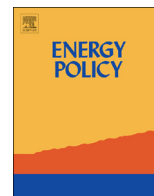




ELSEVIER

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Do regulatory mechanisms promote competition and mitigate market power? Evidence from Spanish electricity market



Victor Moutinho^{a,b}, António C. Moreira^{a,c,*}, Jorge Mota^a

^a Department of Economics, Management and Industrial Engineering, University of Aveiro, Campus Universitário de Santiago, 3810-193 Aveiro, Portugal

^b CEFAGE-UE, University of Évora, Évora, Portugal

^c GOVCOPP, University of Aveiro, Aveiro, Portugal

HIGHLIGHTS

- Competition and regulation in the Spanish electricity market.
- Net supplier and net demander behavior in the spot market.
- Panel cointegration methods used: FMOLS, PMG, MG, DFE and DOLS.
- The price cap regulation is effective in mitigating market power.
- Market power and marginal cost have positive effects on bidding strategies.

ARTICLE INFO

Article history:

Received 24 October 2013

Received in revised form

15 January 2014

Accepted 17 January 2014

Available online 7 February 2014

Keywords:

Capacity generation

Market power

Marginal costs

Panel cointegration

ABSTRACT

This paper estimates the relationships between bidding quantities, marginal cost and market power measures in the Spanish wholesale electricity market for two different regulatory periods: 2002–2005 and 2006–2007. Using panel econometric techniques we find differences in the impacts on bidding strategies for both periods. Hence, the marginal cost and the market power measures affect bid and net quantities. The market power measures also suggest that the coefficient is consistently positive and highly significant for both periods.

Moreover, the market power and marginal costs have mixed effects according to the models proposed for both periods. In addition, our results point to the effectiveness of the different effects of mitigating the market power in the Spanish electricity market. For the 2006–2007 period, the proposed causal relationships are partially validated by the cointegration results, which assumes there is a significant causality between the Lerner Index and the marginal cost.

© 2014 Published by Elsevier Ltd.

1. Introduction

In electrical systems, the supply function includes many different technologies, with different investments, fixed costs, variable costs and marginal costs. This is why the market offers different rewards for different technologies. The producer also offers positive net-supply with positive mark-ups and pushes down prices using its market power, while mark-ups are zero at the contracting point where net-supply is also zero (Holmberg and Newbery, 2010).

As the mismatches persist, specific price-quantity pairs for each of the 24 h of the following day may be different. Aggregating the bids of all power plants owned by a single generator allows obtaining its hourly supply schedule. Therefore, the expected

profit maximizing supply schedule should pass through all ex-post profit maximizing price and quantity pairs (Ciarreta and Espinosa, 2010a, 2012).

A high concentration index and an inelastic demand suggest that producers use market power to set prices well above marginal costs. The Spanish electricity sector suffered from several threats with regard to its sustainability, the main ones being the difficulty in controlling market power and an increasing reliance on bidding strategies in the spot market.

The market power of the two main Spanish producers in the electricity sector is a result of their capacity with regard to pricing in the wholesale market. Endesa's and Iberdrola's ability to establish the marginal prices in the wholesale market cannot be explained only by the large power production installed capacity: the pool pricing offered throughout the different hourly periods is conditioned mainly by the differences between production technologies used by the power plants of the installed system.

Kühn and Machado (2004) showed that the way market power is exercised depends on whether firms are net demanders or net

* Corresponding author at: University of Aveiro, Department of Economics, Management and Industrial Engineering, Campus Universitário de Santiago, 3810-193 Aveiro, Portugal. Tel.: +351 234 370 361; fax: +351 234370215.

E-mail address: amoreira@ua.pt (A.C. Moreira).

suppliers. They suggest that Endesa is a net supplier and Iberdrola a net demander. Although the net demander and the net supplier behavior in market power situations have been referred to by the literature, the effect of net demand and net supply bids have never been analyzed on electricity markets, which is addressed in this study.

Another factor that could have affected the competition in the Spanish spot electricity market of generators is vertical integration. However, its effect on bidding was neutralized by the fact that distribution was a regulated activity and therefore, the distributor profits were not in the objective function (distribution surplus was used for the Costs of Transition to Competition, namely CTC payments) (Ciarreta and Espinosa, 2010a, 2010b, 2012; Crampes and Fabra, 2005). In addition, the incentives provided by the regulation may interfere with the day-ahead market and results in lower prices than the ones predicted by the profit maximization behavior. On the other hand, the CTC payment and administrative price on “internal trends” in the Spanish electricity market were conditional on an average pool price not higher than the price cap revenue for the 2002–2007 period. And so, the revenues obtained for the higher price were subtracted from future CTC payments if the power producer average price exceeded that amount (Ciarreta and Espinosa, 2012). Thus, that price cap revenue criteria should protect consumers while proper regulation should contribute to a fairer market and may provide guidance as to what constitutes anti-competitive practices among market-leading energy providers (Banovac et al., 2009).

The reforms on regulation introduced by the Spanish government (among others, the administration prices on spot trades in electricity in February 2006, the abolition of CTC in June 2006, the virtual power plant for Endesa and Iberdrola, which seek to improve market liquidity and provide a more reliable price of forward contracts, and the legal framework for procurements auctions in February 2007 and April 2007) jointly induced a descending trend in price auctions in spot market in most part of 2007.

Although the application of the new regulatory measures were set up to control the level of concentration and market power, a slow progress in effective liberalization in that period still remained, which has not been analyzed in electricity markets. Accordingly, our aim is to address this gap.

As a result, the main objective of this study is to empirically investigate the impact of important factors that affect bidding strategies in the Spanish wholesale electricity market for the 2002–2007 period. In doing so, this study specifically seeks to achieve the following purposes: (i) to examine the relative impacts of marginal costs on bidding strategy; (ii) to ascertain the direction of causality between bidding strategies and marginal costs under market power mitigation. In order to achieve them, we use the Lerner indexes proxis involving two different time frames: the 2002–2005 and the 2006–2007 periods, which are characterized by different types of regulation.

Using cointegration analysis we will give an overview of what has been the reality for the variables under analysis in the 2002–2007 regulatory period, how they are related to each other and how they have been evolving. Therefore, the present study is relevant to the design of appropriate competition on wholesale market and regulatory policies, including meeting the objectives for the post integrated Iberian electricity market.

Moreover, the rest of the paper is structured as follows. Section 2 succinctly describes the Spanish electricity market. Section 3 provides the literature review. Section 4 describes the data and methodology used in the empirical analysis. Section 5 describes the econometric strategy and presents the empirical results. Section 6 concludes with some policy implications.

2. The Spanish electricity market

The Spanish Royal Decree 2019/1997, of December 26th set new rules which aims to regulate and organize the electricity production market. It was a response to the major restructuring need of the Spanish electricity sector. This Decree, however applied from January 1998 onwards, established a new structure in the electricity market, which is based on a wholesale and a retail market. This structure remains until today.

The wholesale market, called “Omel”, encompasses a set of transactions arising from the participation of market players in the sessions of both the daily and intraday markets. The daily market is the platform in which most transactions take place. All production units as well as external agents registered as sellers can take place as long as they are not linked to a contract.

The demand side involves distributors, retailers, eligible consumers and external agents registered as buyers. There is a single price per hour in the daily market, which corresponds to the marginal price of that market. In each hourly timetable this price is set equal to the price of the last sale bid of the last production unit whose acceptance must have been necessary to meet all purchase bids, in order to ensure the condition that the energy sold is equal to the energy demanded.

Several technologies coexist involving many different cost structures in this new management model of the Spanish electricity market. At any time new investments in power capacity can be made in a single technology. As a consequence, sunk costs and the long service life of the facilities make it possible that the best technologies can coexist at any time.

As a result, technologies with high fixed costs and low variable costs operate almost continuously side by side with the technologies with high variable costs, whose activity is discontinuous and heavily dependent on exogenous variables such as water river flows and wind intensity. Therefore, the market for technologies has different yield for different technologies as a consequence of unpredictable phenomena at the time of investment.

The readjustment of production capacity is not possible in the electricity production sector as most of the investments are not replicable. Moreover, sinking cost discourages the abandonment of technologies whose remuneration do not cover average costs, but only the variable costs.

In this new market structure in which a mandatory market exists to carry out the sale and purchase of electric energy, there must be a neutral agent to regulate all interests at stake. This market operator receives both discriminated energy sell bids from producers for the 24 h of the following day and discriminated purchase bids from distributors, traders and other agents. For each hour of the following day, the market operator aggregates both sale bids (and deploys a price function that grows with power) and purchase bids (and creates a demand function in which price decreases with power).

For a given hour h , sale and purchase bids functions intersect determining a pair of values for price (ph) and power (Ph). All power stations that offered their production power at a price lower than ph are selected to supply during that hour, with the sum of their power being equal to Ph . All selected production centers are paid the price ph , the system marginal price of hour h . For example, if a sale bid of a power station is zero, it will be paid at the system marginal price during hour h . The revenue thus obtained will cover fixed costs of the facility. Also, the power station with the highest price has fixed costs which will be recovered by allocating the other available stations with an additional fund, called “capacity payments”.

At equilibrium, the price of electricity, which is the same for all hourly production, neither take into account the differences in costs nor discriminate the origin of each KWh produced for the

different producers. However, the final price of electricity in addition to include market prices (daily and intraday market price, the cost of the technical constraints solution, the costs of the market ancillary services and the cost of technical management of the system), it includes also retributive elements administratively established, namely “the assurance cost power.” This warranty aims to promote the availability of production units and to encourage investment in production technology.

In this new market operational framework it is important to highlight the pivotal role of compensatory incentives mechanisms to electricity prices, which were a key factor in regulating the Spanish wholesale electricity market. The creation of a compensatory mechanism for the sunk costs in companies producing electricity, called competition transition charges (CTCs), served as collateral for the management of the electric system as it enables to smooth the fluctuations of the electricity final price on the pool, acting as a maximum price. Furthermore, CTCs induced a regulatory mechanism to control the capacity payments requiring a certain level of activity in technological investment adjustments over time.

In the period 2002–2005, the maximum amount of CTCs payments for each generator was computed as the difference between the net present value of the revenues that the firm would have received under previous regulatory regime and estimated market revenues assuming a market average price of 36.06 €/MWh (Ciarreta and Espinosa, 2012). After 2005, CTC compensatory mechanisms were replaced by other market power regulatory measures, namely the promotion of forward contracting to stimulate the competitiveness of the market. Moreover, an administrative price of €42.35/MWh was set as an internal mechanism among some vertical integrated groups in the Spanish day-ahead market (Federico and Vives, 2008).

Table 1 presents the installed generation capacity (GW) by firm of mainland Spain, for the 2002–2007 period. Endesa and Iberdrola are the two main players of the Spanish electricity market as they have the largest installed capacity (around 30% each) of the Spanish market. Hence, as Endesa assures around 25% of its capacity generation from coal and Iberdrola becomes the dominant firm in adaptable hydroelectric output (around 35%), they are able to determine market marginal prices (Federico and Vives, 2008). Thus, their capacity is at least equal to the surplus of market supply that exists in peak demand periods. Consequence to this, the supply by all other producers is insufficient to satisfy the demand.

On this note, Hidrocarbónico and Unión Fenosa, small electricity producers, make their purchase and sale bids in the majority of the time schedules according to the prices set by the two dominant players as they are not capable of setting market prices.

Normally, the two largest players can utilize their important output mix in order to present a flexible bid according to supply and demand forecasts. On the other hand, Unión Fenosa and Hidrocarbónico, whose output mix is reduced, have a lower capacity to present competitive or sufficiently flexible bids. Accordingly, acknowledging that Endesa and Iberdrola will claim high prices, the easiest way for Unión Fenosa and Hidrocarbónico

to sell the largest possible quantity is to bid at price zero, since they know that all the electricity will be sold in the daily market at the marginal price set in the pool (and not at the bid price).

3. Literature review

Several studies (Green, 1996; Baldick et al., 2004) have analytically determined the assumptions of the supply function equilibrium (SFE) with linear marginal costs and linear demand. On the other hand, Newbery (1998) and Holmberg (2007) determined the SFE with constant marginal costs, while Rudkevich et al. (1998) and Anderson and Philpott (2002) developed solutions for symmetric firms under perfectly inelastic demand.

Other studies (Bushnell, 1998; Kelman et al., 2001; Otero-Novas et al., 2000) analyze market equilibrium based on Cournot models. Others (Ausubel and Cramton, 2002; Fabra and Toro, 2005; Von der Fehr and Harbord, 1993; Wolfram, 1999) model the market as a multi-unit auction market. The market power may also be present in equilibrium in multi-unit auction models (García-Díaz and Marín, 2003).

Neuhoff et al. (2005) analyze the impact induced by alternative regulatory mechanisms in the transmission network and conclude that the inclusion of transmission constraints can result in surprising equilibria. On the other hand, Evans and Guthrie (2006), when analyzing different effects of alternative regulatory mechanism, find that price based on the optimized replacement cost is insufficient to allow the regulated firm to break even whenever it has to invest. Yao et al. (2007) analyze the Belgian electricity market equilibrium as a stochastic equilibrium problem with equilibrium constraints (EPEC) and conclude that a forward cap increases firms' incentives for forward contracting, whereas a spot cap reduces such incentives.

The majority of literature mainly focused on short-term decisions, taking existing capacity as given. They also showed that market power can be more fully exercised when the capacity of rivals is exhausted (Borenstein and Bushnell, 1999; Bushnell, 2003; Joskow and Kahn, 2002). The most controversial assumption is that the incumbent generator pursues its maximum profit, taking into account its residual demand function, which relates the price to its electricity output (Ventosa et al., 2005).

When estimating a competitive supply function in terms of marginal cost, Stoff (2002) showed that marginal costs pricing suffices to cover the capital cost of investment, as price spikes will occur in periods of shortages. However, Cramton and Stoff (2006) and Joskow (2007) found that the marginal costs should set the competitive prices when the market is characterized by overcapacity.

The restructuring of the England and Wales electricity markets opened the way to rigorous market power analysis. Wolfram (1999) used direct measures of marginal cost to estimate price cost margins. This showed that the prices were closer to marginal cost than market competition models predicted, as power generators were not taking full advantage of the inelastic demand.

When analyzing the California real-time energy market, Bushnell and Saravia (2002), Borenstein et al. (2002), Joskow and Kahn (2002) and Wolak (2003) used the observed elasticity of residual demand and observed different prices *vis-à-vis* the competitive benchmark price levels. They concluded that the prices cannot be explained by load, gas prices, imports or NO_x-allowance prices.

Zachmann (2007), using a Markov switching model, compared the England and Wales and the German electricity markets and concluded that the latter had a closer relation to marginal costs.

The estimation of marginal costs of quality, between 1995 and 2003, in the UK electricity distribution networks (Jamásb et al., 2012) suggest that the regulatory incentives to reduce service

Table 1

Installed capacity (GW) by the main generators in Spain between 2002 and 2007. Source: Ciarreta and Espinosa (2012) and Federico and Vives (2008).

	Endesa	Iberdrola	Unión Fenosa	Hidrocarbónico	Viesgo	GN	others	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
2005	17.1	18	7.2	2.5	2.3	2.8	2.4	52.3
2007	18.8	20.9	8.8	3.9	2.4	3.6	4.4	62.8

interruptions have not been strong enough to achieve economically efficient levels of service quality. They find that the incentives to encourage utilities to reduce network energy losses have led to performance improvement.

Moreover, the Spanish wholesale market has been extensively analyzed (Ciarreta and Espinosa, 2010a, 2010b, 2012; García-Martín, 2001; Kühn and Machado, 2004; Crampes and Fabra, 2005; Furió and Lucia, 2009; Moutinho et al., 2011).

García-Martín (2001) showed that the coexistence of competition in the electricity spot market and the regulatory compensation mechanism of the sunk costs (CTCs) are not compatible. This study enhanced the market power exercise. An inadequate attribution of the payments between companies in the market can promote both productive inefficiency and delay or prevent new competition, which is desired in these energy markets.

Von der Fehr and Harbord (1993) find that the equilibrium prices do not decrease with the elasticity of demand. This in turn affects the market whose distortion is due to the exercise of market power, which is lower with an elastic demand. Other important findings report to the auctions equilibrium, which fully relies on demand. If it is low, the bids are equal to the marginal cost of the most inefficient agent and only the most efficient will dispatch energy. Thus, the uniform and discrete auction results will be competitive, in the sense that prices are restricted to the marginal costs of the inefficient agent and the total cost of energy production is minimized.

Kühn and Machado (2004), using the supply function with econometric estimation (two-step GMM) for each market operator (Endesa, Iberdrola, Unión Fenosa, Hidrocarburo and Viesgo), showed that the market power exercised by Endesa and Iberdrola has its source in their exogenous variations with an impact on the pool price. They argued that the CTC payments increase or decrease prices according to their behavior as net buyers or net sellers in the market. However, Crampes and Fabra (2005) argued that any positive surplus generated by a distribution firm was shared among the generators according to percentages given by the incentives rights, so that all firms behaved as net sellers.

Fabra and Toro (2005) showed the electricity price formation and collusive behavior in the Spanish electricity market. They confirmed that on the price war stage, the Endesa mark-up is negative and Iberdrola's is positive. However, between the collusion periods, both power generators have positive profit margins, i.e., prices above the marginal costs and thus favorable conditions to the market power exercise. These results were however, strongly influenced by the impact of the CTCs on the biddings of the firms in the market. They further recognize the existence of periods with low prices that are only sustainable due to collusive strategies or alternatively due to the coexistence of low prices coordinated with mixed price strategies, leading to multiple price equilibrium.

Linares and Labandeira (2004) discussed the factors that influence energy efficiency, conservation decisions, and the most appropriate policies for their promotion. They argued that specific policies for promoting energy conservation may be required, based on economic instruments or on the provision of information to consumers.

Furió and Lucia (2009) on the other hand present significant evidence that the generators bidding strategies involve the intraday market. They found out that some power generators have a clear economic incentive to avoid being dispatched in the day-ahead market to be called up in the subsequent transmission constraints resolution process.

Ciarreta and Espinosa (2010b) not only measured market power based on the different bidding behavior of large and small generators at the specific demand level, but also demonstrated that the larger operators in the day-ahead market are able to increase prices significantly above the competitive benchmark.

Ciarreta and Espinosa (2012) analyze the impact of regulation on the electricity wholesale market from 2002 to 2005. They

obtain a measure of the gap between optimal price in the absence of regulation and real prices. Therefore, the regulation affected wholesale prices considerably, but became less effective at the end of the sample period which explains the regulatory regime change introduced at the outset of 2006.

4. Methodology and data

4.1. Econometric methods

The use of cointegration analysis on a set of cross-firms panel data allows the analysis of the nature of any causality that may exist between dependent variables (net quantities and sold quantities) and independent variables (marginal costs, Lerner index and purchased quantity to sell in the open market) in the Spanish OMEL wholesale market. In order to test these relationships a rationalized cointegration analysis is applied on multivariate time series data set.

The use of several explanatory variables simultaneously can increase the existence of multicollinearity among them. Collinearity may have impact on confidence intervals, on the standard errors dimension; the model estimates may also be less precise. Accordingly, we ran the variance inflation factor (VIF) test to detect multicollinearity.

In order to confirm the validity of the panel data to perform the cointegration analysis, the following tests were conducted: panel unit root tests, a panel cointegration test and dynamic panel causality tests. The error correction model (ECM) is a comprehensive linear regression equation that provides a description of the possible nature of interdependence of the short run movements of cointegrated variables under study. We perform econometric analysis using Stata 11.

4.2. Panel unit root tests

We begin the empirical analysis with the application of panel unit root tests to verify whether or not the variables are nonstationary. Panel unit root tests are often grouped into two main categories: first-generation tests, which assume cross-sectional independence (Levin et al., 2002; Im et al., 2003; Maddala and Wu, 1999; Choi, 2001); and second generation tests, which explicitly allow for some form of cross-section dependence (Pesaran, 2007).

In order to test, under the null hypothesis, that all individual series of the panel contain a unit root, Levin et al. (2002) proposed the following panel-based ADF test that restricts parameters by keeping them identical across sectional regions: $\Delta y_{it} = c_i + \rho_i \times y_{it-1} + \sum_{j=1}^k c_j + \rho_i \times y_{it-j} + \varepsilon_{it}$, where $t = 1, 2, \dots, T$ represents time periods and $i = 1, 2, \dots, N$ represents members of the panel. The Levin-Lin-Chu test (LLC) adopts the null hypothesis of $\rho_i = \rho = 0$ for all i , against the alternative $\rho_1 = \rho_2 = \dots = \rho < 0$ for all i , with the test based on the statistics $t_\rho = \hat{\rho}/s.e.(\hat{\rho})$. However, one drawback is that ρ is restricted by being kept identical across regions under both the null and alternative hypotheses.

Five types of panel tests are computed in this paper: LLC test (Levin et al., 2002), Breitung test (Breitung, 2000) and Hadri test (Hadri, 2000), assuming a common unit root, while the IPS test and the ADF-Fischer test assume individual unit root process across the cross-sections.

4.3. Panel cointegration tests

The contribution, among others, for the panel cointegration tests approach has been presented by Pedroni (2001, 2004), Kao and Chiang (2000), and Westerlund (2007).

The statistics based on the homogeneous alternative hypothesis consist on estimates of pooled type, which Pedroni (2001,

2004) calls statistics within-groups. When considering the heterogeneous alternative hypothesis, test statistics are formed by means of the estimated individual values for each panel unit i , which Pedroni (2001, 2004) calls between-groups estimators.

Westerlund (2007) proposed four panel tests of the null hypothesis of no cointegration that are based on structural rather than residual dynamics, and therefore do not impose any common factor restriction. They are designed to test the null hypothesis by inferring whether the error correction term in a conditional error correction model is equal to zero. If the null hypothesis of no error correction is rejected, then the null hypothesis of no cointegration is also rejected (Westerlund, 2007). Two tests are designed with an alternative hypothesis that the panel is cointegrated as a whole, while the other two test the alternative hypotheses that there is at least one individual series that is cointegrated. Each test is able to accommodate individual firm specific short-run dynamics, including serially correlated error terms and non-strictly exogenous regressors, individual specific intercept and trend terms, as well as individual specific slope parameters.

4.4. Estimation of the cointegration vector

After assuring both the nonstationarity of the variables of the equation and the presence of cointegration between them, it is possible to infer what deviations from the long-term equilibrium of the variables influence the short-term dynamics. The answer to these deviations can be represented by an error correction model (ECM), represented by the following reparametrization equation:

$$\Delta y_{it} = \phi_i(y_{i,t-1} - \theta'_i \times X_{it}) + \sum_{j=1}^{p-1} \lambda_{ij}^* \times \Delta y_{i,t-j} + \sum_{j=0}^{q-1} \delta_{ij}^* \times \Delta X_{i,t-j} + \mu_i + \varepsilon_{it},$$

in which $\phi_i = -(1 - \sum_{j=1}^p \lambda_{ij})$, $\theta_i = \sum_{j=0}^q \delta_{ij} / (1 - \sum_{k=1}^p \lambda_{ik})$, $\lambda_{ij}^* = -\sum_{m=j+1}^p \lambda_{im}$, with $j = 1, 2, \dots, p-1$ and $\delta_{ij}^* = -\sum_{m=j+1}^q \delta_{im}$, with $j = 1, 2, \dots, q-1$.

In this study, particular attention will be directed to the following two parameters: ϕ_i and θ_i , the speed of adjustment from the error correction term and the vector of parameter of long-run equilibrium relationship. It is expected that the term ϕ_i would be different from zero and that this parameter would be significantly negative under the assumption that the variables return to their long-run equilibrium.

Based on error correction models, for the estimation of the cointegration vector we use the following methods: mean group (MG), pooled mean group (PMG), dynamic fixed effects (DFE), full modified ordinary least squares (FMOLS) and dynamic ordinary least squares (DOLS). However, Pedroni's (2001) recommendations, in which FMOLS and DOLS estimators are advantageous in their group-means versions due to the greater flexibility under the presence of heterogeneity in the cointegration vectors and to lower size distortion than the estimators within groups.

4.5. Data, specification of variables and proposition of hypotheses

The marginal costs of power generation were obtained for all power plants in the portfolio. Plants were then ranked in order of their ascending marginal costs (merit-order effect). Profit-maximizing producers start generating from the plant with lowest marginal cost.

As demand increases, plants are brought online to meet the demand following the order of merit. Theoretically, daily changes in fuel and carbon prices can change the merit order through their effect on relative marginal costs of power generation.

The data consists of daily observations (24 h moving average) of demand and supply for each agent (Endesa, Iberdrola, Unión Fenosa, Hidrocarburo, and Viesgo) and others agents (fringe competitive group) for each production and demand unit in the

Spanish wholesale electricity market from January 2002 until December 2007. The data of market price, quantity offered for each agent in the wholesale market, and quantity purchased by each agent in the wholesale market to sell in open market were retrieved from OMEL data.

The marginal costs of each power plant are estimated by the following expressions:

$$MC_p = MC_{p,fuel} + MC_{p,CO_2}$$

where MC_p is the marginal cost of power plant p in €/MWh; $MC_{p,fuel}$ is the marginal cost of power plant p due to fuel cost in €/MWh; MC_{p,CO_2} is the marginal cost of power plant p due to CO₂ emissions cost in €/MWh, which was zero for the 2002–2005 period.

We adopted the expression of the marginal costs of a power plant given by: $MC_{p,fuel} = f \times cf / LHV \times \eta_p$ (Lagarto et al., 2010), where $MC_p = MC_{p,fuel}$; MC_p is the power plant p marginal cost in €/MWh; f is the fossil fuel price in €/t; cf is a conversion factor equal to 859,845 kcal/MWh; LHV is the lower heating value in kcal/t; and η_p is power plant efficiency in %.

The marginal cost of power plant due to CO₂ emission costs is given by:

$$MC_{p,CO_2} = P_{CO_2} \times ee_p \times 10^{-3}$$

where P_{CO_2} is the CO₂ emission price in €/t; ee_p is the power plant p specific emission of CO₂ in kg CO₂/MWh.

The different daily periods are significantly conditioned by the differences between the various production technologies used by the power plants that generate the installed power of the system. We used the daily spot prices of fuel, coal and gas to compute the marginal costs. Data of major fuel sources (oil, coal, gas) were retrieved from the Systems and Energy Section database from a national university.

The values used for the unitary marginal costs of the nuclear and hydroelectric technologies are the ones referred to in Ciarreta and Espinosa (2012).

For the mitigation of market power we used a price cap revenue equal to 36.06 €/MWh for the 2002–2005 period and 42.35 €/MWh for the 2006–2007, given by $P_{OMEL} - P_{cap} / P_{cap}$. This measure of market power mitigation will be called hereafter adjusted Lerner index.

Essentially, the study explores two hypotheses.

Hypothesis 1. Marginal costs cause or improve bidding strategies of electricity generators. To test this hypothesis, we use the panel cointegration estimation of a regression model with quantity sold in wholesale market as the dependent variable (Equation 1: $SQty_{it} = \beta_0 + \beta_1 PurchQty_{it} + \beta_2 MC_{it} + \beta_3 AdLernerIndex_{it} + \varepsilon_{it}$). Marginal costs per power plant and the adjusted Lerner index are used as explanatory variables while purchased quantity to sell in open market is used as a control variable.

The expected sign for the estimated coefficient of the marginal cost variable is positive as an increase in marginal costs induces an increase in bid quantities in the market, ceteris paribus. The coefficient of the purchased quantity to sell in open market is expected to be negative (positive) because an increase (decrease) in this variable implies a decrease (increase) in sold quantities in the pool, ceteris paribus. Finally, the expected coefficient of the market power measure is positive given that greater the market power exercise the greater the bid quantities in the pool, ceteris paribus.

Hypothesis 2. Marginal costs cause or improve net quantities transacted by electricity generators. To test this hypothesis, we use the panel cointegration estimation of a regression model with net quantities as the dependent variable (Equation 2: $NetQty_{it} = \beta_0 + \beta_1 MC_{it} + \beta_2 AdLernerIndex_{it} + \varepsilon_{it}$). The marginal cost per power

plant is used as an explanatory variable, while the adjusted Lerner index is used as a control variable.

The expected coefficients of the marginal costs and adjusted Lerner index are positive (negative) since it is expected that market players have a net supplier (net demander) position in the pool and an increase (decrease) in the market power exercise induces an increase (decrease) in net quantities in the pool.

5. Empirical results and discussion

Descriptive statistics as well as correlation matrixes of the above-mentioned variables for both periods are shown in the appendix.

The correlation coefficients are also shown in the appendix. They suggest the nonexistence of collinearity among independent variables.

5.1. Panel unit root testing

Table 2 reports unit root tests for two regulatory periods of 2002–2005 and 2006–2007 for the following variables: quantity purchased in wholesale market to sell in open market, marginal cost, net quantity and adjusted Lerner index. The regressions contain an intercept and a time trend.

The LLC test rejects the presence of unit root under a significant weak evidence for some variables. The Hadri test has a different (stationary) null hypothesis which provides strong evidence that (at least) all panels have a unit root, whilst the Breitung test alternative presents robust results of the presence of cross-sectional dependence for the same panels.

The IPS test shows robust results similar to the Breitung test, while ADF-Fischer test shows robust results for the same panels, but cannot reject the presence of unit root the measure of adjusted Lerner index.

In general, we conclude that the assumption of the non-stationarity of the series is legitimate, indicating the possibility of long-term relationships between the variables. Considering the cases in which the null hypothesis was rejected, it is possible to include such variables in the cointegration study in the following situations: first, assuming that they are first-order integrated and, second, when the panel test does not show such results due to the

high probability of the presence of cross-section correlation (electric power firms).

5.2. Panel cointegration testing

Even if the series are non-stationary, the relationship between variables may be spurious. For this, it is necessary to perform the panel cointegration tests to make sure that there is indeed a long-term relationship.

In Table 3, as far as the Pedroni's (2004), Kao and Chiang (2000) test statistics are concerned, the results provide strong support for the presence of cointegration.

As we take into account cross-section dependencies, the Westerlund's test results, however, provide evidence of cointegration further indicating the possibility of a somewhat bi-directional long-run equilibrium relationship between marginal costs and supply strategy. This is much more consistent for the 2002–2005 regulatory period than for the 2006–2007 period, in which we find non-significant statistical values.

Overall, the results of the two equations suggest that all variables (quantity purchased in wholesale market to sell in open market, marginal cost, net quantity and adjusted Lerner index) are cointegrated, which means that we have uncovered meaningful long-run relationships

5.3. Estimation and interpretation of the relationships proposed

Table 4 presents the results for the different models specifying the sold quantity as the dependent variable and Table 5 presents the results for the same models specifying the net quantity as the dependent variable, when the marginal cost and adjusted Lerner index are the independent variables.

Our interest is now on how the marginal cost, purchased quantity to sell in open market and the adjusted Lerner index affect sold quantities, as shown in Table 4. The results for the adjusted Lerner index suggest that the coefficient is consistently positive and also highly significant for both periods.

On the other hand, the result for the marginal costs show that they are positive (negative) and statistically significant for the 2002–2005 (2006–2007) period for both FMOLS and DOLS.

When analyzing the long-run effect, the quantity purchased in wholesale to sell in open market reveals a significant effect on the

Table 2
Results of panel unit root tests.

Series name	Test assuming a common unit root process			Tests assuming individual unit root process	
	LLC t^* -stat: H_0 : Unit root	Breitung t -stat: H_0 : Unit root	Hadri Z-stat: H_0 : No Unit root	IPS W- t -bar stat: H_0 : Unit root	ADF-fisher χ^2 : H_0 : Unit root
2002–2005					
Level					
Quantity purchased to sell in open market	–8.1919* [0.092]	–9.0587*** [0.0000]	10.4045*** [0.0000]	–4.5276*** [0.0000]	31.6810*** [0.0015]
Sold quantity	–7.768** [0.0500]	–14.2818*** [0.0000]	21.3653*** [0.0000]	–7.7502*** [0.0000]	37.5701*** [0.0002]
Marginal cost	–9.5434 [0.5916]	–25.6914*** [0.0000]	13.8633*** [0.0000]	–8.3045*** [0.0000]	37.0782*** [0.0002]
Net quantity	–11.7781*** [0.0000]	–10.5035*** [0.0000]	17.5422*** [0.0000]	–10.2434*** [0.0000]	53.9699*** [0.0000]
Ad. Lerner index	–9.427*** [0.0000]	–4.8201*** [0.0000]	41.3787*** [0.0000]	–5.1929*** [0.0000]	5.9201 [0.9101]
2006–2007					
Level					
Quantity purchased to sell in open market	–6.5471 [0.939]	–5.465*** [0.0000]	13.8413*** [0.0000]	–1.8742** [0.030]	9.7962 [0.633]
Sold quantity	–5.3469 [0.878]	–4.1341*** [0.0000]	2.6640*** [0.0000]	–1.1450 [0.1261]	8.5998 [0.736]
Marginal cost	–7.1055 [0.516]	–7.7613*** [0.0000]	2.4806*** [0.006]	–2.3282*** [0.010]	14.145 [0.291]
Net quantity	–6.4249 [0.157]	–4.0411*** [0.0000]	3.5358*** [0.000]	–2.1915** [0.0142]	20.990** [0.050]
Ad. Lerner index	–5.6801 [0.318]	–4.2567*** [0.0000]	2.6399*** [0.0041]	–0.3877 [0.3491]	4.5368 [0.971]

Notes:

* Represent significance at the 10% level.

** Represent significance at the 5% level.

*** Represent significance at the 1% level.

Table 3
Results of panel cointegration tests.

2002–2005	Panel cointegration tests	Westerlund	Kao	Pedroni			
Equation 1	T		-1.133 [0.129]				
	G_T	-5.399*** [0.000]		Panel v-statistic	12.389*** [0.000]	Group rho-statistic	-138.937*** [0.000]
	G_α	-92.686*** [0.000]		Panel rho-statistic	-124.600*** [0.000]	Group PP-statistic	-44.754*** [0.000]
	P_T	-11.910*** [0.000]		Panel PP-statistic	-41.200*** [0.000]	Group ADF-statistic	-8.485*** [0.000]
	P_α	-71.940*** [0.000]		Panel ADF-statistic	-6.871*** [0.000]		
Equation 2	T		-4.811*** [0.000]				
	G_T	-5.998*** [0.000]		Panel v-statistic	21.396*** [0.000]	Group rho-statistic	-127.142*** [0.000]
	G_α	-89.058*** [0.000]		Panel rho-statistic	-97.905*** [0.000]	Group PP-statistic	-40.450*** [0.000]
	P_T	-14.201*** [0.000]		Panel PP-statistic	-33.544*** [0.000]	Group ADF-statistic	-10.414*** [0.000]
	P_α	-74.372*** [0.000]		Panel ADF-statistic	-9.310*** [0.000]		
2006–2007							
Equation 1	T		-0.1061 [0.475]				
	G_T	-2.541 [0.808]		Panel v-statistic	-1.2786 [0.899]	Group rho-statistic	-17.908*** [0.000]
	G_α	-21.552 [0.118]		Panel rho-statistic	-10.892*** [0.000]	Group PP-statistic	-14.609*** [0.000]
	P_T	-4.763 [0.953]		Panel PP-statistic	-9.6909*** [0.000]	Group ADF-statistic	-4.7699*** [0.000]
	P_α	-12.380 [0.666]		Panel ADF-statistic	-1.2437 [0.1068]		
Equation 2	T		3.0518*** [0.001]				
	G_T	-2.471 [0.744]		Panel v-statistic	-1.33529 [0.909]	Group rho-statistic	-13.286*** [0.000]
	G_α	-18.293 [0.200]		Panel rho-statistic	-7.1605*** [0.000]	Group PP-statistic	-9.6419*** [0.000]
	P_T	-5.617 [0.671]		Panel PP-statistic	-6.20482*** [0.000]	Group ADF-statistic	-0.96851 [0.166]
	P_α	-13.263 [0.362]		Panel ADF-statistic	0.145579 [0.557]		

Notes: Tests results were generated by Eviews and 'xtwest' Stata module. Pedroni's Panel statistics as well as all of Westerlund's are weighted. Values in [] are robust p -values generated through bootstrapping because of cross-sectional dependence in the residuals.

G_T and G_α are Westerlund group-mean tests.

P_T and P_α are Westerlund panel tests.

*Indicates levels of significance of 10%.

**Indicates levels of significance of 5%.

*** Indicates levels of significance of 1%.

Table 4
Panel cointegration estimation results for the period 2002–2007.

Equation 1 2002–2005 Dependent variable	(1) FMOLS Sold quantity	(2) DOLS Quantity sold	(3) PMG Δ Sold quantity	(4) MG Δ Sold quantity	(5) DFE Δ Sold quantity
Convergence coefficients			-0.1385*** (0.043)	-0.1655*** (0.052)	-0.0926*** (0.005)
Long-run coefficients					
Purchased quantity to sell in open market	0.3433*** (0.028)	-6.238*** (30.970)	-7.071*** (0.024)	-9.317** (0.145)	-10.593*** (0.055)
Marginal costs	781.753*** (95.886)	12.762*** (499.43)	11.599*** (63.820)	15.0619 (360.870)	16.3231 (183.186)
Ad. Lerner index	10714.55*** (1508.642)	1364.011*** (167.463)	825.644*** (116.372)	939.95 (399.574)	736.15** (325.967)
Short-run coefficients					
Δ Purchased quantity to sell in open market			0.2312*** (0.075)	0.2089*** (0.072)	0.2308*** (0.016)
Δ Marginal costs			465.8507** (183.196)	433.0816** (172.912)	350.7268*** (21.938)
Δ Ad Lerner index			6925.549* (1934.054)	6882.364 (1058.709)	6392.839*** (1526.136)
Hausman test (χ^2)			6.63* (0.085)	-2.19	
R-square (r^2)	0.724	0.498			
No. of firms	6	6	6	6	6
No. of observations	8760	8670	8760	8760	8760
Equation 1 2006–2007					
Dependent variable:	(1) FMOLS Sold quantity	(2) DOLS Sold quantity	(3) PMG Δ Sold quantity	(4) MG Δ Sold quantity	(5) DFE Δ Sold quantity
Convergence coefficients			-0.0526** (0.025)	-0.21518*** (0.0495)	-0.07679*** (0.008)
Long-run coefficients					
Purchased quantity to sell in open market	1.4031*** (0.111)	1.369*** (0.139)	1.6698*** (0.1658)	0.5701* (0.3162)	1.6358*** (0.1526)
Marginal costs	-716.54** (337.13)	-2380.97*** (532.83)	-179.860 (557.9)	1787.2*** (556.15)	534.267 (494.8)
Ad. Lerner index	33897.0*** (5934.6)	5586*** (837.8)	40917.58*** (8716.6)	27238.1*** (8356.9)	30943.4*** (8164.6)
Short-run coefficients					
Δ Purchased quantity to sell in open market			0.58425*** (0.1677)	0.47269*** (0.1252)	0.92934*** (0.035)
Δ Marginal costs			673.159*** (243.24)	518.23** (216.85)	376.198*** (55.01)
Δ Ad Lerner index			7468.8* (3833.4)	10812.1 (7874.3)	5311.71*** (1270.9)
Hausman test (χ^2)			-10.54	-21.04	
R-square (r^2)	0.791	0.876			
No. of firms	6	6	6	6	6
No. of Observations	3280	3280	3280	3280	3280

Notes: All equations include a constant sector-specific term. Values in () are standard errors. For DFE estimates, the standard errors are heteroskedastic consistent.

* Indicate significance at the 10% level.

** Indicate significance at the 5% level.

*** Indicate significance at the 1% level.

Table 5
Panel cointegration estimation results—period 2002–2007.

Equation 2 2002–2005 Dependent variable	(1) FMOLS Net quantities	(2) DOLS Net quantities	(3) PMG Δ Net quantities	(4) MG Δ Net quantities	(5) DFE Δ Net quantities
Convergent coefficients			–0.1259*** (0.0323)	–0.21363*** (0.0342)	–0.03342*** (0.0056)
Long-run coefficients					
Marginal costs	162.333*** (132.641)	344.611*** (70321.18)	123.7425 (74.881)	–563.779 (1894.59)	711.136 (1335.5)
Ad. Lerner index	8670.820*** (2214.553)	–6447.959*** (2362127)	–7382.436*** (1332.579)	4374.16 (19632)	4977.01 (23872)
Short-run coefficients					
Δ Marginal costs			268.5258** (135.1426)	341.165* (193.89)	284.801*** (70.576)
Δ Ad Lerner index			–11942.85 (12004.86)	154.283 (3116)	1552.24 (1645)
Hausman test (χ^2)			2.46 (0.483)	–12.41	–542.19
R-square (r^2)	0.635	0.477			
No. of firms	6	6	6	6	6
No. of Observations	8760	8670	8760	8760	8760
Equation 2 2006–2007 Dependent variable	(1) FMOLS Net quantities	(2) DOLS Net quantities	(3) PMG Δ Net quantities	(4) MG Δ Net quantities	(5) DFE Δ Net quantities
Convergent coefficients			–0.10766 (0.0446)**	–0.1401 (0.0365)	–0.8448 (0.004)
Long-run coefficients					
Marginal costs	20.35.4*** (553.16)	2749.32*** (960.74)	81.316 (58.984)	247.514 (1170.008)	313.2265*** (266.19)
Ad. Lerner index	–16311.7* (9380)	–8960.36 (13951)	9067.33*** (2400.1)	8886.245 (9816.59)	4076.08 (4769.13)
Short-run coefficients					
Δ Marginal costs			461.457** (237.00)	220.3749* (119.976)	270.2745*** (29.31)
Δ Ad Lerner index			2050.22 (2362.39)	–21314.38 (17925.49)	–20620.43*** (2049.25)
Hausman test (χ^2)			33.57	–10.57	
R-square (r^2)	0.589	0.666			
No. of firms	6	6	6	6	6
No. of observations	3280	3280	3280	3280	3280

Notes: All equations include a constant sector-specific term. Values in () are standard errors. For DFE estimates, the standard errors are heteroskedastic consistent.

* Indicate significance at the 10% level.

** Indicate significance at the 5% level.

*** Indicate significance at the 1% level.

quantity sold in wholesale market. The coefficient estimates are both positive (0.343 and 1.403) when using FMOLS for both periods, but show mixed results (–6.238 and 1.369) for both regulatory periods when using DOLS.

When comparing PMG and MG estimators, the Hausman test result is 6.63 for the 2002–2005 period and –10.54 for the 2006–2007 period. Then, it is possible to conclude that under the null hypothesis the PMG estimator is preferred for the first period and the MG for the second.

The estimates of speed of adjustment indicate that there is no significant difference in the long-run dynamics (–0.14 for PMG and –0.16 for MG) for the 2002–2005 period. There is also a similar effect in the 2006–2007 period (–0.053 for PMG and –0.215 for MG). This implies that the PMG model, for the 2002–2005 period, does not return immediately to its equilibrium after a shock pushes it away from the steady state whereas for the 2006–2007 period it does return to its equilibrium faster than it does in the previous period. As the error correction term is statistically significant it provides further evidence of the existence of a long-run relationship.

In the long run, for the period 2002–2005, the relationship proposed in Hypothesis 1 is validated for a net demander using the following estimators: DOLS, PMG, MG and DFE. However, the FMOL estimator validates Hypothesis 1 considering the set of agents as net suppliers. For the period 2006–2007, Hypothesis 1 is confirmed in all models for agents behaving as net suppliers. However, the expected sign for the marginal costs is contrary to the theoretically expected for FMOLS, DOLS and PMG models.

Our interest turns to how marginal costs and the adjusted Lerner index affect net quantities, as shown in Table 5. The results for the adjusted Lerner index suggest that the coefficient is consistently positive and is also highly significant for both periods.

The adjusted Lerner index coefficients provide mixed signs when the net quantity is the dependent variable for the 2002–2005 period, with a statistical significance at the 1% level. The market power index for the subsequent period has a negative long-term impact on the net quantity supplied in wholesale market, as far as the FMOLS and DOLS estimators are concerned. The MG and DFE estimators indicate a positive relationship between these variables for both periods under analysis.

In the 2002–2005 period Hypothesis 2 was evaluated considering their agents as net Suppliers, based on the results of FMOLS, MG and DFE estimators. In turn, in 2006–2007 period, Hypothesis 2 was validated when the PMG, MG and DFE estimators were used.

The short-run estimates provide mixed signs for all variables included in all equations analyzed in Tables 3 and 4, for both periods, while several variables are not statistically significant.

6. Conclusions and policy implications

In this article the portfolio bidding quantities, the daily power plant marginal costs and the adjusted Lerner index were studied in order to understand the nature of the cost of the electricity production portfolio and the short-run and long-run relationships among them, using a panel data econometric approach. The results of the panel cointegration validated both hypothesis whose central objectives were to analyze the different impacts on bidding strategies, i.e., the importance of net supplier and demander net positions, which are influenced by marginal costs and adjusted Lerner index. This measure of market power mitigation proves to be significant using the criterion that the price cap followed by the regulatory authorities determines the weighted average right incentives for mitigating the market power, which is very important

in the context of transition to competition in the Spanish wholesale electricity market. Those incentives provided by the regulation may interfere with the day-ahead market and result in lower prices than the ones predicted by the profit maximization behavior.

Ciarreta and Espinosa (2012) have argued that for the 2002–2005 period, 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. Kühn and Machado (2004) also showed that the way market power is exercised depends on whether firms are net demanders or net suppliers. The results found in Hypotheses 1 and 2 supported the importance of the two above-mentioned arguments in which marginal costs and adjusted Lerner index significantly contribute to the behavior of agents as net suppliers and net demanders. Clearly, the bidding strategy and capacity withholding involves generating firms bidding some prices above the variable production costs of their units with the intention of forcing the market-clearing price above competitive levels.

The robustness of our results point to the significant inclusion of these different bidding strategies in the retail market. The market power has a significantly negative long-term impact on the net quantity supplied in wholesale market, as far as the DOLS and PMG estimators are concerned. The adjusted Lerner index has also a statistically positive impact on the net quantity offered, as far as the FMOLS estimator is concerned.

Over the period analyzed, regulators and competition authorities were concerned about the presence of excessive exercise of market power. However, the mitigation of market power has not produced the expected results as our research show.

In fact there were difficulties in monitoring and mitigating price deviations below marginal cost in any of the periods. These deviations seem to have encouraged generators to make additional investments in generation capacity – specifically within the review period involving CCGTs, wind power and solar panel operations – which was a major concern for policy makers and led to production of significant legislation in the second period of analysis of this study.

Our results for the 2006–2007 period show a certain level of inconsistency in our proposed relations in assessing market competition and controlling market power and underpinning investment incentives.

Several reasons can be put forward to explain why the prices in the 2002–2007 period have exceeded the value of 36.06 €/MWh and the domestic price of 42.25 €/MWh. These are also explained as the consequence of the regulatory mechanism applied throughout the period, by the CTC mechanism and by the new payment mechanism of new installed capacity.

Our results for the first period point to the effectiveness of the “CTC payment” effect in mitigating the market power exercise in the Spanish electricity market during the 2002–2005 regulatory period. However, during this period, the differences between real prices and marginal costs are significant as well as the differences between real prices and the regulated price cap.

Moreover, one reason may be associated with the loss of effectiveness of the mechanism over time: with the entry of new generators without CTC rights, regulated revenues in the retail market decreased over time, which led to its abolition in June 2006. Another reason may be related to customers switching to a price-set market (thereby reducing the total amount of payments CTC), thus generating uncertainty in market regulation. The main incumbent generators, mainly Iberdrola, over time reached an amount of revenue through the CTC mechanism identical to what they had already received when the mechanism was introduced. The other basic reason is that the costs changed over time, in particular due to: the availability of hydroelectric power, especially between to 2005 and 2007; the increase in the gas and coal costs

that led to higher generation costs; the emission allowances, that biased the estimates found for the marginal costs in the second period of analysis. Clearly, a regulatory policy encouraging the appropriate mix of technology in the production of electricity is on high demand.

Furthermore, regulatory measures implemented in 2006–2007 sought to mitigate the impact of the increasing electricity tariff deficit, in order to reduce retail market prices, to reduce the magnitude of the tariff deficit, to reduce the market power and to encourage investment in new power plants with cleaner technologies. Our results corroborate the effectiveness of these measures. Nevertheless, the two regulatory periods show different developments in the market. Accordingly, the application of the proposed relationships based on the variables considered in the study encourages further reflections for future research.

In this new 2006–2007 regulatory period, companies generating electricity were subjected to much more important challenges in terms of bidding strategies than in the 2002–2005 stabilization regulatory period. Although price cap regulation seems to be successful in providing incentives within regulatory cost efficiency period, some questions still remain as to its ability to induce the long-term investment, particularly in the presence of demand uncertainty with the integration of the Portuguese and Spanish market.

The recent financial crisis and dramatic falls in investments, mainly as a result of excessive regulatory intervention introduced in the market from 2006 onwards, deserve special attention especially by the typical conflict between regulation and competition emerging in the light of a new set of relevant factors in the market. Therefore, it is important for future research that both these determinants are considered.

References

- Anderson, E.J., Philpott, A.B., 2002. Optimal offer curve construction in electricity markets. *Math. Oper. Res.* 27 (1), 82–100.
- Ausubel, L.M., Cramton, P., 2002. Demand Reduction and Inefficiency in Multi-unit Auctions. University of Maryland Working Paper
- Baldick, R., Grant, R., Kahn, E., 2004. Theory and application of linear supply function equilibrium in electricity markets. *J. Regul. Econ.* 25 (2), 143–167.
- Banovac, E., Glavic, M., Tesnjak, S., 2009. Establishing an efficient regulatory mechanism—prerequisite for successful energy activities regulation. *Energy* 34, 178–189.
- Borenstein, S., Bushnell, J., 1999. An empirical analysis of the potential for market power in California's electricity market. *J. Ind. Econ.* 47 (3), 285–323.
- Borenstein, S., Bushnell, J., Wolak, F., 2002. Measuring market inefficiencies in California's restructured wholesale electricity market. *Am. Econ. Rev.* 92, 1376–1405.
- Breitung, J., 2000. The local power of some unit root tests for panel data. In: Baltagi, B. (Ed.), *Advances in Econometrics*, vol. 15. JAI, Amsterdam (Nonstationary Panels, Panel Cointegration, and Dynamic Panels).
- Bushnell, J., 1998. Water and Power: Hydroelectric Resources in the Era of Competition in the Western US. Program on Workable Energy Regulation (POWER) PWP-056. University of California Energy Institute, Berkeley, CA
- Bushnell, J., 2003. A mixed complementarity model of hydro-thermal electricity competition in the Western U.S. *Oper. Res.* 51 (1), 81–93.
- Bushnell, J., Saravia, C., 2002. An Empirical Assessment of the Competitiveness of the New England Electricity Market. University of California Energy Institute (CSEM WP-101)
- Choi, I., 2001. Unit root tests for panel data. *J. Int. Money Finance* 20 (2), 249–272.
- Ciarreta, A., Espinosa, M.P., 2010a. Supply function competition in the Spanish wholesale electricity market. *Energy J.* 31 (4), 137–158.
- Ciarreta, A., Espinosa, M.P., 2010b. Market power in the Spanish electricity auction. *J. Regul. Econ.* 37, 42–69.
- Ciarreta, A., Espinosa, M.P., 2012. The impact of regulation on pricing behavior in the Spanish electricity market (2002–2005). *Energy Econ.* 34, 2039–2045.
- Crampe, C., Fabra, N., 2005. The Spanish electricity market: plus ça change... *Energy J.* 26 (1), 127–154.
- Cramton, P., Stoft, S., 2006. The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem. Berkeley, California, White Paper for the Electricity Oversight Board.
- Evans, L., Guthrie, G., 2006. Incentive regulation on prices when costs are sunk. *J. Regul. Econ.* 3 (5), 239–264.
- Fabra, N., Toro, J., 2005. Pricewars and collusion in the Spanish electricity market. *Int. J. Ind. Organiz.* 23 (3–4), 155–181.

- Federico, G., Vives, X., 2008. Competition and Regulation in the Spanish Gas and Electricity Markets. Reports of the Public–Private Sector Research Center. IESE Business School. University of Navarra
- Furió, D., Lucía, J.J., 2009. Congestion management rules and trading strategies in the Spanish electricity market. *Energy Econ.* 31, 48–60.
- García-Díaz, A., Marín, P., 2003. Strategic bidding in electricity pools with short-lived offers: an application to the Spanish market. *Int. J. Ind. Organ.* 21 (2), 201–222.
- García-Martín, J.A., 2001. Spot Market Competition with Stranded Costs in the Spanish Electricity Industry, WP 0106, CEMFI.
- Green, R., 1996. Increasing competition in the British electricity market. *J. Ind. Econ.* 44, 205–216.
- Hadri, K., 2000. Testing for stationarity in heterogeneous panel data. *Econ. J.* 3, 148–161.
- Holmberg, P., 2007. Asymmetric supply function equilibrium with constant marginal costs. *Energy J.* 28 (2), 55–82.
- Holmberg, P., Newbery, D., 2010. The supply function equilibrium and its policy implications for wholesale electricity auctions. *Util. Policy* 18 (4), 209–226.
- Im, K.S., Pesaran, M.H., Shin, Y., 2003. Testing for unit roots in heterogeneous panels. *J. Econometrics* 115, 53–74.
- Jamasb, T., Orea, L., Pollit, M., 2012. Estimating the marginal cost of quality improvements: the case of the UK electricity distribution companies. *Energy Econ.* 34, 1498–1506.
- Joskow, P., 2007. Competitive electricity markets and investment in new generating capacity. In: Helm, D. (Ed.), *The New Energy Paradigm*. Oxford University Press, Oxford
- Joskow, P.L., Kahn, E., 2002. A quantitative analysis of pricing behavior in California's wholesale electricity market during summer 2000. *Energy J.* 0 (4), 1–35.
- Kao, C., Chiang, M.H., 2000. On the estimation and inference of a cointegrated regression in panel data. *Adv. Econometrics* 15, 179–222.
- Kelman, R., Barroso, L., Pereira, M., 2001. Market power assessment and mitigation in hydrothermal systems. *IEEE Trans. Power Syst.* 16 (3), 354–359.
- Kühn, K.U., Machado, M., 2004. Bilateral Market Power and Vertical Integration in the Spanish Electricity Spot Market. CEPR Discussion Papers 4590.
- Lagarto J., Sousa J., Martins Á., 2010. The impact of the Iberian electricity market on the competitive behavior of generating companies using a conjectural variations approach. In: Seventh International Conference on the European Energy Market (EEM), 23–25th June, Madrid; 2010.
- Levin, A., Lin, C.-F., Chu, J., 2002. Unit root tests in panel data: asymptotic and finite-sample properties. *J. Econometrics* 108, 1–24.
- Linares, P., Labandeira, X., 2004. Energy efficiency: economics and policy. *J. Econ. Surv.* 24 (3), 573–592.
- Maddala, G., Wu, S., 1999. A comparative study of unit root tests with panel data and a new simple test. *Oxford Bull. Econ. Stat.* 61, 631–652.
- Moutinho, V., Vieira, J., Moreira, A., 2011. The crucial relationship among energy commodity prices: evidence from the Spanish electricity market. *Energy Policy* 39 (10), 5898–5908.
- Neuhoff, K., Barquin, J., Boots, M.G., Ehrenmann, A., Hobbs, B.F., Rijkers, F.A., 2005. Network constrained Cournot models of liberalized electricity markets: the devil is in the details. *Energy Econ.* 27 (3), 495–525.
- Newbery, D., 1998. Competition, contracts, and entry in the electricity spot market. *RAND J. Econ.* 29 (4), 726–749.
- Otero-Novas, I., Meseguer, C., Batlle, C., Alba, J., 2000. A simulation model for a competitive generation market. *IEEE Trans. Power Syst.* 15 (1), 250–257.
- Pedroni, P., 2001. Purchasing power parity tests in cointegrated panels. *Rev. Econ. Stat.* 83 (4), 727–731.
- Pedroni, P., 2004. Panel cointegration: asymptotic and finite sample properties of pooled time series tests with an application to the PPP hypothesis. *Econometric Theory* 20, 597–625.
- Pesaran, H., 2007. A simple panel unit root test in the presence of cross-section dependence. *J. Appl. Econometrics* 22 (2), 265–312.
- Rudkevich, A., Duckworth, M., Rosen, R., 1998. Modeling electricity pricing in a deregulated generation industry: the potential for oligopoly pricing in a Poolco. *Energy J.* 19 (3), 19–48.
- Stoft, S., 2002. *Power System Economics: Designing Markets for Electricity*. IEEE Press, Piscataway, New Jersey p. 2002
- Ventosa, M., Baillo, Á., Ramos, A., Rivier, M., 2005. Electricity market modeling trends. *Energy Policy* 33 (7), 897–913.
- Von der Fehr, N-H., Harbord, D., 1993. Spot market competition in the UK electricity industry. *Econ. J.* 103, 531–546.
- Westerlund, J., 2007. Testing for error correction in panel data. *Oxford Bull. Econ. Stat.* 69, 709–748.
- Wolak, F.A., 2003. Measuring unilateral market power in wholesale electricity markets: the California market, 1998–2000. *Am. Econ. Rev.* 93 (2), 425–430.
- Wolfram, C.D., 1999. Measuring duopoly power in the British electricity spot market. *Am. Econ. Rev.* 89 (4), 805–826.
- Yao, J., Oren, S., Adler, I., 2007. Two-settlement electricity markets with price caps and Cournot generation firms. *Eur. J. Oper. Res.* 181, 1279–1296.
- Zachmann, G., 2007. A Markov Switching Model of the Merit order to Compare British and German Price Formation. Discussion Papers of DIW Berlin 714, DIW Berlin, German Institute for Economic Research.