A discusión

MARKET POWER IN THE SPANISH WHOLESALE ELECTRICTY MARKET*

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ABSTRACT

In the context of the recent electricity market reforms in Europe and the US, we evaluate the performance of the Spanish pool. Our method is not based on price-cost estimates but rather on the different behavior of operators with higher market power as compared to the behavior of more competitive operators. Our results indicate that the two larger operators in the market are able to increase prices by a significant amount as compared to the situation in which each plant is run independently.

Keywords: electricity market, competition, auctions, market power.

1   Introduction

In the context of European deregulation, the Spanish electricity market is undergoing a process of reform with the objective of increasing efficiency and competition. In this paper we explore whether the two larger operators in the Spanish wholesale market exploit their market power and, if that is the case, to what extent market power raises price-cost margins.

Market power is an important consideration in the European deregulation of the electricity industry. Centralized spot markets have been abolished recently in California and in England and Wales. It has been argued that the problems in these electricity markets were due to market power coupled with a tight demand-supply balance (see Green, 2001).[1] The Spanish spot market was introduced in 1998[2] with rules similar to those guiding the English market at the time. In the present context of electricity market reforms in Europe and the US, it seems important to evaluate the performance of the Spanish pool in these years, given that it shares the features of high concentration and tight demand-supply balance. Our paper is a first step towards exploring the efficiency of the Spanish wholesale market.

A high concentration index together with an inelastic demand suggest that firms will use their market power to set prices well above costs. However, depending on other market conditions or auction rules, concentration may give rise to higher or lower margins. Wolfram (1999) found that for the British market prices were much closer to marginal cost than most theories predicted, although she also finds some evidence of strategic capacity withholding. Explanations for the restrained price levels were financial contracts between the suppliers and their customers,[3] threat of entry and threat of regulatory intervention in the market.[4]

In the industrial organization literature several methods have been used to measure market power in electricity markets. Mount (2001) associates systematic patterns of price spikes with market power use in the UK electricity market. Spear (2001) argues that horizontal market power explains price spikes in peak periods observed in the California generation market, as well as the reduction in additions to capacity. Several papers (Green (1994), von der Fehr and Harbord (1993), Borenstein, Bushnell and Wolak (2000) and Wolfram (1999), among others) have used direct measures of marginal cost to calculate price cost margins. Macatangay (2000) proposes a test of "suspicious patterns" of bidding behavior based on the slopes of the supply curves; he shows that "suspects" behave differently from the rest and checks whether the strategies of the suspect firms affect one another. Bushnell and Saravia (2002) measure the competitiveness of the New England electricity market by comparing equilibrium prices with a

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[1] See Fabra (2001) for an overview of the literature on electricity markets and empirical evidence.

[2] Regulated by Act 2019 of December 26, 1997.

[3] See Green (1999) on contracts for differences.

[4] However, Newbury (2002) argues that many European countries lack the necessary regulatory power to mitigate generator market power.

competitive benchmark: the price that would result if no firm exerted market power. They obtain a demand-weighted markup from 4% to 12% depending on whether equilibrium prices include operating constraints or not.[5]

Our approach is different from previous papers measuring the impact of market power in that we do not use cost estimates. Rather, we study the optimal behavior at the electricity auction of firms with high market share and compare it to that of small firms. We model the outcome of the pool as a supply function equilibrium. There has been some discussion concerning the model that best suits this type of market. The choice is not without consequences. Some authors have considered the pool as a continuous share auction (see Klemperer, 2001; Wang and Zender, 2002), and in these models the outcomes are prices above costs: Participants submit supply functions with slopes higher than the marginal cost function so that the residual demand for each participant is also steep and no one has incentives to undercut other competitors; in this manner, high prices may be sustained in equilibrium. However, other authors have used a discrete, multiple-unit model, where prices can be any real number but suppliers must submit a finite number of price-quantity bids; von der Fehr and Harbord (1993) and Fabra have shown that there is an incentive to undercut the rival's price slightly and increase output. The discrete auction model yields either non existence of pure-strategy equilibrium or a Bertrand like equilibrium. This is an extreme result that could be tested with electricity auction data. Considering this debate, we have chosen to analyze also the implications of other models (Cournot competition) for the presence of market power.[6]

The supply function of a large operator[7] at the pool is obtained by aggregating the supply functions of each generating plant under its control. In the absence of any market power, a generating plant would bid at the pool independently of whether it belongs to a large operator or to a small firm, and thus the supply function of a larger operator would coincide with the supply curve obtained as the sum of the supply functions of similar plants under the control of small firms. Of course, in real auctions production units will take into account their effect on other production plants under the same ownership and will respond to their incentive to restrict output and raise prices (i.e. to bid a supply curve more to the left). Larger generators are very often marginal bidders at the auction, determining the price that is paid to all plants for all units sold. This impact on equilibrium prices creates an incentive to offer supply curves which are to the left of the equivalent supply curves of small generators. Our measure of market power is based on this difference on supply curves between larger and small operators at the pool.

More precisely, to measure market power we compare the behavior at the

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[5] In the I.O. literature there is a long tradition of price-cost measurement. See for example Nevo (2001), who estimates price-cost margins in the cereal industry and separates these margins into three sources of market power: product differentiation, multiproduct firm pricing and collusion.

[6] We have not considered models with collusion (sustained through the repeated nature of the game) because in those models it is less clear how to single out an outcome (multiplicity of equilibria and asymmetric players).

[7] In what follows we consider that the size of a generator is its capacity.

pool of "technologically similar" plants, ones under the ownership of larger generators and the others under the ownership of smaller firms. We choose for the comparison plants which are technologically similar and compare their bids for the same auction (same day and same time) so that demand and cost conditions coincide. Thus, any systematic difference in their supply functions can only be attributed to the market power of larger generators. In this paper we observe this different behavior in terms of supply curves at the pool and measure the impact on equilibrium prices.

It is worth noting that, compared to previous works based on price-cost margin estimates, our method provides a lower bound for that margin. In other words, our competitive benchmark is a situation in which each plant is run independently (and the equilibrium price that would be determined in that case) but, since the number of plants is not infinite, each plant would bid above marginal cost. We argue in the paper that the difference between our competitive benchmark and marginal cost is small.

Our main findings for the Spanish pool are that the two larger operators do exploit their market power and consistently submit supply curves which are to the left (higher prices and lower capacity) of the competitive benchmark. We also estimate the increase in price-cost margins for peak and off-peak hours. These results are somewhat consistent with those of Wolfram (1998) who finds evidence that in the British market the larger supplier submitted higher bids for similar plants.

The paper is organized as follows. Section 2 gives a very brief description of the Spanish pool. Section 3 presents the supply function equilibrium model, where we show that in equilibrium a plant under the ownership of a larger generator has a supply function which is to the left of the supply curve of a plant under the ownership of a smaller generator; results for Cournot competition are also provided. In Section 4 we define a measure of the market power of a generator, based on the impact that its bidding has on the equilibrium price: if all the plants of a generator were run independently we would obtain an equilibrium price; when these plants coordinate their bids the equilibrium price is higher. This price difference yields a measure of market power. The rest of the paper presents our empirical results for the Spanish pool. In Section 5 we describe our competitive benchmark and the procedure for measuring each firm's market power and in Section 6 the statistical analysis. Section 7 concludes.

2   The Spanish wholesale electricity market

The Spanish pool for electricity (day-ahead market) started its operations in January 1998.[8] Two companies, Endesa (EN) and Iberdrola (IB), own the majority of generating capacity, while Unión Fenosa (UF) and Hidrocantábrico (HC) are smaller competitors; all are private companies and each owns nuclear,

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[8]After Act 54/1997 liberalizing the market was approved in November 1997 and Act 2019/1997 established the rules of the production market.

thermal plants and hydroelectric units. At the beginning of 2002, EN sold a small part of its capacity (Viesgo) to the Italian company ENEL, which has become the fifth competitor in this market.

The pool works as follows. Before 11:00 a.m., qualified buyers and sellers of electricity present their offers for the following day. Each day is divided into 24 hourly periods.

Sellers in the pool present bids consisting of up to 25 different prices and the corresponding energy quantities for each of the 24 periods and for each generating unit they own; the prices must be increasing. If no restriction is included in the offer this is called a 'simple offer'. A seller may also present a 'complex offer' which may include indivisibility conditions, a minimum revenue condition, production capacity variation (load gradient conditions) and scheduled stop conditions. The pool administrator consolidates the sales bids for each hourly period to generate an aggregate supply curve.

Qualified buyers in the pool present offers.[9] Purchase bids state a quantity and a price of a power block and there can be as many as 25 power purchasing blocks for the same purchasing unit, with different prices for each block; the prices must be decreasing. The pool administrator constructs an aggregate demand with these offers.

In a session of the daily market the pool administrator combines these offers matching demand and supply for each of the 24 hourly periods and determines the equilibrium price for each period (the system marginal price) and the amount traded.[10] This matching is called the *base daily operating schedule (PBF)*. After the *base daily operating schedule* is settled, the pool administrator evaluates the technical feasibility of the assignment; if the required technical restrictions are met then the program is feasible; if not, some previously accepted offers are eliminated and others included to obtain the *provisional feasible daily schedule (PVP)*. This reassignment ends at 14:00. By 16:00 the *final feasible daily schedule (PVD)* is obtained taking into account the ancillary services assigment procedure. There is also an intra-day market to make any necessary adjustments between demand and supply.[11] The result is called the *final hourly schedule (PHF)*.

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[9]From January 1st 2003, all buyers of electricity are considered qualified buyers. Before that date qualified buyers were those with consumption greater or equal to 1 GWh per year. The required consumption has decreased over time from 5GWh (December 1998) to 3GWh (April 1999), to 2GWh (July 1999) and to 1 GWh (October 1999).

[10]Appendix 1 describes the procedure for calculating the system marginal price when demand and supply intersect in a vertical or horizontal section of either the aggregate demand or the aggregate supply curves.

[11]The intra-day market started working in April 1998. In the first three months it had 2 sessions per day. From July 1998 it had 4 sessions per day and from September 1998 it had 5 sessions. Now it has at least 6 sessions.

3 The model

We represent strategic interaction in the electricity market through a supply function equilibrium model,[12] where each generator decides a supply curve for each of the plants it owns. This model fits well the bid rules of the Spanish pool since generators have to submit a schedule of up to 25 prices and quantities, for each production unit and for each hourly period.[13] The supply curve of a generator is then obtained as the sum of the supply curves of all its individual plants. The supply function equilibrium model is considered more appropriate when firms are constrained to maintain the bid for a period of time or when there is demand uncertainty. In the case of the Spanish pool, bids are short-lived (1 hour) and there might be some demand uncertainty but, more importantly, generators "shall be required to submit electric power sale bids to the market operator for each of the production units they own for each and every one of the hourly scheduling periods."[14] This rule implies that all the production units should submit bids even though in periods of low demand some of them are not going to produce. Other authors have analyzed the electricity market as Cournot competition (see Borenstein and Bushnel, 1997) or as a sealed-bid, multiple-unit, private-value auction (see Wolfram, 1999, von der Fehr and Harbord, 1993, and Marín and García-Díaz, 2000).[15] Our main results are not specific to supply function competition and we also comment on the results under Cournot competition and multiple-unit auction models.

Our purpose is to analyze the equilibrium behavior of generators with different sizes and hence different market power in the pool. In our model the participants in the generation market will have different numbers of production units: a generator with m plants (generator 1), a generator with k plants (generator 2) and a third generator with only one plant (generator 3). We assume $m \geq k > 1$. The cost function for each plant is quadratic:

$$C(q_{ij}) = \frac{1}{2} c q_{ij}^2 \tag{1}$$

where q_{ij} denotes electricity produced by plant j owned by generator i. The choice of a linear marginal cost is frequent because it allows the solution to

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[12] See Klemperer and Meyer (1989), Green and Newbury (1992), Green (1996), Baldick, Grant and Kahn (2000), and Bolle (1992).

[13] For a further discussion of the advantages of the supply function equilibrium model over Cournot, see Baldick, Grant and Kahn (2000).

[14] Electricity Market Activity Rules, p. 6. There is an exception to this rule when the production unit has a bilateral contract which, due to its characteristics, is excluded from the bidding system.

[15] Our purpose in this paper is to detect the presence of market power but we do not test our model against other models for the electricity market. In fact, other models could have similar implications to ours concerning market power.

the system of diferential equations to be found more easily. Green and Newbury (1992) use quadratic marginal cost, which requires numerical solution of diferential equations.[16]

All plants are identical. This is obviously a simplifying assumption, useful to explain differences in bidding behavior due to differences in market power, not differences based on cost asymmetries.

Demand function is linear:

$$D_t = a_t - bp_t + u_t \qquad (2)$$

where u_t is a random error with zero mean and p_t denotes price at period t. Note that the slope of the demand function b is assumed independent of time, while the intercept a_t may vary over time. The electricity auction is a uniform price auction; thus, all buyers (sellers) whose offer has been accepted pay (receive) the marginal price for the electricity required (supplied) in their offer. Firms are assumed to be risk neutral and therefore they maximize their expected payoff.

Each plant's bid at the auction will be represented here as a continuous supply function. The problem for generator 1, with m plants, is to decide the supply curve for each plant j at each period t, $q_{1j}^t(p_t)$, such that it maximizes the expected value of profits:

$$\max_{q_{1j}^t(p_t)} \quad p_t \sum_{j=1}^{m} q_{1j}^t(p_t) - \sum_{j=1}^{m} C(q_{1j}^t(p_t)) \qquad \text{for } j = 1, ...m$$

Since all plants owned by the same generator are identical, $q_i^t(p_t)$ will denote the supply curve of any plant belonging to generator i. Substituting (1) and (2) in the profits expression we have:

$$\max_{q_{1j}^t(p_t)} \quad p_t \left[a_t - bp_t - kq_2^t(p_t) - q_3^t(p_t) \right] - \frac{1}{2} c \sum_{j=1}^{m} \left[a_t - bp_t - kq_2^t(p_t) - q_3^t(p_t) - (m-1)q_{1j}^t(p_t) \right]^2$$

$$\text{for} \quad j = 1, ...m$$

The first order conditions for generator 1 are:

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[16] See also Laussel (1992).

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$$p_t \left[-b - k\frac{dq_2^t(p_t)}{dp_t} - \frac{dq_3^t(p_t)}{dp_t} \right] + mq_1^t(p_t) - cmq_1^t(p_t) \left[-b - k\frac{dq_2^t(p_t)}{dp_t} - \frac{dq_3^t(p_t)}{dp_t} - (m-1)\frac{dq_1^t(p_t)}{dp_t} \right] = 0$$

We look for solutions of the form:

$$q_i^t(p_t) = A_i + B_i p_t \qquad i = 1, 2, 3$$

and obtain:

$$A_1 = A_2 = A_3 = 0$$

$$B_1 = \frac{b + kB_2 + B_3}{m + cm\left[b + kB_2 + B_3 + (m-1)B_1\right]}$$

$$B_2 = \frac{b + mB_1 + B_3}{k + ck\left[b + mB_1 + B_3 + (k-1)B_2\right]} \tag{3}$$

$$B_3 = \frac{b + mB_1 + kB_2}{1 + c\left[b + mB_1 + kB2\right]}$$

Solving the system we get the equilibrium values $B_1\,(b, c, m, k)$, $B_2\,(b, c, m, k)$, $B_3\,(b, c, m, k)$, as functions of the parameters of the model, and thus, the equilibrium supply curve for each plant.[17] Since we are assuming that b and c are constant over time, the slope of the supply function is also constant over time. The main result of this section, which will be tested later on, is the following:

Proposition 1 *Large generators submit plant supply curves which are to the left of the plant supply curves of small generators:*

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[17] When the cost function in (1) includes a term $d_i q_i$, the supply function has a non-zero intercept.

$$B_1\left(b,c,m,k\right) \leq B_2\left(b,c,m,k\right) < B_3\left(b,c,m,k\right)$$

The result can be checked from the expressions for B_1, B_2 and B_3 in (3). Figure 1 illustrates the proposition for parameter values $b = 1$, $c = 0.2$, $m = 5$, and $k = 5$. A generator with a large number of plants has to take into account the effect of a plant's bid on the price received by its other plants. Therefore, to maximize total profits, each plant restricts output, that is, it offers a lower amount at each price, or asks for a higher price for each energy volume. Since all production units have the same technology, the different positions of the supply curves are due only to the different market power of the generators. Increasing output (moving the supply curve to the right) has a negative effect on all the other plants' profits. A larger generator would internalize these effects and therefore choose for each plant a supply curve with a higher slope.

Figure 1. Parameter values: $b = 1$, $c = 0.2$, $m = 5$, $k = 5$, $a = 10$. The equilibrium values for supply curves are given by $B_1 = B_2 = 0.46575$ and $B_3 = 2.6542$.

A similar result is obtained under Cournot competition. If firms compete in the level of output of each plant, we obtain in equilibrium: $q_1 \leq q_2 < q_3$ (see Appendix 2).

The aggregate supply function is:

$$S_t = Bp_t + \varepsilon_t \tag{4}$$

where $B = \left(mB_1 + kB_2 + B_3\right)$ and ε_t is an error collecting random breakdowns in production, etc.

Matching aggegate demand and aggregate supply (equations 2 and 4) we obtain the equilibrium price and energy traded:

$$p_t = \frac{a_t}{B+b} + \frac{u_t - \varepsilon_t}{B+b} \tag{5}$$

and

$$q_t = \frac{Ba_t}{B+b} + \frac{Bu_t + b\varepsilon_t}{B+b} \tag{6}$$

Note that q_t and p_t are higher in high demand periods (high a_t) and are affected by demand and supply errors (u_t and ε_t, respectively).
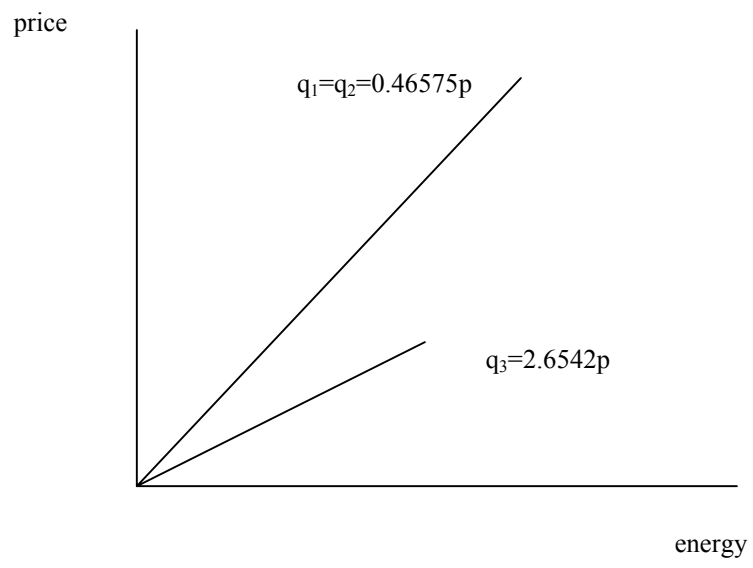
price

$q_1=q_2=0.46575p$

$q_3=2.6542p$

energy

Figure 1

4 A measure of market power under supply function competition

The standard measure of market power is the Lerner index (Lerner, 1934): $\frac{p-c}{p}$, where c is marginal cost. In this section we propose a measure of market power which is a lower bound for the Lerner index. Thus, if we find that market power is significant according to our index, we can be sure that $\frac{p-c}{p}$ is also significant. The measure is based on the comparison of the behavior of a given generator, referred to a particular production unit, to the behavior of a generator who owns only one production unit. If a plant in a larger generator were to bid the same supply curve as a plant from a generator with only one plant, then it would not be using its market power associated with size. However, from Proposition 1 we would expect a larger generator to instruct its plants to restrict output, submitting supply curves to the left. Any difference between the two supply curves will be attributed to market power and the impact on equilibrium prices will be used to construct a measure of individual market power.

More precisely, we define a *synthetic* generator with m plants as a generator which does not maximize joint profits for the m plants, rather it instructs each plant to present a supply curve at the pool to maximize the plant's profits. In other words, a synthetic generator does not internalize the effects of its plants on each other's profits, i.e. it does not exploit its market power.

First, we construct a measure of generator 1's market power. In our analysis of the pool equilibrium, we replace generator 1 by synthetic generator 1. Each plant in synthetic generator 1 maximizes profits individually; as a result, the supply function equilibrium is given by:

$$B_1^s = \frac{b + kB_2 + B_3 + (m-1)B_1^s}{1 + c\left[b + kB_2 + B_3 + (m-1)B_1^s\right]}$$

$$B_2 = \frac{b + mB_1^s + B_3}{k + ck\left[b + mB_1^s + B_3 + (k-1)B_2\right]} \tag{7}$$

$$B_3 = \frac{b + mB_1^s + kB_2}{1 + c\left[b + mB_1 + kB2\right]}$$

where superscript s denotes that the firm is synthetic. Solving this system we obtain $B_1^s = B_3 > B_2$. The equality between B_1^s and B_3 is not surprising: since synthetic generator 1's plants are maximizing individual profits, they behave exactly as the single-plant generator 3 does. It is worth noting that the equilibrium values for B_3 and B_2 are different from before, since generators 2 and 3 react to the behavior of generator 1.

Denote by $p_B(a_t)$ the expected equilibrium price at the pool when firms submit supply curves given by system (3) and $p_{B^{1^s}}(a_t)$ the expected equilibrium price with supply curves given by system (7), i.e. when the slope of the aggregate supply function is $B^{1^s} = (mB_1^s + kB_2 + B_3)$. We define a measure of market power of generator 1 as:

$$MP^1(a_t) = \frac{p_B(a_t) - p_{B^{1^s}}(a_t)}{p_B(a_t)}.$$ (8)

In our model,

$$p_B(a_t) = \frac{a_t}{B + b}$$ (9)

$$p_{B^{1^s}}(a_t) = \frac{a_t}{B^{1^s} + b}$$ (10)

In words, we measure the market power of a firm as the percentage increase in price obtained by joint profit maximization as compared to individual plant profit maximization. Similarly, a measure of market power for generator 2 is:

$$MP^2(a_t) = \frac{p_B(a_t) - p_{B^{2^s}}(a_t)}{p_B(a_t)}.$$ (11)

where $B^{2^s} = (mB_1 + kB_2^s + B_3)$.

Market power for firm 3 is zero by definition since $B_3^s = B_3$.

Our measure of market power is a measure of market power with respect to minimum size (one plant): The market power of a generator with one plant is set at zero and we measure the market power of larger generators.

We can also measure the impact of joint market power as follows. Define $p_{B^{1^s+2^s}}(a_t)$ as the *competitive benchmark*, that is the price that would be determined were each plant to behave independently at the pool. The competitive benchmark is the price that would be determined in the least concentrated market structure, given the existence of $(m + k + 1)$ plants and no entry. When the number of plants tends to infinity then B_1^s tends to $\frac{1}{c}$, that is, each firm submits its marginal cost function at the pool.[18] This is what is usually called 'competitive benchmark' in the relevant literature and if the number of plants is high (as is usually the case) the two definitions will be similar.

We can define the joint market power of generators 1 and 2 as:

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[18] See Appendix 3.

$$MP(a_t) = \frac{p_B(a_t) - p_{B^{1^s+2^s}}(a_t)}{p_B(a_t)}. \tag{12}$$

where $B^{1^s+2^s} = (mB_1^s + kB_2^s + B_3)$, and

$$p_{B^{1^s+2^s}}(a_t) = \frac{a_t}{B^{1^s+2^s} + b}. \tag{13}$$

Our measure is a lower bound for the standard index of market power, $\frac{p-c}{p}$, since $p_{B^{1^s+2^s}}(a_t) > c$, and will be interpreted as such, rather than as the "true measure" of market power. In the example above (see Figure 1) market power for firms 1 and 2 is 0.72243 and joint market power is 0.8358, according to our measure. We can also compute the Lerner index in the example: $\frac{p-c}{p} = 0.85158$, which is close to our measure of market power. An advantage of our procedure for measuring market power (expressions (8) and (11)) is that it shows the contribution of asymmetric firms to the price-cost margin.

It is worth noting that our measure of market power could be defined also for the case of Cournot competition: $p_B(a_t)$ is simply the Cournot equilibrium price and $p_{B^{1^s+2^s}}(a_t)$ is the price that would be determined if plants owned by firms 1 and 2 behaved as independent firms.

Similarly, in a multi-unit auction $p_B(a_t)$ is the auction equilibrium price and $p_{B^{1^s+2^s}}(a_t)$ would be the auction equilibrium price when bids do not maximize joint profits for the generators but individual profits of the production units. However, there is an important difference between this model and ours. In a multi-unit auction, all generators who are not the marginal unit bid so as to sell all capacity having marginal cost below the marginal price;[19] a consequence of this result is that only the marginal generator could have any market power. This implication could be tested with auction data.

5 Estimating Competitive Bidding Behavior

We want to examine the effect of each firmb4s market power. The reference point is the bidding behavior at the pool of a generator who did not exercise any market power. Larger generators present bids for each unit that maximize joint profits for the firm. At the same auction, there are small generators with units of similar characteristics. We approximate the competitive behavior for a larger generator using the bids at the same auction of small generators. The two larger generators in the Spanish wholesale market are Endesa (EN) and Iberdrola (IB). Therefore, we first build a so-called "Synthetic Endesa" (EN^s) and a "Synthetic Iberdrola" (IB^s). Then, we compare the auction outcome to the outcome obtained after replacing the supply functions of the firms by the supply curves of the synthetic firms. More precisely,

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[19] See Theorem 1 in Marín and García-Díaz (2000).

1. First, we build the empirical supply functions of Endesa (EN), Iberdrola (IB), Unión Fenosa (UF), and Hidrocantábrico (HC) using hourly data. We measure the first two firms' market power. Then, we aggregate all of them and generate, together with the rest of the smaller production agents, the aggregate supply function, S_t, for each day and hour. Finally, we intersect the aggregate supply curve with the demand schedule, D_t, and compute the equilibrium price p_t ignoring technical restrictions. The result is a time series of prices p_t:

$$S_t = D_t \Longrightarrow p_t$$

   According to our model the observed price depends on demand and supply parameters as well as on demand and supply random errors (see (9)):

$$p_t = p_B(a_t) + \frac{u_t - \varepsilon_t}{B + b}.$$

   The computed prices do not take technical restrictions into account. Technical restrictions should not not represent a significant downward bias for prices since they involve only a very small fraction of the total volume traded in the daily market.[20]

2. Second, we use UF and HC's production units to build the synthetic Endesa (EN^s) and the synthetic Iberdrola (IB^s). Then, we replace the original supply functions of both firms by the synthetic ones, and obtain an aggregate supply $S_t^{EN^s+IB^s}$. Intersecting this aggegate supply $S_t^{EN^s+IB^s}$ with the demand schedule D_t, the result is a time series of the equilibrium prices as they would have been if Endesa and Iberdrola had followed their synthetic supply curves.

$$S_t^{EN^s+IB^s} = D_t \Longrightarrow p_t^{EN^s+IB^s}$$

   That equilibrium price depends on demand and supply parameters as well as on demand and supply random errors (see (13)):

$$p_t^{EN^s+IB^s} = p_{B^{EN^s+IB^s}}(a_t) + \frac{u_t - \eta_t}{B^{EN^s+IB^s} + b}$$

   Note that the error η_t, with zero mean, is different from ε_t. This is so because productive plants owned by EN and IB have been replaced by similar plants owned by HC and UF.

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[20] In June 2002, technical restrictions affected 1.08% of the volume in the daily market, and implied an increase on the average price in the daily market of just 0.065cEur/kWh

We can also repeat the procedure for each firm individually to find the proportion of the expected price variation which is due to each firm:

$$S_t^{IB^s} = D_t \Longrightarrow p_t^{IB^s}$$

$$p_t^{IB^s} = p_{B^{IB^s}}(a_t) + \frac{u_t - \nu_t}{B^{IB^s} + b}$$

and similarly,

$$S_t^{EN^s} = D_t \Longrightarrow p_t^{EN^s}$$

$$p_t^{EN^s} = p_{B^{EN^s}}(a_t) + \frac{u_t - \mu_t}{B^{EN^s} + b}$$

where ν_t and μ_t are random error terms with zero mean.

3. If neither of the large operators has any market power, then $B^{EN^s+IB^s} = B$ and therefore $p_t^{EN^s+IB^s} - p_t = \frac{\varepsilon_t - \eta_t}{B+b}$, that is, the time series $p_t^{EN^s+IB^s}$ and p_t only differ in the realization of a random term with zero mean, $\frac{\varepsilon_t - \eta_t}{B+b}$.

Under the alternative hypothesis, if the large generators have market power, then $B^{EN^s+IB^s} < B$, which implies that we should expect positive values for the difference:

$$p_t - p_t^{EN^s+IB^s} = p_B(a_t) - p_{B^{EN^s+IB^s}}(a_t) + \left(\frac{u_t - \varepsilon_t}{B+b} - \frac{u_t - \eta_t}{B^{EN^s+IB^s} + b} \right).$$
(14)

and also for $MP(a_t)$.

Our empirical test is based on that implication of the model, although it does not depend on the specific functional form of demand and supply schedules. Under the null hipothesis p_t and $p_t^{EN^s+IB^s}$ will only differ in the realization of a random error, while under the alternative, p_t and $p_t^{EN^s+IB^s}$ will show a systematic difference which is a function of a_t .[21].

We can extend this analysis to individual market power of the two larger generators and check whether $p_t^{EN^s}$ and $p_t^{IB^s}$ are different from p_t.

[21] See Delgado (1993), Cabus (1998), Koul and Schick (1997, 2001), Hall and Hart (1990) and Ferreira and Stute (2002).

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6   Statistical Analysis

We test for differences between the conditional means $E\left[p_t \backslash a_t\right]$ and $E\left[p_t^{EN^s+IB^s} \backslash a_t\right]$, or, in other words, we test whether the functions $p_B(a_t)$ and $p_{B^{EN^s+IB^s}}(a_t)$ are identical or not.

The hypothesis under test is:
$H_o : p_B = p_{B^{EN^s+IB^s}}$,

to be tested against
$H_1 : p_B > p_{B^{EN^s+IB^s}}$

That is, under the null the two series p_t and $p_t^{EN^s+IB^s}$ only differ in the different realizations of the error terms $\frac{u_t - \varepsilon_t}{B+b}$ and $\frac{u_t - \eta_t}{B^{EN^s+IB^s}+b}$, respectively (see expression (14)).

Define:

$$M_t = p_t - p_t^{EN^s+IB^s}$$

$$\alpha_n(x) = \frac{\sum\limits_{t=1}^{n} M_t I\left(a_t \leq x\right)}{n^{\frac{1}{2}}}$$

$$\tau_n^2 = \frac{\sum\limits_{t=1}^{n}\left(M_t - \overline{M}\right)^2}{n}$$

The statistic is:

$$T = \frac{\sup_x \alpha_n\left(x\right)}{\tau_n}$$

Ferreira and Stute (2002) show that under H_o:

$$\sup_x \alpha_n \rightarrow \sup_{0 \leq u \leq \tau^2} B(u) = \tau \sup_{0 \leq u \leq 1} B(u)$$

where B is a Brownian motion. Furthermore, we have that

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$$P[\sup_{0 \leq u \leq 1} B(u) \leq \delta] = 2\Phi(\delta) - 1$$

where $\Phi(\delta)$ is the distribution function of the normal distribution. Thus,

$$P[T \leq \delta] \rightarrow 2\Phi(\delta) - 1$$

We will follow the same procedure to test the hipotheses:

$H_o : p_B = p_{B^{EN^s}}$, to be tested against $H_1 : p_B > p_{B^{EN^s}}$

and

$H_o : p_B = p_{B^{IB^s}}$, to be tested against $H_1 : p_B > p_{B^{IB^s}}$

6.1 Descriptive Analysis

Before presenting the test results we provide some descriptive analysis. The data consists of hourly prices and quantities from the daily electricity whole-sale market.[22] There are a total of 5881 observations, corresponding to the period May 2001 to December 2001, and 8760 observations in 2002, classified in peak, off-peak 1 and off-peak 2 hours (high, low and intermediate demand, respectively).[23]

As a result, we have the following time series: the observed prices, the synthetic prices obtained by replacing EN's bids by its synthetic firm bids, the synthetic prices obtained by replacing IB's bids by the synthetic bids, and finally the synthetic prices obtained by replacing both EN's bids and IB's bids by their respective synthetic bids.

Figures 2 present, for July 2001, the time series of observed prices, compared to IB^s prices, EN^s prices and $(IB^s + EN^s)$ prices. It can be checked in these figures that for that month the synthetic price series is consistently below the observed price for each firm, particularly for IB.

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[22] We do not consider the energy traded in the intra-day market, which amounts to less than 5% of the energy traded in the daily market.

[23] Data are available from May 2001. Following the pool administrator classification, data are divided into three categories:

Peak demand hours: From 16:00 to 22:00 week days (excluding holidays) in November, December, January, and February. From 9:00 to 15:00 week days in March, April, July, and October.

Off-peak 1 demand hours: From 0:00 to 8:00 every day of the year, plus Saturdays, Sundays, and holidays. August is also included.

Off-peak 2 demand hours: From 6:00 to 16:00 and from 22:00 to 00:00, week days in November, December, January, and February. From 8:00 to 9:00, and from 15:00 to 00:00, week days in March, April, July, and October. From 8:00 to 00:00 week days in May, June, and September.
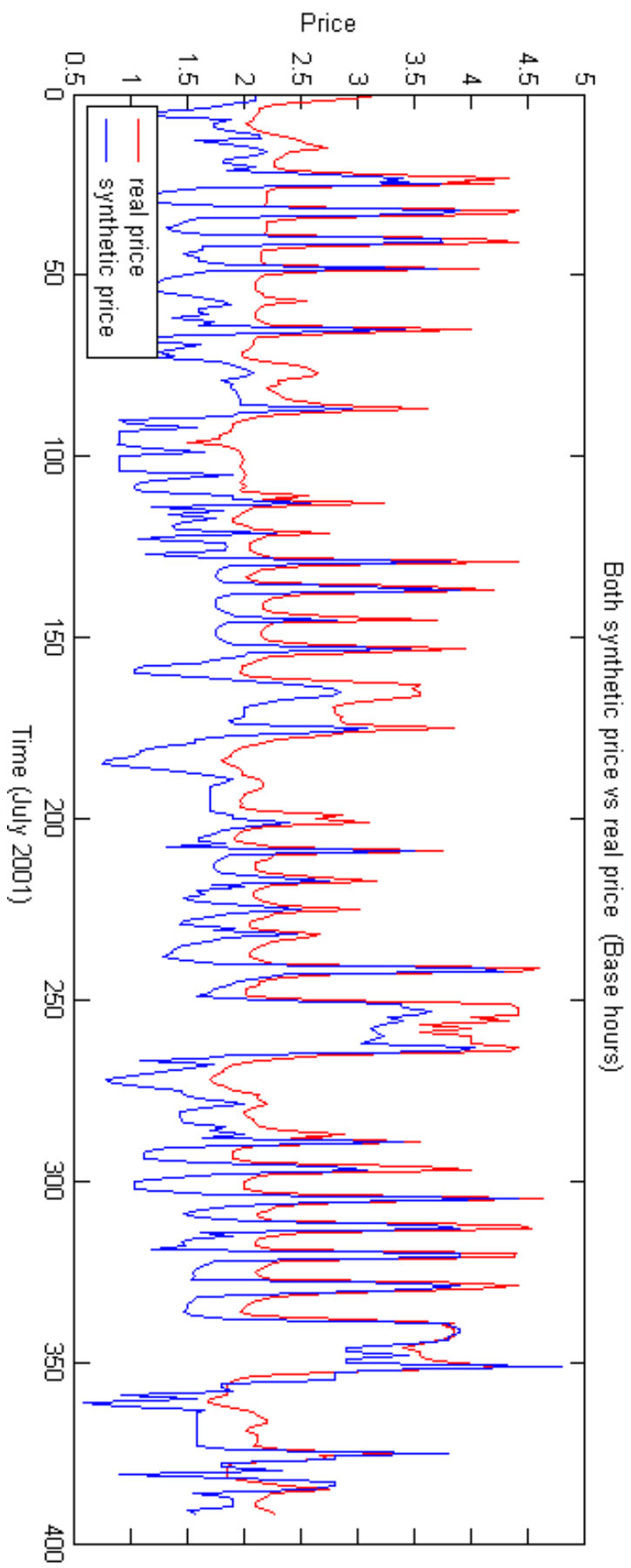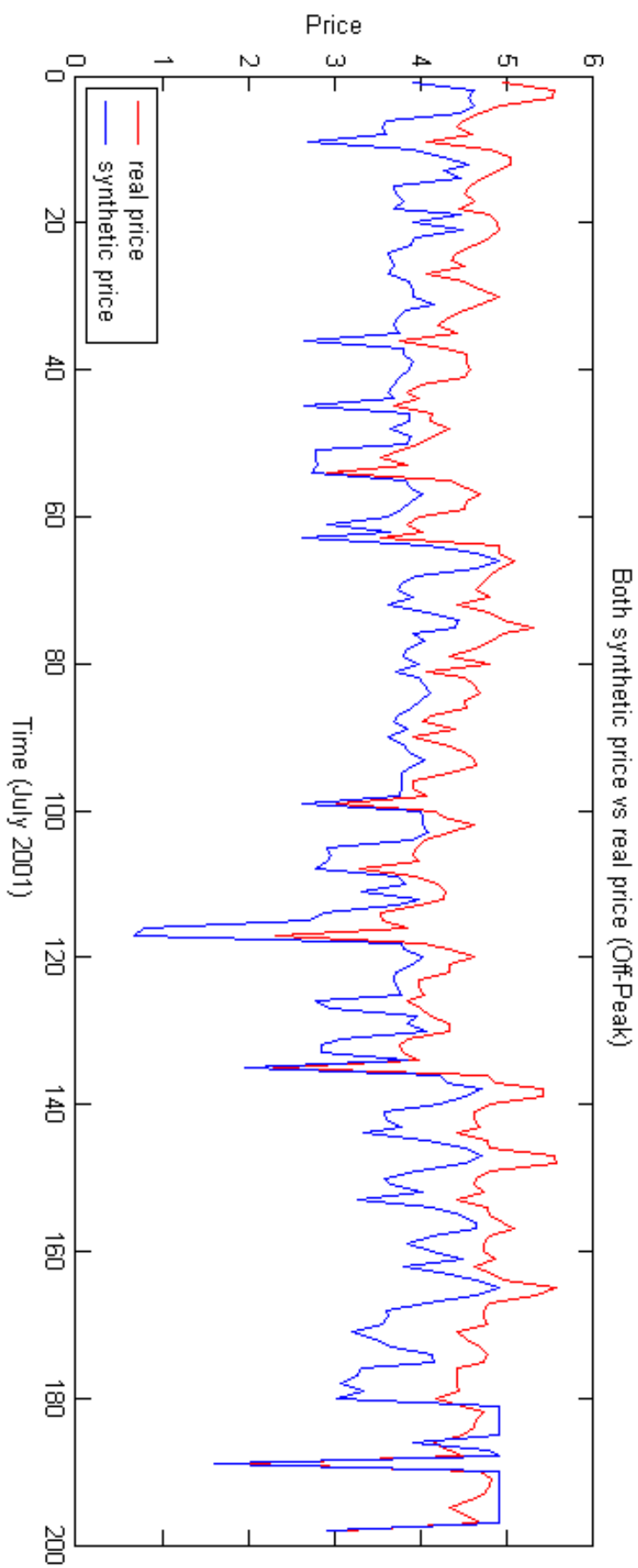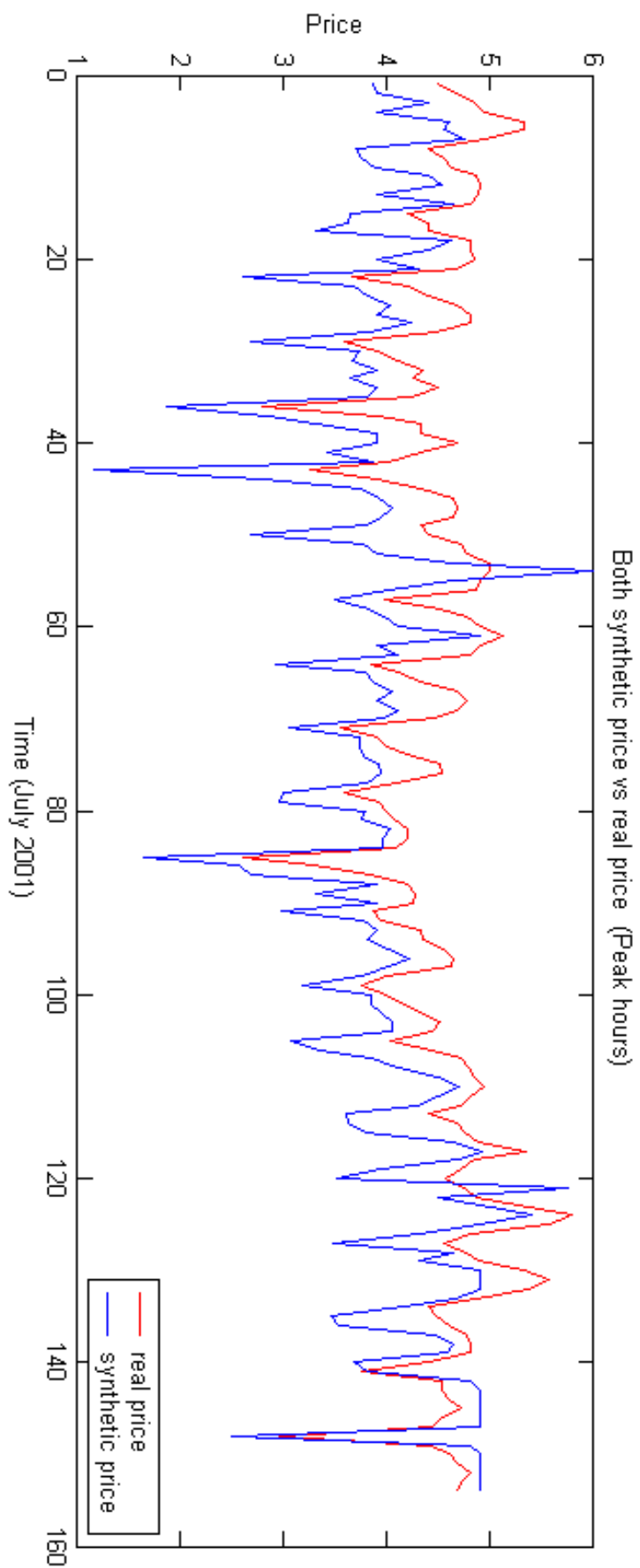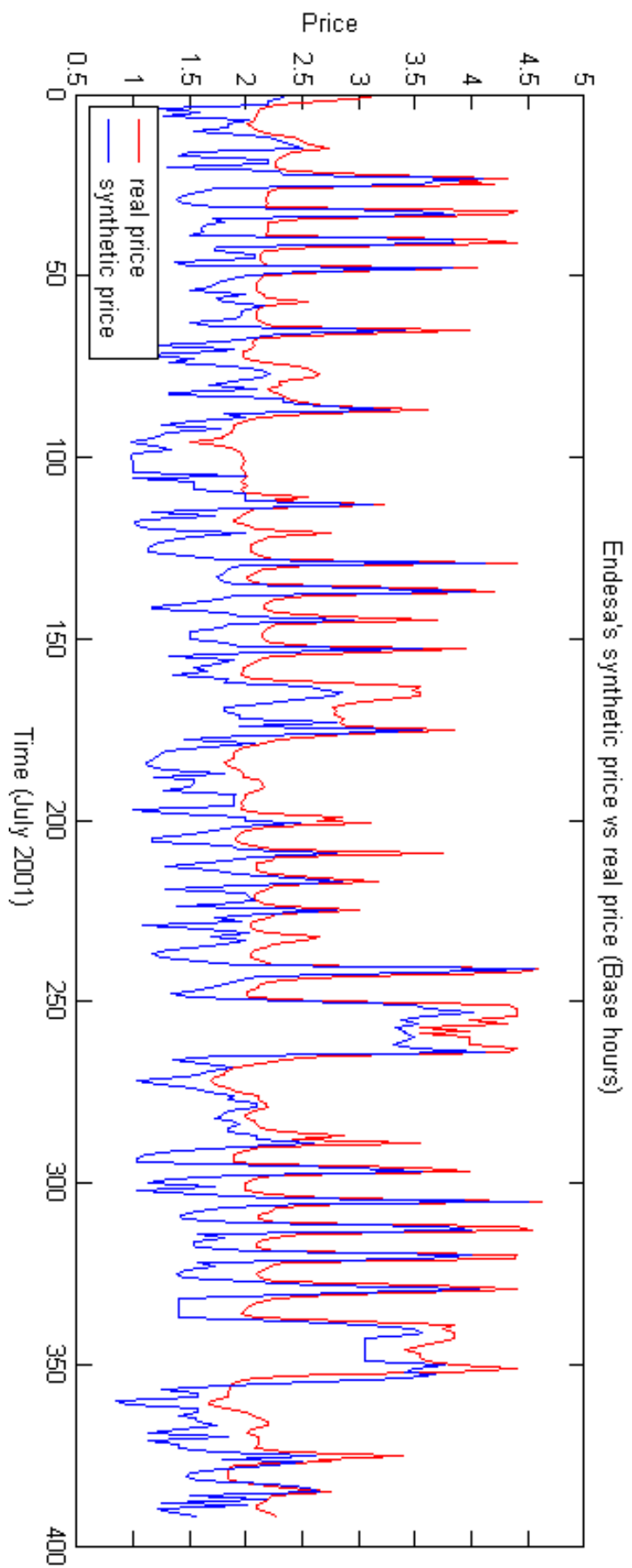
Figure 2

Figure 2 (cont.)

Figure 2 (cont.)

Endesa's synthetic price vs real price (Base hours)

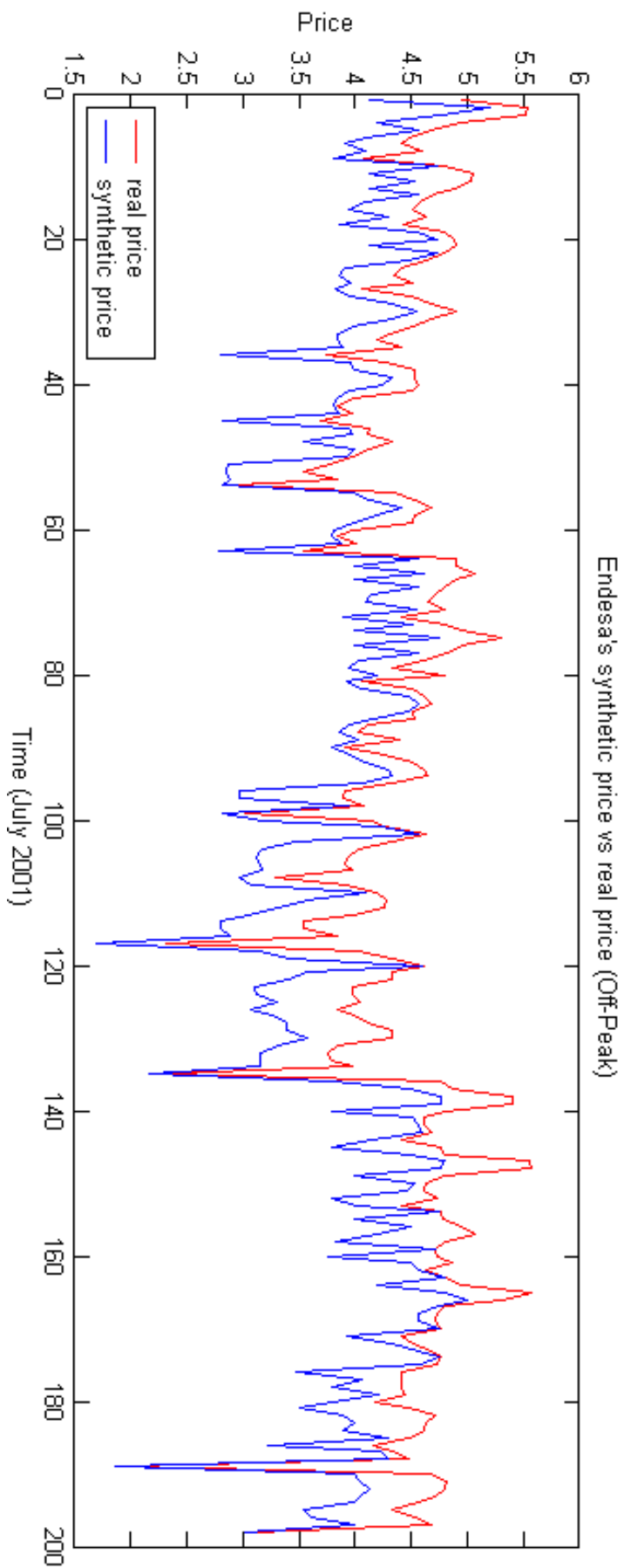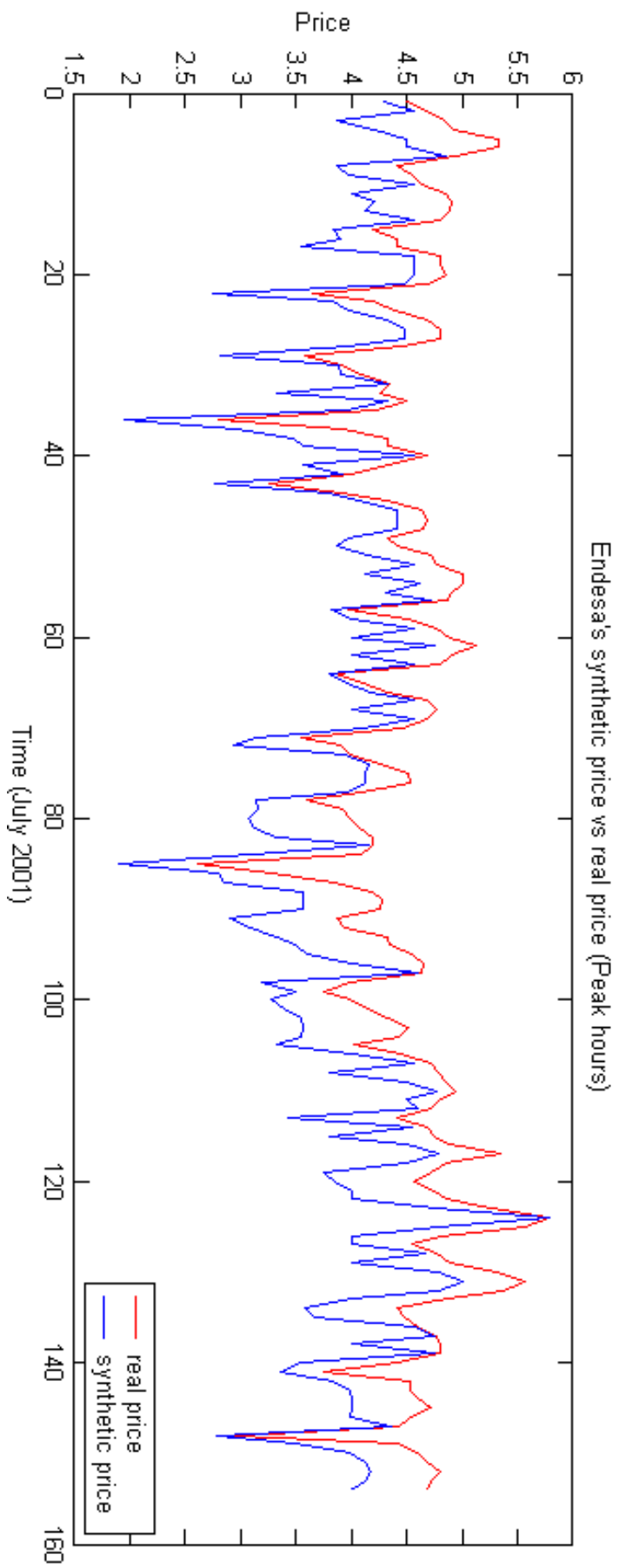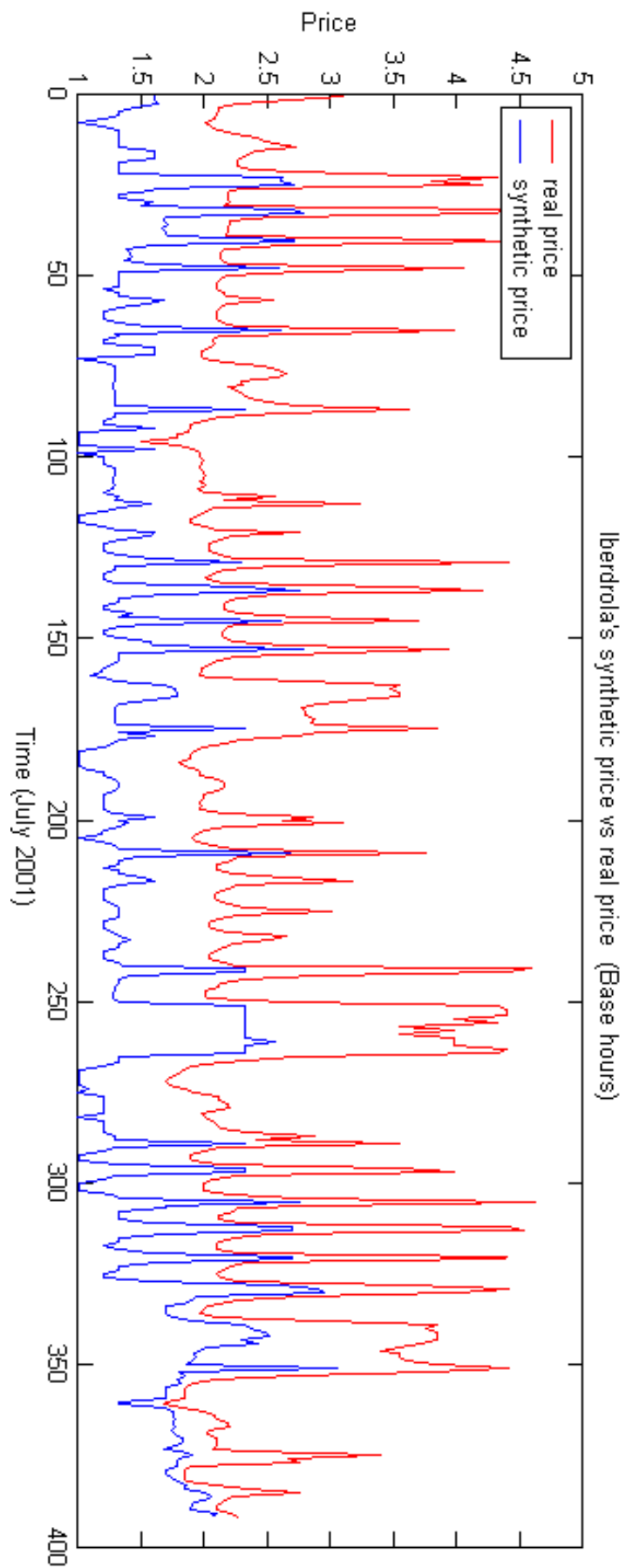Figure 2 (cont.)

Figure 2 (cont.)

Figure 2 (cont.)

Iberdrola's synthetic price vs real price (Base hours)

Figure 2 (cont.)

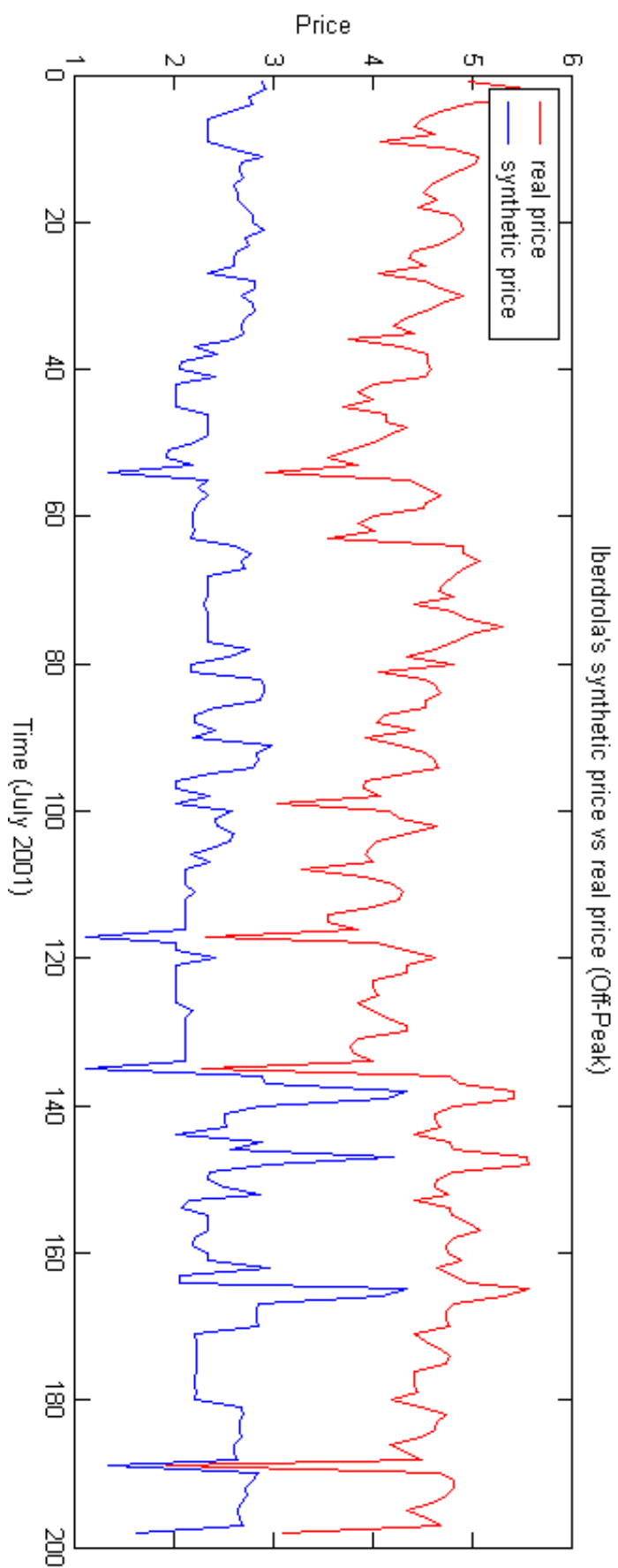Figure 2 (cont.)

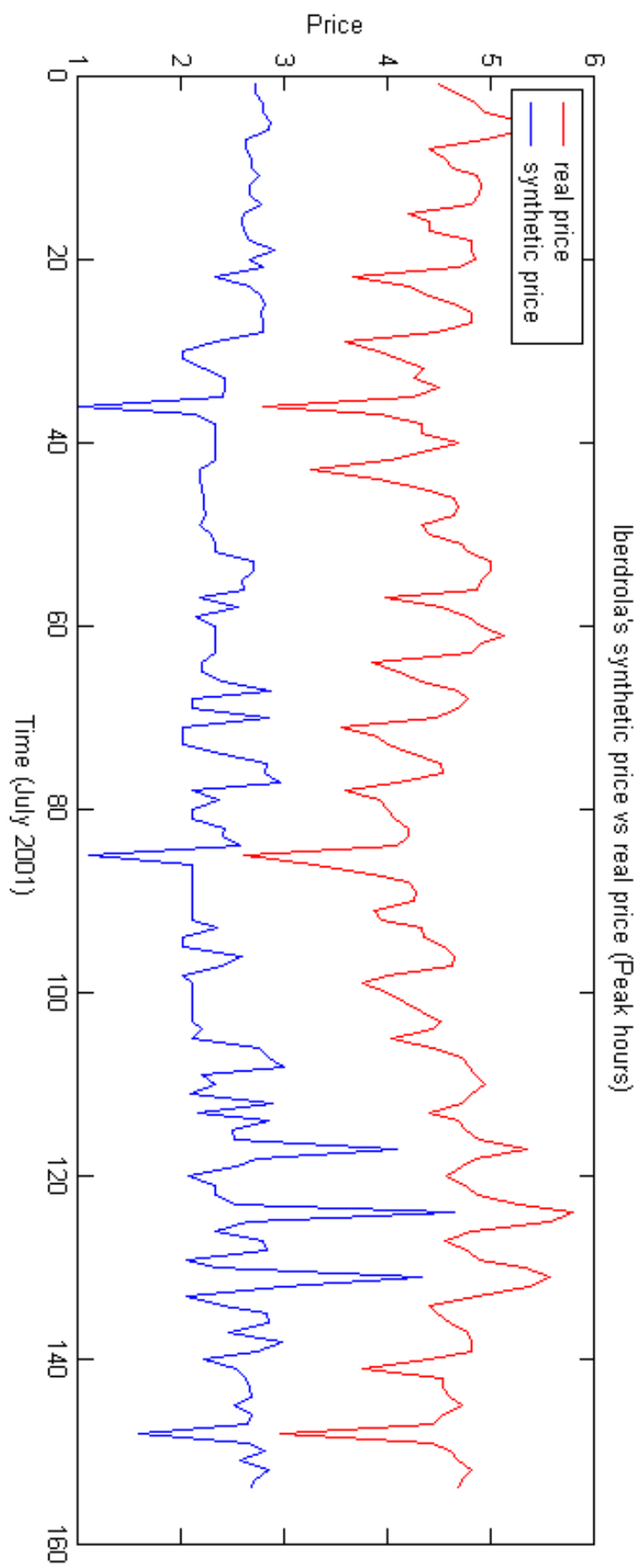Iberdrola's synthetic price vs real price (Peak hours)

Figure 2 (cont.)

6.2 Testing

First, we present a test of unconditional means. The null is that market power is zero. We test this hypothesis for each of the larger firms and we also test whether joint market power is zero. This test focuses on the mean of the time series and does not make use of any further information contained in the data. Results are reported in Table 1. We run the test considering all the observations (column two), peak demand hours (column three), off-peak 2 demand hours (column four), and off-peak 1 hours (column five), for each of the hypotheses to be tested, as explained above.

Table 1. Market Power				
2001		Type of Hours		
	All hours	Peak	Off-Peak 2	Off-Peak 1
$\frac{\overline{P}-\overline{P}^{IB^s}}{\overline{P}}$	0.5117***	0.5131***	0.6167***	0.4578***
	[0.003]	[0.006]	[0.005]	[0.004]
$\frac{\overline{P}-\overline{P}^{EN^s}}{\overline{P}}$	-0.074	0.0933***	0.0838***	-0.181**
	[0.05]	[0.008]	[0.005]	[0.084]
$\frac{\overline{P}-\overline{P}^{EN^s+IB^s}}{\overline{P}}$	0.1682***	0.1902***	0.3555***	0.0689***
	[0.019]	[0.022]	[0.043]	[0.032]

***Significant at 1%

*Significant at 10%

Standard deviations in brackets

May 2001 to December 2001: 504 peak hours observations, 1826 off-peak 2 hours, and 3551 off-peak 1 hours.

On average, in 2001 the differences between the observed prices and the "synthetic prices" are positive. The magnitude of these differences (from 6% to 61%) is explained by the low elasticity of the demand schedule. Small changes in the amount of energy supplied imply large changes in equilibrium prices. One result stands out: Market power is greater for IB than it is for EN, even though EN has a higher market share and higher capacity than IB (see Table 4).

For periods of low demand, market power for EN turns out to be negative. Note that the measure for market power we are using is a lower bound, so when it is negative it contains no useful information. A negative value for the difference $\overline{P} - \overline{P}^{EN^s}$ means that in periods where there is excess capacity small generators are bidding higher prices than EN. This could be due either to some costs difference that we are not capturing or that EN bids more closely to costs than small generators do in low demand periods.

Next, we carry out a test of test of conditional means. This is necessary to test whether the price series are the same or not (not only whether they have the same mean). We compute the T statistic for the Ferreira-Stute's test. In our model a_t is a measure of intensity of demand at each hour t. As an index

for demand level we choose for each t the amount demanded at the maximum price allowed in the auction (18.03 cents).[24] Table 2 presents our results.

Table 2. Statistical Results	
2001	T
H_0: $p_B(a_t) = p_{B_{EN^s+IB^s}}(a_t)$	9.2443
H_0: $p_B(a_t) = p_{B_{EN^s}}(a_t)$	4.8454
H_0: $p_B(a_t) = p_{B_{IB^s}}(a_t)$	157.921

May 2001 to December 2001.

Considering all observations, the statistics in Table 2 allow us to reject the null hypotheses. Thus, we can conclude that plants under the ownership of large generators do not bid as small generators' plants do. Their bids determine higher equilibrium prices.

Again, there is a difference between the two larger firms. EN seems to be exerting a lower impact on equilibrium prices than IB. This may be either a consequence of a more restrictive bidding behavior on the part of IB, especially during peak hours, or reflect differences in technology. The theoretical model in Section 3 does not distinguish between the different production technologies and thus it traces market power only to the level of capacity. However, hydro and thermal generating units have different technical characteristics and they may imply different capabilities to exploit the market power associated with size.

To explore this possibility, Table 3 presents the technology of the plants setting the system marginal price and the ownership of the plants. In off-peak 1 hours, conventional thermal generation units set the marginal price in almost 60% of the auctions, while in peak hours and off-peak 2 hours hydro units set the price in around 80% of the auctions.

Hydro units are very flexible, they allow energy storage and quick output adjustment. For that reason these resources can be used strategically. According to Borenstein, Bushnell and Wolak (2000), a price-taking firm with hydro resources would allocate these resources to peak hours, while a firm with market power is likely to allocate more hydro resources to off-peak periods than to peak periods.[25] This greater flexibility of hydro resources may be behind the greater market power of the company IB as shown in the data. IB has a 52% of its capacity in hydro generating units and 28% in thermal units, while for EN the percentages are reversed (27% and 56%, respectively).

7 Concluding Comments

In this paper we have presented some preliminary results. Our next step is to extend the sample using all the auction days available.

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[24] Note that $a_t = q_t + 18.03b$ where q_t is the amount demanded at a price 18.03 at each t.
[25] See also Bushnell (1998).

Firms setting system marginal price	EN	IB	UF	HC	Others	Total
Base	45.1 %	34.2 %	6.19 %	12.62 %	1.9 %	3528 hours
Off-Peak	35.67 %	50.45 %	9.07 %	4.51 %	0.3 %	1803 hours
Peak	28.73 %	59.4 %	6.47 %	5.4 %	0 %	549 hours
All hours	40.50%	41.87%	7.19%	9.25%	1.19%	5880 hours
Share of total capacity	49.2%	34.3%	11.2%	4.6%	0.7%	46904 MW

Base hours

Plants	EN	IB	UF	HC	Others	Total
Total	45.1 %	34.2 %	6.19 %	12.62 %	1.9 %	3528 hours
Nuclear	0 %	0 %	0 %	0 %	0 %	0 %
Thermal	36.54 %	7.4 %	6.19 %	7.61 %	0 %	57.79 %
Hydro	8.56 %	26.74 %	0 %	5.016 %	0 %	40.31 %
Others	0 %	0 %	0 %	0 %	1.9 %	1.9 %

Off-peak

Plants	EN	IB	UF	HC	Others	Total
Total	35.67 %	50.45 %	9.07 %	4.51 %	0.3 %	1803 hours
Nuclear	0 %	0 %	0 %	0 %	0 %	0 %
Thermal	9.21 %	2.73 %	8.52 %	1.05 %	0 %	21.5 %
Hydro	26.46 %	47.72 %	0.55 %	3.46 %	0 %	78.2 %
Others	0 %	0 %	0 %	0 %	0.3 %	0.3 %

Peak hours

Plants	EN	IB	UF	HC	Others	Total
Total	28.73 %	59.4 %	6.47 %	5.4 %	0 %	549 hours
Nuclear	0 %	0 %	0 %	0 %	0 %	0 %
Thermal	8.53 %	4 %	4.87 %	0.6 %	0 %	18 %
Hydro	20.2%	55.4 %	1.6 %	4.8 %	0 %	82 %
Others	0 %	0 %	0 %	0 %	0 %	0 %

Table 3. Firms and plants fixing the system marginal price; all hours, base, off-peak and peak hours.

Installed capacity	EN	IB	UF	HC
Nuclear	17 %	20 %	18 %	6 %
Thermal	56 %	28 %	44 %	77 %
Hydro	27 %	52 %	38 %	17 %
Total	23099 MW	16088 MW	5253 MW	2566 MW

Table 4. Generators Installed Capacity, 2001.

There are several question that we have left out. The possibility of collusion has been ignored. It is possible that part of the market power that we measure in this paper is due to the repetition of the auction, which would allow firms to sustain outcomes which are more cooperative than the one-shot outcome. In this case the supply curve that we observe would be to the left of the one-shot supply curve predicted by the model. It is difficult to empirically distinguish between the impact of collusion and the effect of 'static' market power. But there are some arguments in favor of market power: collusion would not necessarily imply a difference in behavior between large and small generators if collusion is market-wide (although collusion only between the two larger generators would give rise to such a difference). The analysis of collusion would require further work and is left for future research.

Another important issue which has been neglected here is the fact that producers may own some of the companies who buy electricity in the pool and this may change their incentives to raise prices. Actually, market share of IB and EN on the demand side is not far from their market share on generation. However, this vertical structure does not eliminate the incentives to raise prices on the wholesale market if we take into account that the final price to consumers is regulated and its level is likely to depend on the pool prices. The explicit modelling of this vertical structure and its impact on market power in the electricity market are left for future research.

Other important issues omitted include capacity choice (see Castro, Marín and Siotis (2001). Finally, an interesting issue would be the comparison between the performance of the Spanish pool and that of other markets, such as New England, California, and France.[26]

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[26] The French pool Powernext started operating in November 2001.

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OMEL Electricity Market Activity Rules, April 2001.

9   Appendix 1. The system marginal price

The equilibrium price is the price obtained from the intersection of aggregate demand and aggregate supply curves. At the Spanish pool that price is calculated as follows (see OMEL's Electricity Market Activity Rules):

- The marginal price shall correspond to the price of the last block of electric power supply offered for sale submitted by the last production unit whose acceptance was necessary to satisfy the matched demand.

- The market operator shall accept, at the marginal price, the total electric power offered in those sale bids whose prices are below the marginal price.

- The market operator shall accept, at the marginal price, the total electric power demanded by buyers in all the electric power purchase bids whose maximum prices are above the marginal price, except in cases where there is not enough electric power at prices that are lower than or equal to the marginal price to satisfy the demand that incorporates prices that are higher than the marginal price.

- If there is excess supply at the marginal price, it shall be proportionately deducted from the sales of those units whose price is equal to the marginal price

- If there is excess demand at the marginal price, it shall be proportionately deducted from the quantities of electric power included in the blocks of those purchase bids whose price is equal to the price of the last accepted purchase bid.

When demand and supply cross in a vertical section of the supply curve, according to these rules the marginal price is lower than the market clearing price.

9.1 Appendix 2. Cournot competition

From profit maximization for each firm we obtain

$$q_1 = \frac{a - kq_2 - q_3}{2m + bc}$$

$$q_2 = \frac{a - mq_1 - q_3}{2k + bc}$$

$$q_3 = \frac{a - mq_1 - kq_2}{2 + bc}$$

Solving the system:

$$q_1 = \left(b^2c^2 + bc + kbc + k\right) \frac{a}{b^3c^3 + 2b^2c^2 + 2kb^2c^2 + 2b^2c^2m + 3kbc + 3bcm + 3kbcm + 4km}$$

$$q_2 = \left(b^2c^2 + bc + bcm + m\right) \frac{a}{b^3c^3 + 2b^2c^2 + 2kb^2c^2 + 2b^2c^2m + 3kbc + 3bcm + 3kbcm + 4km}$$

$$q_3 = \left(b^2c^2 + kbc + bcm + km\right) \frac{a}{b^3c^3 + 2b^2c^2 + 2kb^2c^2 + 2b^2c^2m + 3kbc + 3bcm + 3kbcm + 4km}$$

From these expressions it can be seen that

$$q_1 \leq q_2 < q_3$$

10 Appendix 3

Claim 2 *When the number of plants $m + k + 1$ tends to infinity and all generators are synthetic, the solution of the supply curve equilibrium tends to the competitive solution, i. e. each firm bids its marginal cost function.*

    Proof. *The supply function equilibrium when all generators are synthetic is given by:* ∎

$$B_1^s = \frac{b + kB_2^s + B_3 + (m - 1)B_1^s}{1 + c\left[b + kB_2^s + B_3 + (m - 1)B_1^s\right]}$$

$$B_2^s = \frac{b + mB_1^s + B_3 + (k-1)B_2^s}{1 + c\left[b + mB_1^s + B_3 + (k-1)B_2^s\right]}$$

$$B_3 = \frac{b + mB_1^s + kB_2^s}{1 + c\left[b + mB_1^s + kB_2^s\right]}$$

The solution is:

$$B_1^s = B_2^s = B_3 = \frac{(m+k) - 1 - cb + \sqrt{(1 + cb - m - k)^2 + 4cb(m+k)}}{2c(m+k)}$$

And,

$$\lim_{(m+k)\to\infty} \frac{(m+k) - 1 - cb + \sqrt{(1 + cb - m - k)^2 + 4cb(m+k)}}{2c(m+k)} = \frac{1}{c}$$

$$q(p) = Bp = \frac{1}{c}p$$

Thus, in the limit the supply curve for each plant is $p = cq$, which coincides with the marginal cost curve $C'(q) = cq$.

11 Appendix 4. Building a Synthetic Firm

We consider the electricity market on June 28th, 2001, at 18:00 hours. *Puentes Garcia Rodriguez 2* (Code PGR2), is a production unit that belongs to Endesa. It uses lignite and imported coal as input. The plant which is closest in technical characteristics is *Meirama 1*, (code MEI1), which belongs to Unión Fenosa. The table below shows the bids by PGR2, the bids by MEI1, and the corresponding synthetic PGR2, called SPGR2.

Table . Building Synthetic PGR2									
	PGR2 bids			MEI1 bids			SyntheticPRG2 bids		
	P	Q	Cum Q	P	Q	Cum Q	P	Q	Cum Q
Stretch 1	0	216	216	0	532	532	0	331.65	331.65
Stretch 2	1.192	19	235	15	31.2	563.2	15	19.45	351.1
Stretch 3	1.283	106.1	341.1						
Stretch 4	9.9	9.9	351						
Capacity			351			563.2			351.1

If we follow the same procedure with all the plants, we can build the synthetic supply curves of Iberdrola and Endesa in the way described above. Figure 3 below contains the corresponding synthetic supply curves.

The graph shows that the difference between the system marginal price (SMP), 5.566, and the one that would have been obtained with the synthetic firms, 5.316, is 0.25. That is, the SMP was 4.47% higher than it would have been had the firms behaved more competitively. That is the measure of joint market power for the two larger generators in that particular day and hour.
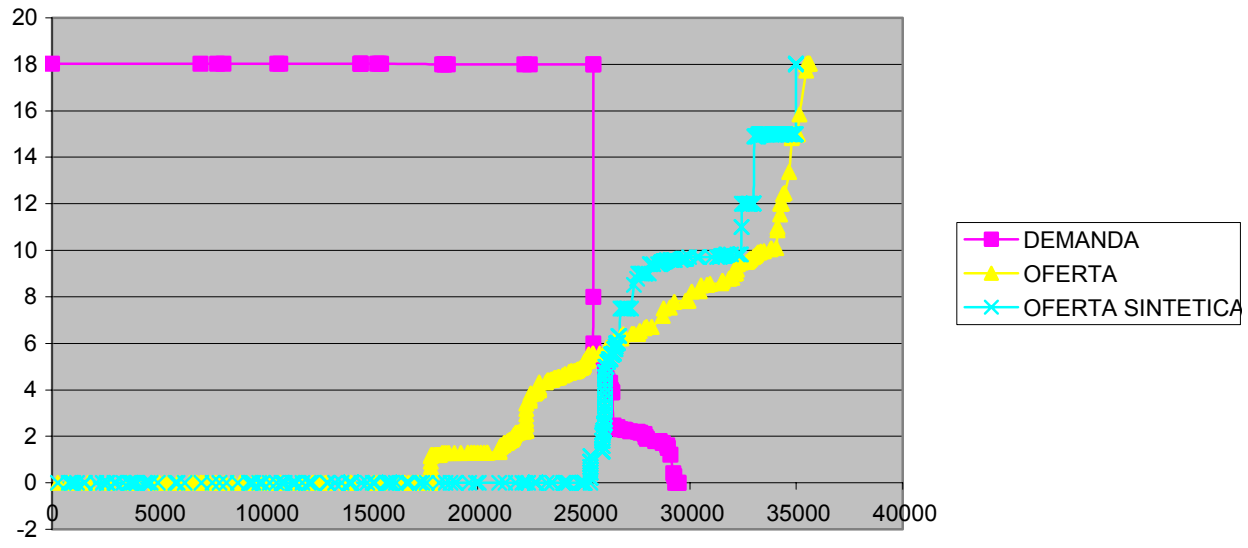
Figure 3