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The Impact of Regulation on Pricing Behavior in the Spanish Electricity Market

The Impact of Regulation on Pricing Behavior in the Spanish Electricity Market.[1]

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Abstract

In this paper we measure the impact of regulatory measures which affected the Spanish electricity wholesale market in the period 2002-2005. Our approach is based on the fact that regulation changes firms' incentives and therefore their market behavior. In the absence of any regulation firms would choose profit-maximizing prices on their residual demands so that the observed gap between optimal and actual prices provides a measure of the effect of regulation. Our results indicate that regulation has decreased wholesale prices considerably, but became less effective at the end of the sample period which explains the change of regulatory regime introduced in 2006.

1 Introduction

A main concern in electricity markets worldwide is excessive market power and high prices, which regulation tries to mitigate. As is the case of many other electricity markets, the Spanish day-ahead market is characterized by high concentration together with an inelastic demand. These features suggest that firms will be able to use their market power to set prices well above costs. However, the incentives provided by the regulator may interfere with the day-ahead market and result in lower prices than the ones predicted by the profit maximization behavior.This paper studies whether regulation between 2002 and 2005 has been able to change prices substantially.

To analyze the impact of regulation on market prices, we obtain a measure of the gap between optimal prices in the absence of regulation and actual prices. As bids are short-lived on the Spanish market and generators are allowed to present up to 25 price-quantity pairs for each production unit, the rules allow sufficient flexibility for the equilibrium price and quantity sold should to be ex-post optimal. Using the hourly residual demand for each generator and its production costs, we compute the ex-post profit-maximizing price-quantity pairs which would be optimal in the absence of regulation. These prices turn out to be consistently higher than the observed prices for the larger generators. These results indicate that the incentives provided by the regulator have been effective in reducing prices and provide a quantitative measure of the impact of regulation.

Previous work has focused on the consequences of high concentration and low demand elasticity on prices and the effect of other features of electricity markets such as the presence of bilateral forward contracts (see Green, 1999). For the Australian electricity market, Wolak (2000) studied the impact of financial hedge contracts on generators' bidding behavior, using different procedures to recover cost functions, and measured market power for each of the eight largest generating firms; he finds that financial hedge contracts have been effective to mitigate market power. Wolfram (1999) found that prices in the British market were closer to marginal cost than market competition models would predict and that this was partly due to the threat of regulatory intervention. Wolak (2003b) measured unilateral market power for the California real-time energy market using the observed elasticity of residual demand; he shows that each of the five large suppliers in 2000 exercised significant market power as compared to the pricing behavior in the 1998-1999 period. A similar approach has been used by Marques et al. (2008) for the Iberian spot market. Green (1996), von der Fehr and Harbord (1993), Borenstein, Bushnell and Wolak (2002) and Wolfram (1999) have used direct measures of marginal cost to estimate price cost margins. Other authors have used different benchmarks. For example, Bushnell and Saravia (2002) use the prices that would result if no firm exerted market power and compare them to equilibrium prices as the competitive benchmark ; Tamaschke et al. (2005) construct a market power index based on the differences between actual market returns and long run competitive prices, while Ciarreta and Espinosa (2010) provide a measure of market power based on the different bidding behavior of large and small generators at the pool.

In this literature, actual prices are compared to a competitive benchmark to obtain a measure of market power. Presumably, the extent of market power depends not only on the characteristics of the market (market concentration, demand elasticity and the extent of forward contracting, among others) but also on regulatory measures affecting firms' behavior. In this paper we measure the impact of regulation on market power by looking at the difference between actual prices (which are assumed to be profit-maximizing under the existing regulation) to the prices that would maximize profits in the absence of any regulatory measures (computed using the observed demand and cost conditions). This approach requires that the actual firms' behavior be consistent with profit maximization. This assumption finds support in the results of Hortacsu and Puller (2008), who found that the behavior of the larger operators in the Texas spot market was profit maximizing.

Besides market concentration and demand elasticity, regulation of the Spanish wholesale market has been an important element providing incentives for price setting. When the Spanish wholesale market was liberalized in 1997,[1] payments

[1] The generation market was organized as a pool but distribution has remained a regulated activity.

for the Cost of Transition to Competition (CTCs, hereafter) were set to compensate generators for their stranded investment costs.[2] Generators received these payments to the extent that the pool price did not go over a certain level, and the CTCs therefore effectively acted as a price cap. Second, regulation may have exerted some influence on firms' behavior through capacity payments, which require a minimum activity level. Third, the antitrust authorities opened several files for price-fixing in the period, which may have worked as a disciplinary device.[3] Thus, several forms of regulation and also the threat of further regulatory intervention in the market may have mitigated market power and reduced prices. This paper seeks to measure the effectiveness of regulation as a whole in the period 2002-2005.[4] Forward contracting, that could have influenced the market competitiveness, was unimportant in the sample period (it was introduced in 2007). Another factor that could have affected the generators' market power is vertical integration, but its effect on bidding was neutralized by the fact that distribution was a regulated activity and therefore distributors' profits were not in the objective funcion of generators (distribution surplus was used for CTC payments). Thus, in the absence of other factors mitigating market power, we can attribute the difference between the profit maximizing prices given the observed demand and cost conditions and the actual prices to regulation.

The paper is organized as follows. Section 2 describes the market and the data. In Section 3, we present the implications of profit maximization in terms of pricing behavior and calculate the gap between the optimal prices given the observed demand and cost conditions and actual prices, providing a measure of

[2] CTCs were established in November 1997 and removed in June 2006.

[3] For example, in November, 2001, the four largest generators were accused of price-fixing conduct during peak demand hours; there was a case against Viesgo, for local market power abuse from December 2002 until February 2003, against Iberdola during 2003, and the case of Endesa against Gas Natural and Iberdrola in 2005 for manipulation of supply bids in the day-ahead market.

[4] In the period 2002-2005 regulation was relatively stable. From 2006 the market has experienced important changes in regulation with the removal of CTC payments, the introduction of Vitual Power Plants in June 2007, the Iberian Market for Electricity in July 2007, and procurement auctions for regulated electricity demand (so-called CESUR) in June 2007.

the effect of regulation on prices. Section 4 concludes.

2 The day-ahead market for electricity

In 1998 the Spanish wholesale market for electricity was reformed and organized as a pool. Qualified buyers and sellers for electricity submit their bids for each hour of the following day. In the sample period, the day-ahead market accounted for more than 95 percent of the total electricity traded.[5]

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.[6] 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 submit offers.[7] 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 day-ahead market the pool administrator combines these offers by matching demand and supply for each of the 24 hourly periods and determines the equilibrium price for each period (the system marginal price, SMP)

[5] More precisely: 97.7% in 2002, 97.3% in 2003, 94.7% in 2004 and 96.9% in 2005. Source: REE, *Red Eléctrica Española*, the Spanish system operator.

[6] According to the Electricity Market Activity Rules, p. 6, 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."

[7] 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).

and the amount traded (the market clearing quantity, MCQ). After this matching is completed, the pool administrator evaluates its technical feasibility; if the required technical restrictions are met then the program is feasible; if not, some previously accepted offers are eliminated and others included to ensure a feasible assignment. There are also several intra-day markets where qualified agents can update their offers by purchasing (selling) electricity if they over (under) bidded in the day-ahead market to attend final demand.

We analyze the behavior of the six main market participants: Endesa (EN), Iberdrola (IB), Unión Fenosa (UF), Hidrocantábrico (HC), Viesgo (VI) and Gas Natural (GN). Table 1 summarizes the evolution of the total installed capacity owned by each generator during the period 2002-2005.

Table 1: Installed Capacity (GW)(1)

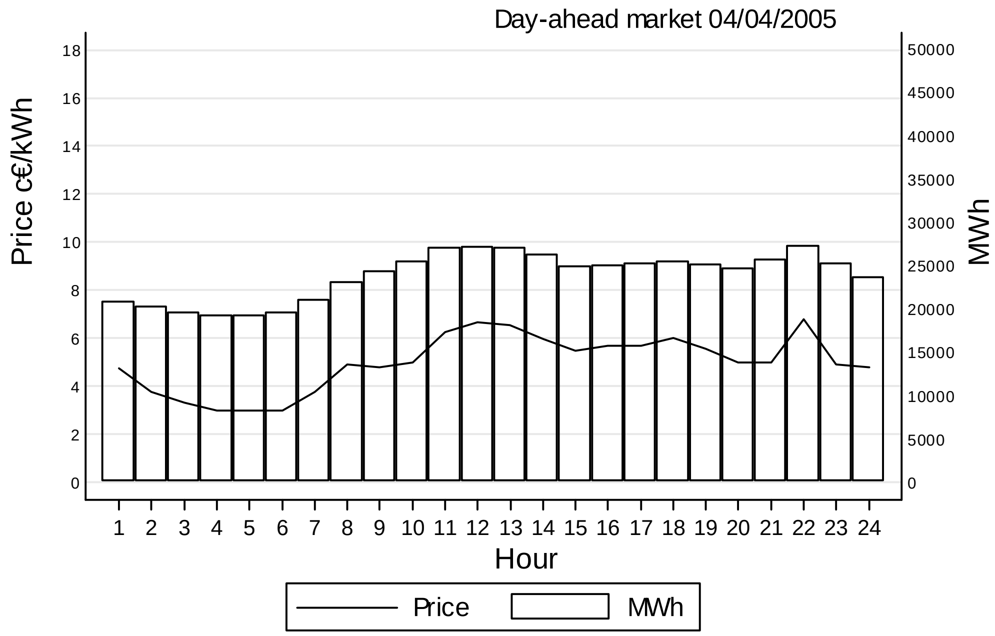
	EN	IB	UF	HC	VI	GN	Other	TOTAL
2002	17.5	16.2	5.2	2.5	2.3	0.8	0.1	**44.6**
2003	17.3	16.3	5.2	2.5	2.3	0.8	1.1	**45.5**
2004	18	17.7	6.4	2.5	2.3	1.2	1.7	**49.8**
2005	17.1	18	7.2	2.5	2.3	2.8	2.4	**52.3**

(1)Special regime (renewables) is not included.

Source: OMEL and CNE

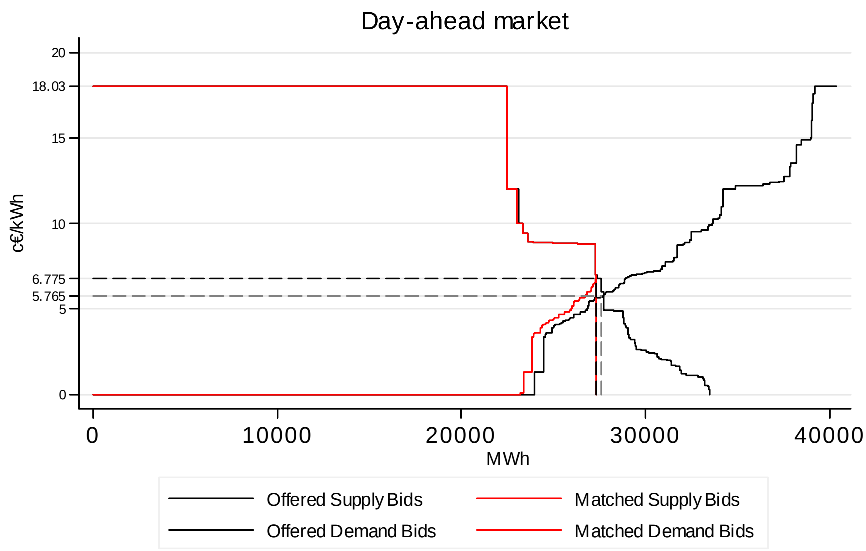
All the generators have a diversified technology mix, except GN which only owns combined cycle plants. Nuclear, hydroelectric, coal-burning and oil-fired capacity has remained almost constant over the period and the increase in capacity has come from combined cycle plants and renewable resources. During the period there has been small scale entry.

Figure 1 shows a typical day load profile; the one depicted corresponds to the 4th of April, 2005, and Figures 2(a) and 2(b) show typical demand and supply schedules for peak (22:00) and off-peak (5:00) hours for the same day.

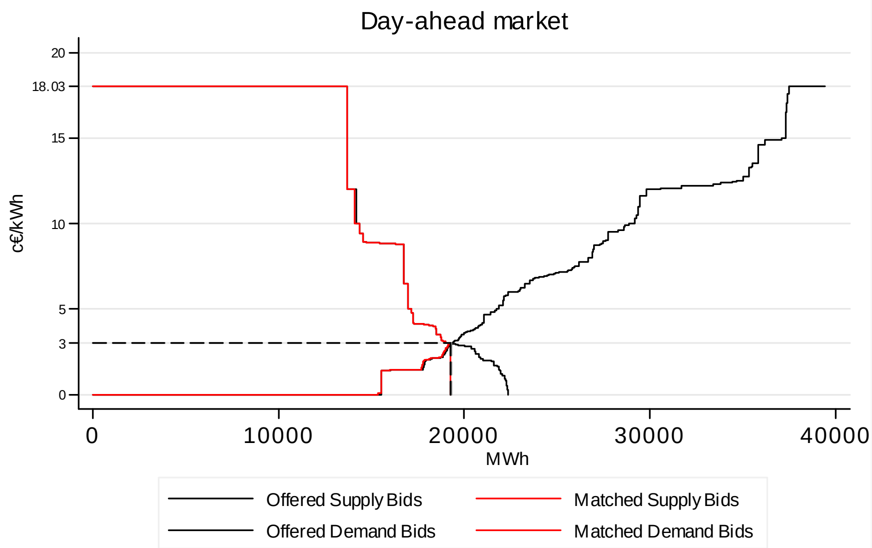


Source: OMEL and own construction

Figure 1



Source: OMEL and own calculations
Figure 2(a) 04/04/2005 at h=22



Source: OMEL and own calculations
Figure 2(b) 04/04/2005 at h=05

There is a horizontal segment that roughly corresponds to the demand of final consumers paying a regulated tariff. Since demand for those consumers cannot react to pool prices, bids for this consumption are usually made at the maximum price of 18.030 c€/kwh.[8] For other consumers, however, the bids reflect a consumption responsive to prices. At hour 22, there is a difference between the SMP before technical restrictions are included, 5.765 c€/kWh, and after these are included, 6.775 c€/kWh. On average, the difference between these prices is around 5%. Our analysis uses demand and supply bids before technical restrictions.

3 Profit maximizing prices

In the Spanish pool, firms submit short-lived bids for each plant (the price-quantity pairs for each of the 24 hours of the following day may be different). By aggregating the bids of all plants owned by a single generator, we obtain its hourly supply schedule. Generators may not know their residual demand for sure, although there cannot be great uncertainty.[9] To maximize expected profits, a generator should bid an amount for each possible residual demand realization so that marginal revenue equals marginal cost. The resulting pair (q, p) should be a point on its supply schedule. This procedure can continue as long as the number of possible realization of residual demand is not higher than the number of steps in the supply function (see Wolak, 2003a).[10] Then, the expected profit maximizing supply schedule should pass through all ex-post profit maximizing price and quantity pairs.

The objective function for generator i for each hour h is:

$$\max_{p_h} \quad p_h D_{ih}^r(p_h) - C_i\left(D_{ih}^r(p_h)\right)$$

where $D_{ih}^r(p)$ is the residual demand at hour h for generator i, which is calculated

[8] In addition, there is also a horizontal segment on the supply schedule that mostly corresponds to the energy sold by those plants that serve baseload, such as nuclear.

[9] García-Díaz and Marin (2003) argue that with short-lived bids demand uncertainty can be ignored.

[10] From his analysis of the Australian market and the California market, Wolak (2003a) concludes that firms were not overly constrained by the market rules from setting the profit maximizing price. The Spanish pool is even less constrained: for each generating unit the supply schedule may have up to 25 steps.

by substracting the supply schedule of all generators but i from the aggregate demand. Using data on individual hourly bids for each plant, we first add the bids for all plants under the ownership of a given generator to obtain the supply schedule of each generator i for hour h. Demand bids are also available which give us aggregate market demand for each hour h.

Once the residual demand is obtained , we have the revenue schedule $p_h D^r_{ih}(p_h)$ for each generator i and hour h. We next build a cost structure based on the unit cost of production of the different types of technologies used in generation. In general, the low cost technologies are hydroelectric and nuclear. Fuel gas, coal-burning and combined cycle plants come second, and their merit order depends on the input market prices. A constant marginal cost up to its hourly operating capacity is assumed for each unit. We order units from cheapest to most expensive to construct the marginal cost function for a generator. Thus, when the input market prices imply that the merit order is hydro/nuclear/coal/combined cycle/fuel gas, the marginal cost function $C'(q)$ for a generator would be,

$$C'_i(q) = \begin{cases} c^{hy} & \text{if} \quad q \leq K_i^{hy} \\ c^{nu} & \text{if} \quad K_i^{hy} \leq q \leq K_i^{hy} + K_i^{nu} \\ c^{co} & \text{if} \quad K_i^{hy} + K_i^{nu} \leq q \leq K_i^{hy} + K_i^{nu} + K_i^{co} \\ c^{cc} & \text{if} \quad K_i^{hy} + K_i^{nu} + K_i^{co} \leq q \leq K_i^{hy} + K_i^{nu} + K_i^{co} + K_i^{cc} \\ c^{fg} & \text{if} \quad q > K_i^{hy} + K_i^{nu} + K_i^{co} + K_i^{cc} \end{cases}$$

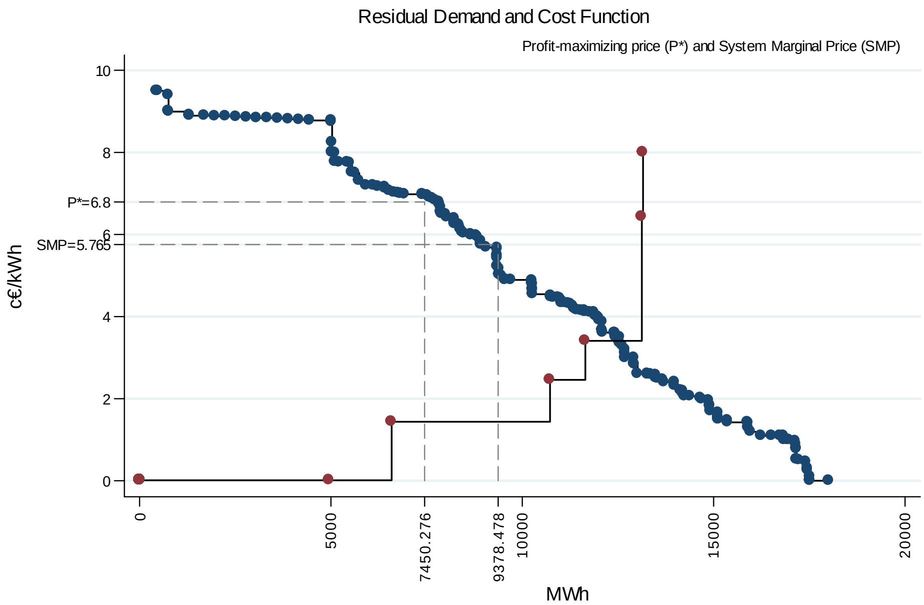
where hy stands for hydroelectric, nu stands for nuclear, fg for fuel-gas, cc for combined cycle and co for coal generation; K denotes capacity of the generator for that type of technology and it is the sum of the hourly declared capacity of the generating units using that technology. The cost data come from the input market prices reported by the Spanish Ministry of Industry.

To illustrate the procedure, Figures 3(a) and 3(b) depict the residual demand schedule for EN on April 04, 2005, at hours 22:00 and 05:00 respectively, the system marginal prices before technical restrictions (5.765 c€/KWh and 3.05 c€/KWh) and the quantities supplied by EN (12155.9 MWh and 10903.6 MWh, respectively). Figures 3(a) and 3(b) also show a marginal cost function for EN. The marginal cost function for each generator is constructed using variable production cost (raw materials and operating costs) and the firm's capacity in each technology (see Appendix 1). The capacity may vary depending on whether a plant is available for production or not.[11]

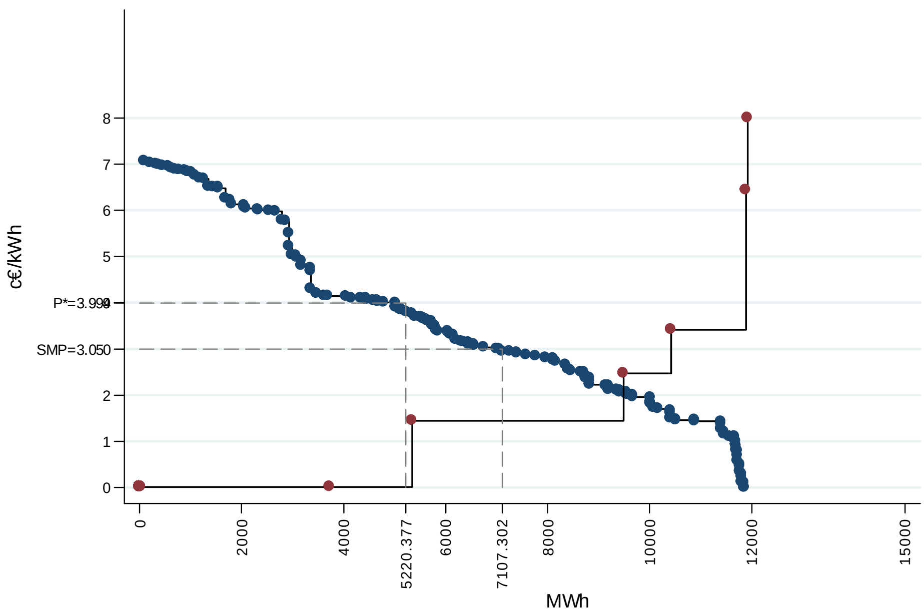
Once the revenue function and the cost function are obtained, we solve the profit maximization problem in the absence of regulation, by computing profits for all possible prices on the residual demand and choosing the price yielding the highest profit. In the example shown in Figure 3, the optimal price for EN at 22:00 is 6.8 c€/KWh and at 5:00 is 3.999 c€/KWh. These profit-maximizing prices are higher than the system marginal prices before technical restrictions

[11] Together with the bids, firms have to report in the day-ahead market the capacity of each plant for each hour. At a given hour, some plants may be unavailable or have lower capacity due to maintenance or other reasons.

(6.8 > 5.765 and 3.999 > 3.05).



Source: OMEL and own construction
Figure 3(a) 04/04/2005 at h=22



Source: OMEL and own construction
Figure 3(b) 04/04/2005 at h=5

We compute these differences for each generator and hour in the period 2002-

2005 and then we test whether the profit-maximizing prices in the absence of regulation for each firm were significantly higher than the observed market clearing prices before technical restrictions. Our hypothesis is that large generators consistently submit bids such that the resulting SMP is significantly below the profit-maximizing level in the absence of regulation. Results are reported in Table 2.

Table 2: Difference between profit-maximizing prices with no regulation and SMP (p*-SMP)

			Generator					
Period	**Hour**	**SMP**	EN	IB	UF	HC	VI	GN
	All	3.175	2.295^a	1.700^a	0.177^a	0.222^a	0.517^a	0.771^a
2002 – 2005	Peak	4.287	2.651^a	3.347^a	-0.106	-0.136^b	0.080^c	-0.089^b
	Off-peak	2.528	2.064^a	0.823^b	0.306^a	0.375^a	0.734^a	0.412^a
	All	3.618	3.255^a	3.808^a	-0.174	-0.183	0.053^c	0.200^a
2002	Peak	4.756	4.624^a	7.330^a	-0.394	-0.478	-0.261	0.286^a
	Off-peak	2.903	2.378^a	1.734^a	-0.080	-0.041	0.232^a	0.108^b
	All	2.731	1.778^a	1.300^a	0.106^a	0.014^b	0.550^a	0.181^a
2003	Peak	3.235	2.642^a	3.018^a	0.135^a	-0.114	0.224^a	0.088^c
	Off-peak	2.272	1.532^a	0.586^a	0.141^a	0.106^a	0.821^a	0.211^a
	All	2.675	1.955^a	0.126^b	-0.034	-0.026	0.180^b	0.873^a
2004	Peak	3.244	1.967^a	0.807^a	-0.070	-0.117	0.058^c	0.573^a
	Off-peak	2.308	1.980^a	-0.165	-0.003	0.011^b	0.266^a	0.961^a
	All	3.675	2.192^a	1.571^a	0.812^a	1.086^a	1.286^a	0.228^b
2005	Peak	5.942	1.322^a	2.151^a	-0.093	0.174^b	0.304^a	0.124^b
	Off-peak	2.627	2.362^a	1.142^a	1.157^a	1.419^a	1.615^a	0.304^a

^{a}Significant at the 1% level; ^{b}at 5%; ^{c}at 10%

Overall, the results in Table 2 indicate that regulation has been effective in controlling prices. The differences between optimal non-regulation prices and observed prices are significant for the main generators and we may draw the conclusion that regulation over the period has been able to mitigate their market power. The differences are higher for the two largest firms EN and IB, than for the rest, UF, HC, VI and GN, with lower market shares (see Table 1).

Figures 4(a) and 4(b) show how these differences have evolved over time. We choose hours 22:00 and 05:00 as representative of peak-demand and off-peak demand hours.

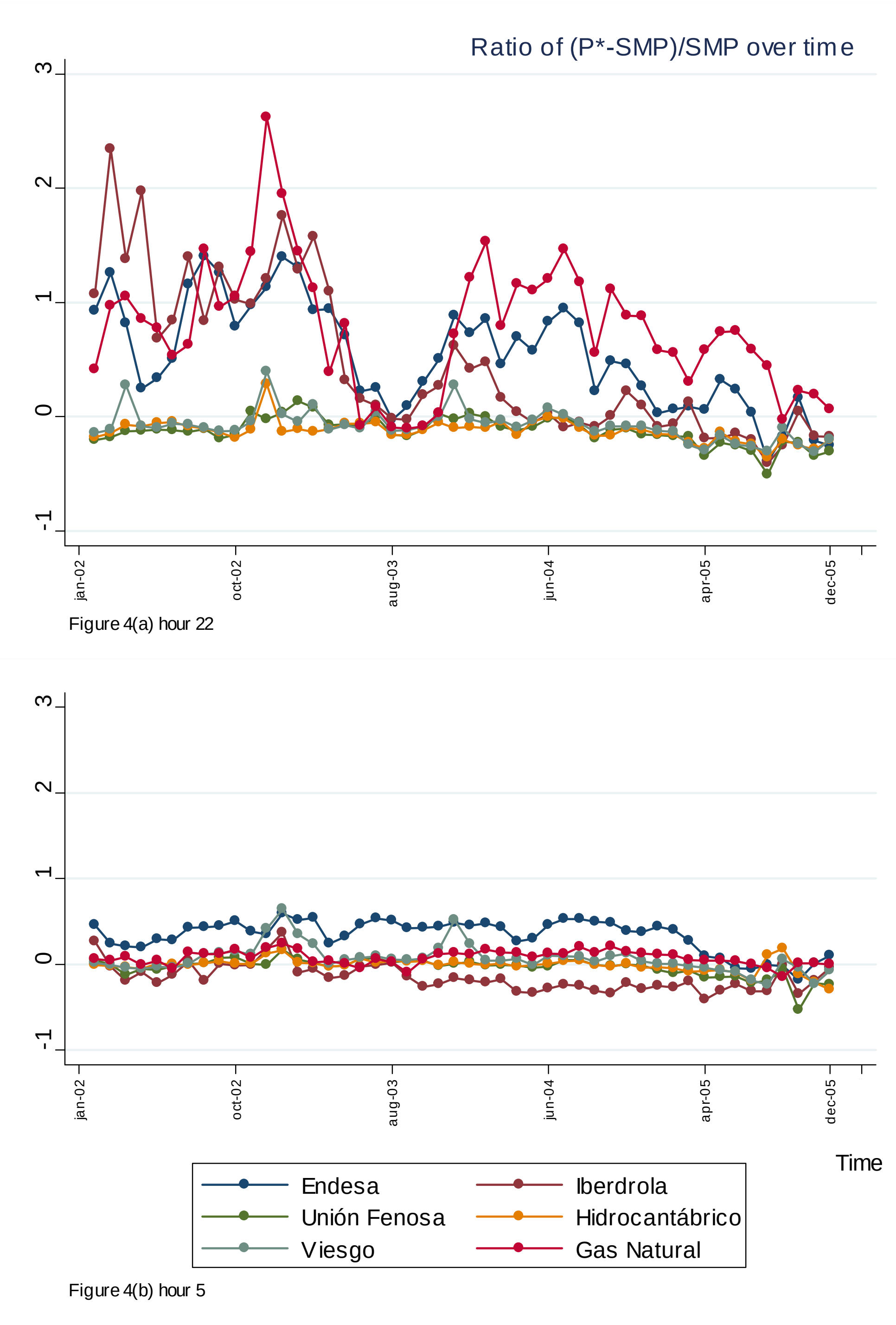


Figure 4(a) hour 22

Figure 4(b) hour 5

We measure the differences between the non-regulation profit maximizing price and the SMP as a proportion of the SMP to control for SMP variations in the sample period. This ratio has a decreasing trend, which points to the fact that over time regulation lost its ability to decrease prices. This is consistent with the firms' anticipating the elimination of CTC payments[12] and led to the introduction of new regulation in 2006. In particular, generators were obliged to sell electricity to their distributors at a fixed-price. This was to avoid sharp increases in prices such as those observed at the end of 2005. This regulation was eventually replaced by new measures: Auctions offering virtual power plant capacity (VPPs) and future contracting in June 2007 and the launch of the Iberian Liberalized Electricity Market (MIBEL) in July 2007.

However, despite the effect that regulation has had on the reduction of market power in the period 2002-2005, the system marginal price may have been far from marginal production costs. If generators offered their marginal cost curves at the day-ahead market, we would observe that the system marginal price is at the intersection of demand and the aggregate marginal cost schedule (competitive price). Table 3 compares the actual prices to the aggregate marginal cost (competitive benchmark).[13]

[12] Act 9/2001 of June 4th set a deadline for these payments in 2010. However, considering that the stranded costs had already been recovered, CTCs were eliminated in June 2006.

[13] Using a different procedure (not based on cost estimates but on the behavior of small competitors to establish the competitive benchmark), Ciarreta and Espinosa (2010) find that the large generators have exerted significant market power in the Spanish wholesale market in the period 2002-2005.

Table 3: Difference between competitive prices and SMP				
Period	**Hour**	**SMP**	**Competitive Benchmark**	**Difference**
	All	3.175	2.308	0.871^a
2002 – 2005	Peak	4.287	2.996	1.267^a
	Off-peak	2.528	2.294	0.239^a
	All	3.618	2.344	1.273^a
2002	Peak	4.756	2.693	2.011^a
	Off-peak	2.903	2.195	0.727^a
	All	2.731	2.019	0.698^a
2003	Peak	3.235	2.267	0.951^a
	Off-peak	2.272	2.018	0.252^a
	All	2.675	2.013	0.671^a
2004	Peak	3.244	2.588	0.651^a
	Off-peak	2.308	2.121	0.199^b
	All	3.675	3.238	2.321^a
2005	Peak	5.942	4.269	2.567^a
	Off-peak	2.627	2.042	0.811^a

^{a}Significant at the 1% level; ^{b}at 5%;

The differences between the actual prices and marginal cost are significant throughout the sample period but increased at the end. This is due to the fact that the price cap effect of CTCs weakened when the generators had collected almost all their rights to CTCs and therefore this regulation was not able to contain bidding as effectively.

In this section, we have calculated non-regulation profit maximizing prices considering the available data on variable unit cost for each technology. As a robustness check, we present the results for the revenue maximizing prices in Appendix 2. The advantage of comparing non-regulation revenue-maximizing prices to the system marginal price is that we do not need any cost estimates. As even the revenue maximizing prices turn out to be higher than actual prices, these differences provide a lower bound for the impact of regulation.

4 Discussion

In the period 2002-2005, the regulation concerning the Competition Transition Charges (CTC) has imposed a price-cap on the pool price. The maximum amount of these payments for each generator was computed as the difference between the net present value of the revenues that the firm would have received under the previous regulatory regime and estimated market revenues assuming a market average price of 3.606 ce/kWh. The amount of CTCs to be paid to the industry in a given year was the surplus obtained by distributors (regulated revenues obtained from the tariff to final consumers minus the cost of distribution, transport and retailing activities); this surplus is assigned to generators according to predetermined shares: 51.2% for Endesa, 27.1% for Iberdrola, 12.9% for Unión Fenosa, 5.7% for Hidrocantábrico and 3.1% for Elcogas.[14] When the weighted average price received by a firm exceeded 3.606ce/kWh the extra revenues were deducted from the generator's maximum CTC entitlement.

After 2005, other regulatory measures replaced the market power mitigating effect of CTCs. Regulation has turned to promoting of forward contracting to stimulate the competitiveness of the market.[15] From 2007, the two larger generators were required to hold a series of auctions offering virtual power plant (VPP) capacity to other generators.[16] VPP capacity is represented by a set of hourly call options giving the buyer of capacity the right to claim energy for delivery at a predetermined strike price. There are baseload and peakload contracts with different strike prices. In each case, contracts with a duration of 3, 6 and 12 months are offered. Additionally, new regulation was introduced in February 2007 and sought to increase the proportion of energy traded through bilateral contracts (CESUR

[14]Elcogas is a small thermo-electric plant with a capacity of 335MW. Property is shared between Endesa, 40%, Électricité de France, 31,4%, Iberdrola, 12%, and smaller shareholders.

[15]Allaz and Vila (1993) showed that the introduction of a future market makes the behavior of the firms on the spot market more competitive.

[16]This regulation replaced other regulatory measure implemented on February 2006 according to which generators would be paid at the marginal price only on their net market position (that is, subtracting demand by the distributors under the same ownership), which was in place until February 2007.

auctions).

This paper has focused on the 2002-2005 period where regulation was relatively stable. Our results suggest that firms' pricing behavior in that period was affected by regulation since a higher system marginal price would have significantly increased generators's variable profits at the pool. An interesting question that is left for further research is the effect of the changes to the regulatory regime that took place after 2005. Finally, in our analysis we have assumed a profit maximizing behavior on the part of firms, ignoring the possibility of collusion. Since the auction is repeated, generators could sustain outcomes which are more cooperative than the one-shot outcome (see Ciarreta and Gutiérrez-Hita, 2006, Fabra, 2003, and Fabra and Toro, 2004). If collusion is the reference point, the effect of regulation would have been stronger than measured.

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Appendix 1. Marginal Generation Costs: 2002-2005

We construct the marginal cost function using the variable production cost (raw materials and maintenance) as reported by the Spanish Ministry of Industry. Table A.1 summarizes the estimated unit costs of generation.

Table A.1- Variable Unit Cost, c€/kwh

	Nuclear	Coal-Burning	Oil-Fired	Combined Cycle	Hydroelectric
2002	1.06	2.15	4.08	2.28	0.02
2003	1.21	2.18	4.38	2.40	0.02
2004	1.34	2.22	4.61	5.12	0.02
2005	1.48	2.47	6.43	3.42	0.02

Source: MITyC. Fixed costs are not included.

Note that between 2002 and 2005 there was a significant increase in the variable unit cost of oil-fired plants. As a result, there have been no further investments in that type of plants and most of the new generation capacity comes from combined cycle plants and renewable sources.

Appendix 2: Revenue-maximizing prices

We look for the price-quantity pairs that maximize the revenue of the generators in the absence of regulation. The revenue is defined over the residual demand under capacity constraints. The non-regulation revenue-maximizing prices are a lower bound for the non-regulation optimal prices and have the advantage of being independent of cost estimates. When there are generation costs, profit-maximizing prices can only be above the revenue-maximizing prices. We include the constraint that the revenue-maximizing quantity is not above the total generation capacity available to the firm at any time period. Thus for each generator and hour, we compute the solution to the following problem,

$$\begin{array}{rl} \max_{p_h} & p_h D^r_{ih}(p_h) \\ \text{s.t.} & D^r_{ih}(p_h) \leq K_{ih} \end{array}$$

where$D_i^r(p)$ is the residual demand of generator i and K_i is the total capacity of generator i. Table A2.1, reports the difference between the non-regulation revenue-maximizing prices and SMP.

Table A2.1: Difference between non-regulation revenue-maximizing prices and SM
($\widehat{\text{p}}$-SMP)

			Generator					
Period	**Hour**	**SMP**	EN	IB	UF	HC	VI	GN
	All	3.175	1.537[a]	1.634[a]	−0.266	−0.170	0.123[b]	0.062[b]
2002 − 2005	Peak	4.287	1.762[a]	2.154[a]	−0.326	−0.276	−0.108	0.014
	Off-peak	2.528	1.281[a]	0.401[b]	−0.006	−0.074	0.234[a]	0.111[a]
	All	3.618	2.015[a]	2.153[a]	−0.331	−0.392	−0.171	−0.006
2002	Peak	4.756	3.184[a]	5.087[a]	−0.574	−0.601	−0.335	0.001
	Off-peak	2.903	1.401[a]	0.992[a]	−0.213	−0.304	−0.100	−0.078
	All	2.731	0.947[a]	0.841[a]	−0.111	−0.194	0.110	0.001
2003	Peak	3.235	1.876[a]	2.110[a]	−0.125	−0.233	−0.003	−0.136
	Off-peak	2.272	0.613[a]	0.071[a]	−0.011	−0.173	0.223	0.088
	All	2.675	1.017[a]	−0.147	−0.231	−0.342	−0.007	0.248
2004	Peak	3.244	1.174[a]	0.231[a]	−0.204	−0.263	−0.194	0.201
	Off-peak	2.308	0.910[a]	−0.437	−0.328	−0.394	0.041	0.288
	All	3.675	1.568[a]	1.071[a]	0.262	0.263	0.586	0.004
2005	Peak	5.942	0.813[a]	1.226[a]	−0.278	−0.007	0.100	−0.009
	Off-peak	2.627	1.711[a]	0.801[a]	0.516[a]	0.574[a]	0.772[a]	0.146[a]

[a]Significant at the 1% level; [b]at 5%.

The price differences in Table A2.1 show that the lower bound for the effect of regulation is significant for the two largest firms, EN and IB, so that this result is robust to the approximation of the marginal cost function. For the other generators differences are in general non significant.