultaneously carries out an implicit allocation of physical daily transmission rights and a clearing of the electricity demand and supply.

Market coupling is a mechanism of integration of electricity markets in different regions or countries. In the presence of Market coupling the utilization of the transmission capacity between different countries is implicitly determined, contextually to the value of the electricity in the different markets. This mechanism contrasts with one in which the right to use the transmission capacity is determined independently of the value of the electricity, with explicit auctions. Explicit auctions have been so far the most used method to allocate interconnection capacity in Europe. In comparison, market coupling has the advantage of flows-netting and of eliminating imperfect arbitrage. Flows-netting implies that the electricity flows scheduled in opposite directions cancel out, allowing the interconnector to be used up to full capacity. Explicit auctions, instead, do not allow flows-netting and determine an inefficient use of cross-border capacity. Since they integrate procedures for the allocation of interconnection capacity with the execution of day-ahead markets, the implicit auctions always provide an efficient use of the same capacity, because they define a traffic flow which is always consistent with the economic signals conveyed by the markets: in fact the import/export flow direction goes always from the market zone with the lower price to the one with the highest.

By allocating the cross-border capacity simultaneously with the clearing of the energy markets, market coupling is able to eliminate the imperfect arbitrage that may arise under explicit auctions. Imperfect arbitrage occurs when electricity flows against price differentials, and it is due to that market participants have to bid for capacity and energy in two different markets (Pellini, 2011).

The market coupling mechanism operates on the Italy-Slovenia border since 1st January 2011. It allows allocating daily physical cross-border interconnection rights between the two countries according to an implicit scheme, through the resolution of the respective day-ahead markets operated by GME and BSP (power exchange operator of the Slovenian electricity market). The initiative was launched in 2008 by the GME, Borzen (Market Operator in Slovenia) and BSP. Considering the current European legislation, the project meets the requirements laid down in Regulation (EC) n. 714/2009 which states that between Member States *"... the coordinated allocation of cross-border capacity through non-discriminatory market-based, with particular attention to the specific characteristics of implicit auctions for short-term allocations ..."* should be encouraged. The Italian-Slovenian markets coupling is also of considerable interest as a preliminary test for future coupling processes that Italy must implement with other borders by 2014. Coupling processes are, in fact, linked to the achievement of the goals set out in the Third Package[3] and Framework Guidelines on Capacity Allocation and Congestion Management for Electricity of ACER[4] according to the deadlines set by the European Commission.

The coupling model adopted on the border between Italy and Slovenia is a decentralized price coupling that reflects exactly the model defined in the Price Coupling of Regions (PCR)[5], a project that GME is conducting in collaboration with other major European power exchanges. GME and BSP use a common matching algorithm, which reproduces the matching rules of their respective markets and takes into account a network model which is representative both of the Italian and Slovenian electricity networks.
This algorithm is run in a parallel and decentralized way by both market operators. They receive bids from the respective market operators and, before running their market sessions, exchange relevant information about the supply and demand curves implied by the received bids and about the network constraints in the respective market zones. Then, GME and BSP simultaneously calculate the results of their markets taking into account the market and network conditions of the other country and determine the electricity flow on the interconnection between Italy and Slovenia, as a function of the prices which are determined on the respective markets.
The key advantage of the decentralized price coupling model is that, while on the one hand, with the adoption of a common algorithm, allows to implement in a single system the matching rules of the two markets joined by the coupling mechanism, on the other hand , through the decentralized management of procedures and the sharing of relevant information, ensures coordination between markets, without requiring changes to the responsibilities, competencies and roles already carried out by GME and BSP within their own national contexts.

The allocation of the interconnection capacity share with Slovenia, which was previously allocated by explicit daily auctions, takes place in the Italian market by integrating the foreign virtual zone BSP[6]. The capacity allocated to that zone follows, in theory, a reserve principle of reserve shared between the national regulatory agencies. It is, in fact, only a portion of the total interconnection capacity between Italy and Slovenia: it has been originally set at 35 MW while the average availability on the frontier equals to 460 MW: the remainder was still to be allocated through monthly and yearly explicit auctions monthly through the foreign virtual zone "Slovenia".

[3] Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13th July 2009
[4] ACER (Agency for the Cooperation of Energy Regulators) is the European Union body created by the Third Energy Package to further progress on the completion of the internal energy market both for electricity and for natural gas.
[5] Joint project of the main European power exchanges aimed at the realization of a market coupling project based on a decentralized approach for the whole Europe.
[6] See paragraph 3.1, page 16, about market zones.

In 2011 the MGP, despite a decline in volumes to 180 TWh (10%), recorded its first full year of operation of the market coupling with the Slovenian border, picking up at the end of year, about 1156 GWh compared to the 262 GWh which were originally reserved to it. In the first 9 month of 2012 the quantity of electricity traded through the market coupling mechanism has already reached 2500 GWh. This confirms the high level of approval of the market operator for the market coupling tool. The project's success is confirmed by three important aspects:

1. The first concerns the potential capacity of market coupling to attract larger volumes than those initially guaranteed by regulation. The allocated capacity in 2011 increased from 64 MW average in January to 165 MW average in December and this significant increase was even stronger in the first months of 2012, when, in correspondence of the expiration of 2001 yearly import contracts, the volumes allocated in the BSP zone peaked at 526 MW in March, with the 97% of the total capacity total allocated between the two countries (See Figure 3-3, Below).

   This figure reflects the appreciation expressed for this type of auction system by the market operators. Operators commonly make extensive use of “use it or sell it” provisions which characterize purchases of interconnection capacity on foreign markets. The use of such provisions allows operators to resell to the Transmission System Operator the forward import capacity bought and buy it again on the day-ahead market through sale bids on the day ahead Slovenian market, keeping the guaranteed price provided by explicit auctions. An indirect proof of this phenomenon is given just by the increase in liquidity from the Slovenian Power Exchange, whose volumes rose up to 1.5 TWh in 2011 and exceeded 3 TWh in September 2012 compared to a mere 0.2 TWh in 2010, thereby gaining an operative continuity which was absent before. This increase, as BSP affirmed[7], *is largely consequence of Market Coupling on the Slovenian-Italian border and higher values assigned to daily transmission capacity between countries*. The success of the project confirms the possibility to implement market coupling projects with neighboring countries with low liquidity markets, thanks to the capacity of the coupling mechanism to extend the resources from the major markets to the minor ones.

[7] http://www.bsp-southpool.com/news-item/items/volume-of-concluded-transaction-in-year-2012-exceeded-3-twh.html

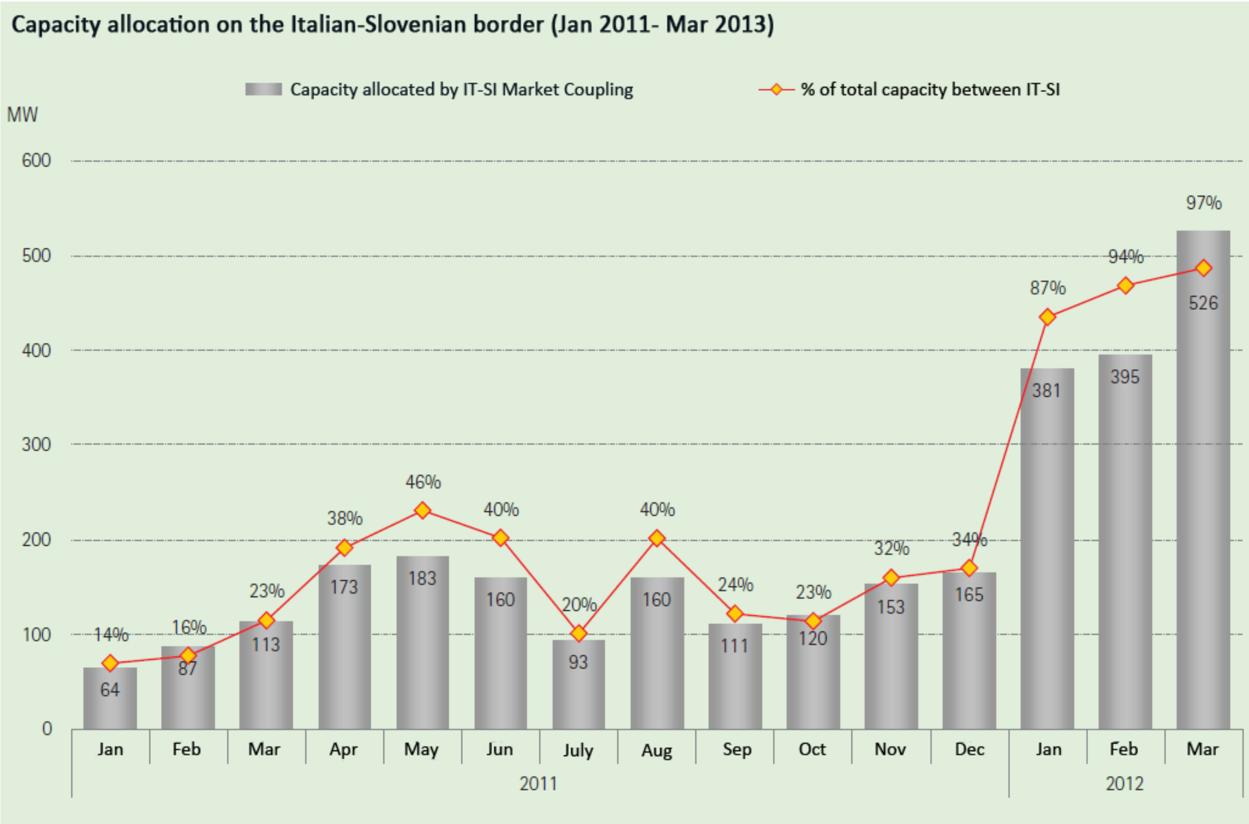

Figure 3-3 Capacity allocation on the Italian-Slovenian Border (source: GME)

2. Market coupling brings an expected increase in efficiency in the use of the interconnection infrastructure between the two countries because of the ability of the system to allocate always the same transit capacity in a direction consistent with the differential in price between the two borders, and because it ensures the full use of the capacity transmission whenever the differential is positive. In 2011 the flows determined by market coupling resulted to be efficient in 100% of cases, compared with 98.2% guaranteed by the previous mechanism based on explicit auction. Though limited, this difference is still significant because the 100% allocated on the BSP zone included a 3% of export flows, while the previous 98% allocated to the Slovenia zone was constituted only by import flows.

3. The coupling mechanism can promote a process of gradual convergence of prices between the two wholesale markets. While the convergence of the prices quoted by the Italian and Slovenian power exchanges has not happened yet (in 2011 respectively €72.24/MWh and €57.20/MWh while in the first nine months of 2012 €78.78/MWh and €56.05/MWh), the progressive increase of the capacity allocated through market coupling has, in fact, attenuated the effects of the difference in generation costs between the two countries, fostering a growing equality between the prices of the North zone and those of BSP zone. In particular, hourly analysis shows for 2011 shows an

equivalence of prices in the 20% of cases, while this equivalence substantially amounted to 0% in 2010. This convergence process underwent a constant and progressive growth from 11% in the first eight months of 2011 to 37% in the last quarter of 2011 and reached 43% in the first three months of 2012 - of which 73% in the month of February - when the wholesale price of the Italian zone was, for the first time, lower than the Slovenian one in the 3% of cases. (See figure 3-4 below).

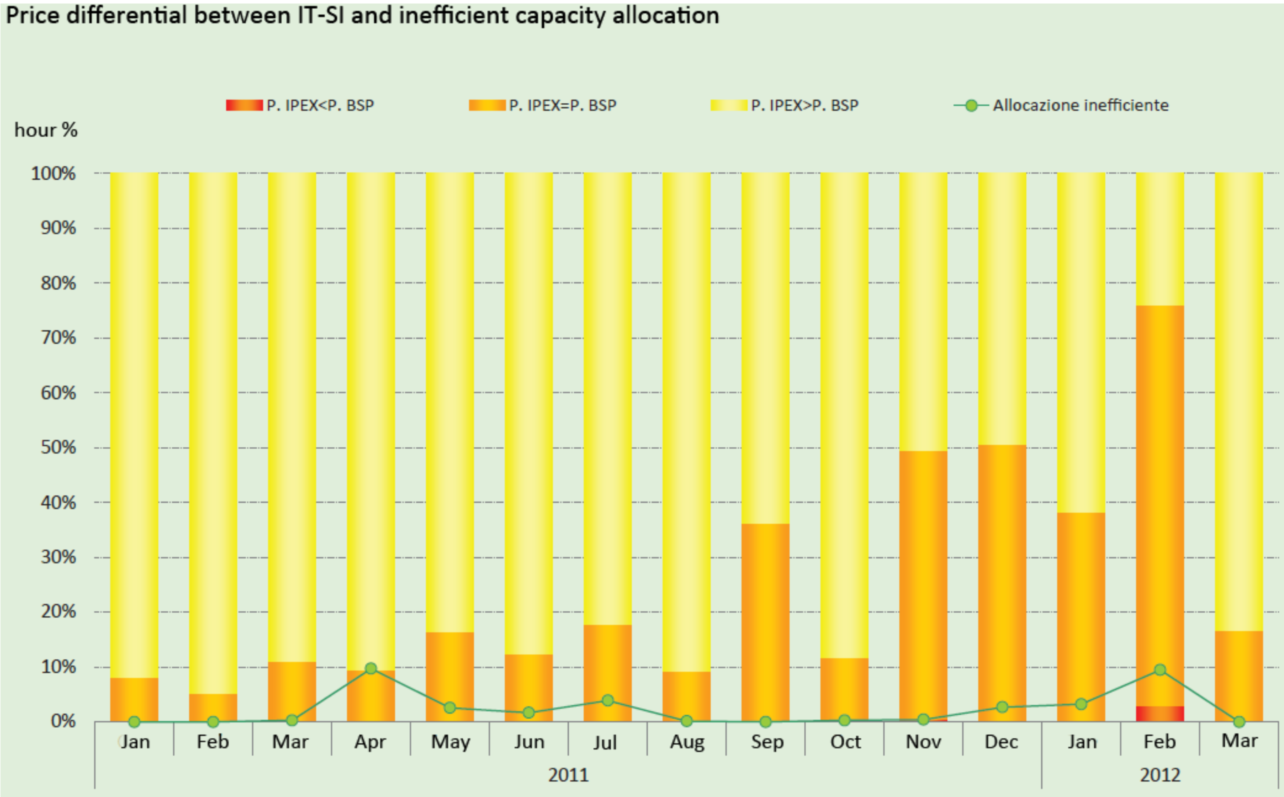

Figure 3-4 Price differential between Italy and Slovenia and inefficient capacity allocation (source: GME)

4. Day-ahead electricity prices

The electricity sector is very different from the other network sectors because of its peculiar characteristics and its vertical structure. In many European countries the sector has been historically organized as an integrated and state-owned monopoly and despite the liberalization process that has been put in place since the half of the 1990s, some segments such as transmission and distribution network remained under monopoly. Some other characteristics must be considered when analyzing the market: electricity is a homogenous product: consumers cannot discern on the base of any particular feature; productions costs can be very different as they depend on type of energy source and technology used; Demand is highly inelastic and there are no substitutes for it; Transmission and distribution are influenced by the distance to cover and the resistance of the transmission grid: therefore in case of congested or segmented grids, it is possible that non-efficient power generators situated in a certain position can guarantee cheaper electricity than more efficient power plants situated in a more distant location.

4.1 Characteristics of electricity prices

Electricity markets have different characteristics not only from financial markets but also from other commodity and energy markets. Most type of energies can be indirectly stored through the storage of the energy sources such as gas or coal. Electricity, instead, cannot be directly economically stored or transported. It can only be indirectly stored in the case of a hydroelectric power plant or via storage of generating fuel. This implies that direct inventories cannot be set up to mitigate supply or demand shocks: therefore the market needs a constant real-time balancing of supply and demand and this is a very difficult task due to the physical properties of electricity production. Therefore, in addition to production and distribution services, electricity markets need balancing and reserve services in order to protect the integrity of the system: an imbalance of supply and demand at any location of an electricity grid can threaten the stability of the whole system since it could potentially disrupt delivery of electricity for all suppliers and consumers on the grid. These peculiar characteristics of the electricity market are reflected in the characteristics of its market price whose historical series present high volatility, seasonality, mean-reversion, spikes and volatility clustering.

4.1.1 High volatility

Volatility of electricity prices is much higher than volatility of financial assets, since shocks affecting supply and demand cannot be easily smoothed out and have a direct effect on the market's clearing prices. Volatility is also influenced by the characteristics of demand and supply which will be pointed out in paragraph 4.2.

4.1.2 Seasonality

The inability to directly store energy results in (predictable) inter-temporal variation in equilibrium prices is called seasonality. Two factors are responsible for the most of the seasonality effect: economic activity and weather conditions which affect the electricity demand. Three different types of seasonality can be observed: intra-daily seasonality (different price values between office time and night time), weekly seasonality (different price values between week and weekend days) and monthly seasonality (different price values between working and holiday periods as, for example, Christmas and summer vacations). Seasonality can affect also the supply side: for example the quantity of hydroelectric energy produced depends from the rain precipitation quantity. Seasonality affects not only the level of prices but also its variance.

4.1.3 Mean-reversion

For industries where technology progresses quickly, as the electricity industry, it is expected that, in the medium term, prices exhibit mean-reversion. Mean-reversion has been largely observed in the spot price empirical data of electricity markets. Mean reversion can be attributed to two different causes. First, in the electricity market it is the demand which influences the quantity of supply: a positive shift of the demand raises prices and creates economic incentives for power generating units with higher marginal costs to enter the market; secondly, mean-reversion could be ascribed to the effect of weather on the demand. As weather is a dominant factor influencing equilibrium prices and its evolution is cyclical and mean-reverting, its mean-reversion process affects demand and equilibrium prices (Knittel and Roberts, 2001). Generally, mean reversion seems to be a function of either how the supply side of the market can react to events or how quickly the events go away. Mean reversion is then a measure of how long it takes for the events to dissipate or for supply and demand to return to a balanced state

(Pilipovic, 2007). However the analysis of mean reversion in electricity prices is more problematic than for other commodities, because of the existence of spikes in the price evolution.

4.1.4 Spikes/Jumps

Existence of spikes in the electricity price dynamics has been clearly observed in the historical data. Spikes consist of significant upward moves followed closely by sharp drops and, while they can be very disruptive for the industry, they can also be twofold useful: when considering the demand side, they help to signal shortages and encourage customers to reduce their usage in times of stress; when considering the supply side, they signal shortages and help bring in more additional supply (Eydeland, 2003). They are, in fact, a direct consequence of the non-storability of electricity which causes the supply to be highly inelastic and forces supply and demand to be coinciding every instant. After the spikes the price does not stay at the new level but quickly reverts to the previous level.

For larger shocks the forces behind demand and supply push back electricity prices faster, while for smaller shocks the speed of reversion is slower due to the existence of adjustment costs. The frequency of spikes is higher in those periods where the excess capacity (the difference between maximum supply and demand is small (Escribano et al, 2002), but they can be observed even when demand is low, for example because of transmission problems or because some plants cannot generate electricity. So the frequency is higher during peak hours of week days. Due to their exceptional nature, spikes are the most complicated risk factor to hedge, but also the most important and urgent. There have been different cases of companies which bankrupted because they undervalued the risk of electricity prices as documented by Weron (2006).

4.1.5 Volatility clustering

Volatility clustering means that conditional volatility varies slowly over time, staying high or low for long periods. This means that high variations of price are followed with more probability by high variations and vice versa. From a structural point of view, this means that conditional volatility of today is connected to yesterday's conditional volatility, for example with an autoregressive mechanism. Unfortunately conditional volatility is a latent variable and not directly observable, therefore GARCH type models are needed to model the clustering. This characteristic is difficult to test because of the existence of seasonality and jumps. Recent studies show that adequate models take seasonality into account and where the effect of spikes has been adequately smoothed out present a high volatility clustering.

4.1.6 Inverse leverage effect

The inverse leverage effect has been noted by Knittel and Roberts (2005) and consists in an inverse reaction to shocks: in presence of positive shocks, the price volatility tends to increase more than in presence of negative shocks, as a result of convex marginal costs.

4.2 Supply and demand curves in the electricity market

Spot prices are determined on the *day-ahead market* by the intersection between demand and supply. As already noted, electricity prices volatility depends also on the characteristics of supply and demand. Due to the instantaneous nature of electricity, supply must equal demand in the market at any moment in time. In the presence of diverse plant technologies, the aggregate supply curve is characterized by a steeply increasing, discontinuous and convex shape. Demand is generally considered as highly inelastic because electricity is a necessity good for which there are no substitutes and is highly weather-dependent. It is normally divided into three categories: residential, commercial and industrial. Each category has different characteristics and statistical properties. As it can be intuitively acknowledged, the residential demand is the most affected by weather conditions and therefore shows the greater variability, while industrial demand is the most stable and it is not really influenced by changes in temperature. The demand is also influenced by the characteristics of the supply side.

A simple representation of the supply and demand curves can be observed in the following figure:

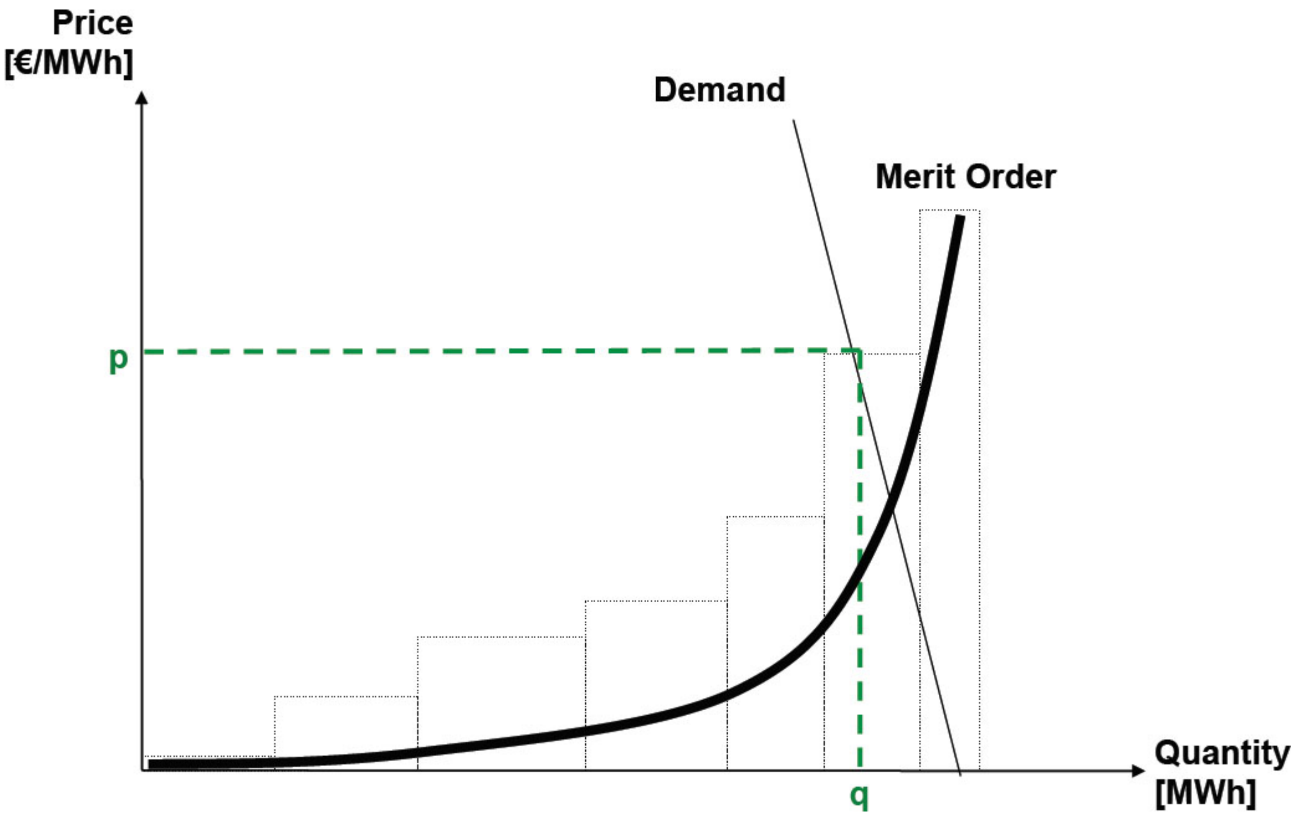

Figure 4-1 Typical supply and demand curves in the electricity market

If the demand level is low, electricity is supplied by using exclusively base-load units with low marginal costs. If higher quantities are needed, other generators with gradually higher marginal costs enter the market. In markets where the curves are both very steep there are great price increases when the demand rises. In certain markets (depending on their structure and the market powers of generators) when the demand level is very high only few generators can satisfy the residual demand: then market power can cause oligopolistic behaviors of generators. In this particular situation, if the supply curve is convex, the effect on prices for a certain increase in the demand will be greater the smaller is the excess capacity (Escribano et al., 2002).

Electricity generation is very capital intensive: as a significant percentage of generation costs are fixed, the marginal cost of production stays below the average cost for a plant operating below its capacity. Therefore, as long as the market price is higher than the marginal cost of production, a plant will produce electricity. It is clear then that excess capacity will cause prices to drop to a level below the average cost of production and generators will encounter a loss. Capital intensity implies a high cost for idle capacity: it is very expensive for a plant to keep the availability to increase electricity supply in the short run. There is no price-responsive mechanism in the electricity market to adjust a supply/demand mismatch. In such a situation the prices will greatly increase, generators will try to supply additional capacity from increasing production in their power plants and the grid system will exercise interruptible contracts. When a mismatch occurs, the price rises for all the electricity sold in the market at that certain time. The critical issue in the electricity markets is their vulnerability to these mismatches due to the very high inelasticity of supply and demand curves. This sets electricity markets aside from other markets where the good can be stored, such as the gas market. In addition, market power exacerbates the price volatility issue raising prices above the level that would be obtained in a perfectly competitive market (Borenstein, 2002).

4.2.1 Factors driving electricity supply

The main factors driving electricity supply are the following: power generating capacity per fuel type; marginal costs of generating power; competitive dynamics and government interventions.

Power generating capacity

The capacity factors vary greatly between power plants depending on the type of fuel that is used and the power plant design. Three basic types of power plants can be distinguished in the electricity generating marketplace:

1. **Base load power plant.** These power plants operate at maximum capacity and only reduce production or shut down to perform maintenance or repairs. Base load power plants have the capacity to cover electricity demand during hours of lowest demand. These plants generate electricity at the lowest costs per MWh since they are designed for maximum efficiency and are operated continuously at high capacity during both peak and off-peak hours. Base load power plants include almost all coal, nuclear, solar and biomass power plants.

2. **Load following power plant.** These intermediate power plants generate electricity only during the day and early evening, when prices and demand are higher. During low-demand off-peak hours load following plants shut down or greatly reduce their output. How many hours a specific intermediate plant operates depends primarily on how efficient it converts fuel into electricity (heat rate); as demand increases, the most efficient plant with the lowest marginal cost starts producing first, the next most efficient thereafter and so on. In terms of capacity factor, efficiency and (marginal) cost per unit of electricity these power plants fall in between base load power plants and peaking power plants. Load following power plants comprise steam turbine (natural gas or sometimes heavy fuel oil) and the most efficient gas turbine power plants (natural gas).

3. **Peaking power plant.** Peaking plants are only online during times of peak demand. The operating hours of peaking plants range from 5 peak-hours a day to 30 hours a year, depending on efficiency

and marginal cost per MWh. Peaking power plants mainly consist of the flexible but expensive gas turbine power plants which, in case of gas supply problems, can also utilize a reserve supply of diesel.

Marginal Costs

In a perfectly competitive market marginal costs determine prices in the marketplace. Fuel prices are the most important drivers of marginal costs. CO_2 emission rights, introduced by the European Union to reduce the aggregate CO_2 emission, are also an important factor, especially for coal fired power plants, since a generator needs these rights to be able to produce and emit the CO_2 needed for its initial production. A third factor influencing the power generating capacity and marginal costs of power plants are technological innovations in the efficiency of different types of power plants. For instance an improved heat rate of coal or gas fired power plants leads to a larger generating capacity and lower marginal costs. Another example is an innovation that requires less maintenance to coal fired (base load) power plants, thereby increasing their actual electricity production against low marginal cost (increased capacity factor).

Competitive dynamics in the power market

The extent to which competition takes place in the power market influences the electricity price. An increase in interconnectivity with other power markets will result in greater competition due to an increase in the available supply.

Government interventions

Whereas government influence can be a major factor determining supply, it is also the least predictable. For example, the recent Fukushima catastrophe led to the decision by the German government to shut down a significant quantity of nuclear plants in the coming years. The day-ahead and forward markets were born as a consequence of deregulation decisions by the European Union. The CO_2 emission allowances implemented by the European Union have had considerable effects on energy prices.

4.2.2 Factors driving electricity demand

The main factors driving electricity demand are instead: economic activity, peak relative to off-peak demand, technological innovations and weather conditions

Economic activity

Ferguson, Wilkinson and Hill (2000) studied the correlation between the GDP per capita (proxy for economic activity) and electricity consumption per capita. They found for all of the OECD countries a correlation coefficient of at least 0.9. This indicates a very close relationship between GDP and electricity use.

Peak relative to off-peak demand

The value of this ratio determines which kind of power plant is the most profitable in the market and how prices vary between peak and off-peak hours. For example a high value means that there is a wide difference between the peak and off-peak demand, therefore plants with a higher operating flexibility (e.g. natural gas plants) are necessary in order to shift the daily level of production between the peak and off-peak levels. On the contrary as the value of the ratio becomes lower, inflexible power plants (e.g. coal) will become more profitable.

In the past decade there has been a growing interest in strategies to reduce peak demand by eliminating electricity use, or shifting it to non-peak times. This strategy is commonly called "demand response". One of the primary methods pursued to reduce on-peak use of electricity in households is through behavioural modification; encouraging people to eliminate on-peak electricity-using activities, or shift them to other periods. In order to provide an economic incentive for such behaviour many utilities have proposed a change in the residential electricity rate structure which has moved from the standard flat-rate per kWh model to a structure following more closely the real cost of electricity at the time it is used: a higher price during peak periods and a lower price in other times.

Technological innovations

Energy efficiency and conservation have gained more and more importance as concerns about global climate change and energy security have intensified. In the last decades many technologies which positively affect energy efficiency have been developed. An example is the introduction of smart meters across Europe, which led to energy saving percentages ranging from a few percentage points to more than 10% and in addition allow for real-time demand side management (van Gewen et al., 2010).

The 'Electricity Consumption and Efficiency Trends in the European Union - Status Report (2009:3)' states that "*Energy and electricity consumption trends over 2004-2007 seem to indicate that residential energy efficiency policies and measures start to be effective. EU energy efficiency policies were significantly reinforced from 2005 on, with new important legislation coming into force or under assessment. The 2007-2012 Action Plan for Energy Efficiency has the objective to control and reduce energy demand and to take targeted action on consumption and supply, in order to save 20% of annual consumption of primary energy by 2020, compared to energy consumption forecasts for 2020*".

Weather conditions

Electricity consumption is influenced strongly by weather conditions: extreme temperatures lead to a widespread use of air-conditioners or heating devices. On a long timescale it is observed that electricity prices reflect marked seasonal patterns (e.g. winters and summers) together with economic activity cycles. On a shorter-time level, electricity demand depends non-linearly on temperature. This relation makes volatility of inelastic demand very sensitive to short-term weather variations. The effect is increased during periods of high demand.

5. Performance of the Italian electricity market in 2011 and 2012

In 2011 electricity consumption was affected by the general climate of uncertainty caused by the economic crisis, because of its close correlation with economic trends. Some specific events of potential relevance to the electricity sector have happened, including insurgencies in Muslim countries of the Mediterranean, and the resulting tension on the supply of gas to southern Europe, and the nuclear disaster Fukushima in Japan, which has led to an increase in demand for LNG[8] from the country, with impact on the Asian markets for gas and a rethinking of energy policy choices of other States.

Regarding Italy, after the feeble signs of recovery recorded in 2010, 2011 has been characterized by stagnation in demand for electricity. In view of the shy GDP growth (+0.4%), electricity consumption (311.7 TWh) has in fact shown a moderate growth (+0.6%), mainly compressed by a significant contraction observed in the last quarter (-3%) at the time of the greater tension on the financial markets. In 2012[9] the consumption has seen so far a decrease of 9.6% on an annual basis, and has been affected also by the estimated GDP decrease (-2%).

2011 and 2012 have seen a real explosion of photovoltaic power (respectively +267.4% and +129.1%) and a more moderate increase compared to 2010, although still significant, for wind power (+19.7% and +61.4%). The bulk of consumption continues to be met by thermal generation (70% of which consists in combined cycle technology) while wind and photovoltaic reached in 2011 a net production of approximately 19 TWh, contributing to the 6% of total consumption (+2.6%). Although still limited in absolute terms, the growing production from renewable sources is having a significant impact on both the wholesale market, relative to the price level and their time profile, and the system as a whole, relative to the reliability of the programs and the critical issues related to the modulation of the injection from these sources.

With regard to the market and the effect on prices, the growth of renewables depresses their level to the extent that the increase of zero-price offer helps to reduce the relative scarcity of supply and to increase the competitiveness at the margin, sending out of order of merit the more expensive offers; it modifies the prices profile to the extent that it pushes down prices during peak hours where the greater solar radiation is present, indirectly favoring an increase in prices in the evening where the market concentration is higher and the traditional sources fix higher prices in order to safeguard their margins. Table 5-1 and 5-2 below summarize the data regarding the Italian electricity system and the volumes traded on the GME from 2007 until 2011.

[8] Liquified Natural Gas

[9] For better legibility, in this chapter the term 2012 refers to the first 9 months of the year 2012.

TWh	2011	2010	2009	2008	2007	Var % 2011/2010
TOTAL DEMAND	**332.3**	**330.5**	**326.1**	**347.1**	**347.6**	**0.6%**
NATIONAL CONSUMPTION	311.7	309.8	299.9	319.0	319.0	0.6%
TRANSMISSION LOSS	18.1	16.2	20.4	20.4	21.0	11.7%
PUMPED-STORAGE PURCHASES	2.5	4.5	5.8	7.6	7.7	-43.5%
NET PRODUCTION	**289.2**	**290.7**	**281.1**	**307.1**	**301.3**	**-0.5%**
HYDROELECTRIC	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	394%
NET IMPORT/EXPORT	**45.6**	**44.2**	**45.0**	**40.0**	**46.3**	**3.3%**
IMPORT	47.3	46.0	47.1	43.4	48.9	3%
EXPORT	1.7	1.8	2.1	3.4	2.6	-5.7%

Table 5-1 National electricity balance for 2007-2011. Source: Terna SpA

	2011		2010	2009	2008	2007***
	TWh	Delta %	TWh	TWh	TWh	TWh
TOTAL VOLUMES (forward + d + f)	524.70	+15%	456.93	401.44	398.51	260.64
ITALIAN SYSTEM (a+b)	311.49	-2%	318.56	313.43	336.96	329.95
Forward Trading	322.49	+33%	242.87	176.47	154.22	97.28
Spot Trading (a+b+c)	**333.36**	**+0%**	**333.18**	**325.36**	**348.61**	**342.69**
(a) MGP	180.35	-10%	199.45	213.03	232.64	221.29
(b) PCE	131.15	+10%	119.11	100.39	104.32	108.66
(c) MA/MI	21.87	+50%	14.61	11.93	11.65	12.74
MSD ex ante	9.59	-56%	21.75	27.16	22.84	26.60

Table 5-2 Total volumes traded on GME markets (TWh). Source: GME

5.1 Trends of the MGP day-ahead market

The total volumes traded in 2011 on the MGP decreased of ca. 19 TWh (-10%), and reached a historical low of 180 TWh, while programs of execution of bilateral contracts increased. This trend is influenced by the general decrease in day-ahead purchases, but there are other affecting issues: in fact, assuming a liquidity equal to the 2010 level, the traded volumes would have fallen by 4.5 TWh, amounting to 184.8 TWh. Instead, liquidity and volumes of the MGP has been decreasing since 2009 and the causes are mainly found in two factors:

a) The fall in volumes traded by non-institutional operators (-17 TWh), which in 2011 saw their share fall to 30%, reducing by 5% the liquidity of the market.

b) The sharp drop in purchases of electricity for pumped-storage hydroelectric plants (-67% in 2011 and -44.8% in 2012), favored by the compression of the differential between peak and off-peak prices. Since these purchases are historically made only on the MGP in order to seize the opportunities of hourly trading that the market allows compared to bilateral contracts, their decline completely affected the MGP, subtracting about 2 TWh to the market volume.

The remaining part of the decrease in volumes, vice versa, does not seem attributable to other external factors. The shift of trading from the spot to the forward market seems to be negligible. In 2012 the traded volumes have decreased of 3.1% on an annual basis.

In 2011, in Europe, the prices quoted by the major power exchanges have shown a moderate growth, reflecting the increase of Brent and of fuels indexed on it. This increase has been only partly mitigated by the ongoing and widespread condition of demand stagnation. This trend is also found in Italy, where the wholesale price of electricity has been confirmed as the higher of the European continent, because of the structural gap produced by a generation fleet which is more expensive on average and is strictly dependent on natural gas combined cycle plants, and especially because of the higher cost of raw material gas than in rest of Europe (about €5.5/MWh more than in the rest of Europe, a figure that accounts for about twice the cost of generation electricity).

In 2011 the PUN value increased, but only partially incorporated the increase in fuel prices, which has been partially offset by a persistent state of overcapacity of the system which the new capacity from renewable sources has helped to exacerbate. The real increase in price has been significantly lower than its nominal value, compressed by further expansion in supply, which has smoothed quotations. Specifically, in 2011, the PUN average reached €72.24/MWh, with an increase relative to the previous year equal to that in neighboring countries (+12.6%) and a significant acceleration of the downward trend for both the volatility (7.6%, -4.2% with respect to the previous year) and the hourly peak/off-peak modulation. This last characteristic, especially is of particular interest, as it reflects the structural changes that are gradually changing the mix of national generation capacity. The massive injection of energy from photovoltaic plants in periods of increased solar radiation contributed significantly to increase the competitiveness in peak hours, favoring a gradual convergence of peak prices to the values observed in other hours.

As a result of this phenomenon, in 2011, the ratio between peak and off-peak prices fell to 1.29 (-9.2%), in line with the levels recorded in the neighbouring countries, historically lower, and indicating a general flattening of the daily profile of the price. Despite a weak slowing down of this trend has been observed in the first months of 2012, this convergence process has strengthened with the approach of summer when climatic conditions and the high number of daily hours of light pushed up the growing availability of photovoltaic capacity. In fact, the peak/off-peak prices ratio reached a minimum of 1.02 in August 2012 and rose back to 1.11 in September. A similar trend, though less pronounced, established itself over the years in the relationship between holiday prices and off-peak prices, down to 1.08 in 2011 (-4.2%), but still greater than the average European figure, because of the effect of concentration in supply, which in holiday hours is structurally higher.

The ongoing change in the supply structure, in a period of weak and less variable demand, favored the beginning of a phase of prices leveling on the IPEX, which manifested both in their reduced hourly modulation, both in the reduced monthly cyclicality shown by the PUN since 2009. The trend exhibited by prices since 2009 showed a progressive and significant reduction of seasonal fluctuations, in favor of a more direct alignment of the dynamics to the underlying trend traced by the generating costs.

The growth observed on electric prices substantially followed the rising costs of generation, which, under the push of the strongly bullish trend registered on oil markets, has been equal to an average annual rate of 19-21%. In this sense, the thrust exerted by the increases observed on the costs has inhibited the bearish effects induced on PUN by overcapacity, reaching its maximum intensity just between August and December 2011. In real terms, however, the recovery exhibited by the price of electricity showed a significant reduction in profit margins of producers incorporated into prices, as shown by the values of the spark spread, which, although on different levels, follows a definitely waning trend over the years, falling even below zero in the summer of 2011.

Fully consistent with the increasing share of sales captured by solar energy systems during the hours of greater lighting and the consequent decline of market power observed in the same time slot, the contraction of the spark spread mainly concentrated in peak hours, both in the first seven months of the year, characterized by a smaller price of PUN, both in the final quarter of 2011, which has been instead affected by higher prices. In this context it is worth noting that the only exception to this otherwise generalized trend is found mainly in the period from October to December, in the hour range from 18 to 20. The fact that these hours represent, within the peak range characterized by medium to high consumption, the hours with less impact on the photovoltaic production, suggests that operators have concentrated in this range, the ability to limit profit losses piled up in the rest of the year.

	2011	% change	2010	2009	2008	2007
PUN (€/MWh)	72.74	+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
Exchange rate $/€	1.39	+5%	1.33	1.39	1.47	1.37
Gas cost indices (€/MWh)						
- 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
Environment Charges (€/MWh)						
- CV	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

Table 5-3 Average yearly values of the PUN and its determinants. Source: GME

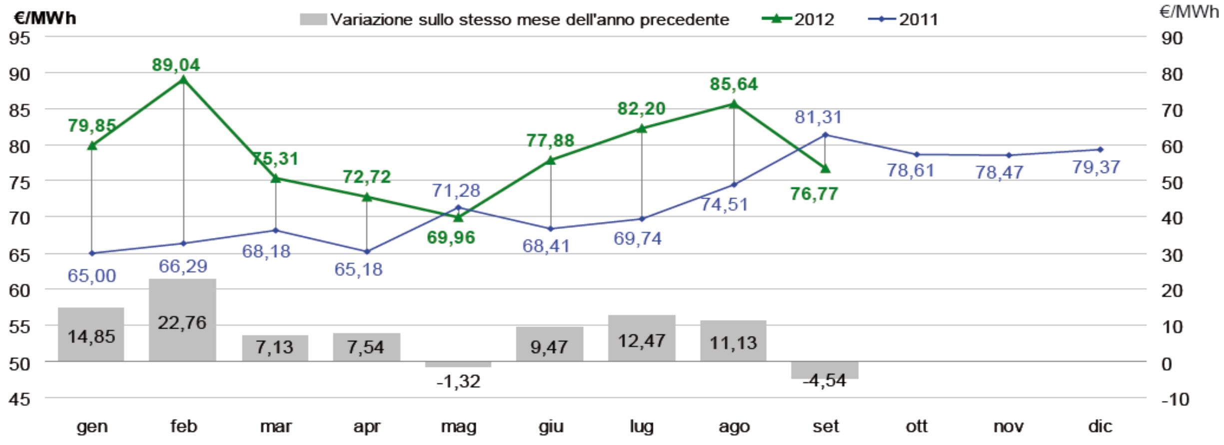

Figure 5-1 PUN trends for 2011 and 2012. Source: GME

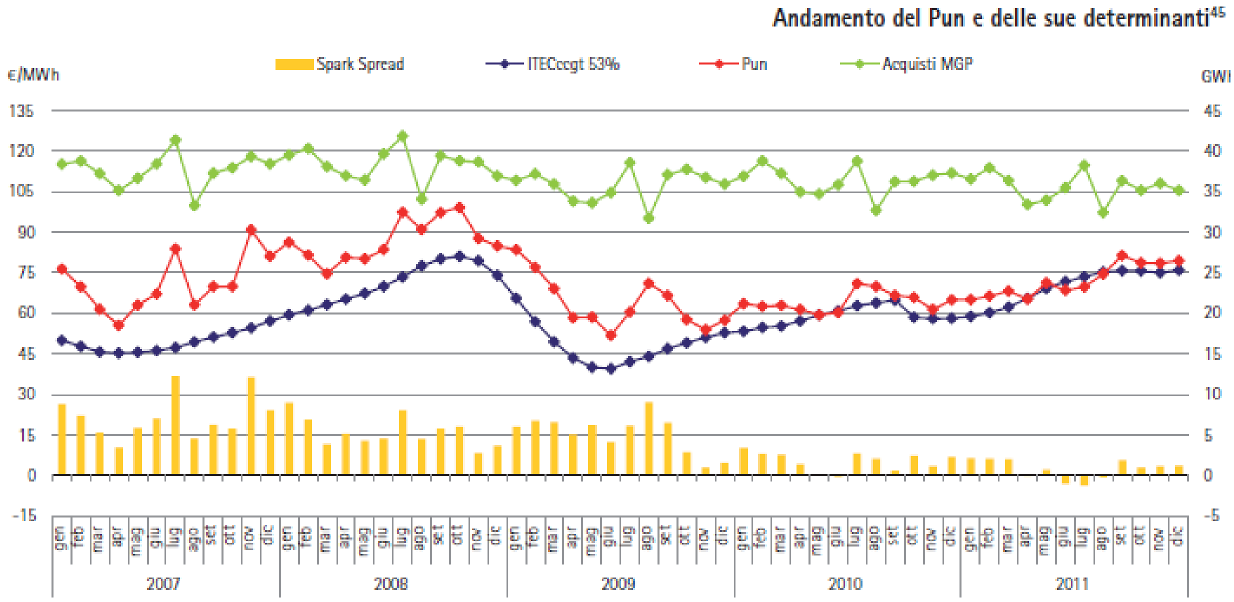

Figure 5-2 PUN trends compared to its determinants from 2007 to 2011. Source: GME

5.2 Demand and supply

The year 2011 has been characterized by a further reduction of the difference between supply and demand, with the first marking a sharp increase (+6%), driven also by the growth of the photovoltaic generation, while the second, after the weak recovery in 2010, records a new decline (-2%), reaching a historical low record from the beginning of trading on the power pool (311.5 TWh). This trend continues in 2012 with a decrease in demand of -5.2% for demand and an increase of +5.1% for supply. This reduction of the relative scarcity of supply has helped to strengthen the trend of gradual improvement in the main indices of competitiveness and to curb the inflationary pressure on MGP prices which have experienced growth rates lower than the generation costs. These figures, however, underestimate the growth of oversupply due to the changes induced in the national generation park and, more generally, in the functioning of the electricity market, by the growth in installed capacity from non-programmable renewable sources. With regard to demand, in fact, these have helped to increase the level of self-consumption which does not pass through the market, causing the volumes recorded in the MGP to appear artificially low. This is confirmed by the fact that the decrease in purchases recorded on the day-ahead market is not reflected in a similar decline in the demand for electricity, which reached 332.3 TWh in 2011 (source: Terna) with a very small increase (0.6%) over the previous year.

5.2.1 Demand

The decrease in purchases on the MGP has affected almost all the national zones. This trend reflects the sharp acceleration of the downtrend in place since 2010, in the relationship between peak and off-peak prices, which is likely to continue in 2012 because of the rise of photovoltaic capacity installation, which is significantly contributing to the increase in the level of competitiveness during peak hours. The reduction of purchases in foreign zones is significant as it fell to a new low record of 3.5 TWh in 2011 (though increased by 65% in 2012). Year 2011 confirms the high inelasticity of demand recorded on national zones, which remains equal to 0.2%, while on the borders, on the contrary, the share of elastic demand still constitutes the major part of the total demand (91.2%), due to the behavior of the operators aimed at looking for opportunities of cross-border trading.

5.2.2 Supply

Reinforcing a trend in existence for eight years, 2011 has seen a further increase in efficient power generation which rose to 121,542 MW (+10%). Increase in thermal power supply fell sharply with respect with the previous years (+1%) compared to a much more marked rise of renewables. The phenomenon is particularly significant with regard to photovoltaic plants, whose gross efficient power generation rose to 12,750 MW - 10% of the total power - marking a rise close to 270%. This led to a further strengthening of overcapacity, which is reflected in an increase in the national supply on MGP of about 30 TWh. Conversely, a slight contraction of (-3%) can be observed on the foreign virtual zones, but that seems to involve quantities offered at a relatively less competitive prices. In these zones, in fact, there is a recovery in sales (2.3%) which brings the total commercial export to values close to 50 TWh, displacing the most expensive national offers and fostering a new increase in the share of sales of MGP satisfied from foreign supply (16%, +1%). The decline in overall sales volume in the MGP (-2.2%) is, therefore, concentrated solely on national zones affected by oversupply. In a context of extreme weakness of electrical consumption, the strengthening of supply induced mainly by the massive increase in production from renewable sources favored, in 2011, a further reduction of concentration and market power, intensifying the dynamics which developed since the beginning of the market.

5.2.3 Sales and source and technology performance

The increase in installed capacity from renewable sources has resulted in a strong increase in sales from these sources on the MGP. In detail, sales of wind and "other renewable technologies" (which includes photovoltaic) reached a historical record of respectively 7.2 TWh (+29%) and 14.5 TWh (+24%), meeting 7% of total purchases. Combined cycles sales fell to 138.5 TWh (-7%) as a result of the inflationary dynamics of raw material gas which has helped to reduce the competitiveness of this technology offers. Hydropower supply sharply fell in sales (-6 TWh), also due to the fall in sales from pumping plants (-1 TWh). Interestingly, coal-fired plants saw an increase in sales (+4.9 TWh), almost entirely concentrated in the Centre South, where sales from this source rose to 13.2 TWh, marking a record growth of 214%. The share of sales from wind and solar power has increased from below 3% to 5% of the total, helping to significantly increase the competitiveness at the margin in those hours and, consequently, to contain the growth of prices. All of these trends continued, though at a slower rate, during 2012.

The combined cycles and technologies classified as "other thermal" - which heads for the most cogeneration and self-producers and waste-to-energy plants - have experienced, in fact, a significant reduction in the success rate, defined as the ratio between sales and volumes offered, and a decrease in the average number of hours with accepted bids. The most important aspect the spark spread, which in 2011 reached an average value of €5.66/MWh (-€3/MWh approximately) which, however mediates quite different zonal values. Analysis showed a reduction in profit margins that affected both the more efficient units (the ones less exposed to competition), and both the less competitive ones. With regard to other energy sources and technologies, there was an increase in the success rate of coal-fired plants (75%, +3% to previous year), consistent with this increase in sales from this source and a more competitive cost structure than other heat sources.

6. Methodology

The goal of this thesis is to assess whether the risk of price spikes in the Italian day-ahead market has changed after the introduction of the Italian-Slovenian market coupling. For this purpose a two-regime switching model along the research of Huisman and Kilic (2012) is employed. This type of model allows examining the prices' behavior under normal and non-normal market conditions and has been successfully applied to describe the behavior of day-ahead prices in the past (see also: Huisman (2008), Mount et al. (2006)).

As has been noted in chapter 4, electricity prices present certain characteristics that differentiate them from other economics variables. Mean-reversion and spikes add greater complexity to the task of analyzing the prices' behavior. Since spikes are not isolated phenomena but are usually recurrent, it is possible to consider the behavior of the time series of prices as cycling between different regimes. In fact, the risk of occurrence of spikes in prices implies that time series models with constant parameters can be defective in the description of their evolution.

Regime-switching models are time-series models in which parameters can have different values according to the regime the model is currently in. Such models includes a stochastic process which is assumed to have generated the regime shifts, therefore allowing for model-based forecasts which incorporate the possibility of future regime shifts. The regime currently operating is generally unobserved (it is directly observable only in a few situations at any point in time), therefore, in order to establish in which regime the process was in at past points in time, statistical inference must be used. The regimes might be non-recurrent: in this case the model can capture permanent "structural breaks" in model parameters.

There are two categories of regime-switching models: "threshold" models and "Markov-switching" models. The main difference between the two categories consists in how they model the evolution of the state process. Threshold models have been introduced by Tong (1983) and assume that regime shifts are triggered by the level of observed variables in relation to an unobserved threshold. Markov-switching models have firstly been introduced into econometrics by Goldfeld and Quandt (1973) and assume that the regime shifts evolve following the outcome of an unobserved, discrete, random variable, which is assumed to follow a Markov process, therefore according to a Markov chain. Markov-switching models became popular after the publication of a seminal paper by Hamilton (1989). For further information it is suggested to refer to Hamilton and Raj (2002) and Hamilton (2005) for an overview of Markov-switching models types and to Hamilton (1994) and Kim and Nelson (1999) for textbook analysis.

In the base model employed for this analysis s_t is defined as the natural logarithm of the day-ahead price for delivery of 1MW on day t and is defined as the sum of a deterministic component d_t which accounts for predictable factors affecting the day-ahead price such as the mean-price level and seasonality and x_t, a stochastic component which represents the unpredictable factors that affect the day-ahead price, such as sharp increases or decreases in demand and supply. s_t is then defined as:

$$S_t = d_t + x_t \quad (1)$$

The deterministic component d_t can also be split in two different components: a mean price level μ_1 and a dummy variable w_t which allows for different prices during the week and weekend days. The dummy variable is equal to 1 if t is a weekend day or 0 otherwise. The deterministic component can then be written as:

$$d_t = \mu_t + \beta w_t \ (2)$$

Where the parameter β is a measure of the deviation between prices for delivery in weekend days and prices for delivery in working days and is therefore expected to be negative, since weekend days generally show lower prices than working days.

The stochastic component x_t takes a different form according to the regime in which the market is. The two-regime switching model is composed by a normal regime (regime 1) which describes the day-ahead market in its normal behavior. In this regime, the evolution of prices follows a mean-reversion model. As already noted in paragraph 4.1.3 the main motivation for the use of a mean-reversion model is that electricity prices exhibit the same mean-reversion characteristics of other commodities. Since supply is fixed in the short-term, a sharp and sudden increase in demand will increase the electricity price. However if demand remains over the average level, additional supply becomes available and lowers the price. The mean-reversion model for the stochastic component is defined as:

$$X_t = (1 - \alpha)x_{t-1} + \sigma_1 \epsilon_{1,t} \qquad (3)$$

Where α is the speed of mean reversion, $\epsilon_{1,t}$ is the error term in regime 1 and is assumed to follow a normal distribution and is multiplied with σ_1, the standard deviation of the error term in the normal regime. Regime 2 describes the behavior of the electricity price under non-normal market conditions which can result to a shock in the price level. The stochastic component in this regime is modeled as a random price shock on the mean price level μ_2, given by a normally distributed error term $\epsilon_{2,t}$ multiplied with σ_2, the standard deviation of the electricity price in regime 2.

$$X_t = \mu_2 + \sigma_2 \epsilon_{2,t} \qquad (4)$$

R_t denotes the regime in which the electricity market is on day t and follows a Markov process which switches between the two regimes with constant transition probabilities. The probability that the market is in regime i in day t given that the market was in regime j the day before is defined by the following equation:

$$p_{i,j} = \Pr\{R_t = i | R_{t-1} = j\} \qquad (5)$$

Therefore $p_{1,1}$ represents the probability that the electricity market is in regime 1 on day t stays in the same in regime the following day and $p_{2,1} = 1 - p_{1,1}$ represents the probability that the market switches from regime 1 to regime 2. These two probabilities are not directly estimated; instead a logistic transformation is used in order to guarantee that the range of estimated probabilities is comprised between zero and one. After the logistic transformation the transition probabilities are represented by the following equation:

$$P_{i,i} = \frac{1}{1+e^{-\lambda_i}} \qquad (6)$$

Maximum-likelihood estimation is then employed to estimate the parameters of the two-regime switching model: $\lambda_1, \lambda_2,\ \mu_1, \beta, \alpha,\ \mu_2,\ \sigma_1, \sigma_2$.

Analyzing the changes in the parameter estimates it is possible to determine whether the risk of price spikes has changed over time, therefore the parameters are estimated for every year (2005 to 2012) available in the sample. The risk of price spikes is expected to decline over the years due to the developing of the liberalization process and the increased connectivity between the different Italian zones, but the main interest is whether the introduction of the market coupling between the Italian and the Slovenian market has led to remarkable changes in the parameters estimates under non-normal market conditions (the second regime).

6.1 Alternate model specification

In addition, an alternate specification for the regime switching model is examined in order to carry out the analysis over the whole time period 2005-2012 instead of doing it for for each single year. An additional dummy variable I_t is introduced to distinguish whether the day t is a market coupling day. Therefore, I_t is equal to one if t is a day after the introduction of the market coupling mechanism and zero if t is a day preceding it. The relevant equations of the model are then rewritten including this new dummy variable. Specifically, equations (2), (3), (4), (6) are rewritten as:

$$d_t = \mu_t + \beta w_t + \mu'_t I_t + \beta' w_t I_t \qquad (7)$$

$$X_t = (1 - \alpha - \alpha' I_t)x_{t-1} + \sigma^A{}_1 \epsilon_{1,t} \qquad (8)$$

$$X_t = \mu_2 + \mu'{}_2\, I_t + \sigma^A{}_2 \epsilon_{2,t} \qquad (9)$$

$$P_{i,i} = \frac{1}{1+e^{-(\lambda_i+\lambda'{}_i I_t)}} \qquad (10)$$

Where the parameters $\mu, \alpha, \beta, \gamma$ now refer to the time period before the introduction of the market coupling mechanism and the parameters $\mu', \alpha', \beta', \lambda'$ are, respectively, the changes in the mean price level, the speed of mean reversion, the weekend effect and the probability of staying in the same regime caused by the introduction of the market coupling mechanism. In order to incorporate the dummy variable I_t , the standard deviations (σ_1, σ_2) are also rewritten as follows:

$$\sigma^A{}_i = \sqrt{(\sigma_i + \sigma'{}_i I_t)^2} \quad (11)$$

Where $\sigma^A{}_i$ is the standard deviation in each regime ($i = 1,2$) incorporating the market coupling effect.

With this different specification, the changes in the parameters estimations before and after the introduction of the market coupling are examined. The expectation is to obtain not only similar but also more accurate results with respect to the specification of the original model, because this specification avoids to introduce the arbitrary division of data between single years and fully captures the market coupling effect on the entire time period basis.

7. Data and descriptive analysis

For this analysis, the daily average day-ahead prices for the Italian power pool (IPEX) are used. Data for the Italian market is collected from the website[10] of GME[11] as hourly prices and ranges from January 2005 (when the IPEX became fully operative, allowing the participation of the demand side to the market) to September 2012. The data for the Slovenian day-ahead prices (SIPX) is collected from the BSP Regional Exchange[12] website. Figure 7-1 depicts the evolution of MGP prices across the whole sample period.

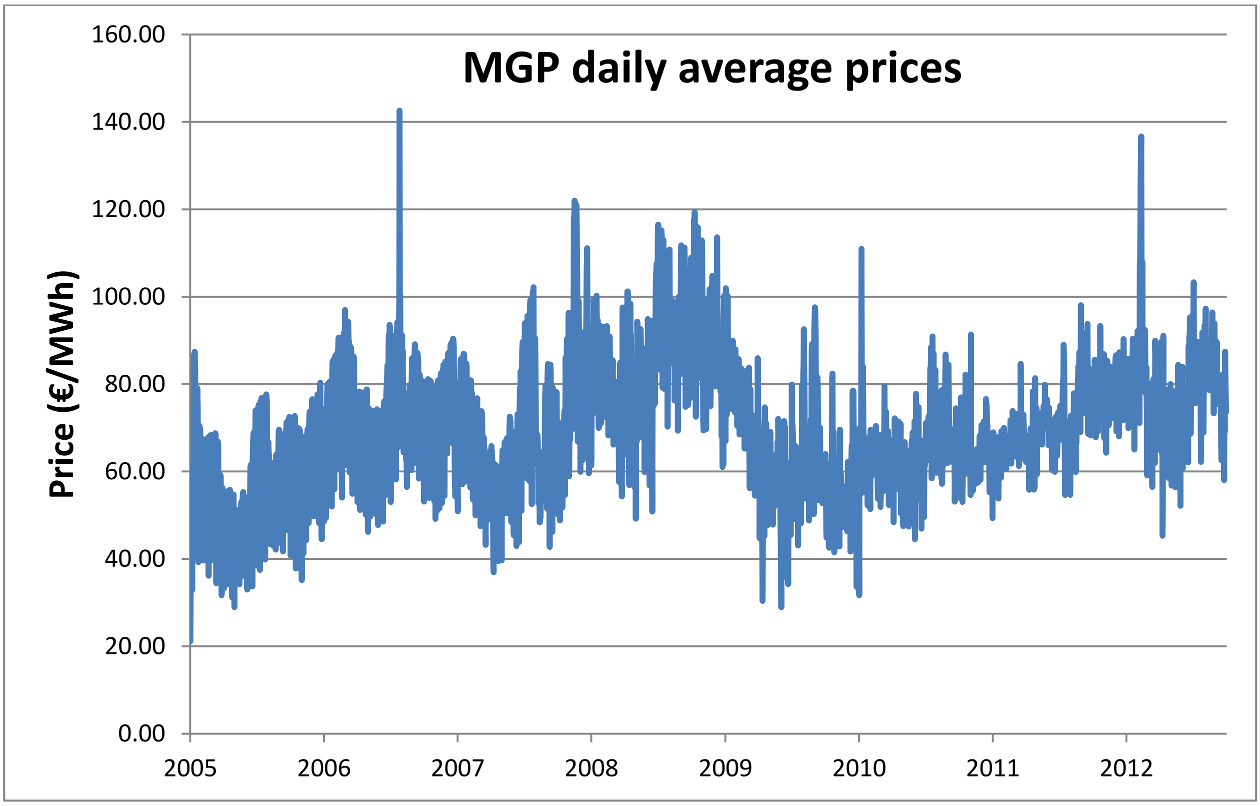

Figure 7-1 Prices evolution in the day-ahead market of IPEX between January 2005 and September 2012.

Table 7-1 reports the summary statistics summary statistics of the MGP for the years 2005-2012. The average price reached a maximum in 2008 and then decreased. Among other factors, this can be attributed to the effect of the economic crisis which reduced the demand (-6% in 2009, in 2011 it is still 2.6% lower than 2008) and therefore the volumes traded on the MGP. The patterns for the maximum and minimum value are less clear. The maximum value, after a sharp increase in 2006, followed a

[10] www.mercatoelettrico.org.

[11] GME is the company with the "mission of organizing and economically managing the Electricity Market, under principles of neutrality, transparency, objectivity and competition between producers, as well as of economically managing an adequate availability of reserve capacity".

[12] BSP South Pool is power exchange for the Slovenian and Serbian markets. www.bsp-southpool.com.

decreasing trend, with the exception of 2010 and 2012. Standard deviation sharply decreased in 2010 and 2011 but rose again in 2012. Skewness and kurtosis tend to be small, with the exception of 2010 and 2012. As these are measures of price uncertainty it is not a surprise that their value is higher in the years where the most extreme price spikes are observed. Together with the trend of prices depicted in Figure 6-1, the descriptive statistics for MGP confirm the existence of extreme price spikes caused by shocks on the demand and/or supply side.

Statistic	2005	2006	2007	2008	2009	2010	2011	2012-Sep
Mean	58.59	74.75	70.99	86.99	63.72	64.06	72.24	78.78
Median	60.13	76.61	68.44	85.97	62.02	63.01	71.04	78.88
Maximum	87.39	142.60	122.00	119.39	101.94	110.94	98.07	136.67
Minimum	21.14	46.19	36.92	49.19	28.91	31.67	53.80	45.29
Stdev	12.67	12.60	15.35	13.06	12.95	8.22	7.89	10.94
Skewness	-0.30	0.06	0.61	0.04	0.38	1.01	0.41	1.08
Kurtosis	-0.74	1.33	0.54	-0.08	-0.07	3.89	-0.25	5.58
N. Obs	365	365	365	366	365	365	365	274

Table 7-1 Descriptive statistics for the IPEX MGP (day-ahead) prices

Table 7-2 reports the summary statistics for the prices of the day-ahead market of the BSP South Pool, Slovenian power exchange which opened in 2010[13]. Though this is a very young market and absolute conclusions cannot be drawn, it is interesting to note that the average price increases from 2010 to 2011 and is it is almost the same in 2012. The maximum value not only increased from 2010 to 2011 but skyrocketed in 2012. The Minimum value in 2011 reaches €0 on Sunday April 3rd. It is difficult to analyze this value, but it can be noted that on that particular day the traded volume are less than one-third of the volumes of the same month's Sundays. BSP states that in April 2011 the 14.8% of total Slovenian consumption was traded on the power exchange, so it possible to assume that on April 3rd the demand was satisfied outside of the market.

Anyway, the general trend of the market is coherent with the existing literature and theory on the effects of market coupling. In 2012 the maximum value is observed on 10th February: the same happens for the Italian market. Correlation between the prices of the two markets increased from 34.9% in 2010 to 60.5% in 2011 and 63.2% in first nine months 2012. As explained by Parisio and Bosco (2008) market coupling increases price convergence between the markets but can also lead to a reduction of the consumers' surplus in the exporting country and, according to Boffa and Scarpa (2009), a reduction in overall social welfare.

[13] Data is available from 18th March 2010 onwards.

Statistic	2010	2011	2012-sep
Mean	46.24	57.20	56.05
Median	46.45	57.60	53.34
Maximum	71.10	88.11	137.92
Minimum	24.51	0	18.98
Stdev	8.64	11.41	18.20
Skewness	-0.01	-0.27	0.93
Kurtosis	0.05	1.77	2.30
N.Obs	289	365	274

Table 7-2 Descriptive statistics for the BSP South Pool day-ahead prices

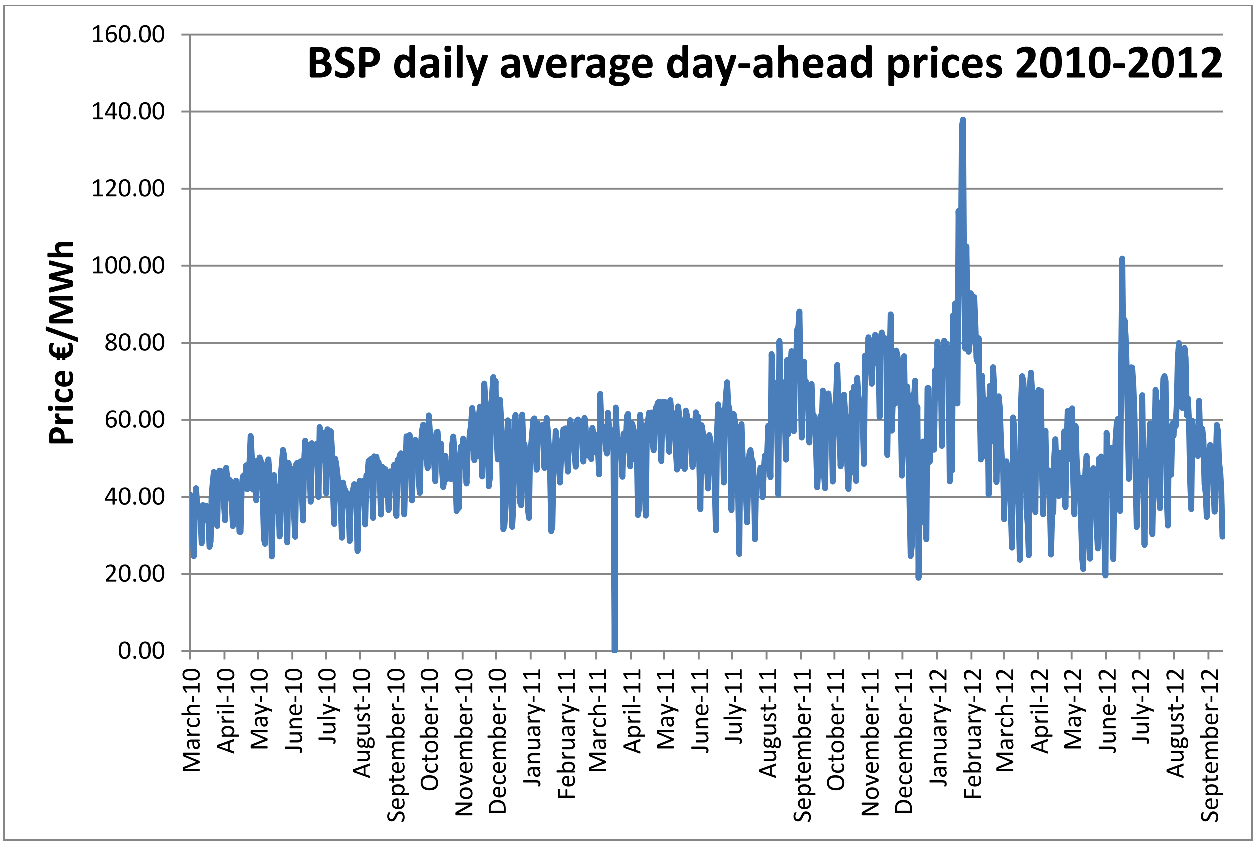

Figure 7-2 Prices evolution in the day-ahead market of BSP between March 2010 and September 2012

Price spikes which hit both the markets in February 2012 can be explained by the exceptionally bad weather that hit Europe and Italy in the first half of February 2012. Severe weather conditions led to a widespread increase in electric prices because of the demand increase for residential and service sector use and the reduction of net imports because of the existing tensions on the other power exchanges due to prices increase. In this month prices reached record levels in the North Zone of IPEX and in BSP power exchange, respectively equal to €89.58/MWh and €85.78/MWh. The greater increase of the

Slovenian price determined the narrowing of the price differential with the Italian, which fell to €3.8/MWh, a new minimum value since the beginning of market coupling. On the 17th and 18th of February, the Slovenian price resulted even higher than the Italian one[14]. In this framework, in February 2012 market coupling allocated 395 MW of cross border capacity, of which 96.4% of hours in imports to Italy and the remaining 3.6% of the hours in exports to Slovenia.

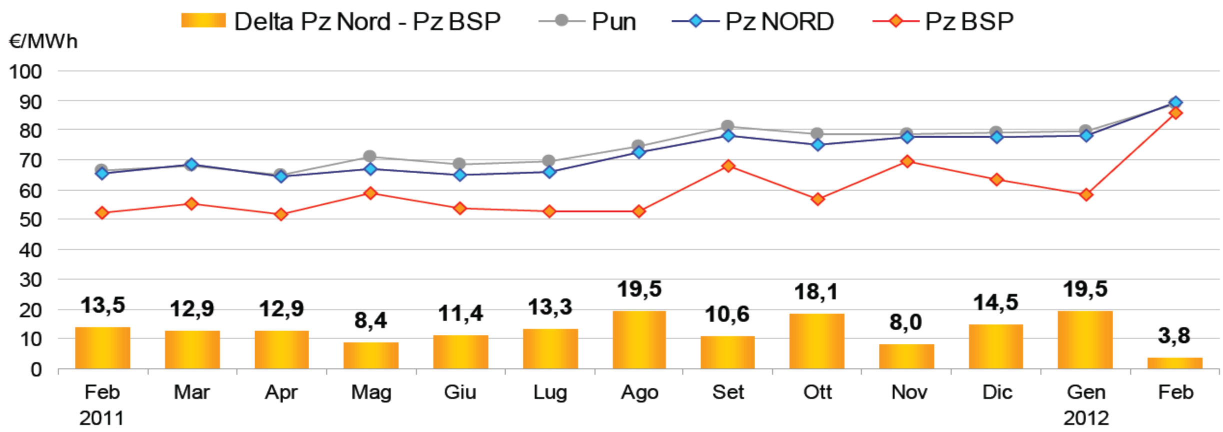

Figure 7-3 North zonal price – BSP price differential Feb 2011 to Feb 2012. Source: GME.

[14] Source: Newsletter n.47 GME http://www.mercatoelettrico.org/Newsletter/20120315newsletter.pdf

8. Results

Table 8-1 displays the parameter estimates obtained from the application of the base regime-switching model to the Italian daily average day-ahead prices. The parameters are almost all significantly different from zero at the 95% confidence level, except λ_1 in 2009, λ_2 in 2006 and 2007, μ_2 in 2006, 2010 and 2011. This means that for 2006, 2010 and 2011, the stochastic component of the price model depends in the non-normal regime only by the shock component.

ITALY	λ_1	λ_2	μ_1	β	α	μ_2	σ_1	σ_2	p_{11}	p_{22}
2005	4.198 (0.556)	3.067 (0.463)	4.238 (0.010)	-0.365 (0.012)	0.657 (0.056)	-0.253 (0.016)	0.087 (0.004)	-0.144 (0.010)	0.985 (0.556)	0.955 (0.463)
2006	2.564 (0.702)	-20.798* (387.038)	4.369 (0.015)	-0.260 (0.012)	0.393 (0.050)	0.009* (0.037)	0.102 (0.004)	0.088 (0.020)	0.929	9.276D-10
2007	3.626 (1.075)	1.061** (0.776)	4.332 (0.029)	-0.234 (0.013)	0.201 (0.053)	-0.217 (0.111)	0.102 (0.011)	0.209 (0.045)	0.974	0.743
2008	4.478 (0.727)	4.264 (1.095)	4.551 (0.016)	-0.126 (0.012)	0.458 (0.066)	-0.167 (0.018)	-0.090 (0.004)	0.126 (0.009)	0.989	0.986
2009	13.011** (42.593)	4.097 (1.009)	4.105 (0.020)	-0.078 (0.015)	0.440 (0.048)	0.301 (0.022)	0.150 (0.0069	-0.081 (0.008)	1.000	0.984
2010	2.827 (0.470)	2.609 (0.553)	4.187 (0.021)	-0.065 (0.010)	0.253 (0.060)	-0.033** (0.025)	0.066 (0.005)	0.131 (0.009)	0.944	0.931
2011	3.508 (0.602)	1.115 (0.543)	4.290 (0.016)	-0.049 (0.008)	0.228 (0.040)	-0.021** (0.039)	0.064 (0.004)	0.125 (0.018)	0.971	0.753
2012	4.735 (1.026)	4.324 (1.030)	4.432 (0.020)	-0.099 (0.013)	0.367 (0.061)	-0.126 (0.022)	-0.085 (0.005)	-0.116 (0.009)	0.991	0.987

Table 8-1 Parameter estimates for the Italian market (Standard Errors are in parenthesis)

*** significant at the 90% confidence level**

**** non-significant**

It is not surprising to note that the mean price level in the normal regime (μ_1) increases until 2008 and drops afterwards, because of the effects of the financial and economic crisis on the electricity demand. This parameter is now trending back towards the 2008 value but it has not reached it yet in 2012.

The mean price level in the non-normal regime (μ_2) displays an up-and-down trend in the first years but is consistently declining since 2009, reaching its lowest value in 2012, therefore its value might have been influenced by the market coupling.

The probability of a spike occurrence ($1 - p_{11}$) which was basically 0 in 2009, after increasing in 2010 has decreased again in 2011 and 2012. Spikes are still present but their impact reduced as also the decreasing values of μ_2 confirm.

The speed of mean reversion under normal market conditions α did not show a particular trend but, after being stable in 2011, ultimately increased in 2012, meaning that price changes are less random and therefore the market is less efficient. This is probably because the dependence of electricity prices from fuel (oil and gas) prices and because of the effects on the European power exchanges of the severe weather conditions of January and February 2012 which have already been outlined in chapter seven.

Volatility estimate in the normal regime (σ_1) again shows an up-and-down trend, but after reaching its maximum value in 2009 declines from 2010 and reaches its minimum in 2012. Volatility in the non-normal regime (σ_2) also declines consistently in 2012. Such a low volatility means that the expected price spikes level can be easily predictable: a small variation means that the spike value will not differ much from the average spike size, which means that the spikes are becoming less variable over time. The decrease in σ_2 and μ_2 which is observed in 2011 and 2012 means that the MGP day-ahead prices have become more stable and this is probably also due to the introduction of the market coupling.

The estimated parameters for σ_1 and σ_2 seem to be slowly converging after 2009. In order to verify this, a two-sample t-test can be employed, verifying the significance of the difference between the estimated parameters of volatility in the two regimes. For this test the function t is defined as:

$$t = \frac{x_1 - x_2}{\sqrt{SE_1{}^2 + SE_2{}^2}} \qquad (11)$$

Where $x_1 = \sigma_1$, $x_2 = \sigma_2$ and SE_1 and SE_2 are respectively the standard error of σ_1 and σ_2. Table 8-2 reports the results and shows that, with the exception of 2006, the volatility in the two regimes are significantly different.

Year	T-test value
2005	21.718
2006	0.682*
2007	-2.287
2008	-22.366
2009	23.741
2010	-6.500
2011	-3.391
2012	2.951

Table 8-2 Independent Two-sample t-test value for volatility in the normal and non-normal regime

*** Statistically not significant. All other values are statistically significant at the 5% level of significance**

The weekend factor β, which is the difference in mean price level between weekend and workdays, shows a significant rise since 2005 but remained more or less stable since 2009. This implies that the difference between weekend and workdays mean log price is smaller and thus the weekend seasonality effect has become smaller since the introduction of the power exchange

As a final analysis point, the convergence through time of the parameters of the Italian and Slovenian markets is verified by looking at the significance of difference between them with an independent two-sample t-test. For this test the function t is defined as in equation (11), where x_1 and x_2 are respectively the estimated parameters for the two markets and SE_1 and SE_2 are respectively the standard errors of the estimated parameters in the two markets.

Table 8-3 reports the results of the t-test and shows that in some cases the estimated parameters are not significantly different, therefore the two markets show some sign of convergence. It is possible to observe that the difference in spikes probability is never significantly different.

	λ_1	λ_2	μ_1	β	α	μ_2	σ_1	σ_2
2010	-1.511*	0.306*	8.415	9.138	-0.832*	5.466	22.207	16.693
2011	0.735*	-0.695*	5.777	9.741	0.595*	0.181*	-3.691	12.763
2012	1.655*	2.443	4.955	7.146	2.467	0.563*	6.092	5.019

Table 8-3 Independent Two-sample t-test value for the parameters of the Italian and Slovenian market
*** Statistically not significant. All other values are statistically significant at the 5% level of significance**

λ_2 , which represents the probability that the market is in the non-normal regime and stays in the non-normal regime for the following day, is significantly different only for 2012. Similarly, the test for the speed of mean reversion α is also significant only for 2012. The t-test for the mean price level in the non-normal regime, (μ_2) instead, is significant only in 2010. This implies that mean price level during the non-normal regime has been converging. However, there is no concrete evidence that the two markets appear to be converging in the short-term and this might be due to a few different aspects. First of all the quantity of data available for comparison is really short, secondly the markets have really different characteristics, both in structure and in size, thirdly the market coupling mechanism has been in place only for 21 months and its allocated capacity is still fairly limited.

8.1 Results for the alternate model specification

Table 8-4 displays the results for the alternate model specification described in paragraph 6.1. The table reports the parameters' estimates before the introduction of the market coupling in the first row, the market coupling effect observed with the introduction of the dummy variable I_t in the second row, and the parameter estimates after the introduction of the market coupling (therefore the sum of the values in row 1 and 2) in row 3.

Before Coupling	μ_1	μ_2	β	α	σ_1	σ_2	λ_1	λ_2	p_{11}	p_{22}
	4.076 (0.046)	-2.227 (0.338)	-0.182 (0.006)	0.069 (0.019)	0.109 (0.003)	0.218 (0.012)	3.278 (0.207)	1.551 (0.246)	0.964	0.825
MC Effect	μ'_1	μ'_2	β'	α'	σ'_1	σ'_2	λ'_1	λ'_2	p'_{11}	p'_{22}
	0.234 (0.047)	-3.270 (1.219)	0.114 (0.009)	0.207 (0.035)	-0.031 (0.004)	-0.089 (0.016)	2.255 (0.861)	2.923 (1.114)	0.996	0.989
After Coupling	$\mu^A{}_1$	$\mu^A{}_2$	β^A	α^A	$\sigma^A{}_1$	$\sigma^A{}_2$	$\lambda^A{}_1$	$\lambda^A{}_2$		
	4.310 (0.093)	-5.404 (1.557)	-0.068 (0.015)	0.276 (0.054)	0.078 (0.007)	0.129 (0.028)	5.533 (1.068)	4.474 (1.360)		

Table 8-4 Parameter values for the Italian market calculated with the alternate model (Standard Errors are in parenthesis)

Differences from the previous model are immediately evident, since now all the parameters are statistically significant at the 95% confidence level.

The mean log price level in the normal regime (μ_1) increases after the introduction of the market coupling, signaling a significant higher price. Of course, this change is not due only to the introduction of the market coupling but also to the evolution of the Italian market and the legislative, technical and economic factors which influenced it. The price level in the non-normal regime (μ_2) sharply declined, indicating that after introduction of the coupling mechanism extreme price levels decreased. The weekend effect parameter (β) increased: this means that the difference between the week and weekend prices became smaller as the weekend prices increased, determining an increase in the overall efficiency of the market. Consistently with the original model, the speed of mean reversion (α) increased, meaning that the changes in prices are less random and, therefore, the market has become less efficient, therefore countering the positive effect of the change in the weekend effect parameter. As expected from theory and previous literature, volatility both in the normal and non-normal regime (σ_1, σ_2) is significantly lower. The increase in the parameter (λ_1) indicates a significant increase in the probability that the market stays in the normal regime after the introduction of the coupling, therefore the risk of price spikes has decreased. This is confirmed by looking at the decrease in the probability of spikes occurrence ($1 - p_{11}$) concerning the market coupling effect.

Employing this alternate model not only gives results which are consistent with the ones of the original model, but presents some benefits. First of all, with this specification all the parameters are statistically significant. Secondly, the effect of the market coupling is clearer, since it not examined anymore on the single years, but on the whole period of existence of the market, therefore it is possible to state that this model allows to fully capture the market coupling effect.

9. Conclusions

In this work, the historical values of the day-ahead electricity prices in the Italian market are analyzed. The period of analysis spans from the fully operational start of the Italian power exchange, 1st January 2005, to the most recent data available, 30th September 2012. The main focus, however, is set on the last two years, 2011 and 2012, and concerns the introduction of the market coupling mechanism between the Italian and the Slovenian day-ahead electricity markets. The goal is to verify whether the risk of price spikes has declined as a consequence of the market coupling, as it has been verified for other countries in previous literature. Firstly, the same methodology of Huisman and Kilic (2012) is applied. The authors analyzed various European markets which became more interconnected over the years and concluded that the increased connectivity and liquidity led to a decrease in volatility and in the impact of price spikes. A regime-switching model with two regimes, normal and non-normal, is employed. The use of such a kind of model allows to model spikes by considering two different market conditions: a normal and a non-normal market condition under which price spikes happen. In addition, a completely new specification of a regime-switching model, which does not arbitrarily divide data between single years, is employed in order to fully capture the market coupling effect. The results from this alternate model are quite encouraging and lay the basis for further refinement and research.

As already outlined in the literature review in chapter 2, the expectation is that the increased connectivity due to the market coupling mechanism yields additional supply in the short-term and reduces the impact of price spikes. The results obtained from the application of the regime-switching model show that in reference to 2010, the year before the introduction of market coupling, the risk of price spikes and volatility have consistently declined, in line with what has been observed for other markets. There is no evidence, however, of a convergence in the short period between the two markets but this outcome might be influenced by the short period of analysis and by the different characteristics of the two markets. The only parameter that does not react according to theory and previous literature is the speed of mean reversion. Future research could concentrate on analyzing the causes behind this in order to help lay down policies to help the Italian market become more efficient.

The outcome of this research confirms the positive effects which can be obtained from the introduction of a decentralized market coupling mechanism between neighbor countries. The Italian-Slovenian market coupling was also introduced as a preliminary test for the Price Coupling Of Regions project that GME is carrying on with other countries' network operators and its positive effects confirm the necessity for GME to put additional market coupling mechanisms into action in order to smooth out the high volatility and the price spikes risk which still characterize the MGP market, with the goal of creating a more efficient market.

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