Interconnection, Congestion and Welfare in the Italian Electricity Market

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Interconnection, Congestion and Welfare in the Italian Electricity Market*

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Abstract

The Italian electricity market is divided into two geographic zones (north and south) and the inter-zonal transfer capacity is limited. During the peak demand periods, market-clearing prices are different across zones. During the low demand period, (when inter-zonal transfer capacity constraints are not met), no arbitrage condition ensures that prices are same across the two zones. We measure the effect on total surplus of new inter-zonal capacity that is sufficient to eliminate zonal pricing. Using the current market data, we characterize the current market structure (with limited transfer capacity). Using these estimates we simulate the market under alternative market scenario (no transfer congestion). We check whether firms too, have an incentive to build inter-zonal transfer capacity. Our empirical results indicate that easing the transmission bottlenecks would result in substantial cost savings for the economy. We further find that the major firm in the market (Enel) does not exercise the fullest extent of its market power.

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1 Introduction

In this paper we estimate welfare effects resulting from interconnecting two geographically distinct markets, in the context of the Italian electricity market. In a sector like electricity where storage is prohibitively costly, a high degree of coordination is required between consumption and production to ensure smooth operation of the market. The transmission network is an essential facility in the electricity market, as any amount of electricity produced has to flow through the grid before reaching the end-user: generators are few and far apart while consumption is present virtually at every point in the territory. Thus, the location, the capacity and the utilization of the grid become important variables while analyzing any policy decisions in the electricity market.

Any congestion in the grid could lead to potential productive inefficiencies, stemming from the fact that cheap generators cannot serve geographically distant customers due to insufficient transmission capacity. These productive inefficiencies naturally generate losses to the system in the sense that the economy could be spending way too much on electricity that what is optimally recommended. These bottlenecks also impede the competitive structure of the market by creating local monopolies. As the demand for electricity is close to inelastic, the presence of local monopolies leads to market clearing prices and quantities significantly different from the first-best (price equals marginal cost).

The main purpose of our paper is to model the congestion present in the Italian electricity transmission system. The Italian electricity market is divided into several zones. The maximum amount of electricity that can flow across the zones is limited. Generators, with varying degrees of efficiency and capacity, are located in every zone. But the transfer capacity is limited, thereby creating potential market imperfections. While the no arbitrage condition ensures that the market clearing price is same across all the zones during the low demand periods[1], in the peak demand periods[2] market clearing prices are different across the zones. That too with the overall demand in Italy showing increasing trend across all the zones over the years, the problem of limited transfer capacity can only exacerbate.

One way to eliminate these potential market imperfections is by investing in the inter-zonal capacity. Due to the magnitude of costs involved, and to legal provisions that limit the scope for private investors in the transmission grid, it is likely that only a public authority is in the position to undertake such a project; if the public authority is benevolent, it will do so if the gain from such investment far outweighs the costs[3]. This paper is an endeavor towards answering the question of whether or not a transmission capacity addition that is sufficient to completely eliminate price dispersion is worthwhile. More precisely, we check if cost savings (accrued to the consumers of electricity) due to the

[1] Periods where the transfer constraint is not met.

[2] Periods where the transfer constraint binds.

[3] The other reasons that make private investment infeasible are: the degree of coordination required, and the legal issues (private investment in transmission line within a country is not allowed in Europe).

additional capacity warrant such investment.

To better understand the contribution of the paper in terms of the existing literature, we present a brief summary of the market structure, the empirical methodology we employ and some main results followed by a detailed literature review. As already mentioned, the Italian market is divided into several zones. For computational convenience we aggregate them into two zones: North and South[4] with generators located in both the zones. There exists a Market Maker (MM) whose role is to coordinate between consumption and generation markets. The MM invites the generators to submit a menu of prices and corresponding quantities they are willing to supply at on an hourly basis (a supply curve). The MM then forecasts the market demand in various zones. Given the location of each generator and demand at various zones the MM solves the problem of optimal dispatch[5] subject to the inter-zonal transfer constraint exogenously set. The optimal-dispatch algorithm yields optimal prices to be charged every hour in every zone, along with the amount of transfer between zones.

On the generation front, both the zones have similar market structure. There is a competitive fringe along with a major generator operating in both the zones. This fringe comprises of several small generating units that produce in the market whenever the market clearing price exceeds their marginal cost. We assume that the major firm in the market, Enel (in both the zones), acts like a residual demand monopolist. To be more specific, we assume that Enel first subtracts overall fringe supply curve from the total inelastic demand and calculates residual demand (for which it is a monopolist). While the evidence presented in the data section gives credibility to the assumption of Enel being a monopolist, it is not clear if Enel is a profit maximizing monopolist. Several concerns play a role in Enel's objective function. Therefore another goal of the paper is to formulate a model and estimate the degree of monopoly power exhibited by Enel: that is to characterize its objective function.

Our empirical methodology can be briefly summarized as follows: using the current market data (constrained transfer regime), we estimate the supply function of the fringe. We then subtract the supply function of the fringe from the inelastic demand and calculate the residual demand faced by Enel. Then by utilizing the realized prics and quantities in the spot market, we characterize the objective function of Enel. Then under the assumption that the objective function does not change due to increasing the inter-zonal transfer capacity, we simulate the market clearing prices and quantities in the market when transfer constraints are eliminated (unconstrained transfer regime). We then compare the total expenditure of consumers of electricity under the constrained regime and unconstrained regime. As of now, our empirical results indicate that if Enel were behaving as a profit maximizing monopolist, the economy would have saved eighty million euros in the month of May 2004, the time period considered in the paper. On the other hand, if Enel were behaving as a perfectly competitive

[4] The rationale behind such an aggregation and the way in which these zones are aggregated are presented in the data section.

[5] The goal of the problem of optimal dispatch is to minimize the total electricity expenditure of the consumers.

firm the economy would have saved three million euros in the same time period. We further find that Enel places a weight of 0.66 on the profit function and 0.34 on consumer welfare. Under the assumption that the weights in the objective function of Enel do not change due to interconnection, we find that easing bottlenecks would result in a saving of around thirteen and a half million euros in the time considered.

One issue we ignore in this is the question of optimal price dispersion. It is possible that total welfare gain (net of costs of increasing transfer capacity) might be maximized at a point where the prices are not always uniform across zones. In a recent paper, Joskow and Tirole (2005) in fact, solve the problem of optimal transfers theoretically. Therefore one possible extension of the present paper could be to address the question of optimal capacity of the inter-zonal transmission line. Another issue that we do not consider is the choice of location of the generator. We assume that the location of the generators across various zones is exogenously fixed. Mazzeo (2002) and Armstrong and Vickers (1993) show that there is an endogeneity between location choice and prices. But in the market considered here, it is not a matter of concern because during the regulatory days (pre 1999), all these generating units were publicly owned. Moreover, a large fraction of the existing plants already existed in 1999. During the process of deregulation, some of these units were auctioned off, while the remaining were retained by Enel. Therefore for the current market players (on the supply side) location is not a strategic variable.

2 Literature Review

The Industrial Organization literature is rich in studies that understand various nuances of regulation/deregulation in the electricity markets. One of the popular tools to model competition in the electricity generation process in some earlier studies is the supply function equilibrium approach developed in Klemperer and Meyer (1989) (here on K&M). K&M develop a model that theoretically characterizes the equilibrium in the case where firms choose “supply curves” as their strategy (a common feature in most deregulated electricity markets). The intuition behind the Supply Function Equilibrium (SFE) can be explained by the presence of uncertainty in the market. Every point on the supply curve can be thought of as the firm’s optimal price-quantity combination to the uncertainty that could be potentially realized. To our knowledge, Green and Newbery (1992)[6] (here on G&N) is the first study to apply K&M to the real data, for the case of the British electricity spot market. G&N use SFE approach to check the nature of competition in the British market. They find that the British electricity market has high mark-ups and substantial deadweight loss (contrary to the general opinion).

Though intuitively appealing, the problem with SFE is the presence of multiple equilibria and cumbersome computations. Several tie breaking rules are suggested to ameliorate the multiple equilibria problem, but they are often ad

[6] There are other studies like Bolle (1992), etc.

hoc and arbitrary. Some recent studies show that the number of equilibria could be reduced under suitable assumptions. For example it can be shown that under certain restrictive assumptions like symmetric producers, inelastic demand etc there is a unique SFE (see Holmberg (2004)). Also, the presence of pivotal firms[7] ensures that the number of potential SFE reduces (see Genc and Reynolds (2005)). Baldick and Hogan (2002) formulate an algorithm for computing SFE under capacity constraints. However, due to the presence of multiple equilibria coupled with involved numerical calculations SFE had not been popular among the empirical economists since G&N. Moreover SFE assumes that there exist at least two firms with significant market power. As already explained, this is not the case in the market we study here, with Enel being the only firm possessing any significant market power.

In terms of questions addressed, the papers that are close to this paper are: Borenstein, Bushnell and Stoft (2000) and Johnsen, Verma and Wolfram (2004), in the sense that they analyze the case of transfer capacity constraints. One unique feature of the electricity market with nodal pricing is that the generator receives the market clearing price of the node he produces at and not at the node he sells at. Another feature is that the total amount of transfer between two zones A and B is the absolute value of transfer from A to B minus transfer from B to A. Borenstein, Bushnell and Stoft (2000) (from here on BBS), in a theoretical model, link these two features with the limited transmission capacity. In particular they show that even by small increments to transfer capacity across nodes (in an electricity market that practices nodal pricing), market clearing prices and quantities get closer to competitive levels. They further show that, in the case of symmetric equilibrium, this result holds true even when the net transfers across zones is zero. The threat of transfer, by itself, is sufficient to guarantee market clearing prices and quantities closer to the competitive outcome.

Johnsen, Verma and Wolfram (2004) analyses the Norwegian electricity market. One nice feature of this paper is that they show how market power can be measured, without having cost or quantity data. However, the overall demand in the market they consider is downward sloping, unlike the present paper. They find that when the transfer capacity across zones binds generators exercise market power better. More precisely, they find that "...prices in local markets are higher during constrained periods when demand is less elastic." This result is contradictory to the one proved in Borenstein, Bushnell and Stoft (2000) because as already mentioned, BBS prove theoretically that the amount of electricity transferred does not play a role in determining competition in the market. Joskow and Tirole (2000) demonstrate that when transmission rights between various generators across zones are in positive net supply, it is possible that potential inefficiencies arise thereby reducing the overall welfare in the market.

Another strand of literature that is relevant for this paper is the literature on organizational objectives. As already noted, the residual demand monopolist in

[7] Firms whose partcipation is a necessary condition for equilibrium.

the market considered, Enel, might be exercising the fullest extent of its market power. Several concerns (for example: regulatory retaliation, political reasons etc) influence its objective function to a large degree. Studies in this literature infer about the objective function of the firm by looking at one or more of the strategic variables that are in control of the firm. For example, Erus and Weisbrod (2003) link compensation of employees at various stages of management with the objective function of the firm. They find that nonprofit and for-profit firms act substantially different in the case of CEO compensation. In his study of Wisconsin health care industry, Ballou (2002) points out that not-for-profit nursing homes charge lower mark-ups than those predicted by the profit maximizing behavior, even after accounting for the effects of product differentiation and influences of competition in the marketplace. Even among the not-for-profit hospitals, religious hospitals charge higher mark-up when compared to the Government homes. Hollas and Stensell (1988) examine the effect of ownership structure on price efficiency by comparing prices across proprietary, cooperative and municipal electric utilities. They find that none of the above mentioned ownership structures maximize profit.

The plan for the rest of the paper is as follows. Section two describes the Italian electricity market. In the third section we present the basic model for both the fringe firms as well as Enel. We discuss the dataset we use and present some summary statistics in section four. We present the results in section five and perform some counterfactual simulations and conclude in section six with some ideas to extend this project further.

3 The Italian Electricity Market

3.1 History of reforms

In 2004, the electricity consumption had been 322 Tera Watt Hours (TWh), an increase of about 0.4% from the previous year. Hydrocarbons (Oil and Gas) account for more than two-thirds of production. Coal accounts for the bulk of the remaining production. Hydroelectricity, tidal power and other bio-friendly generation methods account for less than 0.5% of the total production. Electricity prices remain high in Italy when compared to the rest of the European Union. In the summer of 2005, prices in Italy were close to 14 eurocents per KWh where as the corresponding figures in the other European Union nations are between 8 and 12 eurocents per KWh. Relatively high average costs and lack of any substantial competition are often blamed for these high prices.

Since 1963, until recently, the entire Italian electricity market was under a State owned monopolist, Enel. Following the European Union directive on the energy sector in 1994, significant changes resulted in the structure of the market. Starting from March 1999, these changes resulted in Enel being divested and several generating plants previously owned by Enel being auctioned off. The pace of these reforms is slower than expected and at present, Enel still retains more than 50% of the overall generation capacity. The directive also prescribed a vertical separation, or unbundling, of various stages of production (generation, transmission, distribution and retail). The transmission management is now controlled by Independent System Operator (GRTN).

Prices have not changed substantially changed in the aftermath of liberalization. Average realized electricity prices have been €56.18 per MWh between April and December 2004. The corresponding monopoly price under the pre-liberalization regime would have been fixed at € 56.00, a negligible 0.3% change.

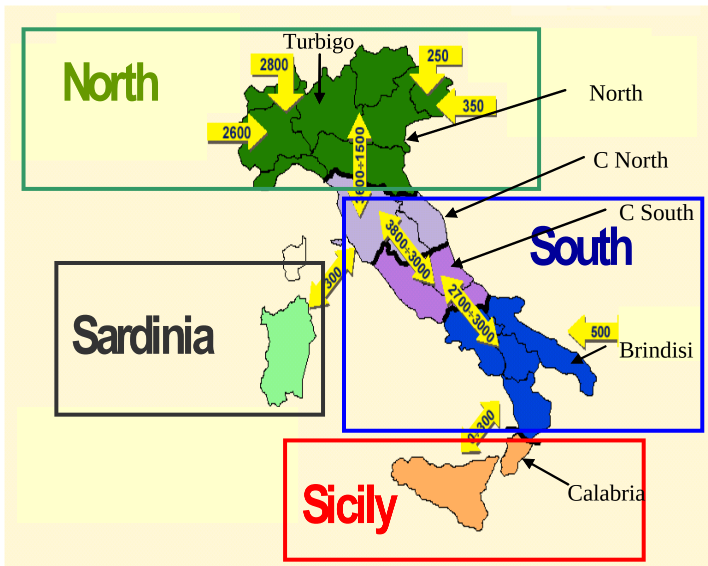
The Italian Government further provided for a non-mandatory spot market to be administered by the Market Maker (GME). The spot market began its operation in April 2004, and until the end of 2004, it operated as a monopsonist with an intermediary (a single buyer AU) in charge of buying from the spot market, the total electricity demanded by the consumers.

3.2 Zonal Structure

Geographically the Italian electricity market is divided into several zones. Each zone identifies a geographical area within which the grid is almost perfect in the sense that congestion is rarely observed. The regulator defines these zones and makes frequent changes to the geographical boundaries of a zone either by joining two zones or separating an existing zone depending on the amount of observed congestion. In 2004, there are a total of seven zones. Five of these zones are located in the Continental Italy (North, Center-North, Center-South and South and Calabria), while the remaining two zones comprise of the islands of Sardinia and Sicily. The most critical bottleneck occurs between North and Center North. In the period considered North and Center-North were separated 46% of the times[8]. There is another bottleneck between the zones of South and Calabria with the markets being separated for more than 25% of the times, but for the reasons described in the data section, we ignore this bottleneck. Center-North and Center-South seldom separated (around 4% of the hours). Center-South and South were never separated in 2004. The following zonal map of Italy better illustrates the zonal structure of the market.

[8] This 46% is for the entire year of 2004, and also includes weekends where the markets were seldom separated.

Figure 6: A map of the Italian zones in the electricity market



Source: www.mercatoelettrico.org

3.3 Current Market Structure

Electricity trade occurs in two markets: contract market and a non-mandatory (to the generators) spot market. At the time of analysis, only sufficiently large firms (industrial consumers) were allowed to sign bilateral contracts with the generators. Spot market is designed to cater to the needs to the residential sector and all the industrial customers that do not sign individual contracts. This spot market also acts as a buffer for any unanticipated short-term shocks to the consumption. Residential sector operates through a single buyer who operates through the spot market. They account for more than 95% of overall spot market quantity. They pay a fixed tariff set by the Italian regulator AEEG. This tariff is fixed throughout Italy, irrespective of zone and is subject to a quarterly review[9]. Industrial spot market customers pay a weighted average or previous month's spot market clearing prices. Generators participating in the spot market receive the market clearing price in the market they participate in. Hence on a given day at a given time, the price paid by the consumers that are buying on the spot market does not depend on the price charged by the selling firms. Therefore the demand in the spot market can be safely regarded as independent of that day's market clearing prices.

Organization of bilateral contracts is straight forward. Contracting parties negotiate a deal that is mutually agreeable to both the concerned players. These contracts are private information (to the generator) and none of the contracting parties are obliged to divulge the information to any third party (including the regulatory authorities). The organization of spot market, on the other hand, is more involved. The market maker (MM) solicits bids from all the generators for every hour every day. Therefore the start of every hour is the beginning of new market. A typical bid submitted by a generator consists of at most fourteen price-quantity combinations[10]. A price-quantity combination is a commitment from the generator, the amount of electricity he is willing to supply at that price[11]. The Transmission System Operator (TSO) decides the maximum amount of electricity that can transfer across zones depending on several criteria like security of supply and other physical attributes. Most often than not, these transmission lines need to undergo regular maintenance operations. These operations frequently cramp the maximum amount of electricity flow across the zones. Moreover as the maximal transfer capacity also depends on the location of the generating units, transfer capacity is subject to wide fluctuations, across various hours even within a single day.

Given the location of the bidding generators, their bid supply curves, transfer constraint set by the TSO and the forecast demand in each zone, the MM solves the problem of optimal dispatch. The goal of this optimal dispatch problem is to minimize the total expenditure on electricity. The MM, then, determines market clearing price and quantities in each zone. All the generators whose submitted bids are below the market clearing price are invited to generate the quantities they committed to in their bids. The generators receive the market clearing price[12][13], in the zone in which they are located and not in the market where the electricity is consumed. As there is a difference between the prices the MM pays to the generators and the price he receives from the retail sector, the MM maintains substantial cash reserves to offset any short-term financial

[9] Household electricity tariff and its consumption is a politically sensitive issue. Therefore, though in principle it is supposed to be set as a weighted average of all the spot market clearing prices (with weights being quantities consumed), several considerations play a role during the review.

[10] The minimum number of combinations is one.

[11] The minimum price that can be bid is zero. Informal discussion with the market experts suggest that if this restriction were not present, bids with negative prices and positive quantities were possible.

[12] Irrespective of their bid prices

[13] If a generator is small (i.e., strictly price taker), he may have an incentive to bid artificailly low prices to ensure that they produce in equilibrium.

imbalances.

For the reasons explained in the subsequent sections, we concentrate only on the spot market. Therefore in the rest of the analysis, any reference to the market means we are referring to the spot market alone and not to the overall Italian electricity market.

4 The Model

4.1 Model Description

This section models the spot market situation of the Italian electricity market. There are two zones in the market: North and South represented by n and s respectively. A central institution coordinates the actions of the two sectors and demand and supply conditions in the overall market[14]. The instutition also acts as a link between the generation sector and the retail market sector. He buys electricity in the spot market and sells it in the retail sector at a predetermined (exogenous as well) price[15]. At that exogenously determined price, the institution is obliged to supply whatever quantity is demanded in the retail market at that price in both the zones. On the demand side, there is a monopsonist (the institution) buying electricity to supply to the end-users. The monopsonist's demand for electricity in the spot market is equal to the total demand in the retail market at given retail price. Another thing to note is that demand in the spot market is fixed in both the zones (i.e. inelastic).

On the supply side, the structure is similar in both the zones. There is a competitive fringe in each zone, comprising of several small firms who supply whenever market clearing price is above their marginal cost of production. There also exists a big firm, Enel with substantial market power. We assume that Enel behaves like a residual demand monopolist. On the face of it, this appears to be a rather strong assumption on the market structure. But one look at the data suggests that the assumption might not be that unreasonable. (Table 4.2 shows the percentage of fringe production in the spot market. We discuss more about this assumption in the next section).

The assumption of the timing of the game is as follows: for every hour the institution estimates the quantity demanded in the retail market and announces the same in the spot market. There is an exogenously set transfer constraint that is known to all the suppliers. This constraint defines the maximum amount of electricity that can be transferred across zones in the market[16]. The firms then place their bids of price quantity combinations. Basing on the location of demand and location of generations along with the transfer constraint the regulator decides the optimal dispatch.

[14] For the ease of theoretical exposition, we combine all the third party entities that play an indirect role in the functioning of the spot market under the term of *central institution.* The market maker, the TSO, and the regulator influence spot market in various stages.

[15] We are modeling a static situation and so we consider the retail price to be exogenously given.

[16] We assume that the transfer is from North to South only.

We make two assumptions on the cost in the market. First, we assume that the cost structure of a given generator is known to all the other generators. We have cost estimates of not just the monopolist, but also several fringe firms. As Hortacsu and Puller (2004) point out about marginal costs: "...if we as economists have been able to gather this information from public sources, firms competing in this market will also have gained this information..."[17]. We further assume that a generator has quadratic cost function, a common assumption in these markets (for example: G&N, Bolle (1992), Wolak (2000) etc). Also, this cost function is continuous. This ensures that the marginal cost function is linear and continuous[18].

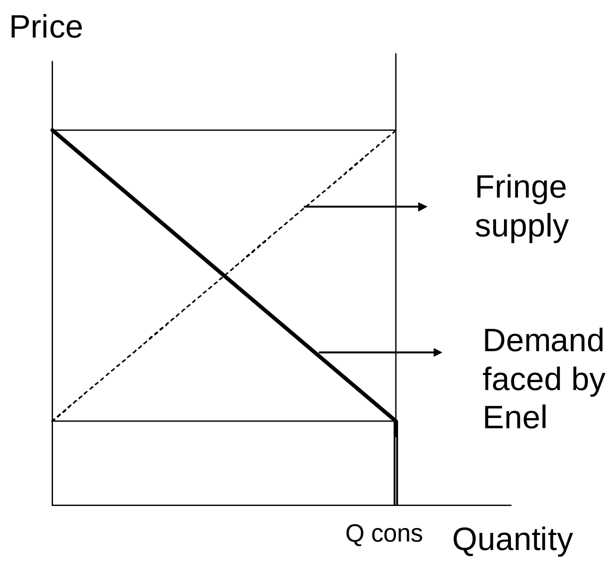
4.2 Fringe Supply

Though the overall demand in the market is inelastic, the slope of the demand faced by Enel is strictly negative. The fringe consists of several firms with different degrees of efficiency (varying marginal costs). Moreover, different fringe firms have different commitments in the bilateral contracts market. Different degrees of efficiency combined with bilateral contracts market and increasing marginal costs ensures that different fringe firms place different threshold prices for spot market participation. Hence as the price increases more and more fringe firms find it profitable to operate in the spot market. Therefore the residual-demand function is downward sloping. The idea becomes clear if we consider the following picture.

[17] Hortacsu and Puller (2004), page 14.

[18] The studies mentioned above generally assume piece-wise linearity of the marginal cost function. But the estimates of the cost function forces us to assume a fully linear cost function.

Figure 7: Fringe Supply and Enel demand function



At first, we characterize the demand faced by Enel when the interconnection line between the markets is saturated. Say the maximum transfer capacity for hour h and day d is given by $T_{d,h}$. The demand function is clearly illustrated in the following graphs:

As price keeps increasing more and more fringe firms find it profitable to enter the market because price is higher than their marginal cost. Hence the supply curve of the fringe is upward sloping, as represented by the thick dotted line in figure 7. The thin vertical line represents the total demand by the monopsonist (equal to the total demand in the retail market). To obtain the demand function for Enel, we need to subtract this positively sloped fringe supply function from the inelastic demand. The resultant residual demand curve (which identifies the demand faced by Enel) is represented by the thick downward sloping line in the picture.

In order to characterize the supply function of the fringe, we estimate the following equation for every hour for every zone. Quantity supplied in bid b at price p on day d is given by:

$$q_{bdh} = \alpha + \beta p_{bdh} + \gamma \,\text{factor}\, prices + \varepsilon_{bd} \tag{1}$$

The parameter we are interested in is β. The additive inverse of parameter β is the slope of the residual demand function faced by Enel. We estimate the equation 1 using ordinary least squares, instrumental IV and day fixed effects. There could be several factors that could influence fringe's bids on a given day. If there is a scale change in the fringe's bids from one day to the other, we would not be able to estimate slope using the equation (1) without bias.

The functional form chosen for the supply curve is linear. Though the assumption of linearity is too restrictive, it often simplifies computations, and more important, guarantees presence of unique equilibrium. In a nonlinear case, equilibrium need not exist when we analyze both the zonal markets jointly. We have, in fact, tried other functional forms like constant price elasticity, but lack of equilibrium forces us to revert back to the case of linearity. Perhaps because equilibrium is not guaranteed otherwise, assumption of linear demand curves is common in the electricity literature[19]. We plan on estimating the supply function using non-parametric methods to check on the assumption of linearity of the supply curve.

After estimating for every hour, we can characterize the supply function of the fringe for every hour for every zone. The supply function of the total fringe for hour h and zone z is of the following form:

$$Q^f_{h,z} = \alpha_{h,z} + \beta_{h,z} p_{h,z} \tag{2}$$

While β is point identified, α is identified up to an error term.

4.3 Behavior of Enel

We assume that the residual-demand monopolist, Enel, knows the supply of the fringe up to the error term. After having previously observed the fringe's behavior over several periods, it is not unreasonable to assume that Enel could reasonably estimate1. Moreover by assumption, the cost structure of various firms that comprise of the fringe is known to Enel. However the presence of uncertainty needs to be explained. The source of this uncertainty is two fold.

First, every firm in the fringe comprises of several small generating plants with varying degrees of efficiency. These plants need to be shut-down occasionally for maintenance reasons from time to time. These maintenance shut-downs are necessitated by technical reasons rather than strategic reasons. So it is not necessary that Enel could guess these shut-downs accurately.

Second, there are bilateral contracts in the market, coupled with increasing marginal costs. A firm's commitment in the bilateral contract market is private information. As marginal costs are assumed increasing, it is not necessarily clear to Enel as to what the market clearing price ought to be to induce market participation by a given firm.

We assume that the cost function of Enel in zone z takes the following functional form:

$$C_{enel}\left(q_{enel}\right) = F + 20.39q + 0.0005q^2$$

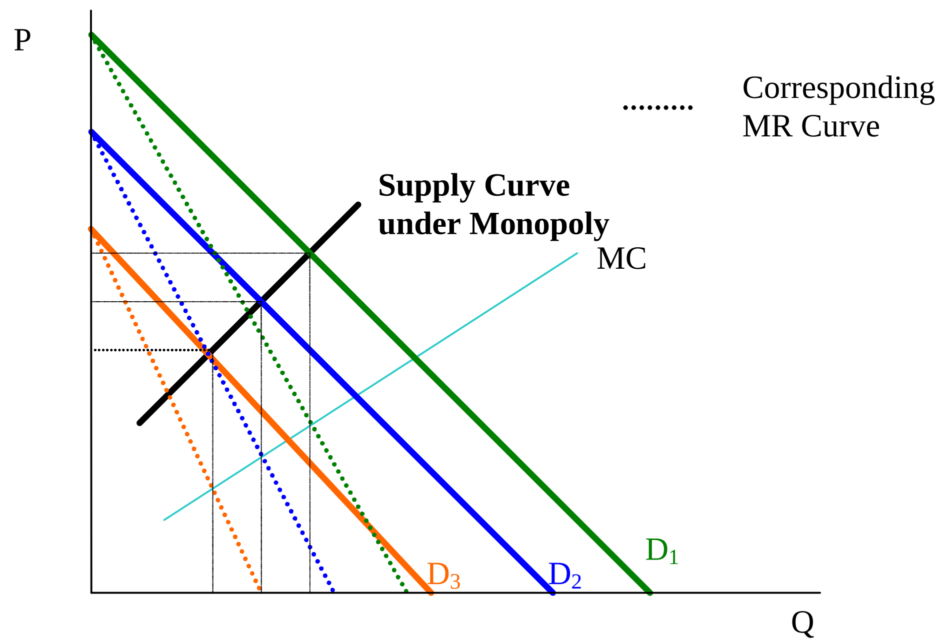
[19] Green and Newbery (1992), Bolle (1992), Hogan and Baldick (2003).

The marginal cost then is:

$$\frac{\partial C_{enel}}{\partial q_{enel}} = 20.39 + 0.001q$$

We also assume that the supply function of Enel is a result of its optimal reaction to various potential realizations of uncertainty. The following graph explains the assumption behind Enel's supply curve where there are three potential realizations of uncertainty under the assumption that Enel is a profit maximizer.

Figure 8: Enel's supply curve for different realizations of uncertainty



At first, we characterize the demand faced by Enel when the interconnection line between the markets is saturated. We call this regime C. Say the maximum transfer capacity for hour h and day d is given by $T_{d,h}$. The demand function is clearly illustrated in the following graphs:

Figure 9: Demand for Enel in the North

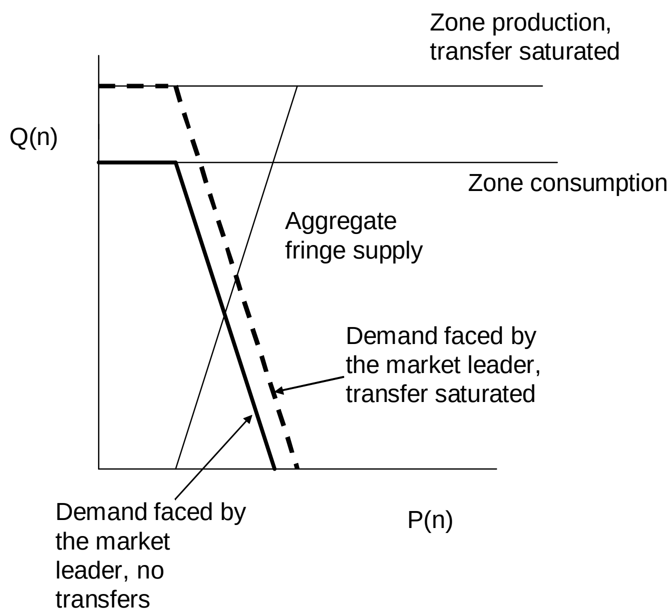
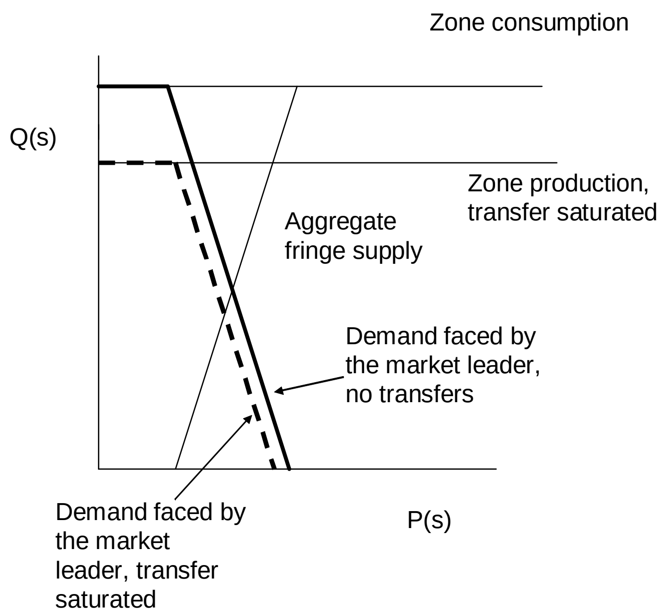


Figure 10: Demand for Enel in the South



The zonal demand faced when the market is separated, in the regime C, is given by:

$$Q_{n,h} = \begin{cases} \overline{Q}_{n,h} + T_h \ if \ p_{h,n} < \frac{-\alpha_{h,n}}{\beta_{h,n}} \\ \overline{Q}_{n,h} + T_h - \alpha_{h,n} - \beta_{h,n} p_{h,n} \ if \ p_{h,n} > \frac{-\alpha_{h,n}}{\beta_{h,n}} \end{cases}$$

$$Q_{s,h} = \begin{cases} \overline{Q}_{s,h} - T \ if \ p_{h,s} < \frac{-\alpha_{h,s}}{\beta_{h,s}} \\ \overline{Q}_{s,h} + T - \alpha_{h,s} - \beta_{h,s} p_{h,s} \ if \ p_{h,s} < \frac{-\alpha_{h,s}}{\beta_{h,s}} \end{cases}$$

where $\overline{Q}_n$ (respectively, Q_s) is the fixed inelastic spot market consumpiton in the North (respectively, in the South). Since we have data on exact quantity and price that Enel received in equilibrium for every hour, we can pointly identify the slope of the demand function.

In the case in which the market is unified, denoted by UC, we assume the market structure does not change, i.e, Enel is still the resiudal demand monopolist, albeit now for the combined demand. Also, two separate fringes are now participating in the market. The total fringe supply would result from the summation of both fringes. The following two graphs illustrate derivation of Enel's demand curve. Figure 9 depicts the aggregation of the two fringe supplies.

Figure 9: The aggregate supply function when the market is unified

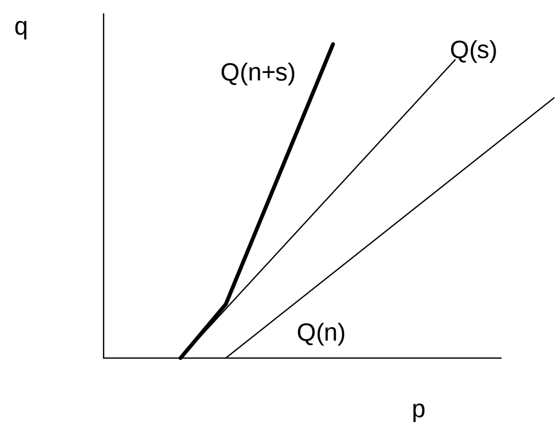
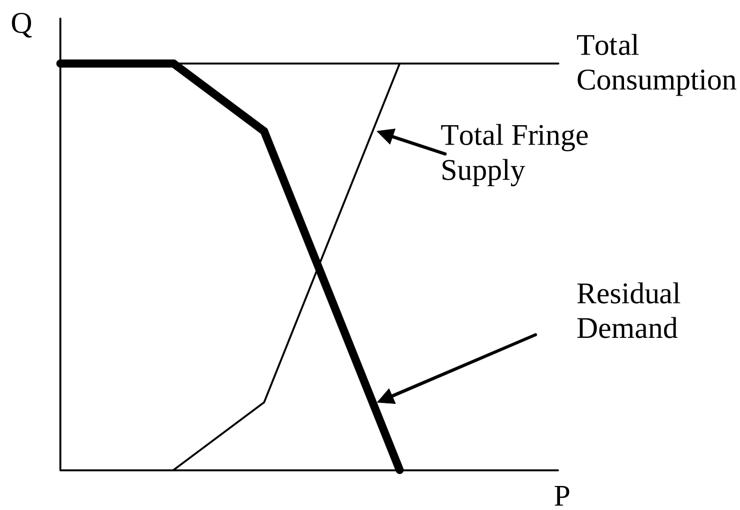


Figure 10 diagrammatically characterizes the demand function faced by Enel.

Figure 10: The demand faced by Enel in the interconnected market



Hence, in the regime UC (i.e, the situation of full interconnection), the demand function faced by Enel takes the following form:

$$Q_h = \begin{cases} \overline{Q} \; if \; p_h < \min\left(\frac{-\alpha_{h,z}}{\beta_{h,z}}\right) \\ \overline{Q} - \alpha_{h,k} - \beta_{h,k} p_h \; if \; \min\left(\frac{-\alpha_{h,z}}{\beta_{h,z}}\right) < p_h < \max\left(\frac{-\alpha_{h,z}}{\beta_{h,z}}\right) \\ \overline{Q} - \alpha_{h,n} - \alpha_{h,s} - \left(\beta_{h,n} + \beta_{h,s}\right) p_h \; if \; p_h > \max\left(\frac{-\alpha_{h,z}}{\beta_{h,z}}\right) \end{cases}$$

where z' identifies the zone with the most efficient fringe firm (i.e., the zone whose fringe firms start offering at the lowets market price), such that $\left(\frac{-\alpha_{h,z}}{\beta_{h,z}}\right)$ is maximum.

4.4 Objective Function of Enel

As already mentioned, due to host of reasons, Enel might not be behaving like a profit-maximizing monopolist. It is therefore necessary to establish Enel's behavior.

As Enel's stock is held jointly by the Italian treasury (around 40%) as well as private investors (the remaining), we assume that the objective function of Enel is a convex combination of both consumer surplus as well as profits. As the demand is inelastic, the consumer surplus in theory is infinity. Therefore we measure change in consumer surplus by change in the total expenditure on electricity. Let α be the weight given to the profits. Therefore the objective function of Enel for a given hour can be written as:

$$\max_{P_n, P_s} \alpha \left(P_n Q_n + P_s Q_s - C\left(Q_n\right) - C\left(Q_s\right)\right) + (1-\alpha)\left(-P_n Q_n^{spot} - P_s Q_s^{spot}\right)$$

Here Q_z^{spot} represents the overall quantity consumed in the spot market in zone z and is the overall spot market production in zone z.

One assumption is that the electricity flows only in one direction: from North to South. In the entire time period we consider for this study, there was not a single occasion when electricity flow from South to North was recorded. While the consumption in the North is entirely catered to by the production in the North, consumption in the South is catered to by both the production in the South as well as the transfer from the North. Notice that there is no transfer constraint because we have calculated equation 2 under the assumption that the transfer constraints bind with equality. Moreover, we consider only those hours where the prices are different across zones (i.e. capacity constraint binds with equality).

We calculate α for each hour for each zone separately and compute overall by taking a weighted average of the realized α's, where the weights are given by the overall quantity consumed in the spot market. Using the estimated weights for consumer and producer surplus, we simulate the spot-market clearing prices when there are no transfer constraints.

$$\max_{P} \overline{\alpha} \left(P Q_n + P Q_s - C\left(Q_n\right) - C\left(Q_s\right)\right) - (1-\overline{\alpha}) P \left(Q_n^{spot} + Q_s^{spot}\right)$$

Here $\overline{\alpha}$ is the average weights that Enel associates with the profit function.

5 Data

5.1 Aggregation of Zones

As already mentioned, the Italian market is divided into six zones: North, Center-North, Center-South, South, Sicily and Sardinia. We ignore the islands of Sicily and Sardinia for the analysis. These islands are cut-off from the main land and often operate separate from the rest of the Italian market. Moreover, though Enel has substantial presence in Sardinia, another firm Endesa Power plays a substantial role in electricity generation. For computational convenience we further combine the remaining four zones into two zones, basing on geographical proximity and market clearing prices. These two zones are: North and South. North zone comprises of just the North, while the South zone comprises of: Center-North, Center-South and South. There are two more generating points: Brindisi and Turbigo. These two are not zones per se, but injections of electricity into the South and North zone grids respectively. Therefore any generator located in either of these areas is treated as the one belonging to the corresponding zone (Turbigo to the North zone and Brindisi to the South).

5.2 Bilateral Contracts Vs Spot Market

In this paper we consider only the spot market and not the contracts market. The data on contracts market are proprietary and are hard to obtain. Moreover, even if one were to obtain these contract data, the contracts written are numerous and varied that it would be computationally intractable to analyze every single case. Wolak (2000), in his analysis of Australian Electricity points out that a typical hedge contract looks as follows: "Hedge contracts are usually signed between a generating company and an electricity retailer. A hedge contract guarantees the price at which a fixed quantity of electricity is sold... If the market price exceeds contract price, then the contract seller pays to the buyer the difference between two prices times the contract quantity..." and vice-versa. The Italian contracts are mostly bilateral contracts and not hedge contracts, but the idea behind the insurance mechanism of a hedge contract holds true even in this case. We have tried obtaining a few contracts to get an idea of how a typical contract should look, but as yet, we are unable to do so. Due to the volatile nature of the transmission capacity fixed by the TSO, it is not unreasonable to assume that these bilateral contracts are generally restricted to a given zone rather than across the zones. Therefore to analyze the question posed, this assumption allows us to ignore contracts market.

5.3 Data Sources

Data are collected from two sources. The primary source of data is the Italian Electricity Market Website. The market maker releases information on all the bids in this website one year from the time of market participation of all the parties concerned[20]. The information contains the following items:

1. The price at which the bid is made (in ascending order of prices)
2. Incremental quantity that the generator commits at that price
3. The name of the generator and the zone he is located in
4. Whether or not the bid is accepted (or partially accepted)
5. Awarded quantity and price to a given firm
6. Status of the bid

Status of the bid indicates whether a bid was replaced, revoked or found incompatible. After the generators submit their bids, they get a chance to either revoke or replace the bids. The Market Maker also reserves the right to

[20] In general, it takes more than a year to release information due to several bureaucratic details.

cancel some bids on the grounds that they are incompatible. The reasons for these cancellations are rather technical and are based upon engineering reasons. However it is clear that these bids are not considered for computation of market structure. Therefore for further analysis we remove these bids from the dataset. From this information, it is straight forward to build the actual bid supply function for the entire fringe for every hour for every day by aggregating the total quantity bid by every firm at a given price. This enables us to estimate the supply function of the fringe for every hour separately.

The other source of data is the Electricity Dataset (El-Da). This dataset is maintained by *Researches for Economics and Finance* (REF), a consulting firm based in Europe. They compile this dataset from *Italian Power Stock Exchange* (IPEX). We use this dataset to get information on the demand side (that is zone wise consumption, import etc of electricity). REF also provides us with the engineering estimates of marginal cost of various generators in the market. The cost function for Enel looks as follows:

$$TC = F + 20.39Q + 0.0005Q^2 \quad R^2 = 0.88$$

Hence,

$$MC = \frac{\partial TC}{\partial Q} = 20.39 + 0.001Q$$

5.4 Choice of Time Period

The time period considered for the analysis is the month of May 2004. The choice of the month is due to the following reasons:

First, the Italian electricity generation is deregulated at the end of March 2004. A major restriction in the current market is the price cap of 500 euros per Mega Watt Hour. Talking to market experts revealed that April 2004 is generally considered to be the month when the relevant players in the market are adapting to the new system in the market.

Second, the market maker releases the data on bidding behavior of participating firms one year from the date of participation. At the time of starting the project, we have data available for April and May 2004. For the reasons mentioned above, we decided to eliminate April 2004.

Third, climate-wise May is regarded as the month with least amount of uncertainties.

Out of the thirty one days in May 2004, ten are weekends and the rest are weekdays. We ignore weekends for the purposes of this paper because the demand across the zones over the weekend is generally low. As a result the transmission constraints are met with equality and hence no arbitrage condition ensures that the prices are same across all the zones. This makes analysis of change in welfare redundant for the weekends. Ignoring weekends leaves us with five hundred and four hours (twenty one days). Out of these, the prices across the North and the South zones are different for three hundred and nine hours. This information is summarized in the following table:

Table 1: Statistics on market saturation	
Total days	31
Weekend days	10
Week days*	21
Total hours considered	504
Hours where prices are the same	195
Hours where prices are different	309

*There are no other holidays in the month

Our initial guess was that we would tend to observe more price parity during the night time than during the night hours where electricity demand is apparently low. But table 1 suggests that this is not the case. On an average the highest price difference occurs in hour 22 (9 P.M. to 10 P.M.) while the least amount of price disparity occurs in hour 5 (4 A.M. to 5 A.M.). The reason for these differences can be two fold. The first one is that the TSO might be scheduling transmission line maintenance operations at night (for public safety reasons), thereby cramping the amount of electricity. The second reason is that several industrial costumers realize that it is perhaps less expensive to operate in the late night times than during the day times. Figure 11 and 12 provide some summary statistics of price differences as well as prices observed respectively in both the zones.

Figure 11: Hourly average prices and quantities

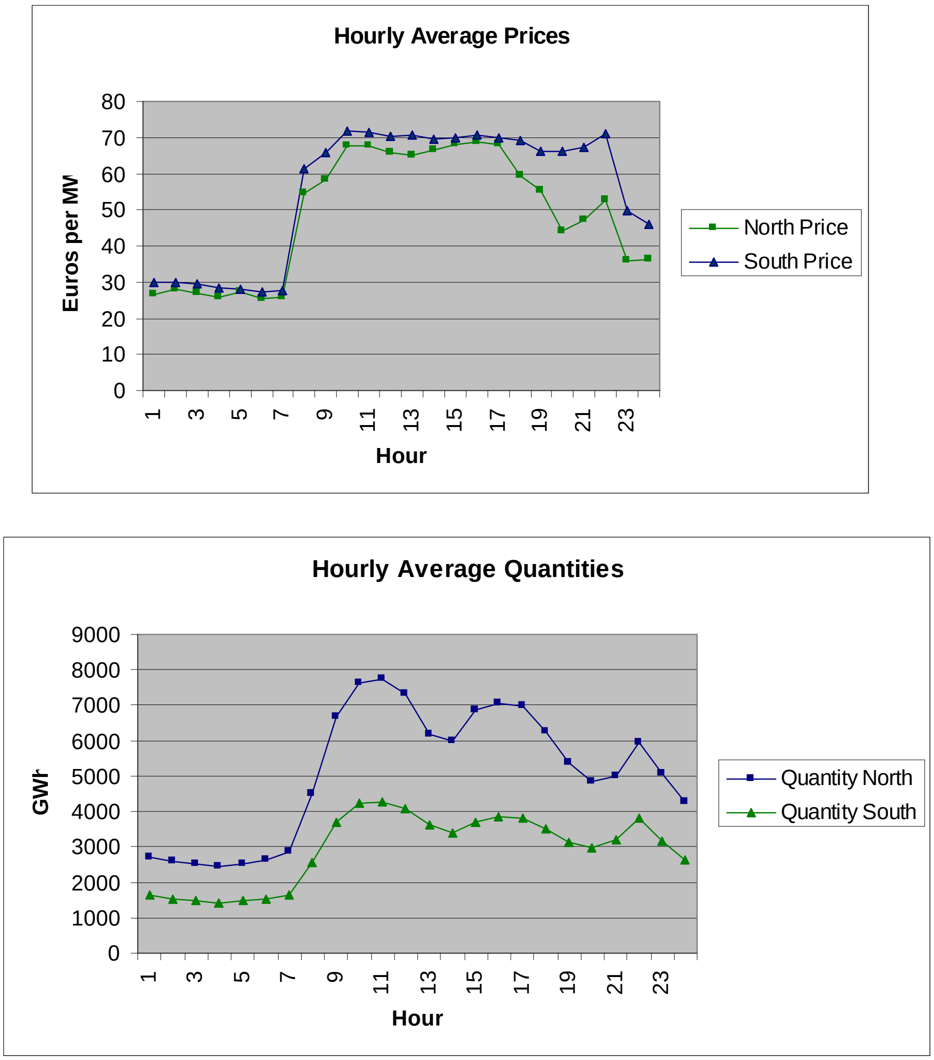
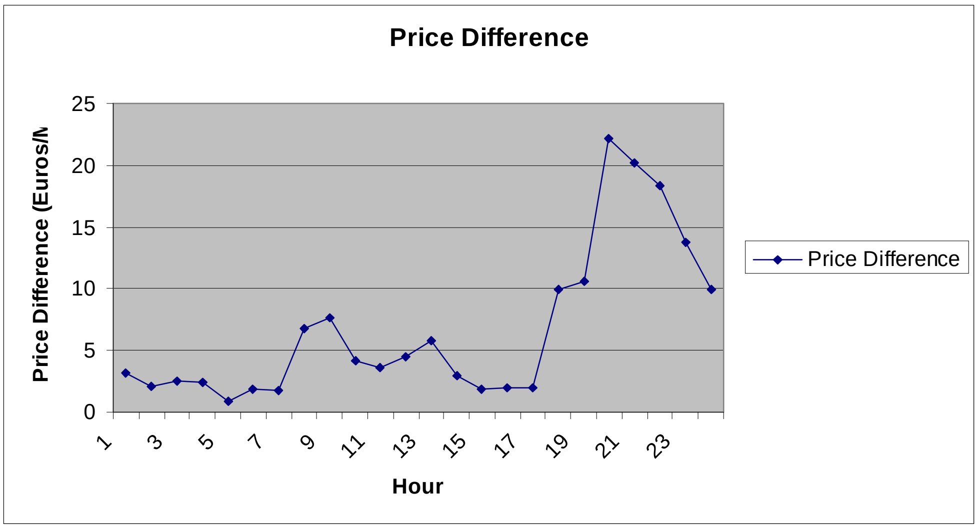


Figure 12: Average price difference between North and South across hours



5.5 Analysis of Bids

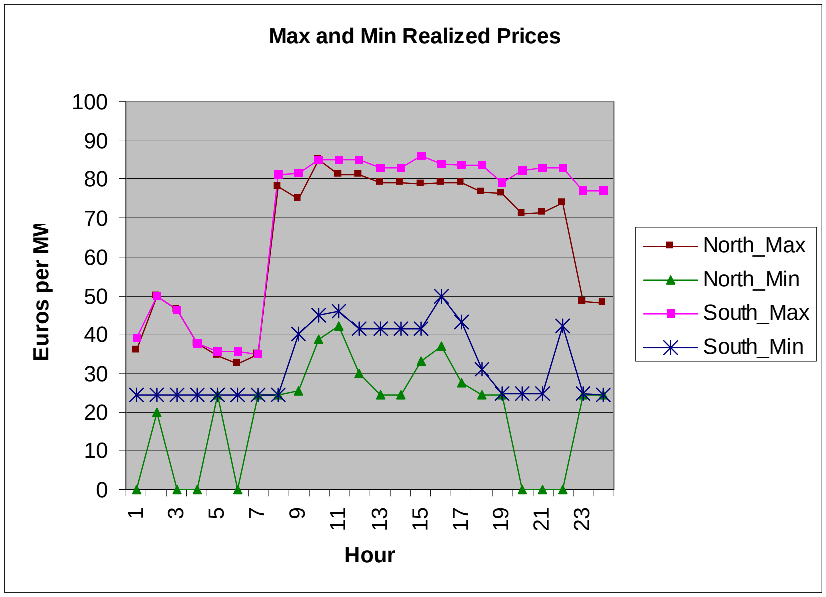
To estimate the supply curve of the fringe, we consider all the bids presented by generators other than Enel. Before we present how we analyzed those bids, we provide a justification to the assumption of Enel acting as a residual demand monopolist. Looking at table 2, it is clear that Enel has significant market power. In fact, in the entire Italy, Enel has close to 60% of the capacity. If we ignore the zones of Sicily and Sardinia, the share is much higher. While in the North, Enel has around 50% of the overall capacity, in South it is close to 80%. There is no other generator that even comes close to 20% of overall capacity.

Table 2: Percentage of fringe production	
Max	58%
Min	5%
Median	31%
First quartile	22%
Third quartile	39%
# of firms in the fringe	13

Generators face a price cap of 500 euros per mega-watt hour. The minimum allowed price is zero. During certain hours, a generator has an incentive to bid zero prices for strictly positive quantity. In fact, our guess is that if negative prices are allowed, many generators would have bid at negative price. This zero price bid ensures that the generator would be asked to produce in the equilibrium. But the generator receives market clearing price. By assumption, a fringe generator is not powerful enough to unilaterally influence market clearing prices. Therefore when a generator bids a zero, he may be doing so for two reasons: either, he is merely ensuring spot market participation, and to obtain strictly positive price, or there are occasions where it is expensive for the generator to shut the plan down and restart. If a generator has substantial commitments in the contract markets for the next hour with none at a given hour, he might find it optimal to ensure spot market participation in that hour. The case is similar for the bids close to price cap where the prices bid are high above the maximum price ever realized. Over some informal discussions with a few fringe generators, it was evident that the generators have a very good idea of the interval in which market clearing price is going to be. Bids beyond this interval are purely random.

According to the model we proposed in the previous section, this estimated supply function of the fringe reflects Enel's belief about fringe's behavior. Considering such bids biases the estimate of beta, the slope fringe's supply function. Therefore to avoid such situation, we took the maximum and minimum market clearing price for every hour and constructed an interval for every hour separately. Lower bound of the interval was 25% below the minimum ever realized during for that hour and upper bound is 25% more than the maximum price ever realized (for that hour). If the lower bound is below zero, we artificially set it equal to zero. The maximum and minimum prices realized every hour (for both the zones) are given below in figure 12.

Figure 12: Maximum and minimum realized prices for every hour



Out of the remaining bids we ignore the bids where the bid price was zero. This was done for the following reason: the supply function of the fringe is supposed to represent the belief Enel has about the fringe behavior. As discussed previously, the lowest possible price that one can bid at is zero and that if the minimum were not zero, it would have been possible to observe negatively priced bids as well. Therefore zero is only a lower threshold and any price-quantity combination involving zero-price does not reflect Enel's true belief on fringe's supply at price zero. Including these bids overestimates the true β (slope of the fringe's supply function).

6 Results

6.1 Fringe Regressions

We estimate 1 by day fixed effects and OLS[21]. The results of the estimation methods are presented in tables 3 and 4.

Table 3: OLS regression

Hour	Slope North^	Slope South	Hour	Slope North^	Slope South
1	15.64	3.19**	13	21.43	4.63
2	17.93	4.29***	14	23.97	5.01***
3	14.07	3.66***	15	25.27	5.71***
4	16.92	2.62	16	25	-2.37
5	17.15	3.52	17	25	5.74***
6	6.77	3.72	18	22.95	5.6***
7	16.43	6.49	19	20.92	5.64***
8	16	5.03***	20	20.59	5.4***
9	15.25	4.9***	21	21.28	5.28***
10	18.88	3.66**	22	25.41	5.3***
11	21.6	3.52	23	24.18	2.57***
12	22.46	5.62***	24	27.09	2.2

^All coefficients are significant at 99% for North

***significant at 99%; **significant at 95%

Table 4: Fixed Effects regression*

Hour	Slope North	Slope South	Hour	Slope North	Slope South
1	12.17	8.71	13	23.27	5.48
2	14.84	7.9	14	23.59	5.58
3	13.63	7.55	15	25.88	5.53
4	13.53	7.89	16	25.76	4.24
5	13.16	8.08	17	25.58	5.09
6	10.56	7.88	18	25.78	6.63
7	11.38	5.85	19	25.58	6.64
8	15.88	6.45	20	25.79	6.63
9	19.59	6.45	21	23.32	6.6
10	22.96	5.22	22	26.78	5.66
11	23.82	5.32	23	27.57	3.9
12	24.92	5.6	24	31.03	3.58

*All coefficients for both the zones are significant at 99%

[21] We instrument prices with total quantity consumed in the zone on that particular day and hour.

The OLS regression results indicate that for the South zone, the slope of the supply curve of the fringe for hour 16 is negative and insignificant. This highlights the need for day fixed effects. Though on a given day, correlation between price and quantity is positive, it is not so when all the days are considered. As expected, the Fixed Effects regression shows that the slopes of the supply of the fringe in the North are higher than that of the South for all the hours. For the rest of the analysis and simulations, we use the estimates obtained from Fixed Effects regression.

6.2 Simulation Results

To answer the question posed in this paper, we need to compare total consumer expenditure on electricity across the two regimes. The results of the simulations are presented in table 5. A comparison across the two monopoly situations indicates that, had Enel been behaving like a monopolist, the Market Maker could have saved close to 80 million euros for the month of May 2004. In the Italian context, due to reasonable climatic conditions, May is considered to be a month of least amount of fluctuations as far as consumption of electricity is concerned. It is also clear that the simulated expenditure incurred by the market maker in either of the monopoly situations is substantially higher than the actual spot market expenditure. This result confirms the hunch that Enel might indeed not be a profit maximizing monopolist.

Similarly, if Enel were pricing at marginal cost, the economy would have saved close to three million euros for the month of May 2004. Once again, simulated perfectly competitive prices are different from the observed prices suggesting that Enel is indeed not acting as a fully benevolent monopolist.

Table 5: Simulation results

Regime	**Total expenditure***	**Hourly expenditure**
Current spot market	€ 168,038,712.28	€ 543,814.60
Unified spot market	€ 154,508,946	€ 500,028.95
Cost savings	€13,529,766.29	
Constrained monopoly	€ 514,750,267.62	€ 1,665,858.47
Unconstrained monopoly	€ 435,372,273.64	€ 1,408,971.76
Cost savings	€ 79,377,993.98	
Constrained competitive	€ 91,324,654	€ 295,549.04
Unconstrained competitive	€ 88,239,238	€ 285,563.88
Cost savings	€ 3,085,415	

*For the entire month of May, when transmission constraints bind

Figure 13 and 14 present the hourly averages of simulated and observed prices in monopoly and perfect competition respectively. Prices in the constrained South are substantially higher than those of North and prices in the integrated market are closer to the prices of the monopoly North than to that of South.

Figure 13: Monopoly prices

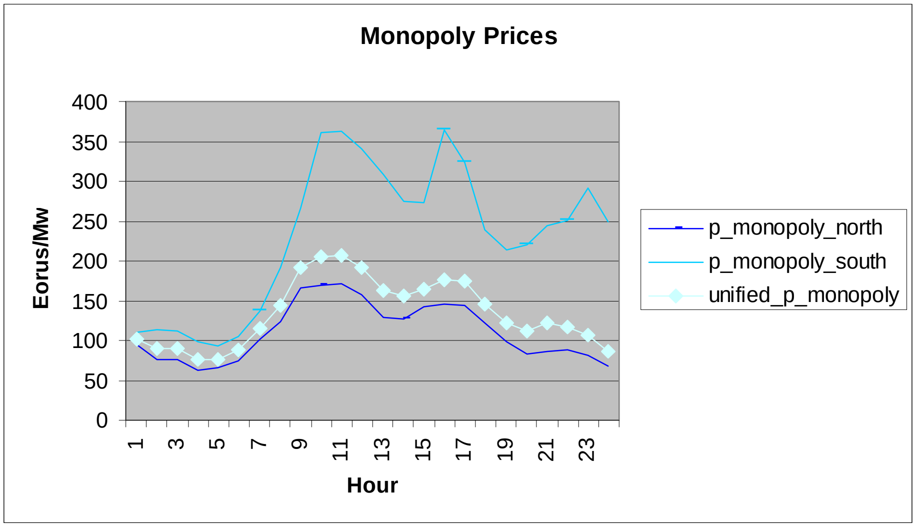


Figure 14: Competitive prices

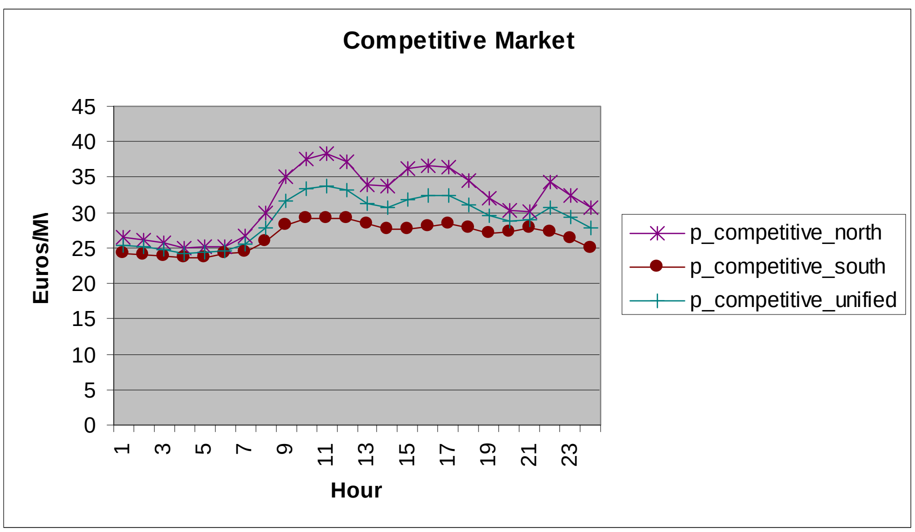
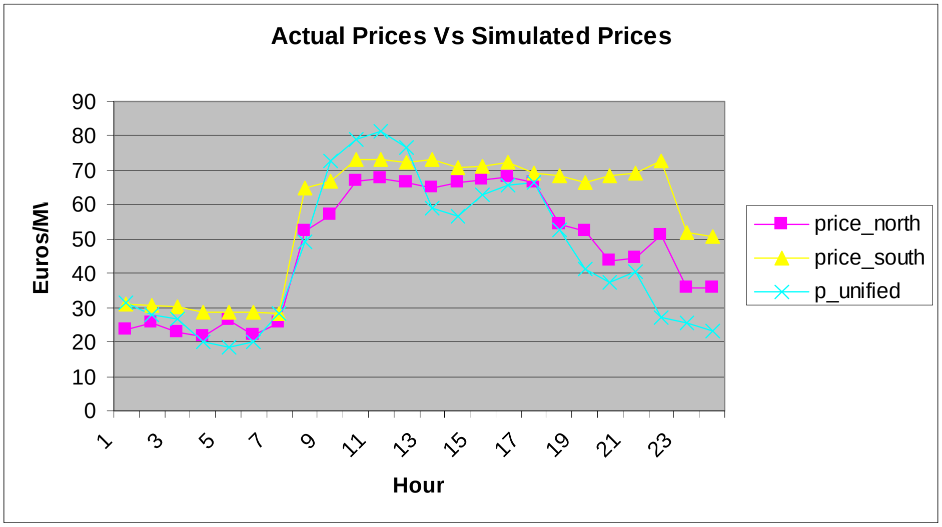


Figure 15 compares actual to simulated prices

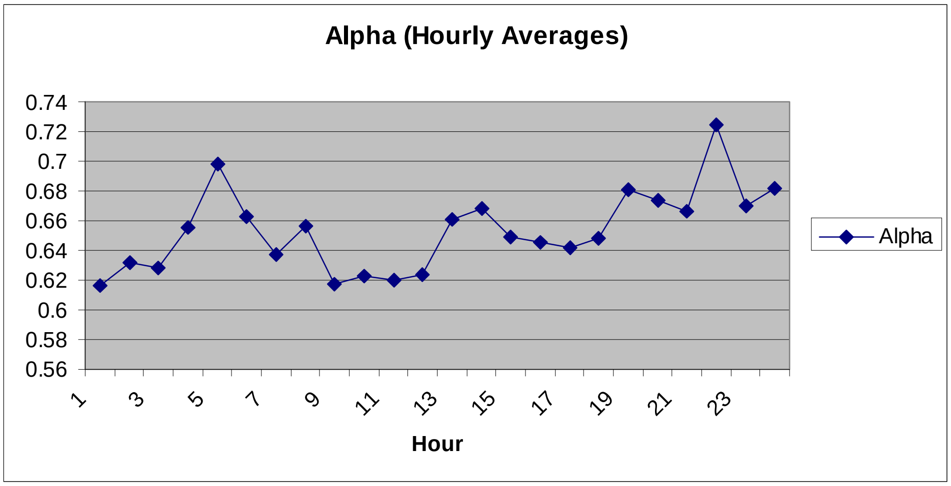
Figure 15: Actual versus simulated prices



To simulate the present market condition, we characterize α, where Enel gives α weight to the profit function and $! - \alpha$ weight to the consumer expenditure. Figure 16 and table 6 presents the results for estimation of α. The average value of α is 0.66. At the end of 2005, the Italian treasury held close to 40% of stock of Enel. The remaining stock of Enel is held by the private investors. Therefore 65% does not seem too unreasonable. α is not widely different across different hours.

Table 6: Summary statistics on α	
Maximum	0.84
Minimum	0.51
Average	0.66
Standard deviation	0.05

Figure 16: hourly average values for α



After calculating the α, we simulate market clearing prices and quantities. Average hourly prices are presented in figure 16. With the help of these new prices we recalculate total expenditure in the spot market. Our results indicate that the economy could have saved close to thirteen and a half million euros due to interconnection in the period considered (May 2004).

7 Conclusion

In this paper we have analyzed the issue of the benefits associated with eliminating transmission bottlenecks across zones in the Italian electricity spot market. The objective function of the major firm in the market (Enel) is ex-ante unclear not only due to the nature of the ownership (partly by the Italian treasury and partly by private investors), but also because of the nature of the market (the market is deregulated, but the Government has the option of regulatory retaliation if It realizes that undue advantages are being realized due to deregulation). We presented a model that characterizes the objective function of Enel. The main purpose of the paper was to obtain cost savings generated to the economy if the transfer constraints were to be completely eliminated. Basing on the proposed model we found that Enel associates a weight of 66% to the profits and the remaining 34% to the consumer welfare with a standard deviation of 5%[22]. This weighting function seems reasonable, especially in light of the fact that the Italian treasury held around 40% of the stock in Enel in May 2004. Under the

[22]Due to the inelastic nature of demand, we measure consumer welfare as the additive inverse of the economy total expednitures on electricity. Therefore, maximizing welfare could be viewed as minimizing total expenditure.

assumption that these weights do not change when transfer constraints were eliminated, we found that the total cost savings would be approximately thirteen and a half million euros in the month of May 2004, the period considered in the paper. We further found that if Enel were to behave like a profit maximizing monopolist (weight on profits is one) or a welfare maximizing monopolist (weight on profits is zero) the costs savings are approximately eighty million euros and three million euros respectively for the time considered. As May is a benign month in terms of electricity consumption (due to climatic conditions), the cost savings for the entire year (from April 2004 to March 2005) would at least be one hundred and fifty million euros.

Our future work would include a more robust estimation approach for the demand function. Our analysis is based on the assumption of linearity of demand and supply functions. In particular, we now assume that the fringe in both the zones is linear (and hence the residual demand faced by Enel is also linear). Specifically we want to consider the step-function approach a la Hortacsu and Puller (2004). Instead of smoothing the supply curve of the fringe (using any functional form), we could consider that the supply function of the fringe to consist of discrete set of points. Another estimation method we have in mind is non-parametric estimation of the supply of the fringe. This technique lets us locally characterize the supply of the fringe at various prices without having to impose any functional forms or additional structural assumptions on the model.

Finally, data are also available on all the bids submitted by Enel. However for the empirical strategy developed in this paper, we only utilize the bids submitted by the fringe firms and the final market clearing prices and quantities observed in the market. Therefore our next endeavor would be to utilize this extra information available about Enel while characterizing its objective function.

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