Ramsey Prices in the Italian Electricity Market

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Abstract

In this paper, we derive optimal zonal prices in the Italian day-ahead electricity market using estimation of a complete system of hourly demand in 2010-2011. In Italy, the hourly equilibrium price for all buyers is computed as a uniform average of supply zonal prices, resulting from market splitting due to line congestion. We model ex-ante individual bids expressed by heterogeneous consumers, which are distinguished by geographical zones. Using empirical estimations, we compute demand elasticity values and new zonal prices, according to a Ramsey optimal scheme. This is a new approach in the wholesale electricity market literature, as previous studies have discussed the relative merit of zonal prices, considering only the issue of line congestion. Our results show that the optimal pricing scheme can improve welfare in the day-ahead Italian electricity market, with respect to both the existing uniform price scheme and the proposal to charge the existing supply zonal prices to the demand side.

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1. Introduction

In the organized electricity markets, the equilibrium price is determined by the intersection of supply and demand functions, resulting from the aggregation of individual bids submitted to the Market operator. In a perfect theoretical market, this solution is efficient, insofar as all agents are price takers and there are not market inefficiencies. In reality, the existence of transmission line congestion, more generally of network security management and of NIMBY (not-in-my-back-yard) syndrome[1] raise the issue of departure from the perfect competitive model. In other word, prices may not necessarily be equal to marginal costs and therefore, there is need to search for a second best solution. In the literature, a widely recommended solution is to set Ramsey (1927) prices, in order to minimize deadweight losses deriving from departing from the efficient solution.

The main aim of this paper is to define an optimal design to determine zonal prices in the wholesale electricity market using explicit information on the individual bids demand side. Surprisingly, the literature of theoretical and empirical analysis of deregulated electricity markets has not taken into account this important side of the market; rather, it has focused analysis on the zonal price differences arising on the supply side of the market. As it is well known, line congestion in a meshed network may give rise to price differentials between any two adjacent zones. In turn, these differences reflect an efficient resource allocation, insofar as they originate from differences in marginal supply costs and technologies.

However, this approach neglects two issues. First, the zonal price scheme does not consider that there is a characteristic of public good in the network management because the network security is an indivisible good. Second, it is rather obvious to consider that consumers' behavior may change in various zones due to price differentials, and this change may have consequences on overall consumer welfare. These two considerations challenge the

[1] It refers to the behavior of local groups of citizens who are opposed to equipment and infrastructures localization near their homes. This can create sub-optimal localization of necessary infrastructures.

conclusion that zonal prices based on zonal marginal costs are necessarily an efficient solution for the system as a whole. This would be the case if the electricity market were characterized by perfect competitive conditions. In reality, zonal prices include private costs, which would be efficient with respect to the network usage. However, they neglect social costs associated with specific network configurations that impinge on the rest of the economic activity.

As a thought experiment, consider an individual who unexpectedly goes to the local hospital. The increased electricity load due to the peculiarity of his illness (e.g., energy intensive artificial lung pumping) gives rise to line congestion and a higher zonal price. From a normative viewpoint, it is necessary to answer the following question: why should all other consumers in the zone pay more? We do not know whether they had the opportunity to decide in advance the optimal transmission level in their zone or anyway to form an expectation to face this problem. This unforeseen event is not under their control. Presumably, there is an increase in the cost of the service for all the consumers in the zone. These considerations give rise to another relevant problem. Should the cost associated to an unforeseen event such as an illness be socialized only to neighboring consumers? Alternatively, should such costs be borne by the entire society? There is the need to assess and quantify the social benefits of the hospital service in that zone with respect to the social cost of the network security in a broader zone. It is evident that this theoretical example raises normative questions involving some value judgments that go beyond the mere issue of efficient allocation of network scarcity. We deem that these normative issues are important and should be explicitly considered when analyzing the electricity market.

With these considerations in mind, we want to place emphasis on the demand side of the electricity market. We analyze the demand response to market signals and estimate the demand elasticity to design an optimal Ramsey price scheme in the Italian deregulated electricity market, where prices are determined in an auction market, the day-ahead Italian power exchange market (IPEX). We assess the welfare implications of the actual market design for determining prices in the electricity market. To conduct such evaluation, we perform a calculation of optimal prices according to Ramsey pricing theory with the objective to maximize social welfare. Then, we compare actual prices and zonal prices to optimal prices, to assess whether the actual price scheme can be improved upon and whether the adoption of zonal prices goes in the direction of optimality. To our knowledge, this is the first attempt in the literature to analyze optimal prices in an organized wholesale electricity market, like the IPEX; therefore, we attempt to bridge the literature of theoretical and empirical analysis of deregulated electricity markets and the literature on optimal price design. Specifically, we use the IPEX data published by the Italian Market Operator ("Gestore mercato elettrico", GME), considering individual bids in the day-ahead market to construct demand schedules in the period 2010-2011.

This paper is organized as follows. Section 2 presents a brief review of the related literature. Section 3 presents the theoretical framework of optimal pricing and the empirical methodology to estimate consumer behavior and describes the data set used. Section 4 presents the results and the discussion. Section 5 presents policy implications and concludes the paper.

2. Related Literature

The methodology to determine the vector of optimal prices involves the estimation of the demand elasticity in order to compute the Ramsey proportionality factor, which is needed to differentiate the charge according to the inverse of the demand elasticity. There are consolidated applications of this method in both theoretical and empirical economic analysis in the public utility sector, starting from the seminal contribution of Laffont and Tirole (1996), discussing the Ramsey optimality of the price cap regulation.

Ramsey pricing appears to influence welfare in the sectors of public utilities. Shepherd (1992) criticizes it by stating that Ramsey prices are a different way to label monopoly behavior. In the transport sector, Jorgensen et al. (2004) discuss the need to subsidize optimally the ferry services in Norway, because they are welfare enhancing, by regulating fares so to generate sufficient revenue to support the sector deficit. Martín-Cejas (2010) discusses the environmental implications of long-term growth in the air transport in Spain and the consequent need to design a Ramsey airport pricing structure for landing fees, which takes into account the social externality of the environmental damage. Hakimov and Mueller (2014) propose Ramsey pricing for landing fees differentiated by distance for five German airports. They find that Ramsey prices are optimal for airports with cost recovery problems, but are inefficient for busy airports and provide inconclusive evidence in favor of Ramsey pricing. Sanchez-Borras et al. (2010) apply Ramsey pricing to the high-speed trains in Europe. Lin and Price (2009) show an optimal gasoline tax in California. Other examples are in the health sector (e.g. Melnick et al. 1992; Danzon, 1997; Wedig, 1993) discussing the application of Ramsey pricing to regulate the physicians market power to induce their own demand.

There are many relatively recent applications related to the electricity markets. Qi et al. (2008) compute Ramsey prices for the Chinese residential sector and Matsukawa et al. (1993) analyze the Japanese utility sector. They both conclude that the welfare effects of rate regulation could be improved by increasing the residential electricity price and decrease the industrial one. Horowitz et al. (1996) discuss the case of unknown bypass costs. Berry (2000 and 2002) discusses Ramsey pricing as a tool for the regulator to discriminate between liberalized and bundled customers and to charge optimally stranded costs. The conclusion is that unbundled customers are more elastic, because they can search for alternatives in the market, and therefore their optimal Ramsey price should be lower than that charged to bundled customers.

Nahata et al. (2007) apply Ramsey pricing of electricity to final customers in Russia, based on estimation of single equation demand elasticities for six major groups of consumers (households and industrial users), using company data provided by the local distributor. Their findings support the view that the pricing policy adopted by the utility is not in accordance with the Ramsey rule and advocate that the welfare improving regulation should lower the price for industrial users and increase the price for households.

Ranieri and Giaconi (2005) propose to apply Ramsey pricing to the regulation of the electricity distribution to final customers and competitive energy sellers in Chile, concluding that the current regulation is not optimal. Kopsakangas-Savolainen (2004) computes the component of the final electricity price relative to network prices based on Ramsey pricing in Finland. Even under the assumption that the wholesale price is determined efficiently, the conclusion is that Ramsey pricing is welfare improving. Lin and Liu (2011) analyze the Chinese pricing reform for energy intensive industries enacted to promote energy efficiency and industrial restructuring. They analyze eight electricity intensive industries demand, showing that the optimal pricing policy is indeed inducing productivity growth.

Santos et al. (2012) analyze the electricity distribution systems in Brazil, combining time-of-use tariffs and Ramsey prices to be charged to both energy consumers and micro-generation units. Their conclusion is that the pricing regulation enacted by the Brazilian Electricity Regulatory Agency can be improved in terms of welfare. Klein and Sweeney (1999) analyze the natural gas distribution utilities in Tennessee using panel data to estimate Ramsey prices. They find empirical support to optimal Ramsey pricing. Hegazy and Guldmann (1996) propose an electricity-pricing scheme to final customers, based on both reliability pricing and real-time pricing. Their proposed pricing approach achieves better economic efficiency than both spot and Ramsey pricing. Pazhooyan and Mohammadi (2000) estimate demand elasticity for electricity in Iran for aggregate groups of final users, residential, agricultural, public and commercial and find that Ramsey pricing is welfare improving with respect to the existing rates.

In summary, we find that there are some critical issues in this literature. On the one hand, many of these applications derive the elasticity of demand in a partial equilibrium approach, without fully exploiting the theoretical founded approach of demand theory[2]. Some other applications estimate demand elasticity for only large aggregate bundles of households and industrial users. On the other hand, the successful practical application of the Ramsey pricing model requires that the policy makers have some knowledge of the demand elasticity for different groups of consumers or buyers in the market. The problem is that these estimates are often not sufficiently robust to justify the intervention of the policy-maker from a normative viewpoint[3]. In practice, it is difficult to find a political legitimacy for imposing a price structure that discriminates buyers, based on non-consolidated empirical evidence. Many studies recommend the adoption of Ramsey pricing on the basis that this reduces the pre-existing cross-subsidies. Typically, this entails to increase prices to residential final consumers and reduce prices to industrial users. It is evident that there is a political issue, because residential users are voters and they would resist a price increase, by punishing the politicians who support the price increase adoption.

On the theoretical ground, Ramsey pricing promotes efficiency by minimizing the deadweight welfare loss resulting from maintaining the budget equilibrium, but does not address at all the issue of equity. In this paper we do not consider the instruments to correct for equity, which have been implemented in practice after the liberalization of electricity markets, such as income transfer or considering agents relative conditions in terms of expenditure marginal utility (Diamond 1975).

In other words, the welfare optimality of the Ramsey pricing is ensured at the aggregate level, but there is no room for taking into account distributive problems in a definitely satisfactory way. The surplus distribution among different groups of buyers is neglected, even if there are ethical implications. It suffices to mention that poor users usually tend to exhibit a more rigid

[2] For instance, Martin-Cejas (2010), Nahata er al. (2007), Lin and Price (2009).

[3] For instance, Santos et al. (2012), Lin and Liu (2011).

behavior in electricity consumption, for lack of alternative opportunities. This would result in higher prices to the poor and consequently lower prices to the rich.

In general, the economic theory recommends adopting Ramsey pricing when the marginal cost for setting the price is not sufficient to collect the necessary revenue. We deem that this is precisely the situation of the wholesale electric market with transmission line congestion. In fact, the efficient marginal cost solution for satisfying the load cannot be achieved and the market splitting is a rationing solution, constrained by some limitation in the physical flow of electricity through the network. In this case, the extra-cost generated by the congestion constraint represents revenue that needs to be collected in the least distortionary manner. In other words, Ramsey pricing is an ideal solution to discriminate among buyers in the electricity market according to their bidding behavior, which expresses in a direct and revealed manner their willingness to pay. Obviously, there exists the related issue of how these optimal prices have to be transferred to the final consumer[4].

It is somehow surprising, therefore, to note that there is not in the literature, to the best of our knowledge, an application of Ramsey pricing to the wholesale electricity market. This is even more surprising given that individual bid data are publicly available and can be used for the direct empirical estimation of the demand elasticity (Bigerna and Bollino, 2014). We deem that the usage of estimated of demand elasticity from observed bidding behavior in an organized market is certainly less controversial than the usage of aggregate elasticity estimates derived from aggregate market data. Indeed, adoption of Ramsey pricing for final users is a very difficult task, because the policy maker does not know precisely the elasticity of demand of the entire population. Aggregate estimation may not be sufficiently precise so to impair the political credibility of the policy action. On the contrary, in an organized market, participants know in advance the rules and if the policy-maker decides to use a Ramsey

[4] This depends on the strategy adopted by the buyers (typically, retailers) in the wholesale market when they charge the final customer. In an ideal world of real time pricing to the final customer, the retailer can act as the agent for the customer who is the principal, leading to an optimal solution as discussed in detail in Bigerna and Bollino (2014).

pricing scheme, as the one proposed here, they should abide. They understand that welfare considerations for the whole society should prevail over the individual market participant interest. This makes the concept of Ramsey pricing more realistic.

3. Optimal pricing and demand behavior

The actual market design of IPEX envisions that the equilibrium point is given by the intersection of the merit order of the supply generators' bids and of the demand bids of buyers, who are traders, distributors and large energy intensive industries buying directly in the IPEX. Zonal differences arise due to network congestions, which determine differences in zonal prices. The market equilibrium is determined in such a way that in the importing zone, less efficient, i.e. more costly plants, are accepted to balance the demand, instead of less costly imports from more efficient plants, located in adjacent zones. Likewise, in the exporting zone more efficient, i.e. less costly plants, are rejected, even if they could export to the adjacent zone to satisfy the demand.

The specific feature of the Italian market is that the legislature has established in the day-ahead market a unique system marginal price (USMP) on the demand side, computed by averaging zonal supply prices. Thus, the actual regulation assumes that consumers are sheltered completely from local congestion issues. The Government[5] made this decision because at the beginning of the deregulation, the localization of generation plants inherited the former national monopolist decisions, taken according to its own objective function. Thus, because Northern regions had abundant low-cost hydro plants, whereas Southern regions had abundant high-cost thermal plants, it would have not been fair to charge different prices to consumers who had no responsibility in generation localization. Therefore, the Italian legislation provides a clear example of the full socialization of network congestion issues,

[5] This principle is established in the Decree of the Minister of Industry of Italy, which creates the new wholesale electricity market (Decreto Ministeriale, 2003).

charging the same price to all buyers. It is evident that this is a second best solution, but no one has yet analyzed the welfare implications for the Italian electric market[6].

In reality, given the shape of the country (long and narrow from North to South) the Italian electric network has some structural peculiarities that would be difficult or impossible to overcome. The network is not heavily meshed and stretches along the east and west coast of the country. Imports flow only from neighboring countries (France, Switzerland, Austria, Slovenia and Greece) and are structurally approximately 14% of total Italian consumption[7]. There are structural bottlenecks across the Apennines Mountains that are difficult to overcome. Moreover, in the two main islands – Sicilia and Sardegna – there is often the need to maintain power flows in the export direction, as ruled by the Transmission System Operator (TSO) for security reasons, to maintain adequate spinning reserve within each Island.

This structural condition has determined the level and the localization of past investments of the former national monopolist, for which local consumers are certainly not responsible. Therefore, zonal prices in the islands, as well as in other zones, may be higher for reasons of security and not necessarily because residents express a NIMBY type opposition to new infrastructural developments. In addition, recent development of renewable energy sources (RES), which has obviously followed the geographical endowment of wind and solar sources, has dramatically changed the market outcomes. In fact, RES are not necessarily located and available according to the demand load, thus creating additional line congestion. As all Italian consumers are equally contributing out of their pockets to the national RES policy (Bigerna and Polinori, 2014), which is considered a public good, we deem that it is not at all granted that local consumers should pay for local line congestion, when it is caused by RES injection,

[6] Some theoretical application to the Italian network can be found in Feng and Fuller (2005), who claim that the USMP does not affect the total economic surplus and provides perverse incentives for investment in new generation.

[7] Details on the Italian electric market are reported in the Market Operator Annual Report (GME, 2013).

on obvious equity ground.

While there is much debate in Italy regarding these issues, there is a lack of analysis of zonal differences in the demand structure. It should be rather obvious that differences in demand behavior across zones should be the basis to allocate system externality costs, such as congestion costs, which reflect some social objective. The latter is the conclusion of standard welfare analysis in economics. We attempt to fill this gap and study zonal demand structure in Italy assuming a theoretical model of hourly electricity consumption.

We assume that demand behavior in IPEX is expressed by cost minimizing rational agents, labeled "buyers". There are two types of buyers in the market: (i) large industrial firms (such as, cement, steel, chemicals) buying directly into the market, (ii) traders and distributors, buying in the interest of their costumers, who are households, industrial users, services and public administration. Therefore, whatever the final aim of the purchasing activity in the market, we deem that buyers express well-defined demand functions, i.e. they react to price signals expressing a demand elasticity. While the concept of supply elasticity has been widely used and studied in electricity markets, especially in connection with the measurement of suppliers' market power, the focus on the elasticity of demand in electricity markets has been certainly narrower. In fact, most of the analysis is on the final consumer, namely households, behavior in response to prices, but there is only few analysis of the demand side of wholesale electricity markets (Bigerna and Bollino, 2014).

In this paper, we refer to the model of simultaneous demand system estimated in Bigerna and Bollino (2015), which we develop further in order to estimate demand elasticity in IPEX, assuming that there are heterogeneous buyers distinguished by the geographical zone. Electricity demanded in each hour is a different good, because it has a different hourly price, so that the buyer has to solve a simultaneous cost minimization problem for the 24 hours in each day. We postulate that the behavior of each buyer *j* can be described with a two-stage cost (expenditure) function. In the first stage, buyer chooses to allocate his budget between consumption during the day and during the night. This yields demand for two aggregate goods defined as "group demand": daily e_d and nightly e_n electricity demand. In the second stage, the buyer j chooses within each group to demand the hourly electricity e_{hj} for each hour h. Electricity is demanded during the day (hours 10:00 to 21:00) for many different economic usages and during the night (hours 22:00 to 9:00) for less differentiated needs. This yields demand for 24 elementary goods, which are defined as "elementary demand" for electricity (12 hourly demand functions within each group).

We assume that the cost functions for each buyer j (representative of zone j) at each stage are of the standard form: $c_j = c_j(p, u_j)$, where the cost is a function of utility and prices. Standard duality theory allows to invert the cost function into an indirect utility function, from which Roy's identity yields the usual Marshallian demand functions for each group k in the first stage and for each hour h in the second stage, for each buyer j:

$$e_{kj} = e_{kj}(p, E_j) \qquad k = d, n \tag{1}$$

$$e_{hj} = e_{hj}(p_d, E_{dj}) \qquad h = 10, 11, \dots, 21 \tag{2}$$

$$e_{hj} = e_{hj}(p_n, E_{nj}) \qquad h = 22, 23, \dots, 9 \tag{3}$$

where the price vector in the first stage is: $p=(p_d, p_n)$ and in the second stage is: $p_d=(p_{10}, \dots, p_{21})$ during the day and $p_n=(p_{22}, \dots, p_9)$ during the night. E_j is total expenditure of buyer j and, in the second stage, E_{dj} is total expenditure in the day and E_{nj} is total expenditure in the night.

We assume that the policy maker has knowledge of individual demand functions and is willing to charge to buyers belonging to the same zone optimal prices taking into account efficiency objectives (therefore, j identifies a zonal group of buyers). Specifically, to maximize hourly efficiency, the policy maker considers each hour independently and takes into account only differences in zonal demand elasticities. The policy maker is facing different supply zonal prices in each hour h and in each zone j arising from congestion p_{hj} and has to decide how to charge prices on the demand side to different zones. The efficient price for the entire system $p^e{}_h$ will be the marginal bid that is necessary to supply the market in absence of transmission line congestion. At this price, the total market revenue would be insufficient to cover the total market cost, inclusive of transmission line congestion, and therefore there is need to introduce an optimal charge to be paid by buyers.

We assume that the policy maker knows the efficient price without transmission line congestion and wants to determine the optimal charge t_{hj} to be levied in each hour h to each group of buyers in zone j, which has to be added to the price in order to satisfy the constraint that total market revenues equal total market costs:

$$p_{hj}{}^{*} = p^e{}_h + t_{hj} \tag{4}$$

In eq. (10) the optimal Ramsey price is defined as the sum of the efficient price and the zonal optimal tax in each hour h. This entails computing for each hour h optimal prices for all zones j according to the classic Ramsey (1927) formula:

$$[(p^{*}{}_{hj} - p^e{}_h)/p^e{}_h] \,/\, [(p^{*}{}_{hi} - p^e{}_h)/p^e{}_h] = (1/|\varepsilon_{hj}|) \,/\, (1/|\varepsilon_{hi}|) \tag{5}$$

subject to the constraint*:*

$$G = \sum p_{jh} e_{jh} = \sum p_{jh}{}^{*} e_{jh} \tag{6}$$

i.e., the charges over the efficient price are inversely proportional to the demand elasticity, where $p^{*}{}_{hj}$ and $p^{*}{}_{hi}$ are optimal prices, p_{hj} are historical zonal prices, e_{hj} are quantities, ε_{hj} are estimated own price elasticities[8] for each hour h and zones i and j. Notice that with the representative consumer hypothesis in each zone j, this solution is equivalent to a maximization of a social welfare function $W = W(V_1, V_2, \ldots, V_J)$, where $\partial W/\partial Vj>0$, with the constraint to obtain the same amount of revenue G from the market equilibrium outcome.

Notice the crucial feature that revenue G is derived charging t_{hj} to each consumer j according to his/her consumption behavior. In this case, consideration is not given for distributive equity

[8] Given the two-stage structure of the demand system, we need to use unconditional elasticities for each hour in eqs. (2)-(3), which depend on both aggregate and hourly behavior. Detailed description of the formulae to recover from estimated parameters the unconditional elasticities under weak separability in two-stage demand systems can be found in Bigerna and Bollino (2014) and Edgerton (1997).

but only for efficiency; thus, charges are higher for inelastic goods with respect to more elastic goods.

To estimate empirically the demand system, we use individual bid data published by the GME from January 2010 to December 2011 (approximately 1 million records per month). We report some aggregate statistics in Table 1. We construct aggregate demand quantity and price vectors for six geographical zones, which comprise three domestic areas and three border countries: North, Center-South, the Islands, France, Switzerland (with Austria and Slovenia) and Greece. We assume that buyers behave differently by zone, so that we have six heterogeneous types of buyers. Notice that we have considered the neighboring foreign countries because Italy imports approximately 14% of total electricity consumption and buyers who contract electricity purchases from the foreign zones may have different behavior from the others.

We obtain approximately 537 thousand observations per year, which we use to estimate the demand systems for hourly electricity. We use as parametric function the Generalized Almost Ideal demand model (Bollino, 1987), which satisfies consumer theory restrictions, i.e., adding up, symmetry, homogeneity and heterogeneous consumer exact aggregation constraints[9]. The functional forms for demand functions are in the first stage:

$$e_{kj}= \gamma_{kj} + E_j^s/p_k\, [\alpha_{kj} + \textstyle\sum_t \alpha_{ktj}\, ln(p_t) + \beta_{kj}\, ln(E_j^s/p^s)]$$

$$E_j^s = E_j - (\textstyle\sum \gamma_{kj}\, p_k)$$

$$p^s = \textstyle\sum w_k\, ln(p_k) \qquad (7)$$

for the two group demand daily ad nightly, $k = d,n$ and for each buyer j. E_j^s denotes the supernumerary expenditure and p^s denotes the Stone price aggregator.

The demand functions are in the second stage:

$$e_{hj}= \gamma_{hj} + E_{kj}^s/p_h\, [\alpha_{hj} + \textstyle\sum_f \alpha_{hfj}\, ln(p_f) + \beta_{hj}\, ln(E_{kj}^s/p^s)]$$

$$E_{kj}^s = E_{kj} - (\textstyle\sum \gamma_{hj}\, p_h)$$

[9] The GAI demand model is suitable for estimation of flexible demand behavior, especially with large variability across heterogeneous agents (Bigerna and Bollino, 2015).

$$p^s = \sum w_h \ ln(p_h) \qquad (8)$$

where e_{hj} is the elementary demand in each hour h during the day and during the night, $k = d,n$ and for each buyer j. E_{kj}^s denotes the supernumerary expenditure and p^s denotes the Stone price aggregator. The estimated parameters are γ_{kj}, γ_{hj} expressing the committed quantity parameters; α_{kj}, α_{hj}, α_{ktj}, α_{hfj}, β_{kj}, β_{hj} are structural coefficients; w_k, w_h are average budget shares. We take the derivative of eq. (7) and (8) with respect to prices in order to compute the zonal elasticities ε_{hj} for each hour h and for each buyer j, so that all structural parameters are used to construct the elasticities, which are computed at the equilibrium prices and quantities.

4. Empirical results and Discussion

We estimate demand functions given in eq. (7)-(8) at both stages with seemingly unrelated regression (SUR) method using the TSP program (Hall and Cummins, 2005), and we derive unconditional elasticities for each quarter and each zone in the period 2010-2011. Observations used for estimation in the four quarters of 2010 are 5897, 4289, 4447 and 5542, and in the four quarters of 2011, they are 4988, 4678, 4869 and 5236. We assume interaction of the committed quantity parameters with daily dummies for each equation[10]. For each quarter, we estimate in the SUR system 195 coefficients at the first stage and 2478 coefficients at the second stage[11].

Empirical estimations of eqs. (7)-(8) are plausible and quite accurate, with R squared in the .96 - .99 range for all equations and very high proportion of coefficient significance (Table 2). Specifically, at a 5% confidence level, almost all estimated coefficients are significant; most of the remaining non-significant coefficients are the committed quantity parameters. Thus, we obtain quite high precision estimation of price response parameters, which we use to estimate demand elasticities. We have tested with the Likelihood Ratio test for the zonal differences in structural parameters in both stages. We reject the null hypothesis of identical parameters for

[10] Precisely, we have shifted the parameters γ_{kj}, γ_{hj} by multiplying them with daily dummies. This yields a different estimated committed quantity for each day, which is tested below.

[11] To use a parsimonious specification, in empirical estimation, we impose $\alpha_{jhk} = \alpha_{hk}$ for $h \neq k$.

all six zones, thus supporting the finding that zonal heterogeneity exists, based on LR test values largely above critical values. In Table 2, we report detailed LR values for all quarters at the first stage, which are all significant (LR values above 1000 with respect to a critical chi-square value of 23 with 10 degrees of freedom).

Estimated own price elasticities are significantly different across zones and time of the year, within the range - .04 to -.12 (Table 3). Elasticity values are generally higher during morning and late evening hours, as expected, when aggregate economic activities are changing, ramping up in the morning and down in the evening. In addition, zone elasticity estimation shows that price elasticities are relative higher for zones 1 and 2 in 2010 and zones 5 and 6 in 2011. These results are important because the differences in estimated elasticities by zones and hours motivate our analysis of optimal prices taking into account welfare considerations in constructing the social optimal pricing scheme. We compute optimal prices for every hour, but to save space, we report only annual averages[12].

We report the results of the Ramsey price computation, subject to the constraint that charge revenue in every hour yields the market equilibrium outcome, by hourly averages for 2010 and 2011.

The operational measurement of the efficient price requires carefully designing the counterfactual definition of absence of line congestion. The difference between the actual market outcome inclusive of line congestion and the hypothetical no congestion outcome is the basis for the monetary measure of the congestion cost imposed on the society. In practice, there are at least three different definitions of the concept of "Congestion rent". The first definition simply considers the price difference between two adjacent zones times the load in the congested zone (e.g., this is used by the Nord Pool and the NYISO, Imran and Kockar,

[12] Detailed results are available from the authors upon request.

2014). The second definition considers the monetary revenues accrued to the payments to the transmission line owner (typically, the TSO), which is the price difference times the flow through the line (this is used by most TSO in the EU, including Italy, AEEG 2008). A third, more general, definition considers the opportunity costs of transmission constraints, i.e. the cost that would be avoided if generation would flow to load in absence of transmission system congestion. In this case, the equilibrium price would be set at a value in-between the two zonal prices, depending on the capacity availability in the surplus zone. This definition of congestion can be operationally computed only if individual bids are available, in order to re-simulate the system marginal price setting, without transmission constraints. This implies that bids have not been made opportunistically, based on expectation that congestion would inevitably occur.

In normal cases, it is expected that that total cost of load is lower without congestion, for the benefit of the consumers. Assume that there are two zones, A and B, with abundant generation capacity and different loads equal to 8 and 10 GW, respectively, but with transmission capacity between the two zones equal to 2 GW (Figure 1, Case 1). Market splitting results in different prices equal to 40 in zone A and 60 EUR/MWh in zone B. Generation will be 10 GW in the low price (saturating the transmission capacity) and 8 GW in the high price zone, with a cost of 400K and 440K EUR, respectively. The total cost is 880K EUR. Assume that in absence of congestion, the marginal price for the two zones is set at 45 EUR/MWh, i.e. equal to the lower cost generation zone (Figure 1, Case 2). This means that the supply from the low cost (surplus) zone is increasing to 11 GW at a price of 45 EUR/MWh to serve the load to the other (deficit) zone and the more costly units with price above 45 EUR/MWh are rejected in both zones. The transmission flow is now 3GW without constraint. The cost is 495K EUR in zone A and 315K EUR in zone B, with a total cost of 810K EUR. There is a net benefit compared to the congested case.

However, in extreme cases, it may happen that total cost of load is higher without congestion.

Alternatively to the previous case, assume that the marginal price to serve the overall load is set at 50 EUR/MWh, (Figure 1, Case 3). In absence of congestion, lower cost additional generation in the surplus zone displaces the more costly generation in the deficit area. However, the cost is 495K EUR in zone A and 315K EUR in zone B and the total cost would be 900K EUR, paradoxically higher than that in the congested situation of Case 1.

In this paper we constructed the efficient price for the entire system p^e_h in each hour, considering the opportunity cost of congestion. Operationally, we assumed that the network is void of congestion in every hour and we compute the system marginal price for the whole country, using the initial merit order assigned to each supply bid by GME and identifying the marginal bid that equates the cumulated supply to the total market quantity. In other words, we have simulated the market equilibrium algorithm, assuming that there is no transmission line congestion in the Italian market. As expected this efficient price is equal to the USMP when there is no market splitting and it is lower than the USMP paid by buyers in about 95% of the hours when market splitting occurs, because congestion raises zonal prices above the efficient price.

In the remaining 5% of the hours, a peculiar event happens: the zonal price is the same for all zones in mainland Italy, except in Sicilia, where the zonal price is lower. In this case, the USMP is the weighted average of mainland and Sicilia and results slightly lower than the mainland price. However, given the relative small size of Sicilia compared to the rest of the country, the computation of the efficient price, which assumes away the line congestion between Sicilia and the rest of Italy, yields the marginal price equal to the mainland price and therefore slightly higher than the USMP. In this case, we assume that congestion has no effect and we assume that the efficient price is equal to the USMP.

Specifically, we report the comparison between actual and optimal prices by hours for the six zones in years 2010 and 2011 in Tables 4 and 5. In the left panel, we report the historical USMP and the average zonal prices. In the central panel, we report the optimal prices, and in the right panel, we report the ratio of optimal to the historical zonal price.

Notice that the average USMP has been 64.5 EUR/MWh in 2010 with an hourly range between 39.6 and 81.0. In 2011, the average USMP has been 72.2 with an hourly range between 50.1 and 87.6. The hourly variability seems to be similar in both years, with higher values in the late morning hours in 2010 and in the early evening hours in 2011. In 2010, zonal prices are decisively higher on average than USMP by approximately 29% in zone 3, approximately 10% lower than USMP in zone 6 and also moderately lower than the USMP in zones 1, 2 and 5. In 2011, these spreads across zones show a similar but more favorable pattern. In particular, the zonal price in zone 3 is only 17% higher than the USMP.

Turning the attention to the optimal prices, we notice that the overall zonal pattern changes significantly. The optimal prices are constructed according to eq. (10), as a markup over the efficient price p^e_h, in order to yield the same (weighted) average of the USMP. Notice this weighted average of optimal prices is higher than the efficient price, as explained above, on average, by about 2-5%. In other words, the simulated cost of congestion is about 2-5% of the total cost, higher during peak hours in both years.

In 2010, the optimal prices are higher on average than USMP in zones 2, 4 and 5. In 2010, the optimal zonal price should have been lower than the historical zonal prices, on average, in the early morning hours zones 1 and during all day in zone 3, while it should have been higher in zones 2, 4, 5 and 6. This result is very interesting because it shows that the optimal pattern would be to charge lower prices than zonal prices in the North during the night and the Islands all day and higher prices in the Center of Italy. In addition, higher optimal prices than the historical zonal prices should be charged to the demand in all the three foreign zones. Note that the difference between historical and optimal prices is highest during the peak-hours. The average optimal price differential with respect to the historical zonal price is in the order of 4-5% in zones 1 2 4 and 5 and it is 11% in zone 6 and -20% in zone 3. The maximum differential is around 10% in zones 1 2 4 and 5 and it is 22% in zone 6 and -32% in zone 3.

In 2011, these patterns are even clearer. In 2011, the optimal prices are higher on average than USMP in zones 4, 5 and 6, i.e. all foreign zones. Moreover, in 2011 the optimal prices should be on average approximately 3% higher than zonal prices in the zones 1, 2 and 4 and approximately 6% to 8% higher in the two foreign zones 5 and 6. On the contrary, the optimal price should be 13% lower than zonal price in zone 3.

Our result can contribute to the recent debate in Italy, about the possibility to introduce zonal prices on the demand side, too. Contrary to the existing regulation, advocates of zonal pricing think that consumers should fully bear congestion costs so that they have an incentive to support new generation and network development. They also think that this will discourage opportunistic opposition to new plants and transmission lines, i.e., discourage NIMBY-type opposition to new developments. It is clear that this position cares only about a partial equilibrium solution, namely the network efficiency, given the geographical structure of the Italy.

On the contrary, our results show that the optimal prices exhibit a low variability around the USMP, while the zonal prices exhibit a higher variability around the USMP. This confirms that the proposal to charge zonal prices to the demand side is worsening the overall welfare of the demand side. In addition, these results show that the actual regulation to charge a USMP to all buyers is worse in terms of welfare. In summary, the pattern of Ramsey pricing shows that the optimal policy is to design higher prices in those zones and hours when price elasticity values are lower, namely in some foreign zones, and more so during daily peak hours.

5. Conclusion and Policy Implications

We have estimated a complete demand system with different zonal behavior in the Italian electricity market. We have distinguished six zones, three national zones and three foreign zones, and we have used the estimated zonal price elasticity values to compute an optimal

Ramsey price scheme. Our results show that than zonal prices are not optimal and that there are better solutions, i.e., adopting an appropriate price design mechanism to increase consumer welfare.

There are two relevant issues in the electricity market that can be solved by adopting an optimal Ramsey pricing scheme. The first issue is given by line congestion. The second issue is given by the existence of RES with zero or negligible marginal cost. As it is well known, both issues are rendering the price formation mechanism useless in transmitting efficient signals to the market.

In fact, the determination of equilibrium pricing in the electricity market, which is performed by charging zonal prices to consumers is not optimal in the sense of welfare maximization. This is so because line congestion causes price differentials, which are not necessarily induced by consumer behavior. In this sense, we think that line congestion has to be considered as a public good, which generates externalities to the complete electric system.

In addition, if a marginal RES sets the equilibrium price at zero, this is clearly inefficient in providing the adequate market signal to guide the profitability for the conventional fossil-fueled generation in the long run. Moreover, it has an adverse effect even for the development of RES and for the new EU strategy to privilege market-based subsidies, such as feed-in premium. If the equilibrium price is zero, this displaces not only conventional fossil-fueled generation but also the feed-in premium, which obviously will be insufficient to cover the difference between the RES cost and the zero market price.

Thus, the optimal solution is not zonal pricing. This latter scheme would be akin to the idea of letting consumers living in the plains to have access to low-cost wheat produced in the more fertile fields and forcing consumers living in the hillside to consume high-cost wheat produced in the high-cost fields. Centralized dairy produce markets have demonstrated over a long time that centralization is the way to improve overall welfare in modern economic system.

In conclusion, we advocate a comprehensive market reform of demand prices, which is based on the principle of price differing according to the demand elasticity structure. The policy makers should be aware that they face active and sophisticated economic agents, who need a robust regulatory framework, aimed at promoting the maximization of efficiency and welfare, in the wholesale electricity market. Our result show the way to implement substantial improvement in the existing regulation.

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Table 1 — Italian market IPEX prices and quantities * - 2010-2011

Years	2010				2011			
	Equilibrium Market prices (EUR/Mwh) and quantities (MWh)							
	Price			Quantity	Price			Quantity
	Min	Average	Max		Min	Average	Max	
all hours	10.0	66.5	174.6	26438	10.0	71.1	164.8	25958
peak hours	71.5	84.2	174.6	41104	75.9	86.5	142.9	40263

*****Equilibrium market prices minimum, average and maximum values in EUR/Mwh and equilibrium market quantity in MWh in the year. All hours refers to all 24 hours of the day; peak hours refers to 11:00-15:00 business days hours only.

Table 2 – Estimation of hourly electricity demand systems - 2010-2011 - Diagnostics (*)

Period of estimation	No. obs.	R squared min values	% of param. significant at 5% level	LR test for zonal parameter differences
2010 IQ	5897	0.99	100	2849
IIQ	4289	0.98	100	1434
IIIQ	4447	0.99	100	977
IVQ	5542	0.97	100	1344
2011 IQ	4988	0.99	100	4544
IIQ	4678	0.96	100	6868
IIIQ	4869	0.99	100	6557
IVQ	5236	0.98	99	1259

(*) Estimation of systems of equations (7)-(8). Col. 1: period of estimation. Col.2: number of observations per period. Col. 3: R-squared minimum values of hourly equations in the system (maximum is always equal to .99). Col 4: proportion of estimated parameters that are significant at 5% level. Col. 5: Likelihood ratio test for restricted systems estimation, chi square values with 10 Degrees.of.Freedom - critical value (1%) = 23.

Table 3 – Estimated own price elasticities by zones (*) - 2010-2011

	2010						2011					
Hours	E1	E2	E3	E4	E5	E6	E1	E2	E3	E4	E5	E6
1	-0.07	-0.11	-0.06	-0.09	-0.09	-0.08	-0.06	-0.04	-0.04	-0.06	-0.06	-0.06
2	-0.07	-0.10	-0.06	-0.08	-0.08	-0.08	-0.06	-0.04	-0.04	-0.06	-0.06	-0.07
3	-0.05	-0.10	-0.05	-0.08	-0.08	-0.08	-0.05	-0.04	-0.04	-0.05	-0.05	-0.06
4	-0.04	-0.09	-0.05	-0.07	-0.07	-0.07	-0.04	-0.04	-0.03	-0.04	-0.05	-0.06
5	-0.04	-0.07	-0.05	-0.06	-0.06	-0.05	-0.05	-0.04	-0.03	-0.04	-0.05	-0.06
6	-0.06	-0.10	-0.05	-0.08	-0.07	-0.08	-0.05	-0.04	-0.04	-0.05	-0.06	-0.06
7	-0.10	-0.10	-0.06	-0.08	-0.08	-0.09	-0.06	-0.05	-0.05	-0.06	-0.07	-0.07
8	-0.10	-0.11	-0.08	-0.09	-0.09	-0.10	-0.07	-0.05	-0.06	-0.07	-0.08	-0.09
9	-0.07	-0.12	-0.07	-0.09	-0.08	-0.09	-0.07	-0.06	-0.06	-0.08	-0.09	-0.10
10	-0.06	-0.06	-0.05	-0.05	-0.05	-0.06	-0.04	-0.05	-0.04	-0.05	-0.04	-0.05
11	-0.07	-0.06	-0.05	-0.05	-0.05	-0.06	-0.04	-0.05	-0.05	-0.05	-0.05	-0.05
12	-0.06	-0.06	-0.05	-0.05	-0.05	-0.06	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05
13	-0.06	-0.06	-0.04	-0.05	-0.05	-0.06	-0.04	-0.05	-0.04	-0.05	-0.04	-0.05
14	-0.06	-0.06	-0.04	-0.05	-0.05	-0.05	-0.04	-0.04	-0.04	-0.05	-0.04	-0.04
15	-0.06	-0.06	-0.05	-0.05	-0.05	-0.06	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
16	-0.04	-0.05	-0.05	-0.05	-0.05	-0.06	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
17	-0.06	-0.05	-0.05	-0.05	-0.05	-0.06	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
18	-0.07	-0.05	-0.05	-0.05	-0.05	-0.06	-0.05	-0.04	-0.04	-0.05	-0.04	-0.05
19	-0.07	-0.06	-0.05	-0.06	-0.05	-0.06	-0.04	-0.05	-0.05	-0.05	-0.05	-0.05
20	-0.06	-0.06	-0.05	-0.06	-0.05	-0.06	-0.04	-0.04	-0.04	-0.05	-0.05	-0.05
21	-0.05	-0.05	-0.04	-0.05	-0.05	-0.05	-0.04	-0.04	-0.04	-0.05	-0.04	-0.05
22	-0.11	-0.10	-0.07	-0.09	-0.09	-0.11	-0.07	-0.06	-0.07	-0.08	-0.08	-0.09
23	-0.11	-0.11	-0.06	-0.09	-0.09	-0.10	-0.06	-0.06	-0.06	-0.07	-0.08	-0.09
24	-0.11	-0.10	-0.06	-0.09	-0.09	-0.09	-0.06	-0.05	-0.06	-0.07	-0.07	-0.08

(*) Zones are: 1=North; 2= Center and South; 3= Islands; 4= France; 5= Switzerland etc.; 6=Greece.

Table 4 - Hourly zonal prices and Ramsey optimal prices – 2010 averages - EUR/MWh

	USMP	**Historical zonal prices**						**Ramsey Optimal Prices**						**Ratio of Optimal to Zonal prices**					
Hours		**Z1**	**Z2**	**Z3**	**Z4**	**Z5**	**Z6**	**O1**	**O2**	**O3**	**O4**	**O5**	**O6**	**R1**	**R2**	**R3**	**R4**	**R5**	**R6**
1	52.9	53.3	52.0	55.0	53.3	53.3	50.7	52.8	53.0	52.7	53.1	53.0	52.9	0.99	1.02	0.96	1.00	1.00	1.04
2	48.1	48.5	46.8	50.6	48.5	48.5	45.6	48.1	48.2	47.9	48.2	48.2	48.1	0.99	1.03	0.95	0.99	0.99	1.06
3	44.7	45.3	43.3	47.0	45.3	45.3	42.3	44.6	44.8	44.6	44.9	44.8	44.8	0.98	1.04	0.95	0.99	0.99	1.06
4	40.7	41.1	39.3	43.1	41.1	41.1	38.4	40.4	40.8	40.5	40.8	40.7	40.8	0.98	1.04	0.94	0.99	0.99	1.06
5	39.6	39.9	38.2	42.4	39.9	39.9	37.4	39.4	39.7	39.4	39.7	39.7	39.6	0.99	1.04	0.93	1.00	1.00	1.06
6	41.7	42.1	40.4	44.4	42.1	42.1	39.5	41.5	41.9	41.5	41.9	41.8	41.8	0.99	1.04	0.94	1.00	0.99	1.06
7	50.9	51.1	48.9	54.5	51.1	51.1	48.4	50.7	50.9	50.7	51.0	50.9	50.9	0.99	1.04	0.93	1.00	1.00	1.05
8	60.9	59.6	57.8	71.4	59.6	59.6	57.0	60.7	60.9	60.6	61.1	60.9	61.0	1.02	1.05	0.85	1.02	1.02	1.07
9	69.4	66.1	63.0	94.4	66.1	66.1	60.4	69.0	69.6	68.9	69.7	69.5	69.6	1.04	1.10	0.73	1.05	1.05	1.15
10	78.2	75.0	69.9	109.2	75.0	75.0	65.3	77.9	78.5	77.9	78.5	78.3	78.3	1.04	1.12	0.71	1.05	1.04	1.20
11	81.0	78.7	72.6	110.6	78.7	78.7	66.7	80.7	81.2	80.7	81.2	81.1	81.1	1.03	1.12	0.73	1.03	1.03	1.22
12	80.9	78.8	72.8	109.3	78.8	78.8	66.9	80.6	81.2	80.6	81.1	81.0	80.9	1.02	1.12	0.74	1.03	1.03	1.21
13	71.7	66.5	65.6	101.8	66.5	66.5	63.1	71.5	71.9	71.2	71.9	71.8	71.7	1.08	1.09	0.70	1.08	1.08	1.14
14	68.4	64.5	62.7	93.8	64.5	64.5	60.3	68.1	68.5	68.1	68.6	68.5	68.4	1.06	1.09	0.73	1.06	1.06	1.13
15	69.8	67.4	63.5	92.9	67.4	67.4	60.0	69.5	69.9	69.5	70.0	69.9	69.8	1.03	1.10	0.75	1.04	1.04	1.16
16	70.2	68.2	63.8	92.6	68.2	68.2	60.1	69.7	70.4	70.1	70.5	70.3	70.3	1.02	1.10	0.76	1.03	1.03	1.17
17	72.4	69.4	66.0	96.6	69.4	69.4	63.6	72.0	72.6	72.2	72.6	72.5	72.5	1.04	1.10	0.75	1.05	1.04	1.14
18	75.4	*70.8*	*69.1*	*103.4*	*70.8*	*70.8*	*67.2*	*75.1*	*75.4*	*75.2*	*75.5*	*75.4*	*75.4*	1.06	1.09	0.73	1.07	1.07	1.12
19	75.8	*70.4*	*69.5*	*106.4*	*70.4*	*70.4*	*67.7*	*75.5*	*75.9*	*75.5*	*76.0*	*75.9*	*75.8*	1.07	1.09	0.71	1.08	1.08	1.12
20	76.2	*69.3*	*70.2*	*109.9*	*69.3*	*69.3*	*69.0*	*75.8*	*76.4*	*75.7*	*76.5*	*76.3*	*76.3*	1.09	1.09	0.69	1.10	1.10	1.11
21	79.2	*71.9*	*72.9*	*115.6*	*71.9*	*71.9*	*71.1*	*78.5*	*79.7*	*78.8*	*79.5*	*79.3*	*79.3*	1.09	1.09	0.68	1.11	1.10	1.12
22	74.5	*68.6*	*68.3*	*106.4*	*68.6*	*68.6*	*66.8*	*74.7*	*74.6*	*73.9*	*74.8*	*74.6*	*74.7*	1.09	1.09	0.69	1.09	1.09	1.12
23	65.7	*63.2*	*62.8*	*81.6*	*63.2*	*63.2*	*60.4*	*65.9*	*65.7*	*65.3*	*65.8*	*65.8*	*65.8*	1.04	1.05	0.80	1.04	1.04	1.09
24	60.0	*58.1*	*57.5*	*72.3*	*58.1*	*58.1*	*56.0*	*60.2*	*60.0*	*59.6*	*60.1*	*60.0*	*60.0*	1.04	1.04	0.83	1.03	1.03	1.07
Ave	*64.5*	*62.0*	*59.9*	*83.6*	*62.0*	*62.0*	*57.7*	*64.3*	*64.6*	*64.2*	*64.7*	*64.6*	*64.6*	*1.03*	*1.07*	*0.80*	*1.04*	*1.04*	*1.11*
Stdv	*13.8*	*11.9*	*11.4*	*25.8*	*11.9*	*11.9*	*10.5*	*13.7*	*13.8*	*13.7*	*13.8*	*13.8*	*13.8*	*0.04*	*0.03*	*0.10*	*0.04*	*0.04*	*0.05*
Min	*39.6*	*39.9*	*38.2*	*42.4*	*39.9*	*39.9*	*37.4*	*39.4*	*39.7*	*39.4*	*39.7*	*39.7*	*39.6*	*0.98*	*1.02*	*0.68*	*0.99*	*0.99*	*1.04*
Max	*81.0*	*78.8*	*72.9*	*115.6*	*78.8*	*78.8*	*71.1*	*80.7*	*81.2*	*80.7*	*81.2*	*81.1*	*81.1*	*1.09*	*1.12*	*0.95*	*1.11*	*1.10*	*1.22*

Note:
USMP= national average price on the demand side. Zn= zonal prices. On= optimal prices. Rn= ratio optimal price / zonal price. Zone numbers are n: 1= North; 2=Center-South; 3= Islands; 4= France virtual zone; 5= Switzerland, Austria, Slovenia virtual zones; 6= Greece virtual zone.
Ave= hourly averages; Stdv=standard deviation; Min. Max= minimum and maximum hourly values.

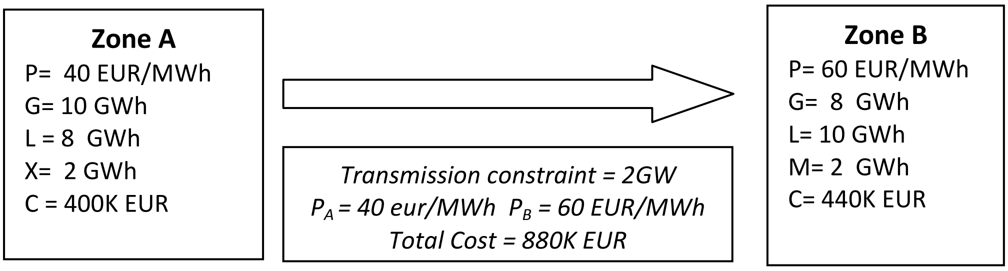
Table 5 - Hourly zonal prices and Ramsey optimal prices – 2011 averages - EUR/MWh

	USMP	**Historical zonal prices**						**Ramsey Optimal Prices**						**Ratio of Optimal to Zonal prices**					
Hours		**Z1**	**Z2**	**Z3**	**Z4**	**Z5**	**Z6**	**O1**	**O2**	**O3**	**O4**	**O5**	**O6**	**R1**	**R2**	**R3**	**R4**	**R5**	**R6**
1	65.5	65.0	64.7	69.8	65.0	60.2	64.5	65.6	65.4	65.3	65.6	65.7	65.6	1.01	1.01	0.94	1.01	1.09	1.02
2	58.0	57.8	57.4	60.5	57.8	53.8	57.3	58.0	57.7	57.8	58.0	58.1	58.2	1.00	1.01	0.96	1.00	1.08	1.02
3	53.5	53.3	52.8	56.2	53.3	49.6	52.8	53.5	53.2	53.3	53.6	53.6	53.8	1.00	1.01	0.95	1.01	1.08	1.02
4	50.5	50.3	49.9	52.6	50.3	46.9	49.9	50.5	50.4	50.3	50.5	50.6	50.7	1.00	1.01	0.96	1.00	1.08	1.02
5	50.1	49.9	49.6	52.5	49.9	46.6	49.5	50.2	50.0	50.0	50.2	50.2	50.4	1.00	1.01	0.95	1.00	1.08	1.02
6	54.4	54.3	53.9	56.5	54.3	51.0	53.8	54.4	54.2	54.3	54.4	54.5	54.6	1.00	1.01	0.96	1.00	1.07	1.02
7	63.3	63.0	62.5	65.8	63.0	59.7	62.5	63.3	63.1	63.2	63.3	63.4	63.5	1.00	1.01	0.96	1.00	1.06	1.02
8	69.2	68.4	67.4	76.7	68.4	66.3	67.1	69.2	68.9	69.0	69.2	69.4	69.6	1.01	1.02	0.90	1.01	1.05	1.04
9	77.9	75.9	73.5	93.0	75.9	73.0	71.9	77.7	77.5	77.6	77.9	78.0	78.2	1.02	1.06	0.83	1.03	1.07	1.09
10	82.8	80.1	77.0	101.1	80.1	76.6	74.5	82.8	82.8	82.8	83.0	82.8	82.9	1.03	1.08	0.82	1.04	1.08	1.11
11	83.7	81.3	76.9	100.8	81.3	77.5	73.9	83.6	83.7	83.6	83.8	83.6	83.7	1.03	1.09	0.83	1.03	1.08	1.13
12	82.9	80.6	76.2	98.5	80.6	77.1	73.5	82.8	82.9	82.8	83.0	82.8	82.9	1.03	1.09	0.84	1.03	1.07	1.13
13	74.3	71.1	70.7	91.6	71.1	69.1	69.6	74.2	74.3	74.1	74.4	74.2	74.3	1.04	1.05	0.81	1.05	1.07	1.07
14	71.3	68.9	67.7	85.0	68.9	66.9	66.6	71.2	71.3	71.2	71.4	71.2	71.3	1.03	1.05	0.84	1.04	1.06	1.07
15	73.5	71.6	68.9	86.7	71.6	68.8	66.7	73.4	73.5	73.4	73.6	73.4	73.6	1.02	1.07	0.85	1.03	1.07	1.10
16	75.3	73.5	70.8	88.2	73.5	70.1	68.4	75.3	75.3	75.3	75.4	75.3	75.3	1.02	1.06	0.85	1.03	1.07	1.10
17	78.1	75.9	73.9	92.4	75.9	72.2	72.4	78.0	78.1	78.0	78.1	78.0	78.2	1.03	1.06	0.84	1.03	1.08	1.08
18	84.3	81.3	80.5	98.9	81.3	78.0	78.9	84.3	84.3	84.3	84.4	84.3	84.4	1.04	1.05	0.85	1.04	1.08	1.07
19	85.5	81.6	82.4	103.1	81.6	78.8	81.0	85.4	85.4	85.4	85.6	85.5	85.6	1.05	1.04	0.83	1.05	1.09	1.06
20	87.6	82.0	85.0	110.7	82.0	79.0	83.6	87.5	87.5	87.5	87.7	87.6	87.9	1.07	1.03	0.79	1.07	1.11	1.05
21	87.2	81.6	83.3	114.0	81.6	78.3	82.7	87.1	87.2	87.1	87.3	87.2	87.4	1.07	1.05	0.76	1.07	1.11	1.06
22	82.0	77.7	78.2	103.8	77.7	74.2	77.8	81.9	81.6	81.8	82.1	82.2	82.5	1.05	1.04	0.79	1.06	1.11	1.06
23	74.6	72.2	72.1	88.6	72.2	69.4	71.6	74.5	74.4	74.4	74.7	74.8	75.0	1.03	1.03	0.84	1.03	1.08	1.05
24	68.1	66.8	66.4	77.2	66.8	63.4	66.4	68.0	67.9	68.0	68.2	68.3	68.4	1.02	1.02	0.88	1.02	1.08	1.03
Ave	*72.2*	*70.2*	*69.2*	*84.3*	*70.2*	*66.9*	*68.2*	*72.2*	*72.1*	*72.1*	*72.3*	*72.3*	*72.4*	*1.03*	*1.04*	*0.87*	*1.03*	*1.08*	*1.06*
Stdv	*12.0*	*10.6*	*10.5*	*19.0*	*10.6*	*10.7*	*9.9*	*12.0*	*12.0*	*12.0*	*12.0*	*11.9*	*12.0*	*0.02*	*0.03*	*0.06*	*0.02*	*0.01*	*0.04*
Min	*50.1*	*49.9*	*49.6*	*52.5*	*49.9*	*46.6*	*49.5*	*50.2*	*50.0*	*50.0*	*50.2*	*50.2*	*50.4*	*1.00*	*1.01*	*0.76*	*1.00*	*1.05*	*1.02*
Max	*87.6*	*82.0*	*85.0*	*114.0*	*82.0*	*79.0*	*83.6*	*87.5*	*87.5*	*87.5*	*87.7*	*87.6*	*87.9*	*1.07*	*1.09*	*0.96*	*1.07*	*1.11*	*1.13*

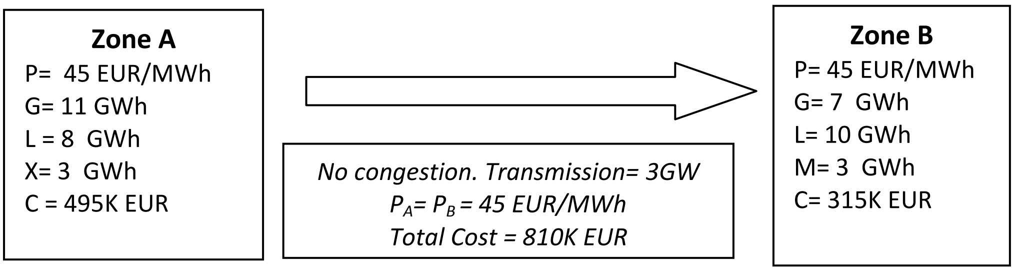
Note:
USMP= national average price on the demand side. Zn= zonal prices. On= optimal prices. Rn= ratio optimal price / zonal price. Zone numbers are n: 1= North; 2=Center-South; 3= Islands; 4= France virtual zone; 5= Switzerland, Austria, Slovenia virtual zones; 6= Greece virtual zone.
Ave= hourly averages; Stdv=standard deviation; Min. Max= minimum and maximum hourly values.

Figure 1: Market Configuration of two zones

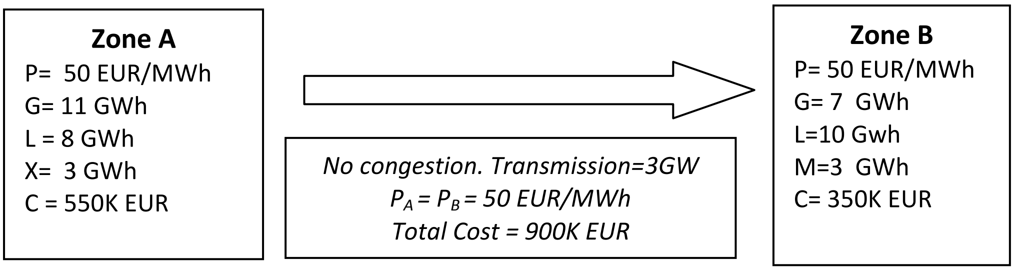
Case 1



Case 2



Case 3



P= Price as determined by the market equilibrium. P_A= price in zone A. P_B= Price in zone B.
G= Quantity of generation in the zone. L= Load in the zone. X= quantity of export to the other zone.
C= Cost in the zone.Total Cost= sum of the costs of the two zones.