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Measuring the impact of market coupling on the Italian electricity market using ELFO++

Elisabetta Pellini

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MEASURING THE IMPACT OF MARKET COUPLING ON THE ITALIAN ELECTRICITY MARKET USING ELFO++

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ABSTRACT

This paper evaluates the impact on the Italian electricity market of replacing the current explicit auction mechanism with market coupling. Maximizing the use of the cross-border interconnection capacity, market coupling increases the level of market integration and facilitates the access to low-cost generation by consumers located in high-cost generation countries. Thus, it is expected that a high-priced area such as Italy could greatly benefit from the introduction of this mechanism. In this paper, the welfare benefits are estimated under alternative market scenarios for 2012, employing the optimal dispatch model ELFO++. The results of the simulations suggest that the improvement in social surplus is likely to be significant, especially when market fundamentals are tight.

JEL Classifications: C61; C63; D40; L10; Q40.

Key Words: Market coupling, market integration, Italian day-ahead electricity market.

Measuring the impact of market coupling on the Italian electricity market using ELFO++*

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1 Introduction

Since the second half of the 1990s, European Countries have started a long process of liberalization of their electricity supply industries with the aim of building an internal electricity market (IEM henceforth). The IEM in turn represents the key tool for achieving the EU long-term energy policy goals of competitiveness, sustainability and security of supply, included in the EU energy policy papers of the last two decades (i.e. EC, 1995; EC, 2007b; EC, 2010).

In 2011, fifteen years after the enactment of first electricity directive 96/92/EC, the realization of the IEM is still a work in progress. The delay in the achievement of market integration has often been attributed to the general approach that was followed during the initial stages of the reforms. Among others, Vasconcelos (2009) points out that the main drawbacks of the first electricity directive included the freedom granted to Member States in the adoption of the first directive's general principles and that important issues, such as the definition of common rules for the opening of wholesale and retail markets and also for enabling cross-border trade, were not addressed. However, since 2009 there has been significant progress towards the creation of the IEM due to the introduction of a bottom-up regional approach and to the enactment of the Third Legislative Package[1]. Particular progress has been made with respect to the issue of cross-border trade of electricity and several actions have been taken by different stakeholders, (i.e. European Commission, transmission system operators and energy regulators), to improve the management of the interconnections so as to increase the amount of available transmission capacity between several countries. The limited amount of available interconnection capacity between several countries is

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[1] The Third Legislative Package includes Directive 2009/72/EC, Regulation 713/2009/EC and Regulation 714/2009/EC.

closely related to the mechanism currently used to address the problem of network congestions. In particular, one of the most significant sources of inefficiency stems from the use of the explicit auction mechanism to allocate the daily available cross-border capacities to market participants. At the European level, the solution devised to this problem consists of replacing the explicit auction mechanism with the implicit auction mechanism, so-called market coupling. By internalizing the cross-border capacity allocation in the day-ahead energy market, market coupling is able to guarantee the efficient use of the interconnectors.

The economic literature on market integration stresses that countries with high-variable cost generation capacity are expected to obtain a positive welfare from integration. The Italian electricity market represents a suitable case-study to test this assumption. In particular, this paper evaluates the welfare effects of introducing market coupling to allocate the daily available cross-border interconnection capacity between Italy and its neighbouring countries, namely France, Switzerland, Austria, Slovenia and Greece[2]. Two alternative market scenarios are simulated for the year 2012[3], using the optimal dispatch model ELFO++. The first scenario, called the *Reference Scenario*, reflects the characteristics and the dynamics most likely to occur in the marketplace, namely an electricity demand that remains weak over the year, reflecting a climate of uncertainty surrounding the Italian economy, and overcapacity on the supply side of the market. In contrast, the alternative *High Scenario* sets out the key variables of the electricity market assuming tighter market fundamentals, namely higher demand and higher cost of producing electricity. For each scenario, four alternative cases are modelled, namely Perfect Competition, Business As Usual, Market Coupling and Market Coupling with producers of Northern Italy acting as price takers[4]. These four cases feature alternative models of allocating cross-border transmission capacity, that is, explicit auctioning and market coupling, and alternative market settings (perfect and imperfect competition).

The remainder of the paper is organized as follows. Section 2 provides an overview of the cross-border congestion management methods used in Europe, highlighting the weaknesses of the current methods and the strengths of those proposed. Section 3 reviews the main economic literature on market integration, comparing the results of both theoretical and empirical work. Section 4 summarises the structure of the markets included in this study and explains the rationale for

[2] Since January 2011, a mechanism of market coupling is being implemented on the Italy-Slovenia border.
[3] Employing 2012 allows the best reflection of actual Italian electricity market fundamentals, while adopting either 2010 or 2011 would result in biased outcomes, given that over these two years the electricity market fundamentals have been significantly affected by the recession of the Italian economy. Forecasting beyond 2012 would require knowing how the capacity payment, introduced with Resolution ARG/elt 98/11, should be incorporated into the simulation model.
[4] Northern Italy is the zone that would be most largely affected by market coupling given that it borders all the neighbouring countries but Greece.

choosing Italy as the object of this welfare analysis. Section 5 describes the electricity market simulation model ELFO++, while Section 6 presents the assumptions used to build the alternative market scenarios. Section 7 reports the results of the simulations and carries out the welfare analysis. Section 8 concludes and provides a brief description of questions for further work.

2 Criticisms in market integration: cross-border congestion management methods

The economic literature addressing the issue of market integration, (see for instance Turvey, 2006; Domanico, 2007 and Creti et al., 2010), highlights that increasing the level of interconnection among separated electricity markets is expected to bring several benefits. First, market integration would enhance economic efficiency, because if a more diversified plant mix can be dispatched, the probability that demand is met by the least-cost producer increases. Second, it would reduce market concentration, given that cross-border trade opens the national markets to foreigner participants and hence it would also diminish the probability of national incumbents exercising market power. Third, it would strengthen security of supply, as several interconnected systems work as back-up for each other. Finally, it would mean a reduction in the required reserve capacity, because at any given point in time an interconnected country could rely on its neighbours' capacity, thus decreasing the internal level of spare capacity. However, all these benefits can only be exploited if the national transmission system operators (TSO) coordinate and actively cooperate with each other when dispatching their respective systems.

Despite these potential benefits, the EU-wide market integration has proved to be a complicated target to achieve. Since the enactment of the Directive 96/92/EC, the liberalization reforms[5] have not been implemented uniformly in Member States, with the result that alternative market designs have emerged across Europe. In addition, there has been a problem of insufficient interconnection and of inefficient use of the available transmission capacity between Member States, as the interconnectors were historically designed to provide back-up for sudden faults rather than to facilitate trade between countries.

[5] Liberalisation reforms of the electricity sector have been implemented by the enactment of the following European Directives: Directive 96/92/EC, known as the "First Electricity Directive"; Directive 2003/54/EC known as the "Second Electricity Directive", Regulation 1228/2003/EC on cross-border trade in electricity; Directive 2009/72/EC, Regulation 713/2009/EC and Regulation 714/2009/EC which are part of the so-called "Third Legislative Package".

In 2006, to speed up the process of market integration, the European Regulators' Group for Electricity and Gas (ERGEG) launched a project called Electricity Regional Initiatives (ERI), setting up seven electricity regions in Europe (see Table 1) as an interim stage towards complete market integration. ERI are based on the voluntary cooperation of several stakeholders across the European Union, namely regulators, TSO, power exchanges, generation companies, consumers, Member States and the European Commission. A country is allocated to an ERI based on the countries with which it shares a geographical border and therefore may be involved in several ERIs. Each region has a lead National Regulatory Authority (NRA) which coordinates the activities, as indicated in the second row of Table 1.

The main goals of the ERI are to identify and implement practical solutions to remove barriers to trade and facilitate regional market integration. Across the regions, common priorities associated with the development of cross-border trade and with the enhancement of competition include: the adoption of common congestion management methods to maximise the use of interconnection capacity, the development of new interconnectors, the increase of transparency in market information, the introduction of cross-border balancing markets and the identification of regulatory gaps among countries.

	Baltic States (BS)	Central East Europe(CEE)	Central South Europe (CSE)	Central West Europe (CWE)	Northern	South-West Europe (SWE)	France, UK, Ireland (FUI)
NRA	*Latvia*	*Austria*	*Italy*	*Belgium*	*Denmark*	*Spain*	*UK*
Austria		x	x				
Belgium				x			
Czech Republic		x					
Denmark					x		
Estonia	x						
Finland					x		
France			x	x		x	x
Germany		x	x	x	x		
Greece			x				
Hungary		x					
Ireland							x
Italy			x				
Latvia	x						
Lithuania	x						
Luxembourg				x			
Netherlands				x			
Norway					x		
Poland		x			x		
Portugal						x	
Slovakia		x					
Slovenia		x	x				
Spain						x	
Sweden					x		
United Kingdom							x

Table 1: Seven Electricity Regional Initiatives. Source: ERGEG.

This paper focuses on issues related to cross-border congestion management methods, and in particular on capacity allocation mechanisms. Cross-border congestion management methods are defined as a set of rules used to organize cross-border network access, including methods for the calculation of the available transmission capacity, mechanisms for the allocation of available transmission capacity to market participants and procedures to relieve potential congestion (Frontier Economics and Consentec, 2004 pp. 4-6).

Explicit Congestion Management Guidelines were first introduced as Annex to Regulation 1228/2003/EC, then amended in November 2006, and finally substituted by Annex I to Regulation 714/2009/EC. The key principle of the capacity allocation procedures of these Guidelines is that: *"congestion management methods have to be market-based, i.e. capacity can be allocated only by means of explicit (capacity) or implicit (capacity and energy) auctions. Both methods can be used on the same interconnection. For intra-day allocation continuous trading may be used."* (Paragraph 2.1).

Detailed rules of capacity calculation and capacity allocation methods are specified in the Framework Guidelines on Capacity Allocation and Congestion Management (CACM) for Electricity, published by the Agency for the Cooperation of Energy Regulators (ACER) in July 2011[6].

The Framework Guidelines envisage the following provisions regarding capacity allocation. The TSOs have the possibility to sell long-term[7] transmission rights in the form of either Financial Transmission Rights (FTR) or Physical Transmission Rights (PTR) with the "use-it-or-sell-it" clause. In FTR auctions, the TSO sells financial contracts that entitle the holder to receive, over a given period of time, the price difference between two interconnected countries, generated by the congestion. The holder does not have any right to physically use the interconnector. In contrast, in PTR auctions, the TSO sells to market participants the right to inject power in a country and to (simultaneously) withdraw power in another country over a given period of time. Moreover, under the "use-it-or-sell-it" clause, capacity holders must either use or sell the capacity in the day-ahead market. The Framework Guidelines establish that the day-ahead transmission capacity has to be allocated on the basis of implicit auctions using a price coupling mechanism. While for intra-day transactions, capacity is allocated implicitly with energy and under continuous trading.

[6] The Framework Guidelines confirm the principles of congestion management methods identified in the "target model of congestion management methods" developed by the Project Coordination Group of experts (PCG), established by ERGEG in 2008.
[7] Long-term is meant to be any period longer than a day, normally ranging from a week to several years.

Under the implicit auction mechanism, the day-ahead interconnection capacity between two countries is allocated simultaneously with energy flows, thus implicitly with respect to the energy auction. Implicit auctions can implement either the market splitting or the market coupling solution. In the case of market splitting, transmission capacity across two or more borders is allocated within the energy auction by a single power exchange, which splits the market into different price areas whenever the congestion occurs[8]. In the instance of market coupling, the power exchanges of different countries cooperate with each other to calculate the optimal energy flows among the several markets. There are two alternative approaches to implement market coupling, namely the centralised market coupling and the decentralised market coupling. Centralised market coupling involves the power exchanges collecting bids and offers from market participants and submitting them to a central matching unit (CMU) which runs an algorithm for clearing the markets. Alternatively, decentralised market coupling involves the power exchanges sharing bids and offers data to calculate simultaneously the allocation within their markets adopting a common matching algorithm.

Market coupling can take the form of either price or volume coupling. Under price coupling, the algorithm is able to determine prices, quantities and flows for each of the coupled markets, whereas under volume coupling only the net flows across the borders are calculated. Price coupling is the mechanism object of this analysis, as it is the one identified by ACER in the Framework Guidelines to be the target model for day-ahead capacity allocation. In this paper, the term market coupling refers always to price coupling.

EuroPEX (2003) sketches a procedure for decentralised price coupling, as follows. On the day-ahead of the delivery day, each TSO publishes the relevant interconnector capacities, while market participants submit the bids/offers to the power exchange (including bilateral contracts). Each power exchange forecasts a most likely cross-border flows scenario, on the basis of historical patterns and using bids/offers and performs a first market clearing for its own market, so determining the equilibrium price and quantity. Also, each power exchange calculates a net export curve that shows the relationship between the internal market price and the net export volume. Then, the power exchanges share their net export curves and calculate a new set of area prices and flows, with the objective of reducing price differentials, thus maximizing the usage of the cross-border capacity. Finally, each power exchange is responsible for notifying the TSOs with their power schedules resulting from the market clearing.

[8] This is what happens in the Nordic region and between Spain and Portugal

The market coupling/splitting projects currently in operations in Europe are summarize in Table 2.

Project Name	Description	ERI	Status
NordPool and Estonia	market splitting among Norway, Finland, Sweden and Denmark since 1999, extended to Estonia since April 2010	Northern and BS	On-going
Trilateral Coupling (TLC)	price coupling among Belgium, France and the Netherlands since November 2006	CWE	Ended and substituted by CWE coupling in November 2010
Iberian Electricity Market (MIBEL)	market splitting between Spain and Portugal since 2007	SWE	On-going
Czech Republic and Slovakia	price coupling between Czech Republic and Slovakia since September 2009	CEE	On-going
European Market Coupling Company (EMCC)	tight volume coupling between Germany and Denmark and Germany and Sweden since November 2009	CWE and Northern	Ended and substituted by CWE-Nordic ITVC coupling in November 2010
Central West Europe (CWE)	price coupling among Belgium, France, Germany (including Austrian area), Luxemburg and the Netherlands since November 2010	CWE	On-going
Central West Europe and Nordic Interim Tight Volume Coupling (CWE-Nordic ITVC)	tight volume coupling between CWE and Nordic market via: Baltic cable between Germany and Sweden, Kontek cable between Germany and East Denmark, DK West cable between Germany and West Denmark and NordNed cable between the Netherlands and Germany the since November 2010	CWE and Northern	On-going
Nordic and Polish market coupling (SWE-POL)	price coupling between Northern region and Poland via the SWE-POL cable between Sweden and Poland since December 2010	Northern and CEE	On-going
Italy and Slovenia coupling (ITA-SI)	price coupling between Italy and Slovenia since January 2011	CSE	On-going
Central West Europe and Great Britain coupling (CWE-GB)	price coupling between CWE and Great Britain via the BritNed cable between the Netherlands and Great Britain since April 2011	CWE and FUI	On-going

Table 2: Current and past projects of market coupling and market splitting across Europe as of August 2011. Source: ERGEG.

The alternative market-based mechanism to allocate cross-border interconnection capacity is that of the explicit auction. In contrast to the implicit auction, market participants must procure PTR in a dedicated market, before scheduling their power output on the interconnector. Different explicit auctions can take place for allocating capacity over different time horizons, including yearly, monthly and daily auctions.

At present, in Europe, interconnection capacity allocation is carried out using explicit auctions for the yearly and the monthly allocation, and either explicit auctions and or market coupling in the day-ahead timeframe. The procedure of capacity allocation is as follows. First, the national TSOs cooperate to determine the Net Transfer Capacity (NTC) of the interconnector for each direction separately[9]. The TSOs then split the NTC into three tranches to be allocated in subsequent phases, namely yearly, monthly and daily allocation phases. More precisely, the capacity available for each time frame is called Available Transfer Capacity (ATC) and it is calculated as the difference between

[9] NTC is defined as the "maximum exchange programme between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions" (ETSO 2001, p.7).

the NTC and the capacity allocated in the previous phases, the so-called Already Allocated Capacity (AAC):

$$ATC = NTC - AAC \quad (1)$$

In addition, in the monthly allocation phase, the TSO augments the ATC for each direction by the amount of capacity that has not been sold in the yearly phase and also by the amount of capacity allocated in the opposite direction in the yearly phase. The same also occurs for the daily allocation. In the case of the explicit auction the amount of daily ATC is sold separately for each direction, while in the case of market coupling no separated auctions take place and the flows on the interconnectors are determined simultaneously with the clearing of the energy markets.

Thus, the main advantages of market coupling consist of flows-netting and of eliminating imperfect arbitrage. Flows-netting, also known as the superposition principle, implies that power flows scheduled in opposite directions cancel out, therefore allowing the interconnector to be used up to full capacity. By contrast, explicit auctions, featuring a separated allocation of PTR for each direction, deny flows-netting and determine an inefficient use of cross-border capacity. The only netting provision implemented in the day-ahead timeframe under explicit auctions refers to the amount of capacity sold in a previous allocation phase and nominated in one direction that can be used to increment the ATC of the opposite direction. Moreover, market coupling, allocating the cross-border capacity simultaneously with the clearing of the energy markets, is able to eliminate the imperfect arbitrage that may arise under explicit auctions. Imperfect arbitrage occurs when power flows against price differentials, and it is due to that market participants have to bid for capacity and energy in two different markets.

The adoption of market coupling, though in theory it could determine an optimal use of interconnection capacity, also requires that major technical barriers relating to the non-harmonised market designs of the different EU countries be overcome. EuroPEX (2003) and Creti et al. (2010) mention the following barriers, which must be overcome by the synchronisation and the harmonisation of the markets. All the power exchanges involved in market coupling need to have the same gate closure time for the day-ahead auction, the same computation time for running the market clearing algorithm and the same deadline for publishing the results. Bidding arrangements need to be harmonised as there is a potential difficulty with the likes of the French and German markets allowing for block bidding[10], while others including Italy allow trading only for hourly or half-

[10] Block bidding means offering a given amount of power at a fixed price for a number of consecutive hours.

hourly products. Internal congestion management methods can vary across countries, given that some countries use redispatching through counter-purchases by TSOs to relieve the congestion, while others implement a market splitting algorithm, which in turn determines the calculation of different prices for the several nodes or zones of the grid. In addition, there are also some cases, i.e. Italian and Greek markets, where the price that clears the demand side of the market is different from that applied on the supply side. Finally, in markets using pay-as-bid day-ahead auctions, it is necessary to introduce a reference price for the determination of cross-border flows direction.

Addressing all these difficulties is essential to implementing a market coupling mechanism that can be rolled out across the EU member states.

3 Literature review

There is a growing economic literature on electricity market integration that can be summarized in three main streams. The first stream consists of theoretical work that analyses the impact of integration on market power in electricity generation. The second stream includes empirical work that highlights the inefficiencies of the explicit auction mechanism to allocate day-ahead cross-border interconnection capacities. The third stream groups empirical analysis of the impact of introducing an implicit auction or additional cross-border transmission capacity on the social welfare of the newly integrated markets.

There are several theoretical papers analysing the impact of integration on the extent of market power in electricity markets. Borenstein et al. (2000) show that the introduction of a transmission line between two separated symmetric monopoly markets fosters competition, even when the connecting line has a small capacity.

This literature also addresses whether alternative market designs for energy and transmission markets have a different impact on the degree of market power. The integrated energy and transmission market design typically refers to the nodal spot pricing mechanism, as proposed by Schweppe et al. (1988)[11], complemented with FTR, as defined by Hogan (1992). The unbundled or

[11] Nodal spot pricing is a method for managing network congestions that allows for calculating different spot prices when the lines are congested. Under perfect competition, nodal price represents the marginal cost of delivering power to a certain node, while the difference between prices represents the opportunity cost of constraints.

separated energy and transmission market design[12] features bilateral contracts for energy trade and PTR to access the transmission facilities. Chao and Peck (1996) demonstrate that separated energy and transmission markets, where PTR are defined as flow-gate rights[13], determines a welfare maximizing outcome in a perfectly competitive market with no uncertainty and perfect information, just as nodal spot pricing complemented by FTR. Joskow and Tirole (2000) confirm the result of Chao and Peck (1996) of equivalence of PTR and FTR for perfectly competitive energy and transmission markets. However, once the assumption of perfect competition is dropped, they show that both PTR and FTR enhance or mitigate market power depending on market power configuration and on the microstructure of transmission rights market. Physical rights may determine a worse welfare outcome than financial rights, because they can be strategically withheld from the market. Thus, Joskow and Tirole (2000) suggest the introduction of either "use-it-or-lose-it" or "use-it-or-get-paid-for-it" provisions to prevent strategic withholding of transmission rights by market participants. In contrast to Joskow and Tirole (2000), Neuhoff (2003), assuming that all PTR are acquired by traders, demonstrates that integrated energy and transmission markets reduce market power relative to the separated market design. Gilbert et al. (2004) extend the analysis of Joskow and Tirole (2000) examining the impact on market power of alternative allocation rules and auction designs of transmission contracts, and also evaluating whether subsequent trading of transmission contracts can solve the problem of incorrect initial allocation of rights. They find that efficiently arbitraged uniform-price auctions may mitigate market power, while grandfathering and pay-as-bid auctions may increase it. Moreover, they show that contract trading cannot correct the outcome of an inefficient initial allocation. Parisio and Bosco (2008) evaluate the welfare effect of introducing cross-border trade between two isolated countries. They model transmission rights allocation according to an implicit auction mechanism and show that cross-border trade may lead to price convergence between countries. Welfare gains and losses across countries are determined by a volume effect and a strategic effect of the interconnection. In the importing country, the volume effect leads consumers' surplus to increase and producers' rent to decrease, while in the exporting country the opposite occurs. The strategic effect implies that the reduced demand in the importing country flattens the supply curve in that market, which can further increase consumers' surplus in the importing country, but also reduce the consumers' surplus in the exporting country. Ehrenmann and Neuhoff (2009) analyse the difference between explicit and implicit auctions for oligopolistic markets. For a simple two-node network, an implicit auction reduces the ability of strategic

[12] The integrated energy and transmission market design corresponds to the case of implicit auction, while the separated design corresponds to the case of explicit auction.
[13] Transmission rights can be defined according to either a point-to-point approach, which defines the right to inject power in a point and to withdraw in another point, or a flow-gate model, which defines the right to use the lines on which power flows (Hogan, 2000).

generators to exercise market power. Moreover, a numerical simulation for the case of the North-western European Network shows that integrated markets lead to lower electricity prices than separated markets. In partial contrast with the above literature, Boffa and Scarpa (2009) stress that integration may facilitate collusion and reduce the aggregate welfare of the newly integrated markets. They model the case of two markets, one where a collusive monopoly price prevails and a second one where some excess capacity exists. They show that when markets are integrated, the excess capacity in the second market can be used to satisfy the demand in the first market. If the first market is able to absorb the new capacity without decreasing the price, and if the second market experiences a price increase as a consequence of the reduced level of spare capacity, it possible that interconnection leads to an aggregate social welfare reduction.

The second stream of literature provides an assessment of the inefficiencies of explicit auctions in allocating cross-border transmission capacities. Newbery and Mc Daniel (2002), analysing the results of the auctions held for the Dutch-German interconnector and for the French-England interconnector, find that under explicit auctions capacities are underused, as result of no flows-netting. Moreover, imperfect arbitrage is present, as the average price of daily capacity is lower than the monthly and annual prices. Similarly, Kristiansen (2007), assessing the performance of the Kontek cable and of the interconnector between West Denmark and Germany, also finds evidence of imperfect arbitrage. Höffler and Wittman (2007) show analytically that flows-netting maximizes the physical usage of cross-border capacity and decreases the incentive for the auctioneer (TSO) to withhold capacity for increasing his profits. Bunn and Zachmann (2010) demonstrate that under the explicit auction, a generator, which is both a dominant player in one market and a competitive player in the other, has an incentive to acquire transmission rights to export against price differential, thus resulting in an inefficient use of cross-border interconnections. In addition, Bunn and Zachmann (2010) provide a measure of the inefficiency generated by the use of an explicit auction on the Anglo-French Interconnector. The results highlight that electricity tends to flow against the price differential mainly in peak-time hours, whilst in off-peak hours flows are nominated correctly. Moreover, the results show that the French incumbent, which is a competitive player in UK, exports to UK even when prices in France are higher. Meeus (2010) computes a performance indicator for different auction mechanisms on the Kontek Cable between Denmark and Germany, and finds that one-way price coupling is able to outperform both the no-coupling and the volume coupling. However, because price coupling has been implemented only in one direction from Denmark to Germany, this mechanism fails to completely eliminate cross-border trade inefficiency.

The third stream of literature includes several studies regarding the impact of either market coupling or additional cross-border transmission capacity on the social welfare on the newly integrated markets. Hobbs et al. (2005) analyse the potential impact of market coupling for the Belgian and the Dutch markets, before the start of the Trilateral Coupling project among Belgium, France and the Netherlands. The authors estimate the welfare effect of the project simulating a Cournot-Nash equilibrium model under five alternative market settings[14]. The results show that if the Belgian incumbent plays strategically the change in aggregate social surplus due to market coupling is quite significant, but it occurs at the expense of the Dutch consumers. On the other hand, when the Belgian incumbent acts as a price-taker, market coupling brings a smaller increase in the aggregate social surplus, but more equally distributed among Belgian and Dutch consumers. Finally, Hobbs et al. (2005) highlight that market coupling could induce the incumbent to become a Cournot player, given that the opening of the market to foreign competition could lead to a diminished threat of regulatory intervention. Finon and Romano (2009) analyse the effect of market integration on electricity price showing that consumers living in countries with high-variable cost capacity enjoy a price fall at the expense of consumers living in countries of low-cost capacity. Malaguzzi Valeri (2009) evaluates the effect of additional interconnection capacity between Ireland and Great Britain simulating a model of optimal dispatch. The author finds that aggregate social surplus increases when more interconnection capacity is available, though at a decreasing rate. Moreover, the paper highlights that the size of the interconnector needed to make Ireland and Great Britain a single market depends on the differences in the production mix between the two countries. In particular, as the cost of the CO2 allowances increases, the two systems become similar and need less additional interconnection capacity to reach integration.

An empirical evaluation of the effect of market integration for the Italian market is still to be carried out, as pointed out by Creti et al. (2010). The only study providing some evidence of the inefficiency of explicit auction mechanism is that of Gestore dei Mercati Energetici (2008, GME)[15]. GME (2008) identifies four potential efficiency gains from the adoption of implicit auctions, namely lower operational risk[16], lower trading risk/cost[17], increased liquidity in less mature energy markets[18] and an efficient use of interconnection capacity[19].

[14] These are: all firms acting as price-takers in every market; the Belgian incumbent, Electrabel, acting as Cournot player everywhere under both usual transmission allocation and market coupling; Electrabel acting as price-taker in Belgium but as a strategic player outside, under both usual transmission allocation and market coupling.

[15] GME (2008) estimates the value of unused cross-border capacity between Italy and France, Italy and Switzerland, Italy and Austria for year 2007 in approximately 162 M€.

[16] This should stem from a single bidding procedure for both the energy and the interconnection capacity.

[17] This is because operators no longer need to forecast energy price before bidding for capacity and can save costs of participating on different trading platforms.

This paper provides a contribution to the empirical literature on market integration, presenting a comprehensive investigation of the welfare effect of introducing price coupling in the Italian electricity market. In particular, the change in social welfare is measured with respect to the change in the productive efficiency of the electricity market. As in Hobbs et al. (2005) and in Malaguzzi Valeri (2009), the evaluation of the welfare changes are carried out over a specific year, in this case 2012, and results are obtained by using a structural simulation model. A brief overview of the electricity markets included in the CSE area is presented in Section 4.

4 The electricity markets of Central South Europe

Italy, together with France, Germany, Austria, Slovenia and Greece make up the Central South Europe (CSE) electricity regional initiative. In what follows, Switzerland, although not part of the CSE is included in the analysis of the CSE area, as it borders Italy, France, Germany and Austria.

The Italian electricity market is the highest priced area in the CSE region. Figure 1 shows the dynamics of the monthly average day-ahead spot electricity prices of France, Germany Switzerland, Austria, Italy and Greece over the period 2007-2010. Spot prices of France, Germany and Switzerland are provided by EPEXSpot, which is the power exchange in charge of managing the day-ahead spot market for these countries. Data of the Austrian, Italian and Greek markets are publicly available on the web site of the Austrian Energy Exchange (EXAA), of the Italian Power Exchange (IPEX) and of the Hellenic Transmission System Operator (HTSO) respectively. Slovenia is excluded from the analysis as the day-ahead market opened in 2010. A distinguishing feature of both the Italian and the Greek markets is that the demand and the supply side of the market are cleared by different prices, namely zonal prices for the supply side and a single price for the demand side. The demand side price is the reference market price and it is that included in the analysis. The reference price for Italy is the Prezzo Unico Nazionale (PUN), while that of Greece is referred as to System Marginal Price (SMP). In both cases the reference price is computed as an average of the zonal prices weighted by the respective zonal load[20] [21]. As it emerges from Figure 1, the IPEX-PUN price has consistently been above the other day-ahead spot prices over the whole period. The gap, of about 18-20 €/MWh over

[18] This is what happened to Finland when joined NordPool in 1998 and to Belgium after the lunch of Trilateral Market Coupling (TLC) between France, Belgium and Netherlands in 2006

[19] Efficient use of interconnection capacity means that facilities are always fully used and that the net cross-border flows always go from the low-price area to the high-price area.

[20] To be precise, as highlighted by Creti et al. (2010), the PUN is not only a weighted average of zonal prices calculated ex-post, but it must be at the same time the reference price below which none demand bid is accepted.

[21] The Italian market is divided in the zones as listed in Section 6, while the Greek market comprehends two zones, namely Northern Greece and Central-Southern Greece.

the period, is particularly evident with the prices of the countries on the northern border of Italy, namely France, Switzerland, Germany and Austria. By contrast, the price differential between Italy and Greece has become significant, i.e. around 12-16 €/MWh, only since the beginning of 2009, partly reflecting the deepening of the recession of the Greek economy.

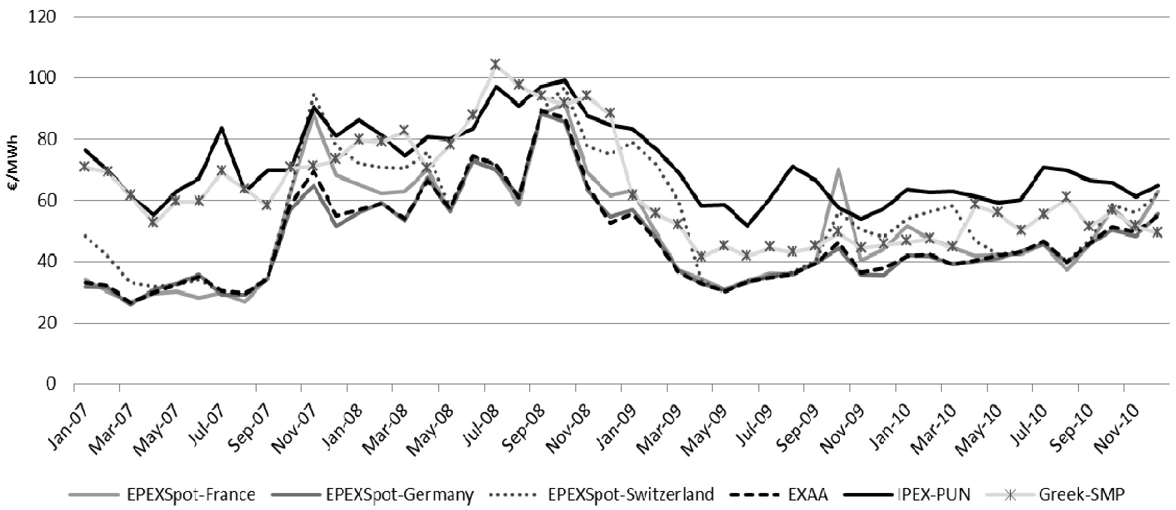

Figure 1: European monthly average electricity prices. Source EPEX Spot, GME and HTSO.

The price differentials are due primarily to the differing generation mixes between the countries. Given that the short-run variable cost of generating electricity essentially reflects the cost of fuel, countries with a generation mix based on low-cost fuels (nuclear, hydro, lignite and coal) have a cost advantage relative to countries with high-cost capacity (burning natural gas and fuel oils)[22]. In addition, the heterogeneity of the production mix matters when determining the spot price. A well-diversified production mix includes an efficient amount of both base-load generation, mid-merit and peak-load capacity[23].

The generation mix of the CSE area markets as of 31st December 2010, the latest data available from ENTSO-E[24], is presented in Table 2. Total net installed capacity[25], stands at about 438 GW, of

[22] Burning natural gas can be more convenient than using coal, as the price of the CO2 allowances rises. Moreover, it must be considered the relationship between the oil price and the CO2 allowances price to contrast the convenience of employing natural gas against coal.
[23] Base-load plants feature high fixed costs but low variable costs, thus they are suitable for running over the majority of the hours of the year, while peak-load plants have low fixed cost and high variable costs, so that they are mainly used to cover the consumption peaks. Mid-merit capacity is in between.
[24] For Switzerland the data are as of 31st December 2009.
[25] Net installed capacity is defined in the ENTSO-E's glossary as the maximum electrical net active power that a power station can produce continuously throughout a long period of operation in normal conditions, where: net means the

which 43% of capacity is fossil fuels power plants. Germany has the largest net installed capacity (about 152 GW) and the most diversified production mix of the area. Fossil fuel plants account for 45% of total net installed capacity (69 GW) and include mainly coal-fired plants (45 GW) and natural gas plants (21 GW). Nuclear power plants (20 GW) represented a large share of the net installed capacity until March 2011, when the German government introduced a Nuclear Moratorium in the aftermath of the Fukushima disaster. Hydro power plants (including pumped storage) account for 7% (11GW) of installed capacity, while non-hydro renewables account for 31% (47 GW) of capacity.

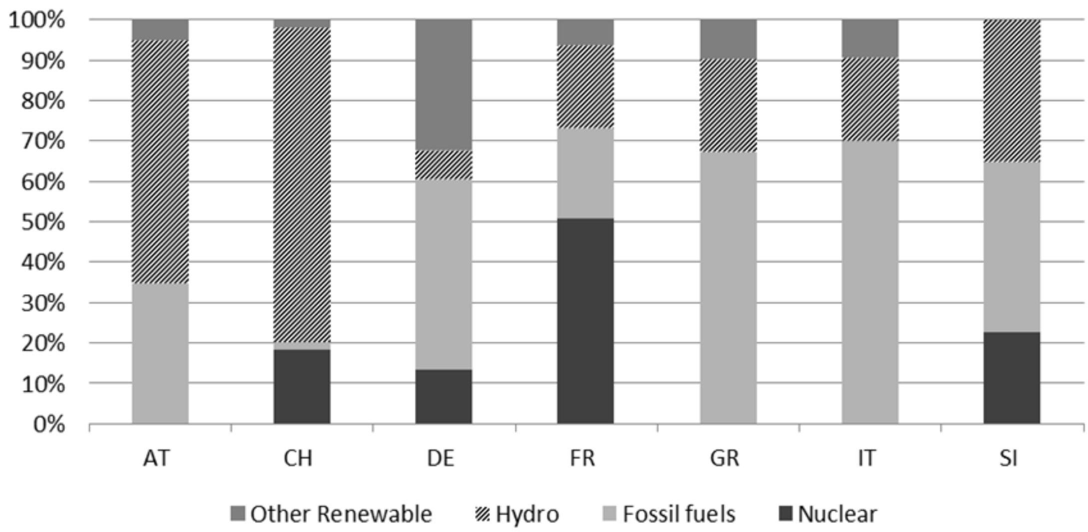

Figure 2: Generation capacity mix in Central South Europe as of 31st December 2010. Source: ENTSO-E.

France is Europe's second largest electricity market after Germany. The market is dominated by the state-owned utility EDF, which manages the country's 58 nuclear power plants and owns 85% of installed capacity (IEA, 2009). The total net installed capacity of France as of 31st December 2010 is about 123 GW, of which about 50 % comes from nuclear plants (63 GW), 21% from hydro power plants (25 GW) and about 22% are conventional thermal plants (27 GW). Among fossil fuel plants, 10 GW are from fuel oil plants, 8 GW from coal-fired power stations and 9 GW from natural gas plants. Other renewables represents only 6% (8 GW) of capacity. Switzerland largely relies on the hydropower and nuclear plants, which represent 76% (13 GW) and 18% (3 GW) respectively of its total net installed capacity (18 GW). Austria has a total net installed capacity of about 21 GW, with hydro accounting for about 60% (13 GW), and fossil fuels for about 35% (7 GW). Slovenia's total net installed capacity is negligible compared to the other countries of the region. It has 3 GW of capacity,

difference between, on the one hand, the gross generating capacity of the alternator(s) and, on the other hand, the auxiliary equipments' load and the losses in the main transformers of the power station.

of which 24% is nuclear, 45% is fossil fuels (mainly lignite) and 30% is hydro. There is no nuclear generating capacity in Greece, which does the majority of its generation with fossil fuels (9 GW out 14 GW of total net installed capacity). Italy is the third largest market of CSE area, accounting for about 106 GW of net installed capacity; 75 GW of which is fossil fuels (30 GW are of plants fuelled by natural gas only and 19 GW are of plants using both natural gas and oil derivatives) while hydro represents about 20% (21 GW). Other renewables account for 9% of total net installed capacity (10 GW). As is in Austria and Greece, Italy has no nuclear capacity.

Figure 3 shows a map of both physical and commercial exchanges of electricity within the CSE region, also reporting the production and consumption data of the 2010 electricity balances for the region. The data is taken from the ENTSO-E statistical database. Germany and France are the first and the second CSE's largest markets[26], with a net production[27] of more than 500 TWh in 2010. Italy ranks third in the CSE area, with a total net production of about 286 TWh, while Austria, Switzerland, Greece and Slovenia are comparatively small markets. Moreover, Germany, France and Slovenia are net exporter of electricity, while all the other countries are net importer.

Our focus is on the exchanges of electricity that take place in the CSE area. Figure 3 reports the data for both the net physical flows and the net commercial flows of energy between the relevant countries of the region. As defined in ENTSO-E's glossary, physical flows of energy represent the real movements of energy between neighbouring countries as metered on the interconnectors, while commercial flows are exchange programs of electricity between adjacent areas stemming from contractual agreements signed by market actors[28]. In highly meshed grids, programmed exchanges often differ from physical flows because power moves between two points following every available parallel path between the two points, rather than a unique predetermined path. In this analysis we are only concerned with commercial flows.

The most important commercial flows of energy occur from Switzerland to Italy (22.4 TWh), from France to Switzerland (19.5 TWh) and from France to Italy (16.2 TWh). Trade between Austria and Italy and between Slovenia and Italy is comparatively small, accounting for 1.6 TWh and 2.8 TWh respectively. Figure 3 also reveals that the flows from Switzerland to Italy originate in France, while

[26] Germany and France are also the largest markets in Europe.

[27] According to ENTSO-E glossary, net production is the gross generation less the electricity absorbed by Generating Auxiliaries and the losses in the main generator transformers.

[28] Furthermore, physical flows include the flows resulting from all the electricity markets, namely the day-ahead market, the intra-day market, the market for ancillary services, and correspond to the electricity metered less the unbalances. Commercial flows represent only the flows resulting from the day-ahead market.

those on the north-eastern Italy border come directly from Germany. Thus the modelling can be simplified to an analysis of cross-border exchanges between Italy and France as well as the exchanges between Italy and Germany. The methodology followed to model the cross-border exchanges of electricity between Italy and its neighbouring countries is set out in Section 6.1.

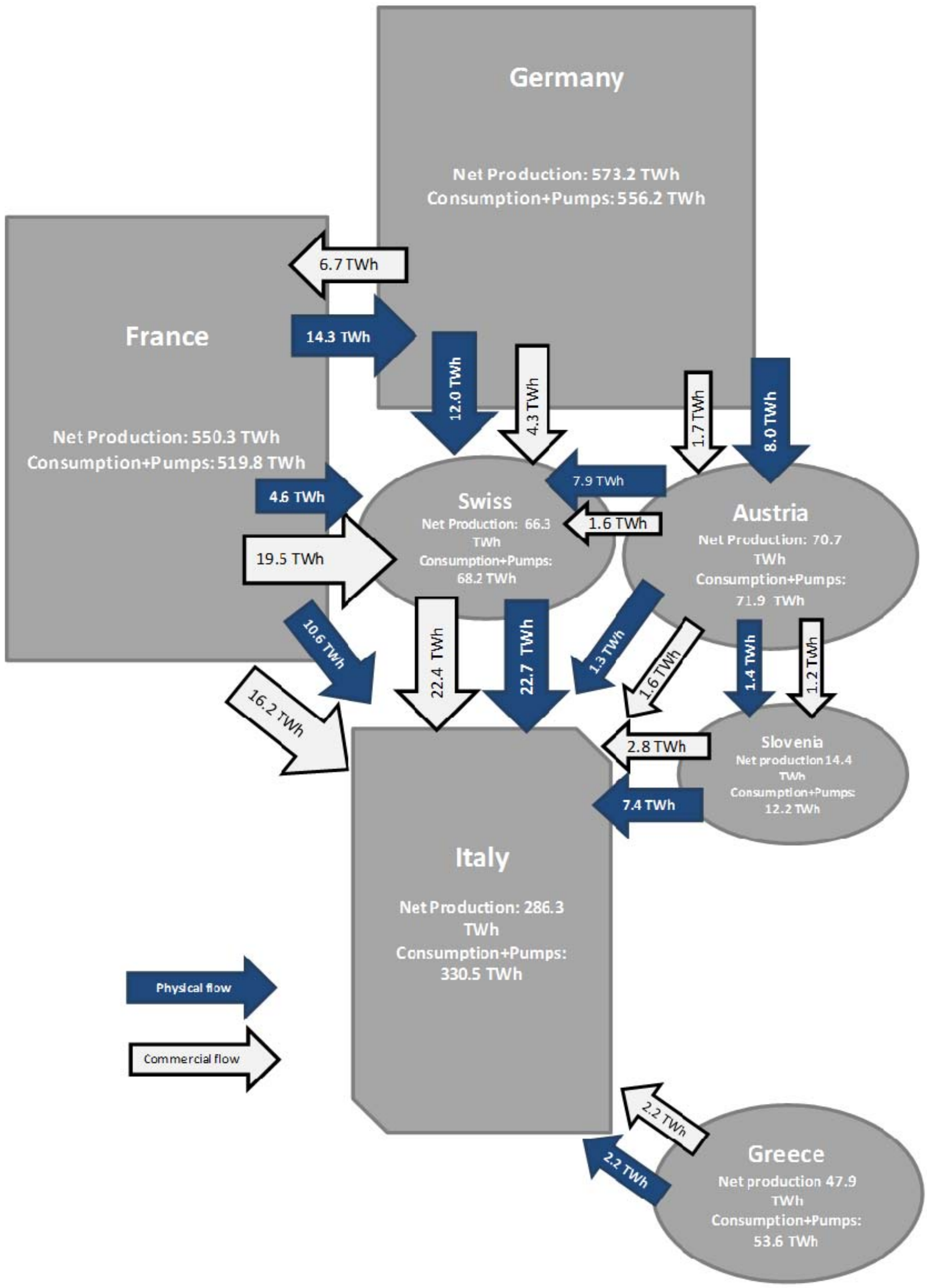

Figure 3: Map of physical and commercial net energy flows across Central South Europe in 2010. Source: ENTSO-E.

5 Methodology

The methodology used in this paper to evaluate the welfare effect of introducing market coupling between Italy and its neighbouring countries is based on the deterministic simulation of the Italian day-ahead electricity market under two alternative scenarios, while the foreign electricity markets are not explicitly simulated. The two alternative scenarios, the *Reference* and the *High* scenarios, largely reflect those elaborated by the Italian company Ricerche per l'Economia e la Finanza (ref. henceforth) in March 2011. Ref's scenarios include the most up to date information of the Italian power system and realistic assumptions about the evolution of the Italian electricity market, which are validated and adopted by several market operators[29].

The *Reference Scenario* is so called because it is based on assumptions and market features that are intended to replicate those which are most likely to occur in the market place. The internal consumption of electricity is assumed to exhibit only a small increase with respect to 2010, due to the enduring recession of the Italian economy. By contrast, the yearly average crude oil price, which represents the key driver in determining the variable cost of generating electricity, is assumed to be considerably higher than in 2010, when it was about 79 $/bbl, reaching the value of 97 $/bbl[30]. This in turn is expected to determine a substantial increase in the Italian wholesale electricity price with respect to that registered in 2010. Moreover, subject to similar market dynamics, also the Italian neighbouring countries are expected to see their respective electricity prices growing remarkably.

In the *High Scenario,* national demand is assumed to show a more pronounced increase with respect to 2010, as a consequence of an assumed hypothetical recovery of the Italian economy over the year. Furthermore, the oil price is expected to jump to the value of 122 $/bbl. Such a rise in oil price is expected and therefore assumed in the modelling to have a massive impact on the level of the Italian electricity prices. At the same time, the wholesale electricity prices across the borders are expected to suffer from the rise in input prices and also rise.

The simulations are carried out using the ref's model ELFO++, the Italian market leader tool for simulating the outcomes of a liberalised electricity market, which models the Italian power system with a very high level of detail and implements a robust algorithm for the solution of the day-ahead market[31]. The ELFO++ model and its database are set out in detail before each of the scenarios are

[29] Ref.'s scenarios and ELFO++ model are currently adopted by major Italian market operators such as ENEL, Edison, Acea, ERG, and Iren.
[30] All the variables forecast for 2012 are expressed in 2010 real terms.
[31] ELFO++ is programmed in FORTRAN language and features an interface built in Microsoft Access.

presented. Detailed description of the two 2012 scenarios and of the underlying hypothesis is provided in Section 6.

ELFO++© ref. is a production cost-based model for simulating the outcomes of a competitive day-ahead electricity market, where several generation companies sell their power output either offering it to a centralised power exchange or signing Over The Counter (OTC) contracts. ELFO++ is a structural model that simulates the results of the Italian day-ahead electricity market using a deterministic approach, where all the parameters and the constraints of the power system are taken as input to the system's scheduling optimization problem. The model delivers the optimal scheduling of the Italian hydrothermal power system over a yearly time horizon with hourly discretization. The optimal scheduling of a hydrothermal power system is an optimization problem well known in the literature, first addressed in the early 1960s[32]. Mathematically, the optimal hydrothermal scheduling problem is a nonlinear mixed integer optimization problem, including two separate sub-problems: the Unit Commitment (UC) of the thermal units and the Dispatch (DS) problem.

The UC problem aims at determining the optimal hourly sequence of start-up and shut-down manoeuvres for all the thermal units of the power system, together with a preliminary hourly dispatch schedule for all the units in the system. It is a non-convex optimization problem with discrete variables. The constraints to the problem are given by: load to be served, minimum run time and minimum down time restrictions, transmission lines limits. A Dynamic Programming algorithm is implemented in ELFO++ to solve the UC problem[33]. Dynamic Programming evaluates alternative sequences of thermal units statuses with the objective of minimising the operating cost of the power system.

The DS problem aims at determining the power output (MW) of each generating unit that minimises system operating costs under several technical constraints, provided that the unit commitment schedule for thermal units is already fixed. The DS is a convex quadratic programming problem with continuous variables, where the objective function consists of a quadratic cost

[32] Yamin (2004), among others, offers a review on the topic. In the pre-liberalization era, the prevailing paradigm of organizing the electricity supply industry was by either regulated or state-owned vertically integrated utilities, which operated the power system with the target of supplying load, maximizing security and minimizing cost. By contrast, since the introduction of the restructuring reforms of the last twenty years, the decisions of production have been taken by decentralized competitive markets, in which several competitors act so as to maximize their own profits. Thus, nowadays, the main approaches for simulating the results of competitive electricity markets include, in addition to production cost-based models, equilibrium models, featuring mainly either Cournot or Supply Function Equilibrium (SFE) competition, and agent based models (Ventosa et al. 2005).

[33] Dynamic programming is largely used in the literature to address this kind of problem (see, among others, Snyder et al. 1987).

function with constraints including: load to be served, minimum and maximum power output restrictions for both thermal and hydro units, hydro plants reservoirs limits and transmission lines limits. The method used to solve this problem requires the implementation of the Kuhn-Tucker optimality conditions using the most suitable algorithm to take into account the size of the problem.

The overall problem is solved via an iterative procedure that is summarized in the flow chart in Figure 4.

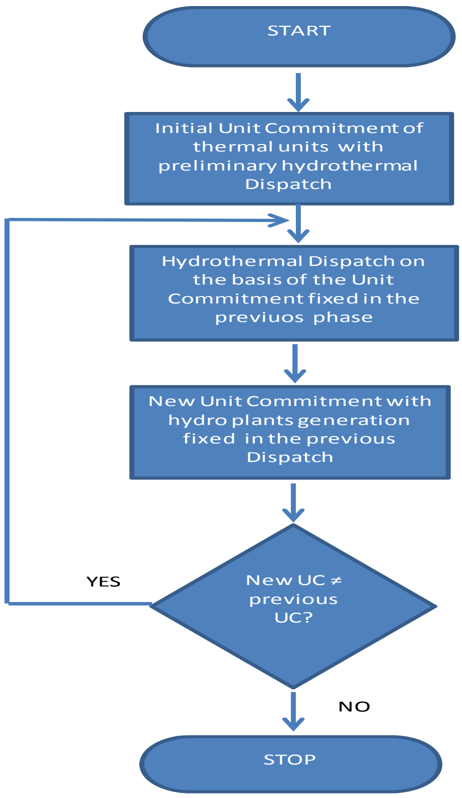

Figure 4: Flow chart of the algorithm implemented in ELFO++

The hydrothermal scheduling problem is modelled as follows. Given a power system consisting of G thermal units, H hydro plants, L transmission lines connecting Z zones of the grid, the model is set to find the sequence of start-up and shut-down manoeuvres of the thermal units and the power output of all the units over T time periods to minimise the power system expenditure subject to several constraints. The minimisation equation is given in Equation 2 below:

$$\min \varphi = \sum_{t\in T}\sum_{g\in G}\left[\left(A_{2gt}p_{gt}^2 + \left(A_{1gt} + F_{gt} + B_{gt}\right)p_{gt} + A_{0gt}u_{gt}\right) + W_g\delta\left(u_{gt} - u_{gt-1}\right)\right] + \sum_{t\in T}\sum_{h\in H} F_{ht}p_{ht} \tag{2}$$

where A_{2gt} is the 2nd degree coefficient [€/MW^{2}h] of the hourly cost curve for the thermal unit *g* at time-step *t, p_{gt}* is the power output [MW] of the thermal unit *g* at time-step *t, A_{1gt}* is the 1st degree coefficient [€/MWh] of the hourly cost curve for the thermal unit *g* at time-step *t, F_{gt}* is a coefficient [€/MWh] used to control the production of thermal unit *g* at time-step *t, B_{gt}* is the bid-up [€/MWh] on the marginal cost used to determine the offer price of the thermal unit *g* at time-step *t, A_{0gt}* is the 0 degree coefficient [€/h] of the hourly cost curve for the thermal unit *g* at time-step *t, u_{gt}* is the status (1=on / 0=off) of the thermal unit *g* at time-step *t, W_g* is the start-up cost [€] of the thermal unit *g*, $\delta(x)$ is a step function δ =0 for x< 0 and δ =1 for x> 0, F_{ht} is the coefficient [€/MWh] used to control the production of hydro plant *h* at time-step *t*, p_{ht} is the power output [MW] in generation (+) or the power absorbed in pumping (–) from the hydro plant *h* at time-step *t.*

Subject to the following constraints:

thermal units power output constraint:

$P_{mgt} \leq p_{gt} \leq P_{Mgt}$ [g∈G , t∈T], (3)

where P_{mgt} is the minimum power output [MW] of the thermal unit *g* at time-step *t* and P_{Mgt} is the maximum power output [MW] of the thermal unit *g* at time-step *t;*

hydro plants power output constraint:

$P_{mht} \leq p_{ht} \leq P_{Mht}$ [h∈H , t∈T], (4)

where P_{mht} is the minimum power output [MW] in generation/pumping of the hydro plant *h* at time-step *t* and P_{Mht} is the maximum power output [MW] in generation/pumping of the hydro plant *h* at time-step *t;*

storage volume of hydro plants basins constraint:

$V_{mht} \leq v_{ht} \leq V_{Mht}$ [h∈H , t∈T], (5)

where V_{mht} is the minimum storage volume [10^3m^3] of the reservoir of the hydro plant *h* at the end of the time-step *t*, v_{ht} is the actual storage volume [10^3m^3] of the reservoir of the hydro plant *h* at the end of the time-step *t* and V_{Mht} is the maximum storage volume [10^3m^3] of the reservoir of the hydro plant *h* at the end of the time-step *t;*

hydro plants basins balance equation:

$v_{ht} - v_{h(t-1)} = a_{ht} + \Sigma_{\mu \in \Omega h} q_{\mu t} - q_{ht}$ [h∈H , t∈T], (6)

where a_{ht} is the natural inflow [10^3m^3/h] to the reservoir of the hydro plant *h* at time-step *t*, q_{ht} is the discharge [10^3m^3/h] of the hydro plant *h* at time-step *t*, *μ* is the hydro plant upstream the *h* hydro plant and Ω is the number of hydro plants of which the discharge flows in the reservoir of the hydro plant h;

compatibility of capacity/power of the hydro plants:

$$q_{ht} = p_{ht} \left(\delta(p_{ht})/c_{h+} + (1-\delta(p_{ht}))/c_{h-} \right) \quad [\, h\in H \,,\, t\in T \,], \tag{7}$$

where $ch+$ is the energy coefficient [MWh/10^3m^3] for generation of hydro plant h, $ch-$ is the energy coefficient [MWh/10^3m^3] for pumping of hydro plant h;

zones balance equation:

$$i_{zt} = \Sigma_{g\in Gz}\, p_{gt} + \Sigma_{h\in Hz}\, p_{ht} - (C_{zt} - E_{zt}) \quad [\, z\in Z \,,\, t\in T \,], \tag{8}$$

where i_{zt} is the grid injection [MW] of the zone z at the time-step t, C_{zt} is the load [MW] of the zone z at time-step t and E_{zt} is the equivalent generation [MW] in the zone z at the time-step t;

power reserve constraint:

$$\Sigma_{g\in Gz}\, (P_{Mgt}\, u_{gt} - p_{gt}) \geq \max\,(r_{zt} - r_{Hzt}\,,\, 0) \quad [\, z\in Z \,,\, t\in T \,], \tag{9}$$

where r_{zt} is the minimum total spinning reserve [MW] for the zone z at time-step t, r_{Hzt} is the available hydro spinning reserve [MW] in the zone z at time-step t;

transmission lines constraint:

$$S_{mlt} < s_{lt} < S_{Mlt} \quad [\, l\in L \,,\, t\in T \,], \tag{10}$$

where S_{mlt} is the minimum transit [MW] on the equivalent interconnection l at time-step t, s_{lt} is the actual transit [MW] on the equivalent interconnection l at time-step t and S_{Ml} is the maximum transit [MW] on the equivalent interconnection l at time-step t;

transmission lines balance equation:

$$s_{lt} = \Sigma_{z\in Z}\, \sigma_{lz}\, i_{zt} \quad [\, l\in L \,,\, t\in T \,], \tag{11}$$

where σ_{lz} is the sensitivity coefficient of the interconnection l to the injection of the zone z;

network balance equation:

$$\Sigma_{z\in Z}\, i_{zt} = 0 \quad [\, t\in T \,] \tag{12}$$

In ELFO++ database, all the major thermal units (with a capacity larger than 15MW) are modelled individually including the information specified in the above equations, namely location in the grid, minimum and maximum net efficient power output, production technology, fuels mix, quadratic fuel consumption curve, fuels costs, constraints about start-up and shut-down manoeuvres, and also commissioning and decommissioning dates, maintenance schedules, company owner, rate of accidental unavailability and pollution emissions.

Hydro units are modelled as grouped in hydropower stations distributed in the different zones. Each station is described according to: type of facility (run of river, reservoir, pumped storage), location in the grid, owner company, maximum and minimum net efficient power output, energy coefficients for both generating and pumping activities, rate of accidental unavailability, daily profile of natural inflows in the reservoirs, storage volume of the reservoirs. Power output from hydro plants is offered to the market at zero price, according to a peak-shaving allocation. This implies that during peak-load times hydro plants are used to generate electricity, while during night hours they pump water to the upstream basins.

The transmission network or grid is modelled as a radial network, where each node represents a given zone of the Italian market. The zones correspond to those identified in the Decision ARG/elt 116/08 by the Italian Authority for Electricity and Gas (AEEG) and they are classified as: Geographical Zones (Northern Italy, including Aosta Valley, Piedmont, Liguria, Lombardy, Trentino Alto Adige, Veneto, Friuli Venezia Giulia, Emilia Romagna; Central-Northern Italy, including Tuscany, Umbria, Marche; Central-Southern Italy, including Lazio, Abruzzo, Campania; Southern Italy, including Molise, Apulia, Basilicata, Calabria and two separated zones for Sicily and Sardinia); National Virtual Zones (Monfalcone, Rossano, Brindisi, Priolo and Foggia, which are only points of injection and are called limited production points); Neighbouring Countries' Virtual Zones (France, Switzerland, Austria, Slovenia, Corsica, Corsica AC and Greece).

The power exchange limits among zones are modelled with hourly detail and refer to the values imposed by the TSO Terna.

System load represents the electricity demand net of pumped storage plants consumption, export, power plants' auxiliary services consumption and gross of network losses. ELFO++ considers the day-ahead market demand, which corresponds to the system load less the amount of self-consumption[34]. Market demand is assumed to be completely inelastic to price. Furthermore, it is modelled separately for each of the above geographical zones, with hourly detail.

[34] Self-consumption is the consumption of electricity made by self-producers. These in turn can be either natural persons or companies that own a generating facility for covering their own power needs.

In ELFO++, all power plants with dispatching priority according to the Italian legislation, namely renewables, CHP units and plants incentivised with the CIP6 mechanism[35], as well as electricity produced by self-producers not used for self-consumption, are assigned a predefined hourly power output schedule. For each hour of the day, the total amount of production from these sources is subtracted from market demand to simulate dispatching priority. Net imports from neighbouring countries can also be modelled via a fixed production schedule. Alternatively, it is possible to model cross-border exchanges of electricity by extending the transmission network so as to include foreign countries' zones.

ELFO++ can simulate the electricity market according to either perfect or imperfect competition. In order to simulate imperfect competition, the modeller has to set out exogenously the hourly profile of strategic behaviour for the several market competitors[36]. In particular, the variable describing the player's strategic behaviour takes the form of an additional component (called bid-up) that shifts up the offer curve that the player *i* submits to the day-ahead market for producing electricity in the hour *t* using the thermal unit *g*[37].

The offer curve of the thermal unit *g* for the hour *t* is a linear function[38] that relates the price of the electricity produced by the unit *g,* e_g [€/MWh], to the power output p_g [MW]. If the player *i* offers the power output of the unit *g* for the hour *t* at a price equal to marginal cost, then the offer curve for the hour *t* is given by the marginal cost curve of the unit *g*, as follows[39].

$$e_{gt} = MC_{gt} = 2A_{2gt}p_{gt} + A_{1gt} \tag{13}$$

By contrast, if the player *i* offers the power output of the unit *g* adding a bid-up to marginal cost B_{gt}, then the offer curve for the hour *t* becomes,

$$e_{gt} = 2A_{2gt}p_{gt} + A_{1gt} + B_{gt} \tag{14}$$

To set out the bid-up profiles, the modeller has to fix ex-ante the desired outcome of the simulation, for instance the desired electricity price or the desired plant's operating margin, and then has to

[35] The Interministerial Price Committee (CIP) Resolution 6 of 29 April 1992, known as CIP6 mechanism, envisages incentivises for the production of electricity from both renewable sources and from the so-called assimilated to renewable sources, namely some cogeneration units, power plants using refinery or industrial residues.
[36] This is due to that ELFO++ follows a production cost-based approach rather than a neoclassical game-theoretic one.
[37] In the day-ahead market, the market operator holds 24 separated auctions for procuring power for each of the 24 hours of the following day. Thus, generators submit a different offer curve for each plant, for each hour of the day.
[38] The function is linear because it is the first derivative of the quadratic hourly cost curve of the unit *g.*
[39] The term F_{gt} in Equation 2 is neglected in this formulation.

construct the bid-up profiles so as to achieve the designed target. In this paper, the bid-up profiles for the year 2012 are constructed to achieve a target value of yearly average clean spark spread[40]. Moreover, the bid-up profiles are set to reproduce the typical hourly electricity price dynamics, which implies very low or negative bid-up values for the off-peak hours and very large bid-up values for peak-load times. Finally, the bid-up values are differentiated for each of the above Geographical and National Virtual zones, so as to reproduce zonal prices differentials very similar to those of the year 2010[41]. As no major changes are expected to the transmission lines or to the number of power plants on line between 2010 and 2012, this seems a reasonable assumption to make.

The bid-up calibration procedure developed by ref. consists of the following steps. First, a preliminary simulation without bid-up, i.e. where generators offer at marginal cost, is carried out. This simulation yields the system marginal cost of generating electricity for the Italian power system for the simulated year. Second, the modeller computes the difference between the yearly value of system marginal price needed to achieve the target value of clean spark spread, and the yearly average system marginal cost found in the preliminary simulation, so as to obtain a yearly average bid-up value. Third, the yearly average bid-up is used to build an hourly profile of bid-up for each zone of the market and a new simulation including this new variable is run. Finally, if the resulting system marginal price matches its target value, the calibration procedure ends. Otherwise, the bid-up profiles are adjusted[42] and further simulations are run until the target is achieved.

6 Data assumptions

All the variables included in the scenarios, with exception of those related to the model of cross-border exchanges of electricity, which are detailed in Section 6.1, are prepared by ref. and reflect ref.'s view about the expected evolution of the Italian electricity market as of March 2011. The two scenarios account for different values of market demand, fuels prices, players' strategies and foreign countries' electricity prices. By contrast, all other inputs listed below are held constant across the two scenarios.

[40] Clean spark spread is a measure of gross margin of a gas-fired power plant from selling a unit of electricity. In this analysis, it is calculated as difference between national single price PUN and the variable cost (inclusive of fuel, EU-ETS allowances and green certificates) of generating electricity for a combined cycle gas turbine plant with 53% average efficiency.

[41]. Bid-up profiles can be modelled according to different degree of complexity. In addition to model different bid-up profiles for each zone, it is possible also to set out a single bid-up profile for each generating unit in the system, or alternatively to assume a common profile for each production company or technology.

[42] The adjustment consists of adding or subtracting an offset value.

Large hydro power stations (>10MW) including reservoir and run of river facilities are assumed to generate about 38 TWh in 2012, while pumped storage stations are expected to produce about 4.7 TWh and to consume 6.2 TWh.

Electricity generated both from renewable sources (namely small hydro, solar, wind, geothermal biomass and waste plants) and from assimilated to renewable sources (namely some cogeneration units, power plants using refinery or industrial residues) is granted dispatching priority by the Italian legislation, thus it is modelled via a predefined production schedule that account for about 37 TWh, and 18 TWh respectively.

Internal network constraints are modelled as power exchange limits among the zones of the Italian grid. The model closely follows the limits determined by the Italian TSO for the year 2011: REV15 "Valori dei limiti di scambio fra le zone di mercato", TERNA.

The distinguishing features of the *Reference Scenario* can be summarised as follows. In 2012, due to the economic recession, the Italian system load is assumed to grow only modestly with respect to 2010 (330.45 TWh), reaching 332.16 TWh. The amount of self-consumption is expected to be in line with the values registered in the recent years, namely about 13.51 TWh. The day-ahead market demand, given by the difference between the system load and the self-consumption, is therefore equal to 318.65 TWh. The main component of the variable cost of generating electricity, namely crude oil price, is expected to show substantial increase with respect to 2010, mainly driven by a rise in oil demand by non-OECD Asia, Middle East and Latin America. Thus, oil price is assumed to average around 97 $/BBL, with the €/$ exchange rate at about 1.42 €/$. Other fuels prices, namely coal, fuel oil, diesel and natural gas prices, are expected to increase in the same proportion of crude oil price, given that they display a long-run relation with oil price. Bid-up profiles are calibrated so as to reflect the structure and dynamics of the competition observed in the Italian marketplace since 2009. In addition, these bid-up profiles allow generators to gain profits that are consistent with the low level of electricity demand and with the situation of substantial overcapacity of the power system expected in 2012. In particular, it is assumed that participants act so as to reach a value of the clean spark spread of 2 €/MWh in the simulation of the Business As Usual case[43].

[43] These bid-up profiles are able to produce a price result for the Business As Usual case which is line with that quoted on the Italian forward market in June 2011.

The key assumptions underlying the *High Scenario* are the following**.** The Italian economy is assumed to show a moderate recovery in 2012 with respect to 2010 and consequently the Italian system load is expected to grow up to 335.61 TWh. Thus, considering the same level of self-consumption of the *Reference Scenario* (13.51 TWh), day-ahead market demand is assumed to reach 322.10 TWh. Oil price is expected to increase steeply with respect to the 2010, up to the yearly average value of 122 $/BBL (with the €/$ exchange rate about 1.42 €/$ as in the *Reference Scenario)*, due to a higher oil demand by non-OECD Asia, Middle East, Latin America, Europe and Northern America. Other fuels prices, namely coal, fuel oil, diesel and natural gas prices, follow the crude price escalation. Players' strategies are more pronounced than in the *Reference Scenario*, as the electricity demand and the general economic situation allow an improvement in generators' profit margins. In particular, bid-up profiles are calibrated so that generators get a clean spark spread of 5 €/MWh in the simulation of the Business As Usual case.

For each scenario the following four alternative cases are simulated. Perfect Competition (PC) case: in this baseline case, market participants are assumed to act as price-takers, offering their power output at marginal cost. The allocation of rights for using cross-border interconnection capacity is carried out via explicit auctions that take place yearly, monthly and daily. Business As Usual (BAU) case: market participants compete with each other offering their power output at a price higher than marginal cost. As in the previous case, the allocation of rights for using cross-border interconnection capacity is carried out via explicit auctions that take place yearly, monthly and daily. Market Coupling (MC) case: the daily available cross-border interconnection capacity is allocated via market coupling, while explicit auctions are held for the allocation of long-term capacity. As in the BAU case, market participants are assumed to offer their power output at a price higher than marginal cost. Moreover, they are assumed to keep offering with the same hourly bid-up profiles as before. Market Coupling with producers of Northern zone offering at their marginal costs (MCNO) case: the allocation of the daily available cross-border interconnection capacity is carried out via market coupling as before, but now generators located in the Northern zone of the Italian market fear the threat of potential sharper competition with market participants in bordering countries, and hence are assumed to behave as price-takers.

6.1 Cross-border exchanges of electricity

In this paper, two alternative settings of cross-border interconnection capacity allocation between Italy and its neighbouring countries are considered. The first, which is set out in the PC and BAU cases, features explicit auctions for allocating both long term and day-ahead interconnection capacity. The second, which is assumed for the remaining cases, includes explicit auctions for the allocation of long term capacity and market coupling for the day-ahead capacity.

The foreign electricity markets are not explicitly simulated, rather they are represented employing several foreign zones. Each foreign zone includes an equivalent[44] generator, which can produce an amount of power output at most equal to the interconnector's maximum NTC in import to Italy, and a load, which is at most equal to the interconnector's maximum NTC in export from Italy. Each equivalent generator is assumed to offer a share of its production via long-term bilateral contracts and to participate to the day-ahead electricity market for selling the remaining energy. The amount of power output sold under bilateral contracts by each equivalent generator corresponds to a predefined hourly power output schedule, which is assumed to be the same across all cases. Foreign equivalent generators offer in the Italian day-ahead market at their respective foreign day-ahead electricity prices. In addition, to take into account the features of the explicit auction, in the PC and in the BAU cases, before participating in the day-ahead market, market participants are required to buy PTR for using the relevant interconnectors[45].

ELFO++ works as follows. The power output from bilateral contracts is always entirely dispatched, as it is granted dispatching priority. Then, the model determines the daily import/export balance across each border according to the price differential between the Italian and the foreign market. In the PC and the BAU cases only, the price of PTR is added to the electricity price to determine the exchange balance. Furthermore, in these cases, the no flows-netting condition is also accounted for.

Although the CSE region includes several countries, it is worth simplifying the modelling of cross-border trade between Italy and its neighbours, grouping the different bordering countries in broader foreign zones. Figure 3 shows that the net commercial flows from Switzerland to Italy originate in France, while those on the north-eastern Italian border come directly from Germany. Given that net commercial flows follow price differentials between countries, there is evidence of converging behaviour in the pattern of the French and Swiss electricity prices, as well as in that of Austrian and German prices and of Slovenian and German prices. This convergence allows the modelling of trade across the several borders to be simplified to only two main interconnections: a north-western interconnection with France, which sums the flows of both France and Switzerland; and a north-

[44] Equivalent means fictitious generator that groups different generators summing all the respective production capacities.
[45] In the MC and MCNO cases no PTR are needed, given that the several markets are coupled.

eastern interconnection with Germany, which accounts for the flows of both Austria and Slovenia. An in-depth price convergence analysis suggesting that this simplification to the modelling is appropriate is reported in Appendix A.

For the *Reference Scenario*, the forecasts of the foreign electricity prices for 2012, namely the French EPEXSpot-FR, the German EPEXSpot-DE and the Greek System Marginal Price, are based on the following assumptions. Due to the decision taken by the German government in June 2011 to shut-down the seven oldest nuclear plants of the country, the German electricity price is forecast to increase considerably with respect to 2010 (44.49 €/MWh), reaching 59.59 €/MWh. The annual average French spot electricity price is expected to rise, with respect to 2010 (47.50 €/MWh), to the yearly average of 59.24 €/MWh, driven by a higher demand for export to Germany and by the persistent structural imbalance between base-load and peak-load capacity described in IEA (2009). Also the Greek spot electricity price is forecast upward, as a consequence of the surge in fuel price, reaching 62.94 €/MWh.

The methodology implemented to achieve these forecasts is as follows. First of all, for the French and the German prices, the hourly price profile of 2010 is selected and adjusted[46] to the 2012 calendar. Second, the values are scaled[47] so as to obtain quarterly average prices equal to the French Power Futures and the German Power Futures respectively as quoted by EEX on the 7th of June 2011 (http://www.eex.com/en/). Table 3 reports the quarterly futures values.

	French Power Futures €/MWh	***German Power Futures €/MWh***
1st Quarter 2012	68.50	65.02
2nd Quarter 2012	51.00	54.43
3rd Quarter 2012	50.61	55.59
4th Quarter 2012	66.90	63.44

Table 3: Quarterly French Power Futures and German Power Futures quotation as of 7th June 2011. Source: EEX.

[46] The price profile of a given year cannot be adopted as it is to construct that of any other year, because each day of the week has its specific profile. For example, if we want to build the price profile for the 2nd of January 2012, which is Monday, we cannot replicate the profile of the 2nd January 2010, which is Saturday; rather we have to consider the price profile of Monday 4th January 2010.

[47] The values of the quarterly futures are divided by the quarterly averages of the price series of 2010, so to obtain four scaling factors, one for each quarter. Each hourly value of the series of 2010, as adjusted to the calendar of 2012, is then multiplied by the scaling factor so to build the new 2012 price series.

Given that for the Greek SMP there are no futures quoted, the Greek SMP is forecast using the following model, a parsimonious simplification of the autoregressive distributed lags (ADL) of order 12:

$$Greekprice_t = c + trend + Greekprice_{t-1} + Greekprice_{t-3} + Greekdemand_t + Oilprice_{t-1} + \varepsilon_t \qquad (15)$$

where the variable *Greekprice* is the monthly average Greek SMP in €/MWh, while *Greekdemand* is the monthly average Greek system load in MWh, both available online at: www.desmie.gr/content/values_xls.asp?lang=2. Oil price ($/bbl) is the same included in the ELFO++ database of the *Reference Scenario*, provided by ref.

This model is estimated employing monthly average data over the period from January 2006 to March 2011. The forecast for year 2012 is extrapolated assuming that the monthly Greek system load grows linearly of 0.2%, with respect to the same month of the previous year, from April 2011 to December 2012. Then, in order to obtain the hourly price series for 2012, the values of the 2010 Greek price profile are rescaled using the forecast monthly average prices. The results of the OLS regression are reported in Table 4.

Dependent variable: Greekprice

	Coefficient	p-value	
c	-12.34	0.15	
trend	-0.18	0.05	
Greekprice(-1)	0.48	0.00	
Greekprice(-3)	0.22	0.01	
Greekdemand	0.00	0.03	
Oilprice(-1)	0.27	0.00	
R-squared	0.89		
F-statistic	85.75		
Prob(F-statistic)	0.00		
Heteroscedasticity ARCH test:			
F-statistic	0.17	*Prob. F(1,57)*	0.68
Breusch-Godfrey Serial Correlation LM Test:			
F-statistic	0.92	*Prob. F(2,52)*	0.40
Normality test:			
Jarque Bera	0.55	Prob.	0.76

Table 4: ADL estimation of Greek price.

In the *High* Scenario, the foreign electricity prices are expected to be more pronounced than in the *Reference Scenario*. In particular, both the German and the French prices are expected to be driven by an increased electricity demand that reflects an improvement in general economic situation of their countries. Moreover, the large increase in fuels prices also determines a significant impact on these electricity prices. Therefore, the annual average French electricity price is forecast to reach 76.84 €/MWh, while the German price to average around 76.77 €/MWh. The main driver of the surge in Greek electricity price, forecast at 78.09 €/MWh, is the fuel price, given that, contrary to the leading European countries, the Greek economy is expected to remain in a deep recession during 2012.

For all cases of the *High Scenario* all the foreign electricity prices are forecast using Equations 16-18 reported below, which represent the parsimonious versions of ADL models of order 12. As before, the three equations are estimated over the period from January 2006 to March 2011, assuming both the French and the German monthly system loads to increase linearly at 1.7%, with respect to the same month of the previous year, from April 2011 to December 2012. The monthly Greek system load is instead assumed to grow at 1%, with respect to the same month of the previous year, from April 2011 to December 2012. The results of estimations are reported in Table 5.

$$EPEXSpot\text{-}FR_t = c + EPEXSpot\text{-}FR_{t-1} + Frenchdemand_t + Oilprice_{t-3} + \varepsilon_t \quad (16)$$

where *EPEXSpot-FR* is the monthly average French electricity price in €/MWh as provided by EPEXSpot, *Frenchdemand* is the French system load in MW as provided by ENTSO-E. Oil price ($/bbl) is the same included in the ELFO++ database for the *High Scenario*, provided by ref.

$$EPEXSpot\text{-}DE_t = c + EPEXSpot\text{-}DE_{t-1} + Germandemand_{t-1} + Oilprice_t + Oilprice_{t-1} + Oilprice_{t-3} + \varepsilon_t \quad (17)$$

where *EPEXSpot-DE* is the monthly average German electricity price in €/MWh as provided by EPEXSpot, *Germandemand* is the German system load in MW as provided by ENTSO-E. Oil price ($/bbl) is the same included in the ELFO++ database for the *High Scenario*, provided by ref.

$$Greekprice_t = c + trend + Greekprice_{t-1} + Greekprice_{t-3} + Greekdemand_t + Oilprice_{t-1} + \varepsilon_t \quad (18)$$

where the variable *Greekprice* and *Greekdemand* are as defined above and Oil price ($/bbl) is the same included in the ELFO++ database for the *High Scenario*, provided by ref.

Finally, for each of the relevant series, the 2010 price profiles are scaled using the forecast monthly average values.

With respect to the NTC values for 2012, it is reasonable to assume for both scenarios the same exchange limits as of 2011, given that no changes to the interconnectors are expected in future years. The NTC values for exchanges of electricity between Italy and its bordering countries are set by the TSO Terna[48]. These data are used to construct the NTC time series for 2012 in the following way. The France-Italy NTC time series is built summing the NTC values between France and Italy and between Switzerland and Italy, for each flow direction. The Germany-Italy NTC time series is calculated by summing the NTC values between Austria and Italy and between Slovenia and Italy, for each flow direction. The Greece-Italy NTC time series is the same as defined by Terna, for flow each direction. Table 6 and Table 7 report the values of the interconnection capacity as constructed above.

Once computed the maximum hourly values of exchange programs between Italy and foreign zones, it is assumed that for each interconnector a portion of the respective NTC for importing to Italy is allocated in long-term auctions and it is used by holders of bilateral importing contracts. In particular, it is expected that on the France-Italy interconnector about the 25% of capacity is used to deliver 12.40 TWh of net import under bilateral contracts, on the Germany-Italy interface about 50% of capacity is reserved to deliver 1 TWh of net import, while on the Greece-Italy interface about 16% of capacity is allocated to deliver 0.7 TWh of importing contracts. The total amount of net import done via bilateral contracts (about 14 TWh) is estimated to be lower than the value registered in 2010 (about 16.7 TWh). All these conjectures are justified by the expected reduced availability of both German and French exporter, due to the nuclear shut-down decision recalled above, to sign long-term bilateral contracts. Thus, the amount of interconnection capacity available for the daily allocation towards Italy, via either explicit auction or market coupling, corresponds to the total NTC less the capacity allocated to fulfil the obligations stemming from the bilateral contracts defined above.

[48]The data refer to Terna, 2011. Access rule to FRANCE-ITALY, SWITZERLAND-ITALY, AUSTRIA-ITALY, SLOVENIA-ITALY, GREECE-ITALY interconnections. (Capacity Allocation Auction Rules), with the exclusion of the values for the so-called low-consumption weekends.

Dependant variable: EPEXSpot-FR				*Dependant variable: EPEXSpot-DE*				*Dependant variable: Greekprice*			
	Coefficient	p-value			Coefficient	p-value			Coefficient	p-value	
c	-15.80	0.09		*c*	25.02	0.09		*c*	-12.34	0.15	
EPEXSpot-FR(-1)	0.25	0.03		*EPEXSpot-DE(-1)*	0.35	0.00		*trend*	-0.18	0.00	
Frenchdemand	0.00	0.03		*Germandemand(-1)*	0.00	0.05		*Greekprice(-1)*	0.48	0.00	
Oilprice(-3)	0.44	0.00		*Oilprice*	0.37	0.02		*Greekprice(-3)*	0.22	0.01	
				Oilprice(-1)	-0.41	0.05		*Greekdemand*	0.00	0.03	
				Oilprice(-3)	0.51	0.00		*Oilprice(-1)*	0.27	0.00	
R-squared	0.63			*R-squared*	0.74			*R-squared*	0.89		
F-statistic	32.93			*F-statistic*	31.08			*F-statistic*	85.75		
Prob(F-statistic)	0			*Prob(F-statistic)*	0.00			*Prob(F-statistic)*	0.00		
Heteroscedasticity ARCH test:				***Heteroscedasticity ARCH test:***				***Heteroscedasticity ARCH test:***			
F-statistic	0.39	*Prob. F(1,59)*	0.53	F-statistic	0.03	Prob. F(1,57)	0.87	F-statistic	0.17	Prob. F(1,57)	0.68
Breusch-Godfrey Serial Correlation LM Test:				***Breusch-Godfrey Serial Correlation LM Test:***				***Breusch-Godfrey Serial Correlation LM Test:***			
F-statistic	0.99	*Prob. F(2,56)*	0.38	F-statistic	0.14	Prob. F(2,52)	0.87	F-statistic	0.92	Prob. F(2,52)	0.40
Normality test:				***Normality test:***				***Normality test:***			
Jarque-Bera	46.63	Prob.	0.0	Jarque-Bera	37.71	Prob.	0.0	Jarque-Bera	0.55	Prob.	0.8

Table 5: ADL estimation of French, German and Greek electricity prices.

		Winter		Summer	
		7h-23h	23h-7h	7h-23h	23h-7h
*Monday until Saturday **	***France***	6740	6135	5710	5240
	Germany	800	755	680	650
	Greece	500	500	500	500
*Sunday **	***France***	6135	6135	5258	5240
	Germany	755	755	632	650
	Greece	500	500	500	500
		0h-24h			
*Bank Holidays***	***France***	2682			
	Germany	319			
	Greece	500			

**these values hold with exception of Bank Holidays.*

*** The following Bank Holidays of 2012 are considered only: periods from 1st to 8th January, 8th and 9th of April, 25th of April, 1st of May, 2nd of June, 1st of November, 8th and 9th of December, 25th and 26th of December*

Table 6: Indicative and not binding NTC values on the France, Germany and Greece to Italy Interconnection in MW, as aggregation of the original values in Terna, 2011.

		Winter		Summer	
		7h-23h	23h-7h	7h-23h	23h-7h
Monday until Saturday	***France***	2805	3070	2310	2715
	Germany	245	280	190	235
	Greece	500	500	500	500
Sunday and Bank Holidays	***France***	3070	3070	2715	2715
	Germany	280	280	235	235
	Greece	500	500	500	500

Table 7: Indicative and not binding NTC values on the Italy to France, Germany and Greece Interconnection in MW, as aggregation of the original values in Terna, 2011.

For the modelling of the two main features that distinguish the mechanism of explicit auctions from market coupling for the capacity allocation in the day-ahead timeframe, namely the no flows-netting condition and the price of interconnection capacity as resulting from the daily auction, the following procedure is adopted. With respect to the no flows-netting condition, given that ELFO++ carries out flows-netting by default, it is assumed that in 2012, as in 2010, 2.2 TWh is exported via the power exchange from Italy to France and 0.4 TWh from Italy to Greece. Then, the daily available import capacity of the French interconnector is reduced of 600 MW for each hour of period January-February and from October to December[49], while the daily import ATC from Greece is reduced by 50 MW for each hour of the year. Given that Italy is a big importer of electricity, with about 49.5 TWh imported versus only 4 TWh exported on average over the period 2009-2010, this no-netting

[49] Export from Italy to France and to Switzerland typically occurs during winter months, when both the foreign countries reach the peak of consumption.

simulation procedure is carried out only on the import side. Reducing the import capacity in this way guarantees the resulting flow to remain below the actual maximum allowed, though the model continues to schedules power using all the available capacity.

In addition to simulating the no-netting condition, the price of interconnection capacity from the daily auction must be accounted for. The hourly profiles of the 2010 PTR prices are used to model the hourly profiles of the 2012 PTR prices, as they are consistent with the hourly dynamics of the foreign electricity prices in 2010, which in turn are used to model the 2012 foreign electricity prices profiles. Table 8 reports the values in €/MWh of the yearly average prices of the PTR, aggregated by blocks of hours, determined in the daily auctions for the allocation of interconnection capacity (in import) between Italy and its neighbouring countries.

	Average price of physical transmission rights €/MWh for import from:				
	FRANCE	**SWITZERLAND**	**AUSTRIA**	**SLOVENIA**	**GREECE**
From 1 am to 8 am	9.95	7.65	8.10	8.36	4.03
From 9 am to 6 pm	16.22	12.19	5.45	12.76	4.05
From 7 pm to 12 pm	13.09	10.12	11.07	11.42	5.63
Average for 2010	13.35	10.16	7.74	10.96	4.44

**Prices of PTR for export to bordering countries are omitted because close to zero.*

Table 8: Yearly average price of physical transmission rights sold in daily auctions for import to Italy from its neighbouring countries. Source: ENTSO-E.

Given that the auction for the allocation of the daily interconnection capacity closes before the clearing of day-ahead energy markets, the price of PTR reflects the expectations of market participants on the price differential that will be determined subsequently in the energy market. The electricity price differentials between Italy and its northern neighbouring countries averaged around 18-20 €/MWh over the period 2007-2010 (see Figure 1). German and French day-ahead prices are expected to increase considerably in 2012, 35% and 26% respectively[50] from 2010, hence it is reasonable to assume that the prices for import rights from these two countries will be slightly smaller than in 2010, reflecting a drop in the desirability for foreign producers to sell into the Italian market. The forecast values of PTR average prices are reported in Table 9.

[50] The average 2010 EEX and Powernext prices were 44.49 €/MWh and 47.50 €/MWh respectively.

	Forecast average price of physical transmission rights €/MWh for import from:				
	Reference and High Scenario BAU case		*Reference Scenario PC case*		*High Scenario PC case*
	FRANCE & GERMANY	**GREECE**	**FRANCE & GERMANY**	**GREECE**	**FRANCE, GERMANY & GREECE**
From 1 am to 8 am	7.00	3.00	2.00	1.00	1.00
From 9 am to 6 pm	11.00	3.00	2.00	1.00	1.00
From 7 pm to 12 pm	10.00	3.00	2.00	1.00	1.00
Average for 2012	9.41	3.00	2.00	1.00	1.00

Table 9: Expected yearly average price of physical transmission rights sold in daily auctions for import on Italy from its neighbouring countries.

The expected prices of PTR for importing to Italy, modelled for the PC case of both scenarios, are considerably lower than the values modelled for BAU case, as they reflect the difference between the Italian system marginal cost of producing electricity and the foreign prices. The prices for using interconnection capacity in export from Italy are assumed to be zero for all the interfaces.

7 Welfare analysis

The simulation results are presented in Table 10. It is useful to compare each of the alternative cases of the *Reference Scenario* before considering the results for each of the cases in the *High Scenario*.

The Italian day-ahead electricity price (€/MWh) is reported in the first row of Table 10 (System Marginal Price, PUN). The hourly value of the PUN is calculated as average of the hourly zonal prices weighted for the respective hourly zonal load. Market demand (TWh) is the Italian system load less the amount of self-consumptions. Market demand less net import yields the value of internal production of electricity. Generation costs (M€/year) represent the yearly sum of variable costs of generating electricity for the Italian power system. They include three components: fuel cost, EU-ETS allowances cost and green certificates cost. Welfare indicators (M€/year) consist of TSO's surplus (internal congestion rent), consumers' surplus and producers' surplus, while social surplus is the sum of the three components. The last row of Table 10 shows the difference in social surplus (M€/year) relative to the PC case.

Given that demand is completely inelastic to price, in order to provide a quantitative measure of consumers' surplus, a reasonably high value of demand intercept is assumed. Specifically, the values are 300 €/MWh for the *Reference Scenario* and 400 €/MWh for the *High Scenario*[51]. Consumers' surplus is calculated by summing over year the product of the difference between the assumed intercept and the PUN times the market demand, as specified in (19) below. Producer's surplus is the generator's gross margin from producing electricity, as fixed costs are not incorporated in this model. Producers' surplus is calculated by summing over year the difference between consumers' expenditure for internal production ($CEIP_t$), congestion rent and generation costs, as shown in (20) below. Congestion rent is the sum for all the internal transmission lines of the product of the differences in the zonal prices (P_{zt}, $P_{\theta t}$) times the net flow on the constrained transmission lines, as specified in (21) below.

$$Consumer\ Surplus = \sum_{t \in T} [(Intercept_t - PUN_t)\ Demand_t] \tag{19}$$

$$Producer\ Surplus = \sum_{t \in T} (CEIP_t - Congestion\ Rent_t - Generation\ Costs_t) \tag{20}$$

$$Congestion\ Rent = \sum_{t \in T} \sum_{l \in L} [(P_{zt} - P_{\theta t}) Net\ Flow_{lt}] \qquad [z, \theta \in Z\ and\ z \neq \theta] \tag{21}$$

where t=1,…,T (=8784) is the number of hours in 2012, and l=1,..L (=11) is the equivalent transmission line[52], and z and θ represent a given zone with Z the full set of zones. In this analysis, given the assumption of completely inelastic demand, welfare changes account only for changes in the productive efficiency of the electricity market. Further, welfare indicators do not take into account other potential benefits generated by the introduction of market coupling, such as increased security of supply and reduced need of reserve capacity.

Columns (i-iv) of Table 10 contain the results of the simulations carried out for the *Reference Scenario*. As expected, the PC case yields the lowest PUN (65.31 €/MWh). The PUN from the PC case represents the system marginal cost of producing electricity for the Italian power system. The Italian electricity demand is covered by internal production for 285.91 TWh out of 318.65 TWh, while net

[51] The choice of 300 €/MWh stems from that the highest value of PUN of the Reference Scenario is 160.82 €/MWh, while 400 €/MWh refers to the maximum value of 229.32 €/MWh of the PUN of *High Scenario*.

[52] The physical transmission lines of the Italian grid are grouped in fictitious or equivalent lines, which connect the several zones of the Italian market.

import accounts for the remaining 32.75 TWh. Net import is positive because foreign prices, which are assumed to be in the 59-63 €/MWh range, are lower than the internal system marginal cost.

When generators are allowed to exercise market power, as in the BAU case, the PUN goes up by 16% with respect to the PC case, reaching the value of 75.62 €/MWh. As the price of electricity rises, the Italian power system reduces the level of the internal production, which falls to 280 TWh, increasing the share of net import from abroad, which goes up to 38.67 TWh. Congestion rent increases from 37 M€/year of the PC case to 121 M€/year of the BAU case[53]. This is because under imperfect competition, generators located in zones with a scarce level of interconnection, find it profitable to induce congestion into their areas, so as to exert market power on the local residual demand. Imperfect competition determines consumers' surplus to decline by 4365 M€/year (approximately -6%) with respect to the PC case, while producers' surplus increases by 3608 M€/year (81% with respect to the PC case). In total, the change in social surplus with respect to the PC case is a net loss of 672 M€/year.

The impact of market coupling on the Italian electricity market is assessed by comparing the results of the simulations of the MC case against those of the BAU case, reported in the third and in the second columns of Table 10 respectively. As market coupling is introduced, the PUN decreases of 0.70 €/MWh with respect to the BAU case (-1% approximately). As expected, market coupling, maximising the use of the available day-ahead interconnection capacity, allows more power from abroad to flow into the Italian market. In particular, net import rises to 47 TWh from 39 TWh in the BAU case. The competitive effect brought by market coupling determines an increase of Italian consumers' surplus with respect to the BAU case of 210 M€/year (0.30%), whereas producers see their margins reduced by 187 M€/year (-2%). Congestion rent (130M€/year) rises by 10 M€/year with respect to the BAU case. Table 11 reports the values of congestion rent for each congested transmission line. Congestion rent increases for the zones directly exposed to market coupling, namely Northern and Southern Italy, as it exerts a pronounced downward pressure on their prices. Specifically, congestion rent increases by 12 M€/year between Southern and Central-Southern Italy, and by 1 M€/year both on the line between Foggia and Southern Italy and on that linking Northern and Central-Northern Italy. By contrast, congestion rent decreases by 4 M€/year on the transmission line between Central Northern and Central-Southern Italy.

[53] The value of congestion rent resulting from all the simulations are comparable with the actual values and relating to the most recent years, i.e. over the period 2007-2010. In particular, GME (2011) reports that the congestion rent in the Italian electricity market ranged between 121-238 M€ over the period 2007-2010. Further, congestions in 2012 are expected to be slightly smaller than the values registered before 2010, due to the entrance into operation of the new transmission line between Sardinia and Continental Italy and to the low level of demand.

Summing the impact on consumers' surplus, producers' surplus and TSO's surplus, it emerges that market coupling determines a net welfare gain of 32 M€/year with respect to the BAU case.

However, though market coupling increases the competition in the Italian electricity market, it may not be able to exert a sufficient pressure to drive price down to the level of perfect competition. The results show that the PUN of the MC case is still well above the system marginal cost of the PC case (15% higher), with the consequence that social surplus continues to be lower than in the PC case by 640 M€/year.

Column (iv) of Table 10 reports the results of the MCNO case. Here, it is assumed that the introduction of market coupling, representing a credible threat of tighter competition on the Northern border, pushes Northern Italy producers to become price-takers so as to increase their market share. The results highlight that under the MCNO case, the PUN decreases of 2.80 €/MWh with respect to the BAU case (-4%). Net import (40.41 TWh) returns approximately to the level of BAU case (38.67 TWh), but it does not decrease further as foreign power is still much cheaper than the internal one. Consumers' surplus increases by 1208 M€/year with respect to the BAU case (2%), whereas producers' surplus declines by 833 M€/year (-10%). Given that demand is inelastic to price, the drop in producers' surplus is remarkable because Northern Italy producers, decreasing their offer price, can only increase their production of a limited amount. In particular, reducing their margins, producers can at most re-appropriate of the market share they had before the starting of coupling. Therefore, Northern Italy producers have a strong incentive to continue to charge the usual level of mark-up, following the so-called "passive output strategy" of Borenstein et al. (2000). This strategy implies that the incumbent, aware of the limited amount of energy that can be shipped into its market, finds it more profitable to accommodate imports so to congest the interconnectors and hence to act as price-makers on the residual demand. A low electricity price in the Northern zone has a major impact also on congestion rent, as shown in Table 11. With respect to the BAU case, congestion rent increases by 19 M€/year on the line between Northern and Central-Northern Italy, and by 17 M€/year on the line between Central-Northern and Central-Southern Italy. By contrast, congestion rent falls by 19 M€/year on the line between Southern and Central-Southern Italy. Overall, considering also the changes in the congestion rent on the transmission lines between Rossano and Southern Italy and between Rossano and Sicily, congestion rent rises by 21 M€/year with respect to the BAU case. The change in social surplus with respect to the BAU case becomes important, accounting for about 395 M€/year. However, this improvement is still far from the result of the PC case, given that social surplus is 278 M€/year lower than in the PC case.

Columns (v-viii) of Table 10 report the results of the simulation of the four cases for the *High Scenario*. The results of the PC case show the impact on the cost structure of the Italian power system of a major change in market fundamentals, with respect to the *Reference Scenario*. The system marginal cost of producing electricity reaches the value of 79.48 €/MWh, thus rising by 22% with respect to the PUN of the PC case of the *Reference Scenario*. Given that also foreign electricity prices largely increase with respect to the *Reference Scenario*, net import (25.65 TWh) is lower than in the *Reference Scenario* (32.75 TWh), though the level of demand is higher.

Comparing the results of the BAU case against those of the PC case, imperfect competition leads price to rise by 19%, reaching the value of 94.52 €/MWh. As the Italian price surges, the relative convenience of power from abroad increases, with the result that net import goes from 25.65 TWh of the PC case to 34.79 TWh of the BAU case. Congestion rent in the BAU case quadruples with respect to the PC case, going from 42 M€/year to 180 M€/year. This pronounced increase reflects, even more than in the *Reference Scenario*, that generators make a strategic use of the bottleneck on the internal transmission lines. In *High Scenario*, the change from perfect to imperfect competition leads consumers' surplus to fall by 6415 M€/year (-6%), while producers are better off by 5209 M€/year (90%). In total, social surplus shrinks by 1067 M€/year.

As in the *Reference Scenario*, the introduction of market coupling has a beneficial impact on the level of the PUN. In particular, under the MC case, the PUN drops by 0.91 €/MWh with respect to the BAU case. Consumers' surplus grows with respect to the BAU case by about 288 M€/year, while producers' surplus declines by 161 M€/year. Congestion rent increases with respect to the PC case of a small amount with the introduction of coupling (6 M€/year). Thus, the aggregate welfare impact with respect to the BAU case is 133 M€/year. At the same time, the change in social surplus with respect to the PC remains remarkably high (935 M€/year).

	Reference Scenario				High Scenario			
	Perfect Competition PC	**Business As Usual BAU**	**Market Coupling MC**	**Market Coupling North Producers Competitive MCNO**	**Perfect Competition PC**	**Business As Usual BAU**	**Market Coupling MC**	**Market Coupling North Producers Competitive MCNO**
	(i)	*(ii)*	*(iii)*	*(iv)*	*(v)*	*(vi)*	*(vii)*	*(viii)*
System Marginal Price PUN €/MWh	65.31	75.62	74.92	72.82	79.48	94.52	93.61	89.76
Demand TWh	318.65	318.65	318.65	318.65	322.10	322.10	322.10	322.10
Net Import TWh	32.75	38.67	47.19	40.41	25.65	34.79	44.39	35.86
Internal Production TWh	285.91	279.99	271.46	278.24	296.45	287.31	277.71	286.24
Internal Expenditure M€	18921	22320	21540	21297	23868	28615	27554	27090
Total Expenditure M€	20996	25361	25151	24153	25824	32239	31951	30174
Generation Cost M€	14405	14111	13509	13901	18012	17412	16506	17211
TSO Surplus (Congestion Rent) M€	37	121	131	142	42	180	186	208
Consumers' Surplus M€	74601	70235	70445	71443	103016	96601	96889	98666
Producers' Surplus M€	4479	8087	7900	7254	5814	11023	10861	9671
Social Surplus M€	79116	78444	78476	78839	108871	107804	107937	108546
Change in Social Surplus wrt PC case M€		-672	-640	-278		-1067	-935	-326

Table 10: Simulations results under the four alternative cases of the Reference and High Scenario.

Under the MCNO case, where Northern Italy producers reduce their margins, so as to increase their output, PUN declines of 4.76 €/MWh with respect to the BAU case. In the MCNO case, the gain for Italian consumers with respect to the BAU is of 2065 M€/year (2%), while the fall in producers' surplus accounts for 1352 M€/year (-12%). Moreover, the fall in producers' surplus with respect to the BAU case is larger than that observed when comparing the MC case against the BAU case. This confirms the conclusion that under market coupling Northern producers are better off if they continue to charge their usual margins so as to follow the "passive output strategy" outlined above.

As for the *Reference Scenario*, a reduced Northern zone price determines a significant impact on the internal congestion rent. Table 11 shows that, with respect to the BAU case, congestion rent increases by 23 M€/year between Northern and Central-Northern Italy, by 28 M€/year between Central-Southern to Central-Northern Italy and by 5 M€/year on the transmission line between Rossano and Sicily. By contrast, congestion rent decreases by 28 M€/year between Central Southern and Southern Italy. Given that the overall congestion rent is 208 M€/year, the change in aggregate surplus of the MCNO case with respect to the BAU case accounts for about 742 M€/year. Nonetheless, social surplus is still 326 M€/year below the level of the PC case. Thus, though market coupling contributes considerably to the increase of social surplus with respect to the BAU case, yet it is not able alone to exert a competitive pressure such to replicate the results of the PC case.

	Reference Scenario			High Scenario		
	Business As Usual BAU	***Market Coupling MC***	***Market Coupling NORTH producers competitive MCNO***	***Business As Usual BAU***	***Market Coupling MC***	***Market Coupling NORTH producers competitive MCNO***
	Congestion Rent M€	*Congestion Rent M€*	*Congestion Rent M€*	*Congestion Rent M€*	*Congestion Rent M€*	*Congestion Rent M€*
North-Central North	1	2	20	1	2	24
Central North-Central South	13	9	30	22	17	50
Central South-South	64	76	45	93	103	65
Foggia-South	4	5	4	7	9	7
Rossano-South	0	0	1	1	0	2
Rossano-Sicily	36	35	38	52	52	57
Priolo-Sicily	4	4	4	3	3	3
Total Congestion Rent M€	121	131	142	180	186	208

Table 11: Congestion rent by transmission lines for the Reference and the High Scenario.

8 Conclusion

The main aim of this work was to evaluate the impact on the Italian electricity market of the introduction of market coupling to allocate the daily available cross-border interconnection with its neighbouring countries. Market coupling maximizes the use of interconnection capacity between countries, allowing for flows-netting and the elimination of inefficient arbitrage that may occur under the explicit auction mechanism. Simulations of two states of the Italian market, a Reference Scenario which is based on current market fundamentals and a High Scenario which accounts for rises in demand and in fuel prices, support the theoretical expectation that market coupling would determine a net welfare gain for market participants. In the Reference Scenario, the net welfare gain with respect to the Business As Usual case ranges between 32 M€/year and 395 M€/year, depending on whether Northern Italy producers act as oligopolists rather than as price-takers. The increase in social surplus brought by the introduction of market coupling is particularly evident when market fundamentals are tight, as in the instance of the High Scenario. Here, the net welfare gain is estimated to range between 133 M€/year and 742 M€/year. The analysis in this paper, employing the robust and highly detailed simulation model ELFO++, has the merit of providing a sound measure of the minimum gains that could be achieved by market participants.

The analysis in this paper can be developed further. The gains for market participants determined the by the elimination of imperfect arbitrage of explicit auctions could be account for. Moreover, all the market in the CSE area could be explicitly simulated and an aggregate welfare analysis could be carried out for all the countries. Finally, it would be interesting to extend this short-term analysis over a long-term horizon, so as to consider the benefits generated by both the increased security of supply and the lower need of investing in reserve capacity, and the costs of harmonisation and coordination of the national markets for the implementation of market coupling. We leave these extensions to on-going research.

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Appendix A

In order to identify the presence of a common trend in the behaviour of CSE wholesale day-ahead electricity spot prices, a cointegration analysis among the French EPEXSpot-FR, German EPEXSpot-DE, Swiss EPEXSpot-CH and the Austrian EXAA prices over the period from 1st January 2007 to 31st December 2010 is performed[54]. Given the large amount of noise in the hourly and daily price series, natural logarithms of weekly averages of the prices are taken. Figure A1 shows the four price series as transformed in natural logarithms of weekly averages (over a total number of 209 weeks). Descriptive statistics of the series are reported in Table A1 below.

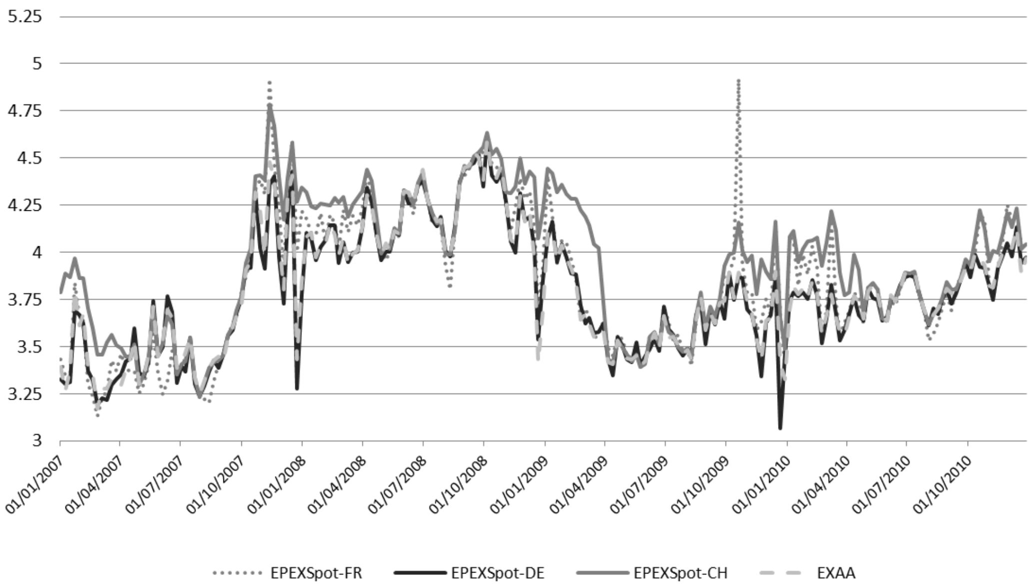

Figure A1: Log of weekly averages of EPEXSpot-FR, EPEXSpot-DE, EPEXSpot-CH and EXAA, over the period 2007-2010. Source: EPEXspot and EXAA.

[54] The data used are the same described in Section 4. The exclusion of Slovenia is due to the fact that its day-ahead auction market only opened in March 2010. In the second step of the cointegration analysis reported below, a further exercise is carried out including only the weeks from the 18th of March 2010 to the end of 2010 to evaluate whether there is convergence between the Slovenian and German day-ahead spot electricity price.

	EPEXSpot-FR	*EPEXSpot-DE*	*EPEXSpot-CH*	*EXAA*
Mean	3.85	3.79	3.94	3.80
Median	3.82	3.76	3.96	3.78
Minimum	3.13	3.07	3.23	3.17
Maximum	4.92	4.60	4.78	4.59
Standard Deviation	0.37	0.32	0.35	0.32
Kurtosis	-0.54	-0.58	-1.02	-0.65
Skewness	0.29	0.27	-0.01	0.34
Count	209	209	209	209

Table A1: Descriptive statistics of log of weekly averages of EPEXSpot-FR, EPEXSpot-DE, EPEXSpot-CH and EXAA, over the period 2007-2010. Source: EPEXspot and EXAA.

In order to establish the order of the integration of the series, the Dickey-Fuller (DF) and the Augmented Dickey-Fuller (ADF) statistics are applied to the log transformation of the price series. The log level of each of the four variables is non-stationary. The EPEXSpot-FR, EPEXSpot-DE, EPEXSpot-CH and the Austrian price EXAA can be regarded as I(1) variables, given that the first difference of the series are stationary. The results are reported in Table A2.

Variable	*t-adf*	*Lag order*
EPEXSpot-FR	-2.53	2
EPEXSpot-DE	-2.20	4
EPEXSpot-CH	-2.27	3
EXAA	-2.30	2
DEPEXSpot-FR	-15.49	1
DEPEXSpot-DE	-13.02	2
DEPEXSpot-CH	-8.82	2
DEXAA	-15.89	1

5% significance level =-2.88

Table A2: Augmented Dickey-Fuller Unit Root tests.

Thus, it is now possible to check whether individually EPEXSpot-CH, EXAA and EPEXSpot-FR, converge to EPEXSpot-DE, and then whether, EPEXSpot-CH, EXAA and EPEXSpot-DE converge to EPEXSpot-FR. The following equation is estimated for each pair of variables:

$P_{i,t} = constant + \beta P_{j,t} + \varepsilon_{i,t}$	*i=EPEXSpot-DE, EPEXSpot-FR* *j=EPEXSpot-DE, EPEXSpot-FR, EPEXSpot-CH,EXAA* *i≠j*	(A1)

Following De Vany and Walls (1999), market integration requires the presence of cointegration, while strong market integration implies testing for the null hypothesis of β=1 in the cointegration relation $p_{i,t} = \alpha + \beta p_{j,t} + \varepsilon_{i,t}$. Perfect integration, that is convergence, requires that both α=0 and β=1.

Table A3 reports the result of estimating Equation A1 for EPEXSpot-DE. The Swiss market does not seem to converge to the German or the French markets, as the null hypothesis of α=0 and β=1 is rejected. However there is evidence of convergence between Austria and Germany.

Cointegration only occurs if the residuals of the regression are stationary. Using ADF statistics to evaluate the stochastic process underlying the residuals, it is shown in A3 that the residuals series of all the regressions are stationary at the conventional 5% level, and therefore all the equations in Table A3 represent a meaningful economic relationship.

Dependent variable EPEXSpot-DE

	Coefficient	Std. Error	t-stat		t-adf
			α=0	β=1	
Constant	0.66	0.12	5.29		
EPEXSpot-CH	0.80	0.03		6.83	
ADF(4)					-3.11
Constant	0.03	0.04	0.79		
EXAA	0.99	0.01		1.10	
ADF(3)					-5.24
Constant	0.70	0.10	7.38		
EPEXSpot-FR	0.80	0.02		10	
ADF(3)					-4.24

Table A3: Convergence analysis of EPEXSpot-CH, EXAA and EPEXSpot-FR, towards EPEXSpot-DE.

TableA4 reports the result of estimating Equation A1 for EPEXSpot-FR. The Swiss price is found to converge to the French market, given that the null of α=0 and β=1 are both accepted. Also the German market converges to the French market. Convergence is not found between the Austrian and French markets. The ADF test carried out on the residuals of all the regressions are found to be stationary, confirming that all the equations represent meaningful economic relationships.

Dependent variable EPEXSpot-FR

	Coefficient	Std. Error	t-stat		t-adf
			$\alpha=0$	$\beta=1$	
Constant	0.08	0.11	0.72		
EPEXSpot-CH	0.95	0.03		1.67	
ADF(2)					-4.35
Constant	-0.19	0.10	-1.78		
EXAA	1.06	0.03		-2.00	
ADF(4)					-3.81
Constant	-0.10	0.12	-0.84		
EPEXSpot-DE	1.04	0.03		-1.33	
ADF(2)					-5.10

Table A4: Convergence analysis of EPEXSpot-CH, EXAA and EPEXSpot-DE, towards EPEXSpot-FR.

The ADF test on the logarithm of the weekly average Slovenian price rejects stationarity also for this series (i.e.*t-adf -2.309, lag order 0*). Thus, Equation A1 is re-estimated, and the results are reported in Table A5 below.

Dependent variable EPEXSpot-DE

	Coefficient	Std. Error	t-stat		t-adf
			$\alpha=0$	$\beta=1$	
Constant	0.18	0.17	1.06		
SI price	0.95	0.04		1.14	
DF(0)					-4.85

Table A5: Convergence analysis of Slovenian price towards EPEXSpot-DE.

The Slovenian price converges to the EPEXSpot-DE price, as the null of α=0 and β=1 are both accepted. Moreover, the ADF test on the residuals of the regression is stationary.

It therefore makes sense to reduce the complexity of the interconnections of northern Italy assuming only France and Germany to be the bordering countries.

Note:

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