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Strategic bidding in vertically integrated power markets with an application to the Italian electricity auctions☆

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ABSTRACT

In this paper we apply a model of optimal bidding behavior to the Italian wholesale electricity market under three hypotheses: i) costs of generation are private knowledge, ii) firms can be vertically integrated, and iii) firms can sell part of their production in advance with bilateral contracts. We first use optimal bid functions and market data to retrieve time-varying marginal cost functions, price–cost margins and Lerner Indexes of market power for a sample of Italian companies. Then, we use estimated costs and actual equilibrium prices to evaluate the elasticity of these series to fuel price variations and estimate a possible differential impact of the dynamics of input expenditures (fuel price above all) on generation costs and final electricity prices. Our estimates suggest that the elasticities of costs and equilibrium prices with respect to oil price are virtually the same and, therefore, that the auction mechanism *per se* does not limit the extent to which cost increases are transferred to prices.

1. Introduction

A major concern of regulators and governments when they evaluate the performances of the recently restructured electricity supply industries is the exercise of market power by firms competing in the wholesale market. These markets work as single price competitive auctions and operate on hourly (or semi-hourly) frequency. The market operator collects demand/supply bids and orders them in descending/ascending order to determine an equilibrium price and a total quantity exchanged. The creation of short term electricity markets was inspired by the idea that introducing competition at the wholesale level would result in lower electricity prices for final consumers. Unfortunately, starting from the first experiences of privatization and deregulation, it was clear that such markets may be prone to collusion or other forms of anticompetitive behavior. Electricity producers can increase substantially their profits if they are able to influence market price through their bidding behavior. It is therefore very important for regulators to understand what forces drive the bidding behavior of generators and how the market mechanism translates bidding strategies into market clearing prices.

Economic theory alone gives little guidance to researchers when they have to evaluate the performance of multi-unit auctions. For that reason the empirical analysis becomes very important to evaluate the performance of these mechanisms. Electricity markets are in this respect a privileged field since all the relevant market data are made available from the market operators. Given the data and a theoretical model that describes the optimal bidding behavior of producers, the researcher is able to measure unilateral market power of the firm and the way in which it influences the final equilibrium price.

We use data published by the Italian market operator to evaluate the performance of the Italian electricity market. The issue is particularly interesting since this market has registered the highest average price level among the other European markets since the very beginning of its operation (April 2004). The reasons explaining this price level have been strongly debated. Some stress the role of the technology mix of the generation park; others claim that the Italian market is too much isolated from the other continental markets. Another possible reason may be that the Italian Electricity generation industry is concentrated and prone to the exercise of

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market power on the part of the dominant operator. Were this the case, the mere establishment of a bidding market would not guarantee the efficiency outcome of the competition.

In this paper we pursue four purposes.

First we generalize to the case of vertically integrated and forward committed firms the behavioral model of Wolak (2003) and Hortaçsu and Puller (2008). Vertical integration as well as forward trading appears as common features of many firms operating in Europe. Hence, this version of the model should approximate the bidding strategy of all these firms.[1] In particular, all the main Italian producers have also their retailing branches, which are separated from the generation branches either from a purely accounting point of view or as separated companies controlled by the same owner. The retailing activity is regulated nation-wise and retail tariffs are determined by the national agency.

Secondly we invert the equilibrium bidding functions and retrieve marginal costs for a group of large Italian firms observed for a four-year sample period.

Then, we use the above values of marginal costs in conjunction with equilibrium prices to compute Lerner Indexes and in doing so we obtain information on the exercise of market power in the Italian electricity market.

Finally, we regress the same marginal costs and equilibrium prices on generation input prices in order to evaluate whether the market mechanism reduces or amplifies the impact of input prices variation. Information provided by these estimations might prove useful for the activity of regulation authorities. Our methodology can be extended to similar markets such as the gas market.

The paper is organized as follows. In Section 2 we briefly discuss the theoretical modeling of electricity auctions and the main issues raised by the empirical estimation of costs and market power. In Section 3 we present a share-auction model of bidding behavior with vertical integration, forward contracting and cost uncertainty, from which we derive explicit relations between prices, costs and residual demand elasticities. This information will be used in the empirical part of the paper. Section 4 contains a description of the Italian electricity auctions (auction rules and structural characteristics of the generation industry) as well as the main properties of the data generation process. Section 5 describes the Italian data on which the empirical analysis is based, while Section 6 contains the estimated marginal costs and Lerner Indexes. In Section 7 we estimate the elasticity of marginal costs and system marginal prices with respect to oil prices and a proxy of gas prices. Section 8 briefly concludes.

2. Modeling bidding behavior in electricity auctions

Wholesale electricity markets can be modeled as multi-unit auctions where multiple identical objects are bought/sold and demand/supply is not restricted to a single unit. The analysis concentrates mainly on the properties of the market design (various possible auction formats) and on the strategic behavior of auction participants, whereas the main focus of applied researchers is on the estimation of firms' market power. Like other cases of auctions for identical and divisible objects – such as Treasury Bills – electricity auctions are often analyzed as quota or share auctions. Ausubel and Cramton (2002), following the line of research first introduced by Wilson (1979), found that when multiple units are sold simultaneously under the uniform price rule, buyers have an incentive to "shade" their demand (reduce their valuation) for all units following the first. In this manner they optimally trade-off a lower probability of winning on the last units against savings on all units bought. Electricity markets, in which the majority of sellers own a number of generating units, show the same type of incentives on the supply side because overbidding on the last units increases the revenues for all the inframarginal units despatched in equilibrium. von der Fehr and Harbor (1993) were the first to apply this approach to electricity auctions in a model of complete information about opponents' costs. Many researchers have implemented and refined this model[2] which – after the work of Crespo (2001) – became known with the name of Bid Function Equilibria (BFE). For a competitive (uniform price) auction BFE predicts asymmetric bidding behavior for bidders: the price setter inflates his bid to raise the equilibrium price, whereas the other firms have a Nash equilibrium response which equates bids at marginal costs. A similar (bid shading) result was obtained independently by Parisio and Bosco (2003, 2008) who relaxed the assumption of costs common knowledge and derived equilibrium bid functions in both isolated and interconnected electricity markets. They show that the extent of bid shading, and therefore the mark-up, depends among other things upon the endowments of generation capacity of each multi-plant firm.

The empirical analysis of electricity auctions is conducted following two intersecting lines of research. On the one hand, following the literature on the econometrics of auction data pioneered by Guerre et al. (2000), researchers aim at recovering the marginal cost functions (valuations) of firms from bid data, under the assumption that each bidder is acting optimally against the distribution of the bids of the opponents.

Other authors (starting from (Wolfram (1999)) estimate market power of electricity firms (Lerner Index, price–cost markup and the like) under the assumptions that costs are known to the researcher. Some other studies follow a combination of both approaches. However, the multi-unit dimension of the electricity auctions poses stronger econometric problems than those of the above mentioned single-unit case. In particular, the interpretation of data generated in equilibrium in the multi-unit case is more troublesome even when the econometrician can observe the equilibrium distribution of all bids (Athey and Haile, 2006). Crawford et al. (2007) test the predictions of BFE using data on bid functions submitted into the England and Wales spot market from 1993 to 1995. They find strong support to the prediction of asymmetric bidding behavior between the price setter and the non-price setters; the mark-up increases with the amount of inframarginal capacity sold by firms and this effect is more pronounced for the price-setter. Altogether Crawford et al. (2007) find that the estimated bid function for the price setter has a lower intercept and a steeper slope than the ones of non-price setters.

Hortaçsu and Puller (2008) characterize the bidding behavior of electricity generators within the theoretical framework of Wilson's share auction. Before them, Wolak (2003) used a similar model of bidding behavior to recover cost function estimates for electricity generation in the Australian National Electricity Market. He shows that under the assumption of firm-level profit maximization, it is possible to estimate the level of marginal costs implied by a given equilibrium price and quantity. Observed bid data can be used to compute directly the Lerner Index of market power.

The finding that firms fail to exploit the full extent of market power in electricity markets is a quite common result in the applied literature. One possible explanation is that each producer has a total capacity to sell in the market but a share of this can be also sold through bilateral contracts in which the difference between the predetermined forward price and the spot price represents the gain or the loss for the seller. This potentially reduces the incentive to exploit spot market power for those generators committed to large forward contracts. The prediction that forward market positions may foster competition in oligopolistic markets is a well known result for two-stage Cournot games (Allaz and Vila (1993)). However, when forward positions are unobservable and market operators are risk neutral,

[1] For instance, among others, the following European firms are both electricity producers and retailers: E.On, Vattenfall, RWE (Germany); EDF, Suez (France); Endesa (Spain).

[2] For example, Brunekreeft (2001), Garcia-Diaz and Marin (2003), Fabra (2003), Fabra et al. (2006).

then incentive to sign forward contracts disappears (Hughes and Kao (1997)). From an applied ex-post perspective, the same pro-competitive results should generate a measurable reduction in the exercise of the potential market power. Moreover firms may be vertically integrated which means that they may be active on both sides of the auction. Bushnell et al. (2008) analyze theoretical and empirical implications of vertical arrangements and conclude that large producers with equally large retail obligations, may find it profitable to overproduce in order to drive down their wholesale costs of power purchased for retail services. As a result, vertical relationships play a key role in determining the competitiveness of the spot markets they analyzed (California, New England, and PJM). At a similar conclusion arrive also Kühn and Machado (2004) for the Spanish market. Their findings support Wolak (2000)'s analysis of long-term contracts in the Australian electricity market, as well as Fabra and Toro (2005) analysis of the Spanish market. Therefore the presence of fixed-price market obligations, either in the form of forward contracts or in the form of retail obligations are expected to reduce the extent of market power.

The partial exploitation of market power may also result from the bidding behavior of firms in which the public sector owns a relevant share. According to Boffa et al. (2010) firms may have objective functions that are convex combinations of public incentive and profits. As a result these firms may trade off profits in favor of lower energy prices for the sake of increasing consumers' surplus.

Given the huge availability of data, electricity markets provide the occasion for an empirical analysis of market power. However, as already stressed by Wolak (2010) the insights gained from this analysis can be more general and easily extended to other bid based markets.

3. A model of bidding behavior

In this section we present a model of optimal bidding in wholesale electricity markets that is framed in the Wilson (1979)'s share auction approach.

We assume that N multi-plant firms compete in a day-ahead market to get the right to supply electricity at price p^e which is the uniform price to be paid to all units called into operation. Total demand is $\hat{D}=D+\varepsilon$, where D is a price-inelastic known quantity and ε is a purely random shift component. Each bidder has costs given by $C_i(q)$, $i=1,\ldots,N$, for which standard properties hold. We assume that $C_i(q)$ is a private information of each bidder. As a result, the hypothesis of independent private value applies to our auction model. Auctions take place on an hourly basis and we treat each hour as an independent auction.[3] Bidders submit supply schedules $q=y_i(p)$ that indicate the optimal quantity offered at price level p. We assume supply schedules y_i, $i=1,\ldots,N$, to be continuous, strictly increasing and differentiable.

From the point of view of bidder i, the equilibrium price p^e is determined where his supply function $y_i(\cdot)$ intersects its residual demand, namely

$$y_i(p^e)=\hat{D}-\sum_{\forall j\neq i}y_j(p^e)$$

The probability distribution of the market clearing price, conditional on the supply $y_i(p)$ can be written as:

$$H^i(p,y_i(p))=Pr\left\{p^e\leq p\middle|y_i(p)\right\}=Pr\left\{y_i(p)\geq\left[\hat{D}-\textstyle\sum_{\forall j\neq i}y_j(p)\right]\middle|y_i(p)\right\}$$

Then, for all p and $y(p)$, $H(\cdot,\cdot)$ is the probability distribution of the equilibrium price conditional on $y_i(p)$, $\hat{D}$ and N. Therefore we have different sources of uncertainty affecting the residual demand function faced by each supplier. However, as stressed by Wolak (2010), what we need to postulate is a joint distribution of all the random variables affecting the expected profit. We assume that H is differentiable in p and $y(\cdot)$. The assumption that each $y(\cdot)$ is a strictly increasing function implies that H has a continuous support $[\underline{p},\overline{p}]$. This is generally established by the Market Operator.

Following Bushnell et al. (2008) we also assume that at least some of the bidders are vertically integrated firms. This happens when firms are organized in such a way that they are upstream generators and, at the same time, downstream retailers. In this manner the same firm acts simultaneously both as buyer and seller. We can assume that the quantity the firms buy in each round of the electricity auction, say x_i, is fixed and sold at a predetermined price p^r (see Section 5 for a discussion). Moreover, since firms are allowed to trade on the forward market, we indicate with z_i the forward quantity and p^f the associated fixed forward price.

Taking into account spot, retail and forward activities, the expected profit of bidder i can be written as:

$$\mathbb{E}[\pi_i]=\int_{\underline{p}}^{\overline{p}}\left[py_i(p)-C_i(y_i(p))+(p^r-p)x_i+\left(p^f-p\right)z_i\right]dH^i(p,y_i(p)). \quad (1)$$

Solving the integral by parts the rhs of Eq. (1) may be rewritten as follows:

$$K-\int_{\underline{p}}^{\overline{p}}\{(y_i(p)-x_i-z_i)+py_i'(p)-C_i'(y_i(p))y_i'(p)\}H^i(p,y_i(p))dp$$

where K is a constant. Euler's equation

$$\frac{d}{dp}\left[\frac{d\mathbb{E}[\pi_i]}{dy'_i}\right]=\frac{d}{dy_i}\mathbb{E}[\pi_i] \quad (2)$$

generates an optimal $y_i^*(p^e)$ such that:

$$p^e=C_i'(y_i^*(p^e))+(y_i^*(p^e)-x_i-z_i)\frac{H^i_{y_i}(p^e,y_i^*(p^e))}{H^i_{p^e}(p^e,y_i^*(p^e))}, \quad (3)$$

where p^e denotes the equilibrium price and

$$H^i_{y_i}(p^e,y_i^*(p^e)):=\frac{\partial}{\partial y_i}H^i(p^e,y_i^*(p^e)),\quad H^i_{p^e}(p^e,y_i^*(p^e)):=\frac{\partial}{\partial p^e}H^i(p^e,y_i^*(p^e)).$$

The numerator on the rhs of (3) measures the shift in the probability distribution of the market clearing price due to a change in the supply of bidder i and the denominator is the density of H^i. Using our definition of H^i and the differentiability of $y(\cdot)$, it is possible to derive a manageable expression for the probability ratio in (3) as follows (see Appendix A for the derivation):

$$p^e=C_i'(y_i^*(p^e))+\frac{y_i^*(p^e)-x_i-z_i}{\frac{\partial}{\partial p^e}\sum_{\forall j\neq i}^N y_j(p^e)} \quad (4)$$

where, given the definition of residual demand for bidder i,

$$-\frac{\partial}{\partial p}\sum_{\forall j\neq i}^N y_j(p)=RD_i'(p).$$

Notice that the numerator of the last term in (4) represents the supply of firm i net of forward commitments and of the quantity bought by that firm in the same round of the auction.

We will use (4) to recover marginal costs of firm i and Lerner Index under the assumption that she behaves in a profit maximizing way like in Wolak (2003).

[3] This is the standard approach (Hortaçsu and Puller, 2008; Wolak, 2003, among others) followed by the literature, which permits an explicit analytical solution to the optimisation problem.

Eq. (4) can be rewritten as

$$\frac{p^e - C_i'(y_i^*(p^e))}{p^e} = \frac{1}{\eta_{RD}(p^e)} \frac{y_i^*(p^e) - x_i - z_i}{y_i^*(p^e)}, \tag{5}$$

where $\eta_{RD}(p^e)$ is the elasticity of the residual demand.

From (5) we notice that an estimate of the Lerner Index can be obtained from the elasticity of the residual demand facing bidder i in the equilibrium, corrected for the ratio that measures the proportional exposure of the firm to the spot price. This makes even more apparent that forward contracts and vertical integration reduce the incentive to exercise market power.

4. The Italian market

The Italian electricity market (IPEX) was established in April 2004 (supply side only) and started to be fully operational from January 2005. The dataset used for our analysis comprises years from 2005 to 2008. In the final year of our sample, the volume of energy exchanged on the day-ahead market amounted to 232 TWh with a liquidity rate of the 69%. Electricity can also be exchanged through bilateral contracts under the control and authorization of the Italian Authority for Gas and Electricity.

The Italian generation industry is characterized by a high quota of thermal production (above 80% for all the sample period) which includes technologies based on oil, gas and carbon. Hydro production amounts at 15% but it is mainly concentrated in the North Zone whereas the South Zone shows a productive mix more concentrated on thermal (90.2%) than on hydro (6.2%) with some increasing share of wind production (3.5%). Finally both islands, Sardinia and Sicily, show a productive mix more concentrated on thermal technologies: 91.6% in Sicily (of which 69.1 on CCGT) and 91.4% in Sardinia (of which 51.3% from carbon and 38% from CCGT). Hydro production has a low share in both islands but wind production is growing considerably, having attracted new investments in the last years. Table 1 summarizes the production data for the Italian electricity industry in our sample period.

Before liberalization, one state-owned monopolist (Enel) controlled all the stages of activity, from generation to final sale. By the time the sector was opened to competition Enel became a private limited company, whose shares were partly sold to the public and partly retained by the state who is still the main shareholder (31%). A portion of Enel's generation capacity (around 15.000 MW of mainly mid-merit units) has been sold to newcomers with the purpose of creating a more leveled playing field in the wholesale market. Starting from 2004, the participation[4] in the IPEX markedly increased: in the year 2008, 81 operators were registered on the supply side and 91 on the demand side. In Fig. 1 we present data on market shares for the years 2007 and 2008. Data show an high degree of market concentration which seems to be a permanent characteristic of the Italian market since its opening.[5]

The increased competition in the IPEX did not have much influence on wholesale prices. On the contrary, electricity prices showed an increasing trend during our sample period. Table 2 reports annual averages for different time slots like peak, off-peak, holidays, etc.

The comparison between the Italian market and other European markets show that there exists a significant gap between Italian prices and other European prices, as it can be evaluated from Table 3. We notice that the French and the German markets (Powernext and EEX, respectively) generated prices which are very close both in levels and in their dynamics (cf. Bosco et al., 2010).

[4] Data are taken from the report published by the GME in 2009, "Annual report 2008".

[5] Time series of Herfindahl indexes classified by zones and peak/off-peak hours can be found in the GME internet site: www.mercatoelettrico.org.

Table 1
Italian electricity production by source.

Composition (%)	2005	2006	2007	2008
Thermo	84.3	84.6	85.8	82.9
Renewable	0.8	1.0	1.4	1.7
Hydro	14.8	14.4	12.8	15.4
Production (GWh)	283,882	295,734	294,770	300,365

Source: Terna. Data net of self productions.

The IPEX is composed by a day-ahead market (MGP), an Infra-day market and an ancillary services market (MSD). MGP operates as a daily competitive market where hourly price-quantity bids are submitted by generators and by buyers. The market operator (GME) orders bids according to a cost-reducing merit order for supply and in a willingness to pay order for demand. The market equilibrium is calculated in the intersection of supply and demand. The resulting equilibrium price (called system marginal price, or SMP) is paid to all despatched suppliers. When MGP determines an equilibrium price and a corresponding equilibrium quantity that are compatible with the capacity constraints of the transmission grid, the wholesale electricity trade is completed. On the contrary, if the volume of the electricity flow determined in the MGP exceeds the physical limits of the grid and in some areas congestions occur, a new determination of zonal prices must be obtained in order to eliminate congestion in those areas.

5. The Italian data

The data we use to infer marginal costs and market power for companies operating in the Italian electricity market are the supply functions of the producers and the bids of the retailers as downloaded from the Market Operator (GME) web site.[6] In particular, for every hour of the days ranging from the 1st of January 2005 to the 31st of December 2008 the relevant fields in the database are listed in Table 4. Notice that according to the Italian market rules quantities exchanged though bilateral contracts are singled out in the same database.

It is worth stressing that the range of admitted prices is [0,500] because of price capping policies and that ca. 90% of the bids report zero-prices, whose meaning, as noted in Table 4, is that the bidder is disposed to pay any price for the demanded quantity. Thus, the demand of electricity results perfectly inelastic, supporting the assumption made in Section 3.

The supply function of an operator, its residual demand and the aggregate supply function can be derived from our database by ordering the offers by price and cumulating the corresponding quantities.

By the nature of the auction rules, the derived supply curves are step functions with zero-derivative almost everywhere. We follow the common practice of approximating the actual step functions by continuous ones using Gaussian kernel smoothers:

$$\hat{S}(p) = \sum_{k=1}^{K} q_k \Phi\left(\frac{p - p_k}{h}\right),$$

for supply curves and

$$\hat{S}'(p) = \sum_{k=1}^{K} q_k \frac{1}{h} \phi\left(\frac{p - p_k}{h}\right),$$

[6] www.mercatoelettrico.org, where data on supply, demand, and quantity traded as bilateral contracts are available.

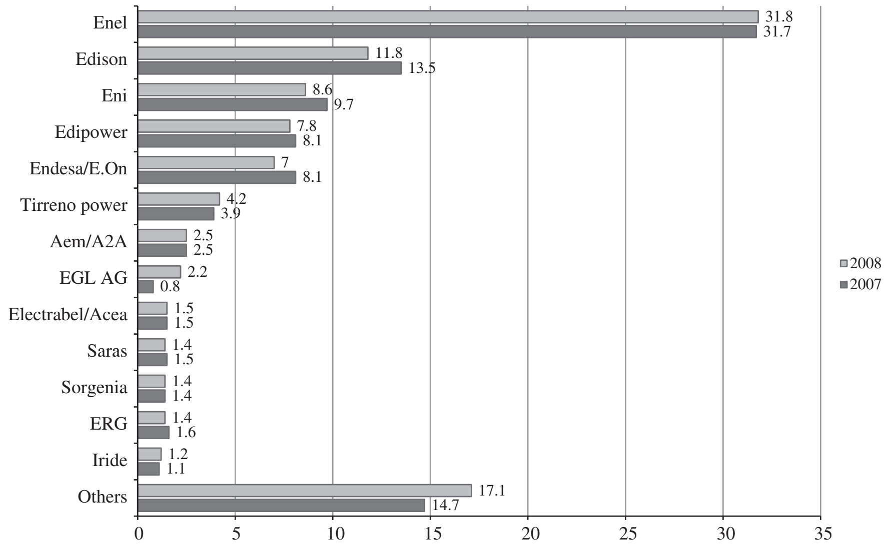

Fig. 1. Market shares of electricity producers.

for their derivatives, with Φ standard normal cumulative probability function, φ standard normal density function and h bandwidth parameter that throughout our analysis has been set equal to 5 Euros.[7]

An example of these approximations is given in Fig. 2, which depicts the aggregate supply curve (top-left), total supply curve of Enel (top-right), supply curve excluding Enel (bottom-left) and the crossing of the residual demand with Enel's supply (bottom-right) together with their kernel-smoothed versions.

As already mentioned, the Italian market is divided into seven zones in which, when congestions occur, different equilibrium prices may prevail. When this happens the producers receive the zonal prices according to the locations of their dispatched plants, while the bidders pay the *unique national price* (abbreviated as PUN), which is computed as quantity-weighted average of the zonal prices. Since the behavior of the operators under congestion may differ from the one described above, we use only the data of those auctions in which the whole country forms one national market. This happens in some 21% of the auctions. The assumption underling this choice is that firms at time t know or can accurately forecast whether at time $t+1$ (i.e. one hour later) the market is going to be national or zonal.

It is important to remark that our sample does not comprise only low-demand auctions, as some may expect. Indeed, in Table 5 one can notice that the quantity exchanged in our sample is some 17% of the total, which is only 4% less than the percentage we would obtain by random sampling. Thus, off-peaks hours (8pm–7am) are slightly over-represented (56.7% instead of 50% of the total), but many peak-time auctions appear in the sample as well. The implication on the nonparametric regressions we compute to recover the marginal cost functions is just a slightly higher uncertainty of the estimates on the right part of the curves, manifesting itself as wider confidence intervals (cf. figures in Section 6).

6. Marginal costs and Lerner Index

For every auction t, using Eq. (4) we can estimate a point on the marginal cost function of the operator i as

$$c_{i,t} := p_t^e + \frac{q_{i,t} - x_{i,t} - z_{i,t}}{\hat{RD}'_{i,t}(p_t^e)},$$

where p_t^e is the SMP, $q_{i,t} := y_{i,t}(p_t^e)$ is the quantity awarded to the operator i in the auction t (including contracts), $\hat{RD}_{i,t}$ is its smoothed residual demand, x_t is the quantity demanded by the same firm and z_t is the quantity sold through forward contracts. So, collecting a sample of pairs $\{q_{i,t}, c_{i,t}\}$ for a period of time in which cost and competition conditions are similar, we can infer the shape of the marginal cost function for the operator i. After some trials, we experienced that quarterly samples represents a good compromise between stability of market conditions (seasonality, input prices, installed capacity, etc.) and sample dimension. In fact, using monthly time-spans there were months with too few sample points to compute meaningful nonparametric regressions.

Figs. 3–5 plot the points $\{q_{i,t}, c_{i,t}\}$ and nonparametric fits (cubic splines) grouped in quarterly samples for the non-dominant medium sized operators Aem (merged in A2A in 2008), E.On and Edison. The estimated functions must be interpreted as average marginal cost functions over each quarter. Excluding few exceptions, the marginal cost functions accord to expectations as for both range (approximately 30–150 Euros) and shapes (nondecreasing and convex). Differences in slope and position among the fitted curves across quarters reflect differences in fuel expenditure as well as some technical/organizational/learning progress. Furthermore, during our total sample period these operators have expanded their capacity by building or acquiring new plants and this may have affected their marginal cost functions. In

Table 2
Mean wholesale electricity prices (Euros).

	2005	2006	2007	2008
Total	58.59	74.75	70.99	86.99
Week day	64.98	81.43	76.48	91.06
Peak	87.80	108.73	104.90	114.38
Off peak	42.15	54.12	48.06	67.75
Holidays	44.33	60.25	58.58	77.88

Table 3
Average European wholesale prices as percentage of mean Italian prices (based on weekday prices at 12:00).

	Omel (ES)	Powernext (FR)	EEX (DE)	APX (NL)
2005	72	70	73	93
2006	49	63	72	88
2007	41	51	57	64
2008	59	83	82	86

[7] We tried $h=1$ and $h=10$ (Euros) as well, but the results did not change significantly.

Table 4
Relevant fields in the Italian electricity auctions database[†].

Producer (seller)	Retailer (buyer)
Operator name	Operator name
Plant name	Unit name
Quantity (MWh) of each offer	Quantity (MWh) of each bid
Price (Euro) of each offer	Price (Euro) of each bid[††]
Awarded quantity (MWh) for each offer	Awarded quantity (MWh) for each bid
Awarded price (MWh) for each offer	Awarded price (MWh) for each bid
Zone of each offer (plant)	Zone of each bid (unit)
Status of the offer: accepted vs. rejected	Status of the bid: accepted vs. rejected

[†] Notice that in the GME database the producer's (seller's) bid is named *offer*, while the retailer's (buyer's) bid is called *bid*. This is in contrast with the terms generally used in the literature as well as in the preceding sections of this manuscript, where the term *bid* is used interchangeably for both supply and demand.
[††] The willingness to buy at any price is coded as zero.

Table 5
Number of auctions and quantity exchanged in our sample compared to the total.

	Number of auctions			Demand (GWh)		
Year	Sample	Total	Ratio	Sample	Total	Ratio
2005	2.017	8.760	23%	44.069	227.579	19%
2006	1.572	8.760	18%	32.638	230.817	14%
2007	1.974	8.760	23%	40.476	223.520	18%
2008	1.697	8.784	19%	38.161	232.249	16%
2005–08	7.260	35.064	21%	155.343	914.164	17%

particular we stress the increased production capacity of E.On in 2008 (Fig. 4), which is to be attributed to the acquisition of Endesa.

In general convexity is the most frequent characteristic of the marginal cost functions we recovered from the Italian market data. A possible explanation for this result, when it is referred to non-dominant firms, is that these operators might be including in their figurative costs an opportunity-cost component motivated by the possibility of not being dispatched (e.g. when the dominant does not leave sufficient market shares to them) especially during off-peak periods. In other words, operators ascribe an high opportunity cost to each produced quantity, particularly to the quantities near the maximum capacity of their plants. This means that when they bid for those quantities they inflate the pure operational marginal cost (basically the cost of their fuel) for that quantity by this "insurance" component. As a result, even when their plants are not entirely dispatched (i.e. when they do not sell at full capacity) their bids on the dispatched part of their supply already cover the opportunity cost associated to the capacity that remains idle. A similar interpretation is postulated by Wolak (2003, p. 167) for the Australian case when he interprets the behavior of marginal costs recovered using bid data generated in that market. However, he relates the opportunity costs to hedging activity motivated by the risk of "unit outages" when they have sold a significant amount of forward contracts. This result, after all, is equivalent to the well known *differential bid shading* property of multi-unit auctions first obtained by Ausubel and Cramton (2002) and then also found in electricity auctions by Parisio and Bosco (2003) and Parisio and Bosco (2008).

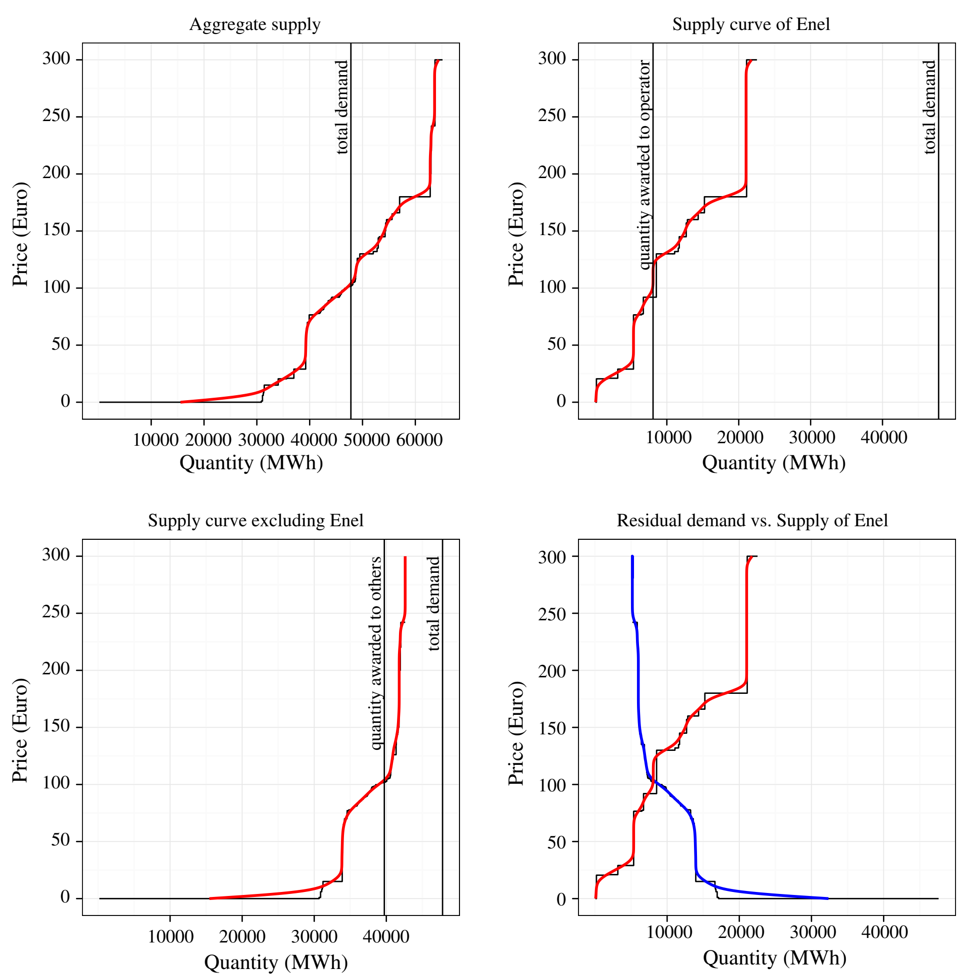

Fig. 2. Supply functions for Enel and kernel smoothing. Auction of Tuesday 2 December 2008 at 4pm.

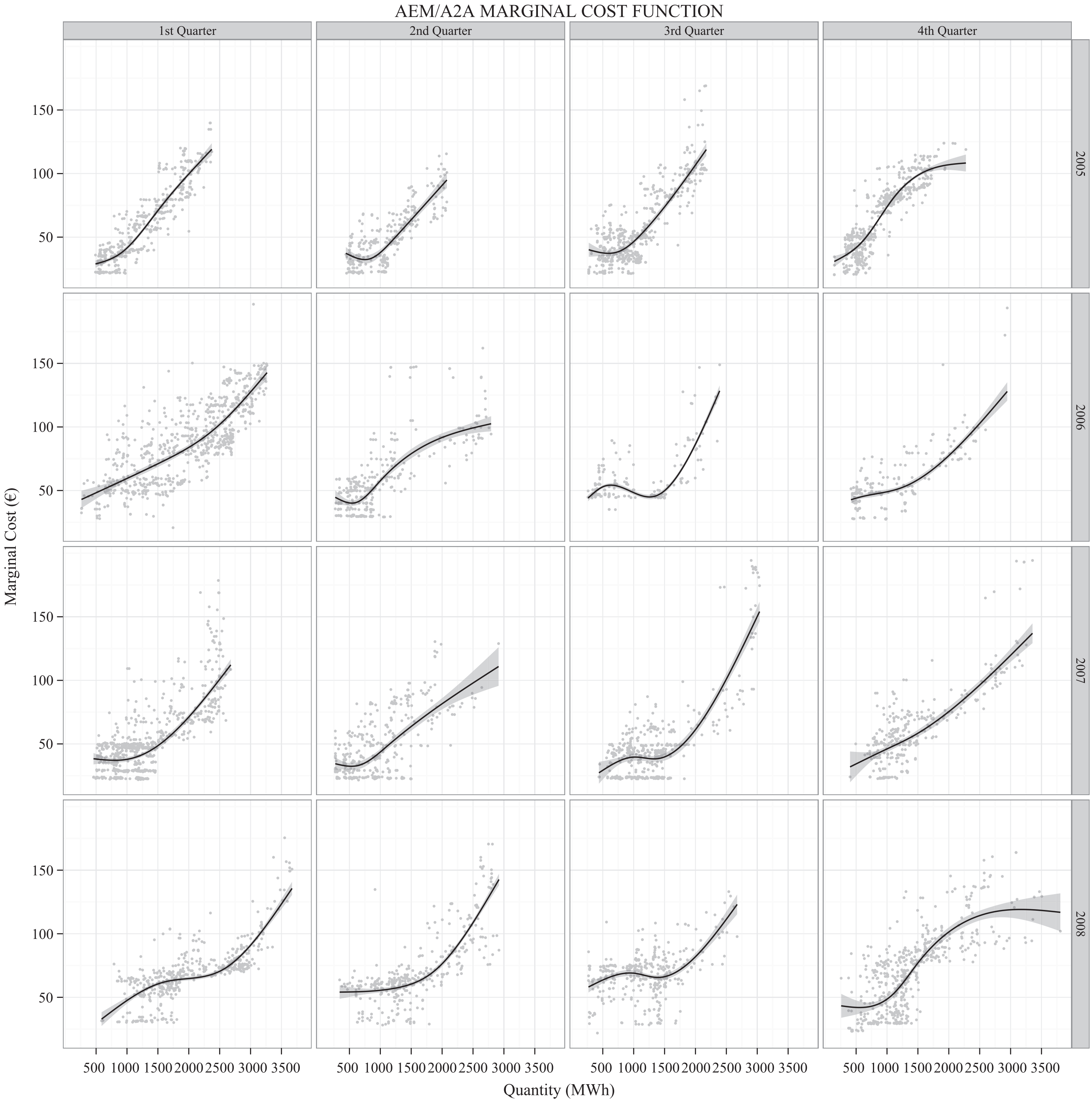

Fig. 3. Estimated average marginal cost function for Aem/A2A.

As for the dominant firm (Enel, Fig. 6), the interpretation of the results appears somewhat difficult. In the first place we notice that some 23% of estimated marginal costs is negative (excluded from the graphs). This happens because in those cases Enel is operating in correspondence to a point on the residual demand with elasticity smaller than one. In other words Enel is not always bidding profit-maximizing supply schedules. Indeed, in most of the cases Enel's supply is indispensable to close the market and therefore she could bid at the price cap level (500 Euro). Paradoxically, this result leads one to wonder why Italian electricity prices are not as high as they could be, despite the fact that they are the highest in Europe (cf. Table 2). Possible explanations can be: i) the concern that extremely high electricity prices can depress the real economy and lead to an eventual drop in demand and profits, ii) the reimbursement for stranded costs which are computed as decreasing function of the company value and, thus, of its profits (Ciarreta and Espinosa, 2010), iii) the very nature of Enel shareholding which is still for one third in the Government's hands; this implies that Enel's behavior is not exclusively profit maximizing (Boffa et al., 2010), iv) moral suasion from regulatory authorities based on comparisons with average European prices (Bosco et al., 2010).

When the dominant was not the price setter, results are more in line with those reported for non dominants. Calculated marginal costs are positive and scatter plots show almost constant kernel fits. Our results are very similar to those obtained by Wolak (2003, Fig. 4.4). As evident from Fig. 6, Enel's marginal costs seem to be decreasing

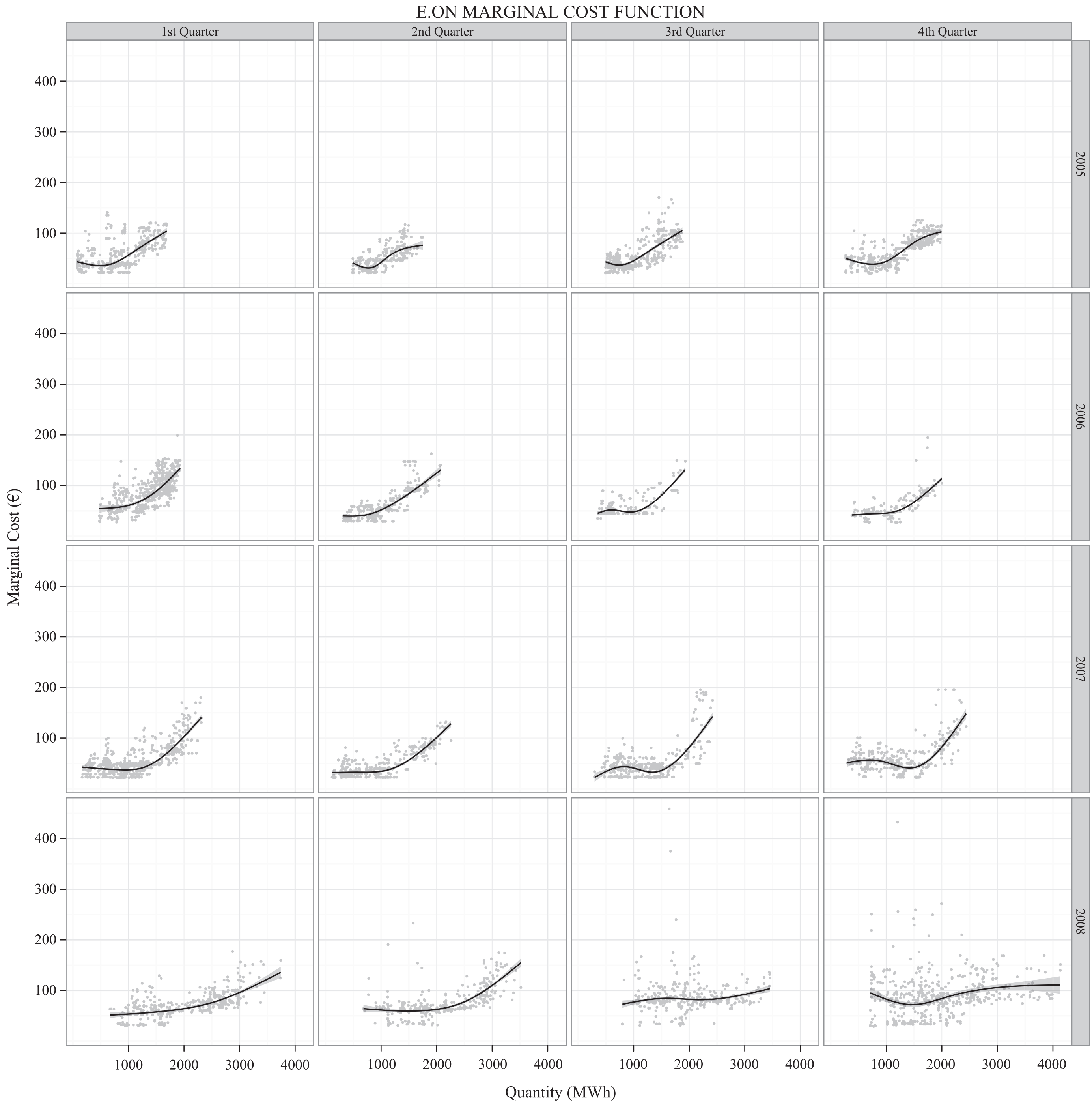

Fig. 4. Estimated average marginal cost function for E.On.

gradually with dispatched quantities. This can be seen as an evidence of the already mentioned non optimal (profit maximizing) behavior of Enel, particularly for high demanded quantities. When demand is high and Enel is indispensable, the optimal asked price could be higher for the same dispatched quantity: $y(p)=y(p^e)$ for $p>p^e$. As a result, the equilibrium price, say p^*, would be larger than the actual SMP, p^e. Therefore, when one uses Eq. (4) the estimated marginal costs are affected by a downward bias:

$$c^{*\prime}-c^{\prime}=p^*-p^e-\frac{y(p^*)-y(p^e)}{RD^{'}}=p^*-p^e>0,$$

where $c^{*\prime}$ is the unknown true marginal cost under high demand. This result is a complementary way to illustrate the underbidding phenomenon analyzed by Hortaçsu and Puller (2008) in a context of known marginal cost. In their case, by starting from observed marginal costs, one expects to find higher prices but one ends up with lower than expected values. In our case, by starting from observed prices, one estimates downward biased marginal costs.

For assessing the market power of the four considered operators, we computed the Lerner Index according to Eq. (5). The results are plotted in Fig. 7 as scatter diagrams of Lerner Indexes against net quantities.

Lerner Indexes of non-dominant operators are almost always very close to zero (first three panels of Fig. 7). The few outlier observations

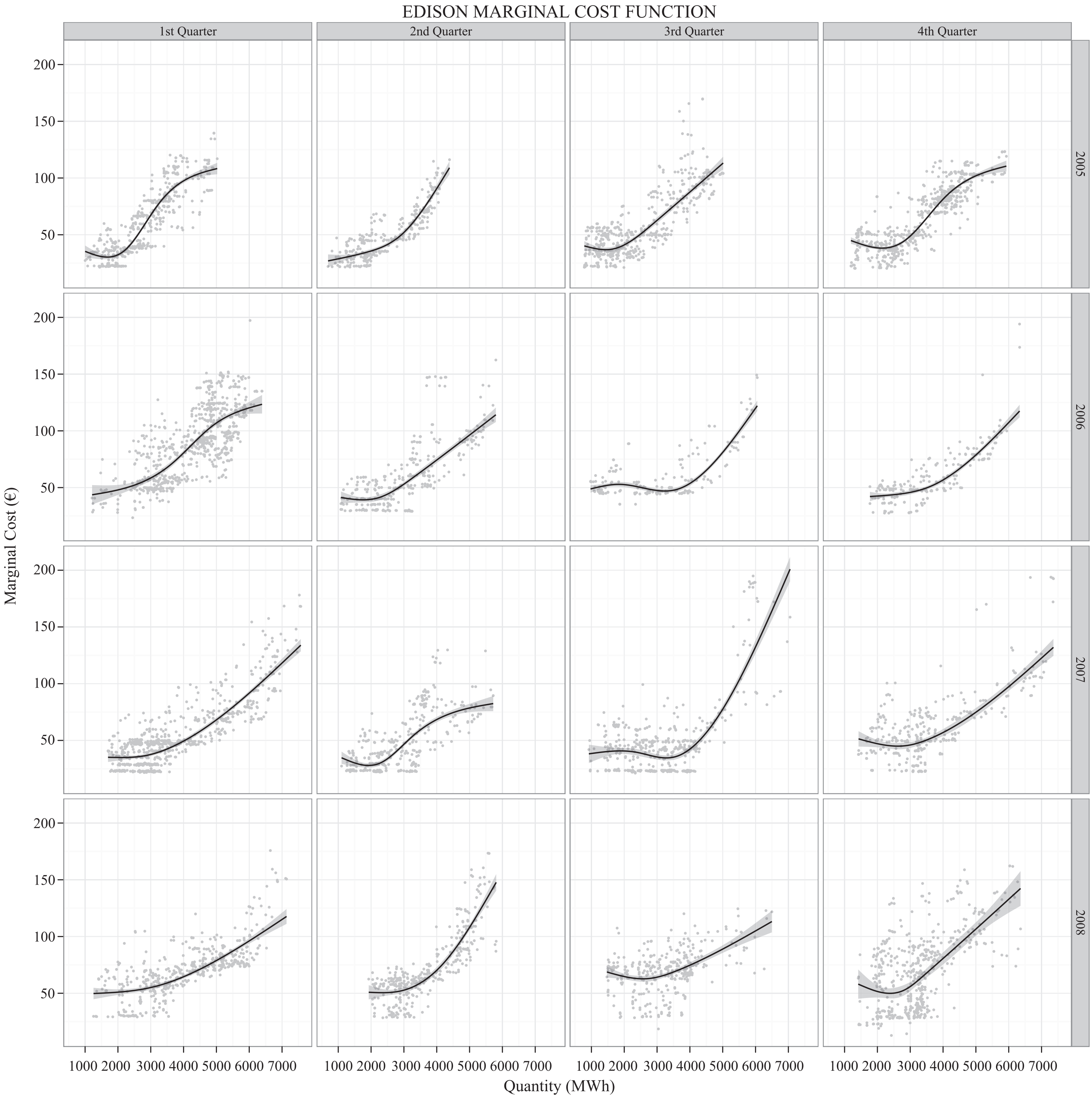

Fig. 5. Estimated average marginal cost function for Edison.

show that, when they can be pivotal, they effectively exercise market power. In the majority of cases however, the above findings agree with the evidence illustrated by Fig. 8, which shows that these firms bid at marginal cost (see Appendix B for details on Fig. 8). The results change substantially for the dominant operator, which has large (absolute) Lerner Indexes both as net buyer and as net supplier. When the Lerner Index is negative, it may be interpreted as a measure of the advantage given by buying on the market instead of producing for retail. However, it should be recalled that since Enel's marginal costs are affected by a downward bias, the corresponding Lerner Indexes are overestimated.

7. Regressing cost and equilibrium prices against fuel price

Short-run generation marginal costs basically depend on fuel prices, according to the technology of each plant. In this section we try to assess whether producers' costs react to fuel changes more or less intensively than equilibrium wholesale market prices. This is done in order to evaluate whether electricity auctions amplify or hamper the impact of fuel changes on wholesale prices.

In order to test the above hypotheses we regress cost observations of three non dominant Italian firms – retrieved from previous calculations – against a measure of production activity of each firm (i.e. its

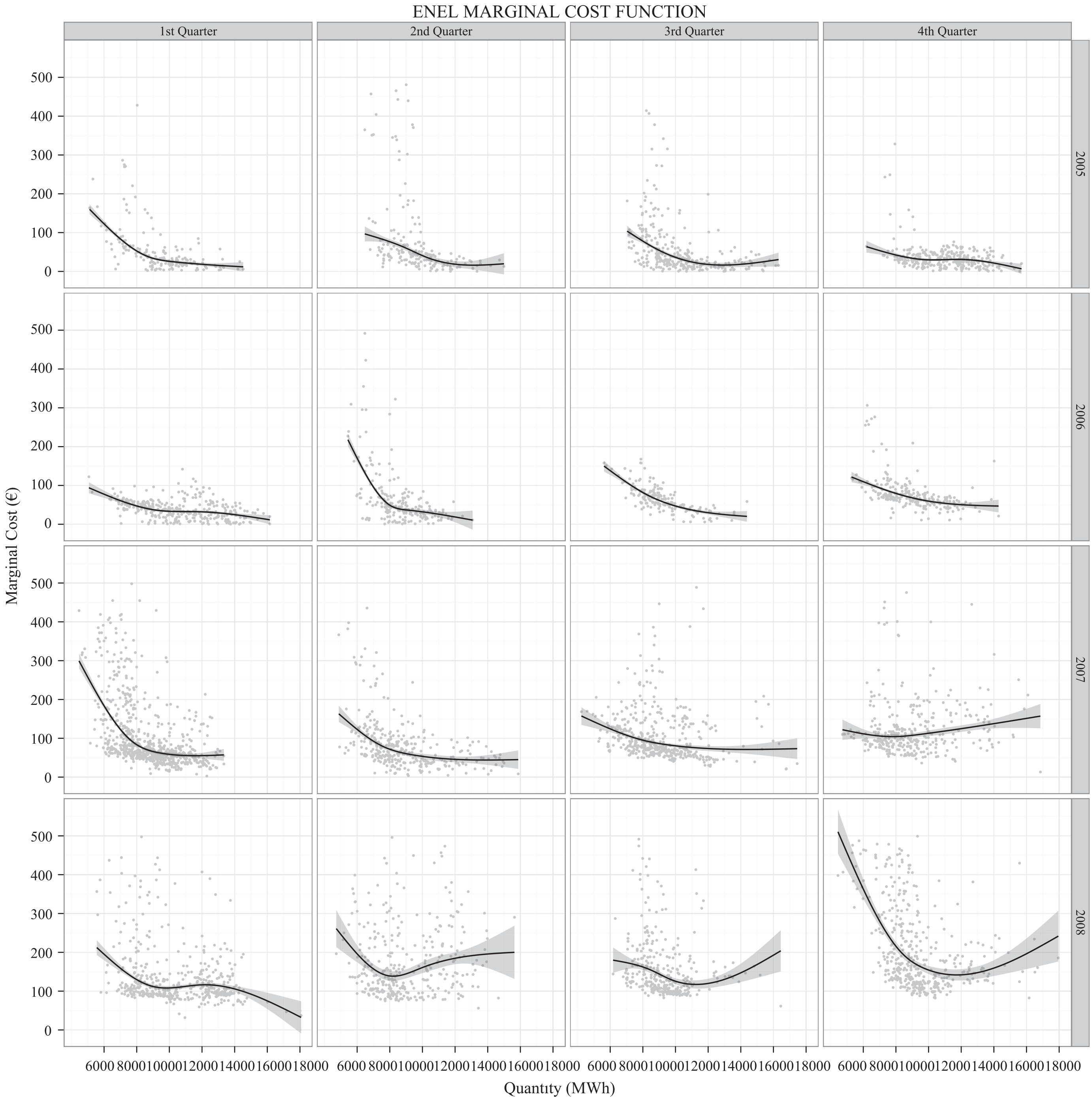

Fig. 6. Estimated average marginal cost function for Enel.

residual demand), a 6-month moving average of Brent prices and a time trend. The 6-month moving average of Brent prices is approximately proportional to gas prices, since gas contracts are generally indexed to oil prices through that formula. We, then, regress the SMP on the same set of independent variables (with total quantity sold replacing residual demand). All the variables are in logarithms so that regression coefficients may be interpreted as elasticities. An autoregression of order 1 captures the dynamics present in the regression errors and makes the inference on the regression coefficients more reliable. Results are reported in Table 6. Notice that, in order to make the estimates robust to the presence of outliers, we used the MM-estimators for regression proposed by Yohai (1987).

As one can see, in each regression the time trend is negative, probably indicating some improvements in productive efficiency and the expansion in capacity over time, which affects marginal costs and market price in almost the same way.

Costs elasticity to residual demand is in a range from 51% to 80%, whereas the elasticity of SMP to total quantity is more than twice as large.

The elasticity of E.On and Edison's marginal costs with respect to the six-month moving average of Brent price is significantly different from zero and it is equal to 124%. The same elasticity is equal to 158% for A2A.

This result is consistent with the above mentioned fact that many gas contracts index gas prices with an average of past oil prices over a six-month period. In our sample the marginal plant used thermal

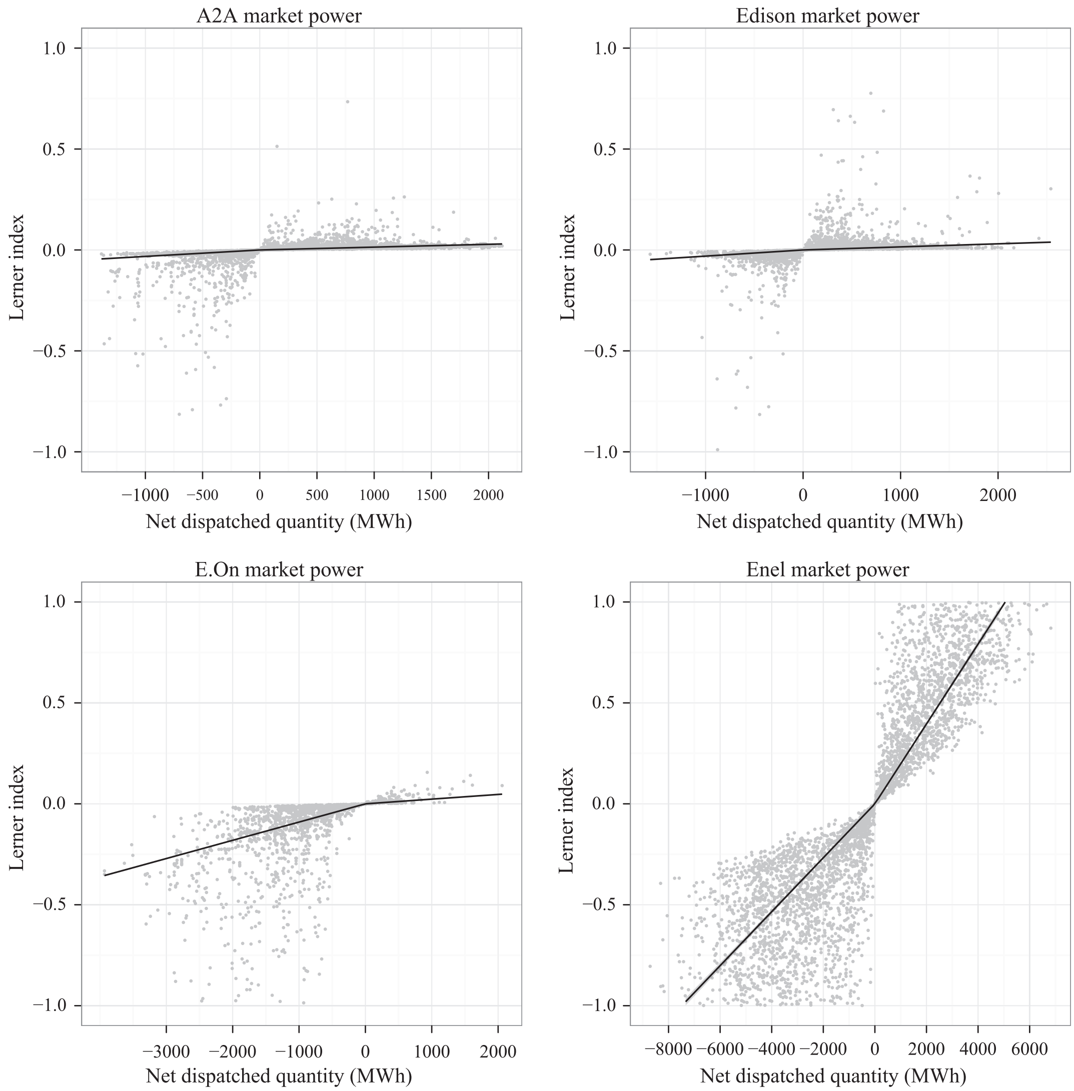

Fig. 7. Lerner Indexes vs. net sold quantity.

technologies in 74% of the times. Values of total elasticity of marginal costs with respect to MA6 of Brent prices higher than one should not surprise since generators do not buy crude Brent oil on the wholesale market. They buy gas and refined oil from sellers which charge them for all their processing costs.

As for SMP, the elasticity with respect to the MA6 of the Brent price is approximately the average of the other three estimated values.

The general conclusion we can draw from the regression results is that fuel price variations affect marginal costs and equilibrium prices in a very similar way. An increase in input prices induces an increase

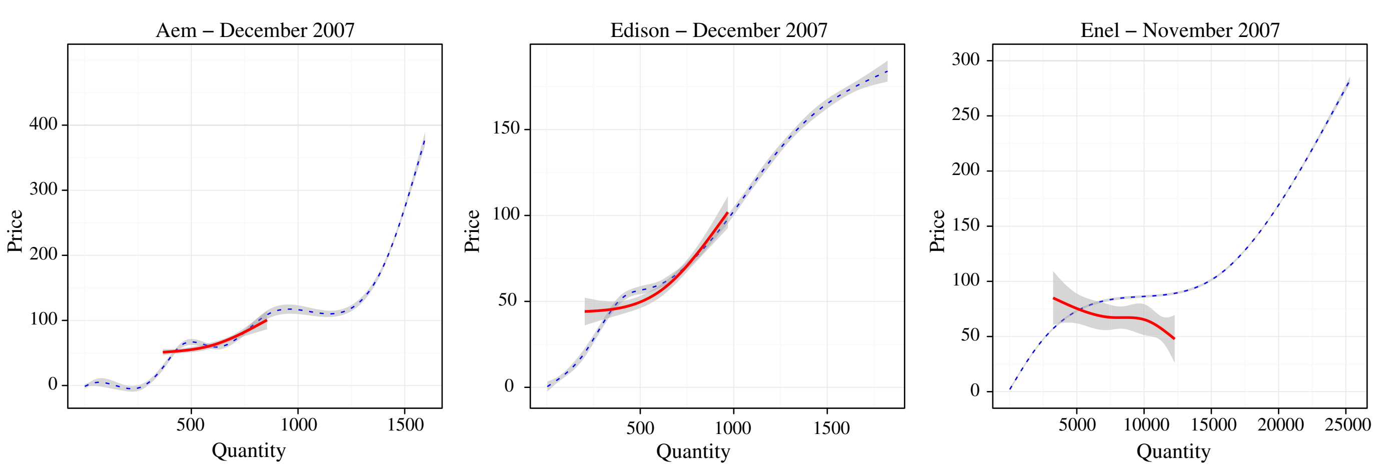

Fig. 8. Estimated marginal cost (continuous line) and supply function (dashed line) for a selection of auctions with similar supply conditions.

Table 6
Robust MM-regression coefficients for the logarithm of marginal costs of A2A, Edison and E.On, and of System Marginal Prices (SMP).

	A2A	Edison	E.On	SMP
Intercept	−5.82	−6.83	−4.00	−16.62
log(RD_i)	0.59	0.80	0.51	–
log(Total Demand)	–	–	–	1.60
log(MA6 Brent)	1.58	1.24	1.24	1.30
Trend	−0.28	−0.23	−0.23	−0.21
AR(1)	0.90	0.91	0.88	0.86

All coefficients are significant at any usual level.

in marginal costs which is above 100%, and the estimation of SMP elasticity indicates that, in presence of inelastic demand, this increase is completely transferred to buyers. Competition among generators does not reduce the extent of a shift in input price on wholesale electricity prices by means of a reduction of profits margins and market power. In this respect the auction mechanism seems to work almost as a cost-plus regulation scheme.

8. Conclusions

In this paper we use a model of optimal bidding in electricity auctions that incorporates cost uncertainty and the hypothesis that some firms might be vertically integrated and might hold forward contract positions to estimate price–cost margins and Lerner Indexes for a set of Italian companies operating from 2005 to 2008. We evaluated the extent of their market power by first estimating generation costs from supply bids and demand elasticity and then derive Lerner Indexes accordingly. The incorporation of vertical integration and forward contract commitments strongly improves the adaptability of existing theoretical models of bidding behavior to the data generated in electricity markets.

We obtain estimates of marginal cost functions for non-dominant firms that are positively correlated with supplied quantities and convex. On the contrary, marginal costs of the dominant firm are flatter and generally decreasing with respect to quantities. This indicates that the theoretical model proposed in this paper accurately reflects the actual behavior of non-dominant firms, but not that of the dominant. As for the Lerner Indexes, they are almost zero for non-dominant firms and suggest the existence of a strong market power of the (vertically integrated) dominant firm both when she is net supplier and net buyer.

Then, we use the series of estimated marginal costs and equilibrium price to assess the elasticity of these series to fuel price variations and to evaluate the way in which the dynamics of costs' components (fuel price above all) affect generation costs and final electricity prices. We test for a possible differential impact of oil prices changes on marginal costs and actual prices, and we conclude that there is no such a difference. As a consequence, through the auction mechanism cost increases are identically transferred to prices, making the auction similar to a cost-plus regulation scheme.

Appendix A. Supplementary data

Supplementary data to this article can be found online at doi:10.1016/j.eneco.2011.11.005.

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