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Evaluating the strategic supply per power plant: evidence from the Spanish wholesale electricity market

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Abstract: This paper analyses the relationship among marginal costs per power plant, fossil fuel prices and electricity bidding quantities in the Spanish electricity market. The results of the panel cointegration and Granger causality methods clearly indicate a differential impact of fossil fuel prices on power plants marginal costs, with a positive effect for gas power plants. The biggest negative impact on marginal costs is seen for coal technology. As a consequence of the characteristics of different production technologies, the set of marginal costs across the sample is based on coal power plants, although Endesa and Iberdrola's marginal costs are predominantly based on gas power plants. Operating costs for hydroelectric power plants are very low when compared to the thermal power plants, which is the base technology used by Endesa, since this technology is strongly dependent on the volatility of commodity markets and on the supply chain and production costs management.

Keywords: fossil fuel prices; capacity generation; power plant marginal costs; panel cointegration.

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1 Introduction

Electrical supply systems are composed of different technologies, which imply different investment and marginal costs in the production of electricity. Some of them have high fixed costs and low variable costs operating almost continuously, while others operate with high variable costs whose production is discontinuous and dependent on exogenous conditions such as hydropower or wind. Accordingly, the market offers different rewards for different technologies, because of unpredictable phenomena at the moment at which the production technology investment occurs. This adjustment is not possible in the electricity production sector because the majority of the investment is not replicable and sunk costs discourage the abandonment of technologies whose remuneration does not cover average costs, only variable costs.

The liberalisation of the Spanish electricity market also led to profound changes in the way electricity producers manage and operate their power plants, as these started facing a large number of strategic decisions with different time scales. The company decisions are now reflected over several time horizons. Long-term decisions are related to the best strategy the company may adopt in the construction of new power plants, as well as in what technology to invest. On the other hand, short-term decisions may include sale proposals offered to the market as well as the scheduling and planning of production of the various generation groups. Apart from these decisions, medium-term decisions, which refer to a period of several months to a year, are some of the most important decisions company must take to properly exploit their generation groups. These type of decision include for example the purchase of fuel, the allocation of water resources (hydro production is limited to water reservoirs that dictate the amount of electricity that such plants can produce between periods of rainfall), seeking to maximise profit.

The increasing the substitution of non-renewable sources by renewable ones in the production of electricity has received special treatment after the European Directives 2001/77/EC, 2003/36/EC, 2009/28/EC and the Energy-Climate Package 20/20/201 (2008). It is important to understand how the substitution of (renewable and non-renewable) primary energy sources can influence the electricity generation supply as the predominance of non-renewable sources of production is relevant to both the energy and environmental policies in order to deploy the right mechanisms and incentives for the direct replacement of fossil fuels among primary energy sources. This increasing attention to global electricity production issues by type of technology and to international policies and incentives necessary for the promotion of renewable sources have required new stimuli to analyse the relationship between electricity production and fossil fuels of primary energy sources used to produce electricity. Moreover, the substitution of non-renewable primary energy sources by renewable ones significantly influences the investment decisions of the electricity generators.

Technology influences operational and economic performance of electricity producers. For example, although hydroelectricity power plants can be started and stopped in order to adapt outputs levels, almost instantaneously, thermal plants are almost inflexible as start-up and shut-down costs are higher (Rangel, 2008; Sandsmark and Tennbakk, 2010). Moreover, while hydroelectricity plants are intrinsically dynamic, thermal plants are intrinsically static as coal or gas consumed in a given period does not affect electricity production in subsequence periods (Rangel, 2008).

Technology also influences the competitive process as hydro plants are more able to quickly respond to their competitors in a short notice than thermal plants (Rangel, 2008).

The cost structure is also influenced by the type of technology, as hydro plants do not incur in fuel costs *vis-à-vis* thermal plants (Rangel, 2008; Sandsmark and Tennbakk, 2010). Moreover, as marginal costs of hydropower available are virtually zero, the main determinant of prices of hydro plants is the opportunity cost of releasing water, which depends on expectations about hydrological conditions, namely periods of drought (Rangel, 2008). These technological characteristics give hydro-bases systems an anti-competitive behaviour that is less stringent than in thermal-based systems (Rangel, 2008; Sandsmark and Tennbakk, 2010). For a closer examination of the Spanish reality see Fabra and Fabra-Utray (2009a, 2009b).

As fuel prices influence the production cost of a plant producing electricity, the latter are used in merit order. In this situation the producer offers positive net-supply with positive mark-ups and pushes down the price using its market power, while mark-ups are zero at the contracting point where net-supply is also zero (Holmberg and Newberry 2010).

Taking into account an optimal mix of production technologies, the fluctuation of demand over time leads the system towards a low variable cost-based-load plant and higher cost mid-merit plant. Accordingly, in order to recover fixed costs, electrical power firms tend to withhold their units as long as their revenues are higher than the lost opportunity costs.

Reforms in the Spanish electricity market, as well as in other European countries, consisted of the transition from a vertically integrated system, including production, transportation, distribution and commercialisation, to a system with divisions based on the largest areas of activity, including regulated non-competitive activities. In general, as a consequence of the characteristics of these different production technologies, coal plants set prices during periods of low demand, thus, hydroelectric plants prevail during peak periods (Fabra, 2009). The purpose of this separation was to increase economic efficiency through price adjustment (a short-term goal) and to improve investment decisions by optimising the risks associated to such investments (a long-term goal). Furió and Lucia (2009) found that some power generators have an economic incentive to avoid being dispatched in the day-ahead market in order to be called up in the constraints resolution process of the subsequent transmission; while Ciarreta and Espinosa (2010) demonstrate that the larger operators in the day-ahead market are able to increase prices significantly above the competitive benchmark. They provided a measure of market power based on the different bidding behaviour of large and small generators at the specific demand level.

This paper addresses the following question: is there a causality relation, in the short and long-run, between power plant marginal costs, bidding quantities and fossil fuel prices?

The main objective is to explore the relationship between power plant marginal costs, bidding electricity quantities and fossil fuel prices, using panel cointegration testing and estimation techniques. The motivation behind this article is to comprehend, on the one hand, if the production marginal costs influence the sale decisions in the wholesale electricity market or, on the other hand, if price movements and consequent units transactioned (coal, fuel oil, natural gas, crude-oil), that influence the production costs and the quantities traded on the market are the result of the behaviour of other players and not the result of the production capacity.

Essentially, electricity in Spain is produced by two vertically integrated incumbent firms: Endesa, that controls 37% and 40.5% and Iberdrola, that controls 39% and 36.7% of, respectively, the total installed capacity and the wholesale production; and three smaller competitors, Unión Fenosa, Hidrocantábrico and Vieago. The generation mix comprises: hydropower, 27.9% of the total capacity in 2003; coal, 18.6%; oil-gas, 15.3; nuclear, 12.1%; CCGT, 6.8%; and renewable resources, of which wind is the most important (8.5%) (Crampes and Fabra, 2005). Ciarreta and Espinosa (2010, 2012), Moutinho et al. (2011, 2014), Fabra and Fabra-Utray (2009a, 2009b) and Federico and Vives (2008) give a deeper understanding of the Spanish electricity market.

The relationship between prices and biding quantities according to the types of technology used in the electricity production for the main five players were plotted and analysed. Their marginal costs curves were also analysed. Differences in slopes and positions among fitted curves reflect differences in fuel expenditure from one month to the next, as well as some technological/organisational/learning progress. In general, we find in the Spanish wholesale market data that non-concavity is the most evident characteristic of the power plant marginal cost behaviour.

Various panel unit root tests were performed to demonstrate that the variables are an integrated process with unit root. Three distinct firm-group panels (first: Endesa and Iberdrola; second: Union Fenosa, Hidrocantábrico, Viesgo and Others; third: all firms) were established to use cointegration estimation techniques such as dynamic OLS to estimate, first, the long-run regression equation and the dynamic error correction model (ECM) and then, to estimate the short-run Granger causality.

The rest of the paper is structured as follows. Section 2 provides a literature review. Section 3 addresses the market equilibrium problem within the context of the Spanish market. Section 4 describes the data and methodology used in the empirical analysis. Section 5 describes the econometric strategy and presents the empirical results and Section 6 concludes with some policy implications.

2 Literature review

The literature highlights several relationships between the marginal costs per plant, fossil fuel prices, bidding quantities and wholesale electricity prices, with different sets of historical data and different methodologies. The following reported studies show some relations between the abovementioned variables, but none include in one model all the variables and simultaneous effects between them.

Brealey and Lapuerta (1997) reported that the national power operator offered their generating sets at marginal cost. Borenstein et al. (2002) and Joskow and Kahn (2002) present hourly marginal costs in the California electricity market and compare these estimates to the wholesale prices. Wolfram (1999) compares market prices with marginal costs for the restructured UK market.

Garcia et al. (2001) analyse the effects of the stochastic nature of inflows on oligopoly hydro scheduling and collusion behaviour between hydro generators. They conclude that the likelihood of collusion increases as reservoir levels increase, since punishment becomes more credible.

In a situation with limited transmission capacity between two regions connected by a single radial transmission line, Johnsen (2001) analyses market power and storage. He concludes that a monopolist increases production in a certain period when inflow is certain to avoid the possibility of becoming export constrained in a subsequent period in the case that high inflow occurs. The main conclusion is straightforward: storage is lower during monopoly than during competitive regimes.

Hydroelectric resources, *vis-à-vis* thermal-based systems, have the ability to smooth the price profile when operated in perfectly competitive environments (Crampes and Moreaux, 2001; Bushnell, 2003). Moreover, demand peaks tend to be shaved-off and enhance two different types of behaviour: as price-takers, hydro generators tend to transfer production from off-peak periods, when prices are low, to peak periods, when prices are high, in contrast, when they have market power, hydro generators tend to sharpen the peaks in order to increase market prices.

Rangel (2008) claims that even in competitive markets average process may differ across periods due to inflows and reservoir capacity management issues. In a different vein, even if the demand function is the same in several periods, levels of perfect competitive prices will be affected as hydro monopolists may exploit capacity constrains through imports and exports (Førsund and Hoel, 2004).

Hydro plants' competitive bidding behaviour is different from that of thermal plants (Sandsmark and Tennbakk, 2010), as it stems from two different characteristics: the source of the imput, water vs. fuel and the type of response to the market (Rangel, 2008; Sandsmark and Tennbakk, 2010). This means that bidding behaviour is the result of a complex dynamic optimisation problem that leads to a differentiated dynamic market power for thermal and hydro producers.

More market power for hydro generators may have a beneficial effect on reliability in hydro-thermal mixed systems, as less competition among hydro producers means that they will undercut thermal producers less often and more water will be stored (Skaar, 2004).

Kim and Knittel (2003) adjusted their previous measure of marginal cost since firms that maximise profits in the short run would not price below marginal cost. This assumption reflects either estimation errors in the marginal cost measures or inter-temporal constraints to shut down power plants.

Guerre et al. (2000) established a relationship between bid quantities and marginal costs recovering the marginal cost functions (valuations) of firms from bid data, under the assumption that each bidder is acting optimally against the distribution of the other opponents' bids.

Zachmann (2008) argues that power plant start-up costs, as well as the cost for reserve capacity, are more important in an electricity system that is based to a larger degree on coal, establishing a relationship between marginal costs and fossil fuel.

Regarding the relationship between fossil fuel prices, based on their bivariate model, Ewing et al. (2002) conclude that there exists a significant diffusion of volatility from the natural gas sector to the oil sector. Mohammadi (2009) finds a bi-directional and stable long-term causality between coal and electricity prices and an insignificant long-term relationship between electricity and crude oil and/or natural gas prices.

In competitive electricity markets, the aggregated supply curve reflects the amount of increasing marginal costs offered by different power plants in order to produce electricity. The electricity supply is affected by three sources of variability: fuel prices, the number of power plants available to produce and the technological rationale (Fezzi and Bunn, 2010).

Sims et al. (2003) present typical costs/Kwh from conventional pulverised coal-fired plants and then compare coal-fired power generation plants with alternative types of generation. They conclude that a gas-fired combined combustion gas turbine (CCGT) would generally have negative mitigation costs compared with the coal-fired baseline, reflecting its lower generation costs.

Analysing three energy technologies, coal, nuclear and CCGT, Safarzynska and Bergh (2011) found that the spot price decreased over time during the period 1990–2002 because of the entry of cheap CCGT stations that eventually replaced more expensive coal and nuclear generators. If power plants lack the opportunity to hedge their profits against fluctuations in electricity and fuel prices, they tend to produce less output.

Methodologically, models developed by the New Empirical Industrial Organization (NEIO) have been formulated incorporating the dynamic nature of statistical approaches and models (Sexton and Zhang, 2001; Karp and Perloff, 1989; Deodhar and Sheldon, 1996). Steen and Salvanes (1999) developed a dynamic model based on a model previously developed by Bresnahan (1982). The main difference between the models is that Steen and Salvanes (1999) introduce an error correction mechanism. This is known as the ECM, which is an adaptation from Bärsden (1989). Nevertheless and as was previously observed, dynamic treatment appears to be unrelated to economic reasoning, having econometric origins with underlying economic implications.

3 The electricity market equilibrium problem

In the structure of the Spanish wholesale electricity market, two large operators – Endesa and Iberdrola – coexist, using their broad mix of production in order to enable them to make flexible offers according to the expected supply and demand. In contrast, smaller operators such as Unión Fenosa, Hidrocantábrico and Viesgo, whose mix of production is lower, have a reduced ability to submit competitive offers or be sufficiently flexible. For these operators, the option to offer their production at around zero prices, knowing that Endesa and Iberdrola will offer at higher prices, is the easiest way to sell as much as possible.

An example of the strategic behaviour of those two dominant operators is the way they bid, especially Iberdrola's, in the wholesale electricity market. For example, hydro plants set the system marginal price in 80% of the time during peak-demand hours, while conventional thermal generators set the price in 60% of the off-peak hours. Although this observation does not necessarily mean that the Spanish hydro firms were capable of significantly distorting market prices away from competitive levels, it does mean that different technologies underpin different competitive behaviour.

This article was motivated by the following three main aspects of the Spanish electricity market: firstly, the large installed capacity of electricity generators influences the ability to establish marginal pricing in the wholesale market; secondly, taking into account the composition of companies' production power plants or mixes of production, the pricing of the offer in the wholesale market over different time periods is restricted mainly by differences among different technologies (hydro, thermal, conventional, nuclear, wind, solar, etc.) used by power plants that generate the installed power in the system; finally, the high cost of electricity production is associated with high volatility in the prices of commodities (coal, gas, fuel oil, Brent) that the producers have to deal with in the production of that energy.

The critical cost assumption in electricity generation for power plant operators depends on fossil fuel prices and therefore this becomes endogenous to the problem. However, this is not a critical issue for plants that usually operate on a baseload (minimum power demand in the system) power basis (as is the case for marginal units such as gas combined cycles or coal power plants) and therefore run continuously.

Another endogeneity issue is the correlation between the prices of fuel oil, coal and gas. The competitiveness of power plants will depend not only on their costs, but also on their income. This income depends basically on the electricity market price, which is in turn determined by the cost of marginal units. Since these are usually gas or coal power plants, the price will be determined by gas, fuel oil, Brent and coal allowance prices. Again, this affects baseload and marginal technologies differently, depending on whether they use coal, fuel or gas.

The issues referred to in the literature review section, show how important electricity markets are, particularly if the goal is to understand the competition policies effects. Accordingly, it is important to understand the shape of the marginal cost curves, for various technologies to know which one is more stringent at any point in time (e.g., Fabra and Fabra-Utray, 2009b). Smaller-sized electricity producers and third party operators taken as a whole cannot find together conditions to establish prices in most of the time periods. The electricity price is the same for every production hour and does not take into account the costs differences nor the source of each KWh produced.

Hence, technologies with high fixed costs and low variable costs operate almost continuously in time and their payback is determined by the hourly prices set throughout the year, whereas technologies with high variable costs whose production is discontinuous and reliant on exogenous variables such as hydraulicity, wind speed; as a result, the market picks up one or other technology by unpredictable events leading to production yields turnouts. This adjustment is not possible in the electricity production sector because most of the turnouts are not replicable and sunk costs encourages the rejection of technologies whose payback is not enough to cover average costs but just the variable costs. Therefore it is unlikely for customers to pay electricity at the market price and that would be a required condition for the capacity reduction and adjustment. Overall, based on the characteristics of those different production technologies, coal plants set the prices mainly on the low demand periods, while hydroelectric plants prevail during rush hours. Their capacity is at least equal to the existent exceeding supply in the market, especially during the peak demand periods. As such, the joint offer from the other producers is not enough to satisfy demand; therefore, pivot companies can increase their prices in response to this demand without being excluded from the market. Specifically, several structural market characteristics allow strategic coordination between operators, like the fact of being a homogeneous product market and relatively transparent in which disagreements regarding pricing are almost immediately detected.

The theory of contestable markets supports that in certain specific market conditions – free market entry and exit, access to the same level of technology and sunk costs – it is possible to a group of oligopolists to behave as if they were in competitive equilibria (Baumol et al., 1982). The option for a price similar to marginal cost is accepted, however, it is still doubtful whether it is relevant in the short or in the long term.

Andersson and Bohman (1985) argue that it is advisable to abandon the concept of long-term marginal cost and to rely on a pricing system based on short-term marginal cost, which is also defended by Joskow (1987). They base their recommendation based on the fact that public services, in general and electricity production systems, in particular, are characterised by significant production indivisibilities.

In Branch's (1993) model, price and capacity are simultaneously determined before the demand is known. As such, they are determined through a demand forecasting model. However, the price setting is not constant for the lifetime (in economic terms) of a power plant.

For different reasons, namely the uncertain evolution of energy prices and wage costs, the electricity tariff cannot be fixed for over a year. Weisman (1994) states that the basic question is to know which is the best measure of marginal costs, short-term or long-term marginal costs. For Weisman (1994), this depends on the specific nature of the transactions, i.e., of the risk associated with the uncertainty of the demand being supported by the company or by the consumer. As the transaction terms implicitly define the allocation of risk allocation between the buyer and the seller, the best measure of marginal cost is a function of this allocation.

According to the Cournot model, each producing company bids a selling proposition to the market for a certain period of time. In the electricity spot market, the purchase bids are sorted in decreasing order so that higher prices offers have priority over lower prices offers, while selling bids orders are sorted in ascending order so that the lower prices offers have priority over higher prices offers. The closing price (equilibrium price) is established by the intersection of the supply and the demand curves. However, because of other restrictions, some deals with economic merit may not match and the closing price is then given by the intersection of the matched supply and demand curves.

The market operator matches the proposals with the electricity demand for each time period and determines the price at which energy will be purchased – the so-called market-clearing price. Then each company chooses the selling amount that maximises its profits, assuming that the amount of energy sold by other companies is fixed. Finally, equilibrium is reached when the amounts that maximise the profit of each company it is determined, since proposals of other companies are known. Green (2000), Neuhoff et al. (2005), Centeno et al. (2007), Bunn and Oliveira (2008) apply several Cournot models to electrical systems. They describe and relate the differences between of the results obtained by the models, as well as the assumptions made by each methodology. The problem of deciding which power plants should be producing electricity is recognised as one of the most critical aspects of the electrical system operation and it has been of particular interest to many researchers over time. Moreover and equally important is that it is necessary to meet the system load while minimising the fuel costs of different plants using different technologies for the production of electricity, taking into account the necessary conditions to grant the safety levels of all equipment used.

This suggests that it is important for companies to have at their disposal different types of electricity production technologies in order to allocate and transfer to generation across the various plants, in order to achieve higher profits. As such, since the dispatch order of the different technologies is based on the electricity generation marginal costs, ordered from the lowest to the highest, the coal plants are scheduled first, followed by the combined-cycle gas turbine and fuel-oil power plants. As such, using a sub-optimal solution, preferably the optimal solution, results in major gains for different electricity production companies.

The absence of studies reporting a causality relation, in the short and long-run, between the three variables (marginal, bidding quantities and fossil fuel prices) of power plant is the main motivation for this study.

4 Data and methodology description

There are several technologies of electricity generation for which it is impractical to explicitly model marginal production costs. Much of the energy is produced by conventional generation sources. Thus a firm's estimated marginal cost function consists of a piecewise linear function of fossil fuel production costs, where each segment of the piecewise linear function represents a quintile of the firm's portfolio marginal cost, beginning at the marginal cost of its least expensive unit and ending at the marginal cost of its most expensive unit.

Under the assumption of firm-level profit maximisation, it is possible to estimate the level of marginal cost implied by a given equilibrium price and quantity (Hortaçsu and Puller, 2008).

However, we adopted the power plant marginal cost expression given by: $MC_{p,fuel} = (f \times cf)/(LHV \times \eta_p)$ (Lagarto et al., 2010), where $MC_p = MC_{p,fuel} + MC_{p,\mathrm{CO2}}$, MC_p is the power plant p marginal cost in euros/MWh; $MC_{p,fuel}$ is the power plant p marginal cost due to fossil fuel costs in euros/MWh; f is the fossil fuel price in euros/ton; cf is a conversion factor equal to 859,845 kcal/MWh; LHV is the lower heating value in kcal/ton; and η_p is power plant efficiency in %. $MC_{p,\mathrm{CO2}}$ is the marginal cost of power plant $_p$ due to CO_2 emissions cost in €/MWh, which was zero for the 2002–2005 period, is given by: $MC_{p,\mathrm{CO2}} = P_{\mathrm{CO2}} \times ee_p \times 10^{-3}$, where P_{CO2} is the CO_2 emission price in €/ton; ee_p is the power $_p$ specific emission of CO_2 in Kg CO_2/MWh. The different daily periods are significantly conditioned by differences between the different technologies of production used by the power plants that generate the installed power of the system.

The above mentioned expression is applied to estimate the marginal costs of coal-fired, fuel-fired and CCGT power plants. For hydro and nuclear power plants the marginal cost was close to zero. The energy produced by hydropower, renewable sources and undefined technologies was considered to be must-run. Accurate estimates of the short-run marginal costs of fossil fuel electricity plants can be calculated since their efficiencies at different output levels are currently available (Lagarto et al., 2010).

The systems that jointly supply the Spanish electricity wholesale market have very similar generating equipment and their variable cost will be equalised due to the substitution of the most obsolete equipment with combined cycle power stations, which increases the exchange capacity (Fernández-Dominguez and Xiberta-Bernat, 2007).

Since electricity demand usually presents a high variability on the daily horizon, every power market needs low marginal cost generation units operating all day (usually with high start-up costs) and flexible plants, typically with higher marginal costs, producing only at the peak. This feature creates an extremely high price volatility on a daily basis, since when the quantity varies, different plants start producing and the pivotal technology (and hence, the marginal cost) changes.

Marginal power generation costs are obtained for all power plants in the portfolio. Plants are then ranked in order of ascending marginal costs (merit order) and profit-maximising producers start generating from the plant with lowest marginal cost. As demand increases, plants are added following the merit order. Theoretically, daily changes in fuel and carbon prices can change merit order through their effect on relative marginal generation costs.

Our focus was on the Spanish electricity wholesale market and its major fuel sources (oil, coal, gas). The data consists of daily observations (24 hour moving average) of demand and supply for each agent (Endesa, Iberdrola, Unión Fenosa, Hidrocantabrico 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 2005. 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.

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. We define the natural logarithms of all used variables. The nominal price of coal is measured as the average of the physical price (API, per short ton), for natural gas as euros per thousand cubic feet at wellhead (gas Zeebrugge) and for crude oil as euros per barrel first purchase price (Brent crude, IPE). All series are given in EUR.

We used an inter-weekly seasonal pattern similar to the daily demand for electricity in order to standardise variables. This filtering method involved the collection of daily data of these variables together with information on calendar factors that may influence the outcome: day of the week, national holiday, post-holiday, eastern, christmas and the year of the observations.

The series obtained were modelled using neural networks. The adjusted values were used to filter the series that have an inter-weekly behaviour similar to the electricity consumption, by simply dividing the consumptions by the adjusted rates. With the application of this filter, it is possible to sense the variation of a given variable after considering the effect of the calendar, i.e., one gets a filtered series of inter-weekly seasonality.

The filtering of seasonality starts by aggregating the series to assure that they have a monthly frequency. After using structural models, one can get the seasonal additive type factors, which are then applied to each series in each case.

The evolution of daily closing market marginal cost and daily closing prices of coal and gas is shown in Figure 1. For the analysis we used a logarithmic transformation. The evolution of the marginal costs for Hidrocantábrico and Unión Fenosa are shown in Figure 2 and Endesa and Iberdrola in Figure 3.

Figure 1 The evolution daily closing market marginal cost and prices of coal and gas (see online version for colours)

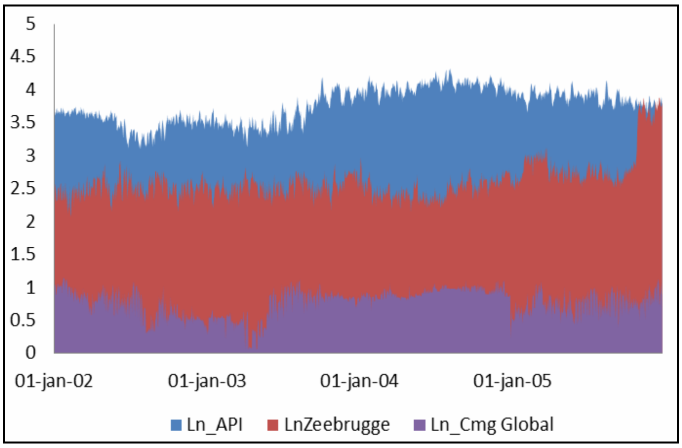


Figure 2 The evolution of Hidrocantábrico and Unión Fenosa's marginal costs

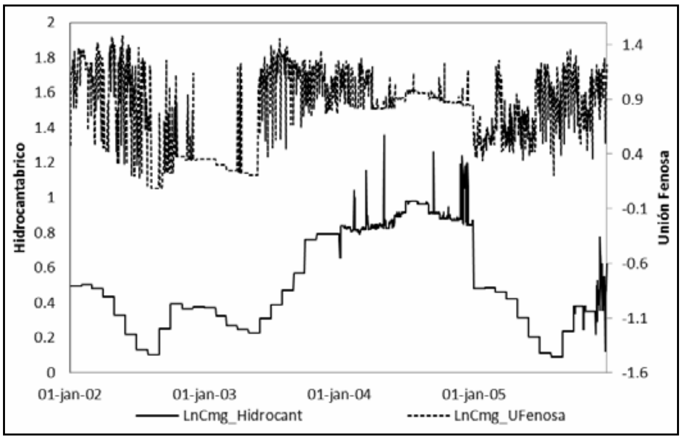
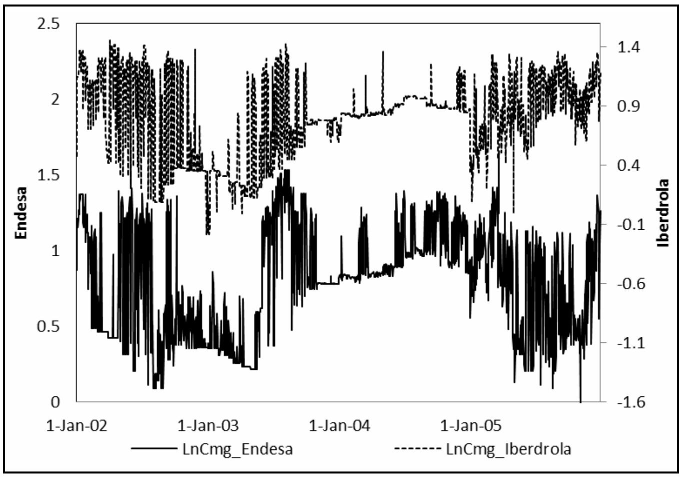


Figure 3 The evolution of Endesa and Iberdrola's marginal costs



We did not include figures for Viesgo and other agents as they had many outliers and peaks which distorts the analysis of the variables of the series.

To empirically analyse the contribution of each part to variations in the marginal costs, our strategy is to isolate the part of the shocks in the identified marginal costs that is induced by fossil fuel prices and supply movements:

$$\begin{aligned}\Delta MC_t &= \alpha_i + \sum_{i=1}^{a1} \alpha_{ij}\Delta MC_{t-i} + \sum_{j=0}^{b1} \beta_{1j}\Delta FuelF_i P_{t-j} + \sum_{q=0}^{ci} \gamma_{1q}\Delta Qs_{t-q} \\ &\quad + \alpha_1 MC_{t-1} + \delta_1 FuelF_i P_{t-1} + \lambda_1 Qs_{t-1} + \varepsilon_{1t}\end{aligned} \tag{1}$$

where ε_{1t} and Δ are the white noise term and the first difference operator, respectively. $FuelF_i$ represents the fuel price for each commodity. Qs_i represents the electricity bid quantity in the wholesale market. The econometric exercise involved three steps. In the first step, the unit root test ascertained whether or not the time series of each variable included in the autoregressive distributed lag (ADL) contained stochastic trend and whether the set variables are non-stationary or not.

In order to test, under the null hypothesis, that all individual series of the panel contain a unit root, assuming that all panels share a common autoregressive parameter, the Levin-Lin-Chu (LLC) (Levin et al., 2002) unit root test was employed.

With the possible assumption that a fraction of the total N individual series panel is stationary with different autoregressive parameters an Im-Pesaran-Shin test (Im et al., 2003) was carried out. This test relaxes the assumption of a common autoregressive parameter and specifies one regression of Dickey-Fuller (DF) type for each cross-sectional unit. Even in this second alternative hypothesis of heterogeneity, we chose to also consider the Fisher-Augmented Dickey-Fuller (ADF) test, based on the combination of significance levels of the individual tests like the ADF.

All the tests discussed so far use as the null hypothesis that the series contains a unit root. We only reject the null hypothesis if the evidence against it is sufficiently strong (according to the classical statistical methods). Testing the null hypothesis of stationarity against the alternative of a unit root, therefore, can be interesting. We also utilise the Hadri (2000) method, which tests the null hypothesis that the data are stationary versus the alternative that at least one panel contains a unit root. Regardless of the alternative hypothesis used, the results of panel tests are difficult to interpret if the null hypothesis is rejected.

The second step in our empirical analysis is to test if marginal costs, electricity bidding quantities in wholesale market and fossil fuel prices are cointegrated. Following Westerlund (2007), we propose four panel cointegration tests. 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 and individual specific slope parameters. Westerlund (2007) develop two group-mean tests, G_r and G_α and two analogous panel results tests, P_r and P_α. In several estimates of these four statistical tests with a deterministic trend the null hypothesis of no cointegration could not be rejected.

Finally, the ECM, in the third step, was estimated by using, firstly, an individual effects regression and secondly, a panel data regression technique. Basically, this approach involves two steps for estimating marginal cost long-run relationships. Firstly, we investigate the existence of long-run relationships among all variables in model 1:

$$\begin{aligned} MC_{it} &= \alpha_2 + \sum_{i=1}^{a1} \phi_{2i} MC_{t-j} + \sum_{j=0}^{b1} \beta_{2j} BrentP_{t-j} + \sum_{j=0}^{b1} \delta_{2j} FuelP_{t-j} + \sum_{j=0}^{b1} \eta_{2j} CoalP_{t-j} \\ &\quad + \sum_{j=0}^{b1} \varpi_{2j} GasP_{t-j} + \sum_{q=0}^{c1} \gamma_{2j} Qs_{it-q} + \varepsilon_{2t} \end{aligned} \tag{2}$$

Secondly, we investigate the dynamic short-run causality on portfolio power plant marginal costs:

$$\begin{aligned} \Delta MC_{it} &= \alpha_3 + \sum_{i=1}^{a1} \phi_{3i} \Delta MC_{t-i} + \sum_{l=0}^{b1} \beta_{3j} \Delta BrentP_{l-j} + \sum_{j=0}^{c1} \delta_{3j} \Delta FuelOilP_{t-j} \\ &\quad + \sum_{m=0}^{d1} \eta_{3m} \Delta CoalP_{m-j} + \sum_{k=0}^{e1} \varpi_{3k} \Delta GasP_{k-j} + \sum_{q=0}^{f1} \gamma_{3j} \Delta Qs_{it-q} + \xi ECM_{t-1} + \varepsilon_{3t} \end{aligned} \tag{3}$$

and the dynamic short-run causality on portfolio bidding quantities:

$$\begin{aligned} \Delta Qs_{it} &= \alpha_3 + \sum_{i=1}^{a1} \gamma_{3j} \Delta Qs_{t-j} + \sum_{j=0}^{b1} \beta_{3j} \Delta BrentP_{t-j} + \sum_{j=0}^{b1} \delta_{3j} \Delta FuelOilP_{t-j} \\ &\quad + \sum_{j=0}^{b1} \eta_{3j} \Delta CoalP_{t-j} + \sum_{j=0}^{b1} \varpi_{3j} \Delta GasP_{t-j} + \sum_{q=0}^{c1} \phi_{3i} \Delta MC_{it-q} + \xi ECM_{t-1} + \varepsilon_{3t} \end{aligned} \tag{4}$$

Finally, we investigate the dynamic short-run as causality on fossil fuel prices (Brent, coal, fuel oil and gas):

$$\begin{aligned} \Delta FuelP_t &= \alpha_4 + \sum_{i=1}^{a1} \gamma_{4j} \Delta Qs_{t-j} + \sum_{j=0}^{b1} \beta_{4j} \Delta BrentP_{t-j} + \sum_{j=0}^{b1} \delta_{4j} \Delta FuelOilP_{t-j} \\ &\quad + \sum_{j=0}^{b1} \eta_{4j} \Delta CoalP_{t-j} + \sum_{j=0}^{b1} \varpi_{4j} \Delta GasP_{t-j} + \sum_{q=0}^{c1} \phi_{4i} \Delta MC_{it-q} + \xi ECM_{t-1} + \varepsilon_{4t} \end{aligned} \tag{5}$$

where ξ is the coefficient of the ECM term, where ECM is defined as:

$$ECM_t = MC_t - \alpha_2 - \sum_{i=1}^{a1} \phi_2 MC_{t-i} - \sum_{j=0}^{b1} \beta_2 FuelF_i FP_{t-j} - \sum_{q=0}^{c1} \gamma_{2j} Qs_{it-q} \qquad (6)$$

This shows how quickly variables converge to equilibrium and should have a statistically significant coefficient with a negative sign. The negativity of this parameter ensures a negative feedback mechanism to drive the dependent variable towards its long run equilibrium.

Table 1 Panel unit root tests

Sample group	*Variable*	*LLC t*-stat: H_0: unit root*	*IPS W-stat: H_0: unit root*	*Hadri Z-stat: H_0: no unit root*	*Fischer-ADF Z-stat: H_0: unit root*
Group 1: Endesa, Iberdrola	*LnMC*	6.5688	–5.899	8.443	–1.930
		[1.000]	[0.000]***	[0.000]***	[0.026]**
	LnBrentP	2.48441	–4.74	20.834	0.004
		[0.993]	[0.000]***	[0.000]***	[0.501]
	LnFuelP	–0.6045	–0.065	20.294	0.862
		[0.272]	[0.474]	[0.000]***	[0.8058]
	LnCoalP	4.0872	–2.803	14.932	1.993
		[1.000]	[0.002]***	[0.000]***	[0.976]
	LnGasP	5.052	–1.446	11.374	2.954
		[1.000]	[0.074] *	[0.000]***	[0.998]
	LnBidQ	5.7063	–5.547	4.2429	–2.732
		[1.000]	[0.000]***	[0.000]***	[0.003]***
Group 2: Unión Fenosa. Hidrocantábrico, Viesgo and others	*LnMC*	4.3686	–6.311	11.805	–3.369
		[1.000]	[0.000]***	[0.000]***	[0.000]***
	LnBrentP	3.5135	–6.715	29.463	0.005
		[0.999]	[0.000]***	[0.000]***	[0.502]
	LnFuelP	–0.8549	–0.0092	28.700	1.220
		[0.1963]	[0.463]	[0.000]***	[0.888]
	LnCoalP	5.7801	–3.963	21.117	2.818
		[1.000]	[0.000]***	[0.000]***	[0.997]
	LnGasP	7.1453	–2.045	16.085	4.178
		[1.000]	[0.020]**	[0.000]***	[1.000]
	LnBidQ	2.8358	–6.413	18.049	–2.854
		[0.997]	[0.000]***	[0.000]***	[0.002]***

Notes: Probability values are reported in parentheses,
***, **, * denote the rejection of the null at 1%, 5% and 10% levels, respectively

Table 1 Panel unit root tests (continued)

Sample group	*Variable*	*LLC t*-stat: H_0: unit root*	*IPS W-stat: H_0: unit root*	*Hadri Z-stat: H_0: no unit root*	*Fischer-ADF Z-stat: H_0: unit root*
Group 3: All firms	*LnMC*	6.3919	–8.558	14.511	–3.865
		[1.000]	[0.000]***	[0.000]***	[0.000]***
	LnBrentP	4.3031	–8.224	36.085	0.006
		[1.000]	[0.000]***	[0.000]***	[0.5024]
	LnFuelP	–1.0471	–0.112	35.151	1.493
		[0.1475]	[0.455]	[0.000]***	[0.932]
	LnCoalP	7.0792	–4.854	25.863	3.451
		[1.000]	[0.000]***	[0.000]***	[0.999]
	LnGasP	8.7511	–2.504	19.700	5.116
		[1.000]	[0.006]***	[0.000]***	[1.000]
	LnBidQ	4.5969	–8.441	21.591	–3.908
		[1.000]	[0.000]***	[0.000]***	[0.000]***

Notes: Probability values are reported in parentheses,
***, **, * denote the rejection of the null at 1%, 5% and 10% levels, respectively

5 Empirical method and empirical results

5.1 Empirical results: unit root tests

Table 1 reports the results of panel unit root tests of the examined variables.

A general-to-specific approach was adopted in order to deal with the number of mismatches: starting with a maximum of 36 lags, we eliminated the non-significant mismatches. According to the results, all variables are integrated.

Table 1 displays the results of four distinct panel unit root tests: LLC, IPS, Hadri and ADF-Fischer. We cannot reject the null hypothesis of panel unit root in all variables, according to the results of the four tests, for all samples, at conventional significance levels. Since we found the existence of unit roots in all the variables, by various panel unit root tests, panel cointegration tests should be conducted to examine whether there is a long-term equilibrium relationship between the dependent variable (marginal cost of each power plant) and the explanatory variables (Brent price, fuel price, coal price, gas price and bid quantities by each electricity operator).

5.2 Panel cointegration tests

The null hypothesis of all the performed cointegration tests the existence of no cointegration. In all cases the null hypothesis of no cointegration among the variables is strongly rejected at the 1% significance level, as shown in Table 2.

Table 2 Westerlund cointegration panel data tests tests

Statistics	*Ln MC-Ln Brent*	*Ln MC-Ln coal*	*Ln MC-Ln fuel*	*Ln MC-Ln gas*	*Ln MC-Ln Qs*
Group 1: Endesa, Iberdrola					
G_r	–3.406	–3.021	–3.55	–3.04	–3.08
	(0.032)**	(0.121)	(0.017)**	(0.113)	(0.101)
G_α	–40.686	–38.080	–43.00	–34.66	–37.93
	(0.000)***	(0.000)***	(0.000)***	0.000)***	(0.000)***
P_r	–4.881	–4.581	–5.10	–4.52	–4.65
	(0.014)**	(0.032)**	(0.006)***	(0.037)**	(0.026)**
P_α	–41.465	–41.100	–44.90	–36.45	–40.95
	(0.000)***	(0.000)***	(0.000)***	(0.000)***	(0.000)***
Firms of group 2: Unión Fenosa, Hidrocantábrico, Viesgo and others					
G_r	–3.757	–3.930	–3.75	–3.71	–3.40
	(0.000)***	(0.000)***	(0.000)***	(0.000)***	(0.002)***
G_α	–44.16	–52.210	–45.87	–42.96	–41.90
	(0.000)***	(0.000)***	(0.000)***	(0.000)***	(0.000)***
P_r	–7.39	–8.040	–7.64	–7.14	–7.30
	(0.000)***	(0.000)***	(0.006)***	(0.000)***	(0.000)***
P_α	–40.46	–53.90	–44.73	–38.93	–42.10
	(0.000)***	(0.000)***	(0.000)***	(0.000)***	(0.000)***
Group 3 all firms: Endesa, Iberdrola, Unión Fenosa, Hidrocantábrico, Viesgo and others					
G_r	–3.64	–3.64	–3.68	–3.47	–3.38
	(0.000)***	(0.000)***	(0.000)***	(0.000)***	(0.001)***
G_α	–43.0	–47.51	–45.11	–40.12	–40.57
	(0.000)***	(0.000)***	(0.000)***	(0.000)***	(0.000)***
P_r	–8.9	–9.20	–9.23	–8.51	–8.92
	(0.000)***	(0.000)***	(0.006)***	(0.000)***	(0.000)***
P_α	–41.3	–49.41	–45,02	–38.34	–43.10
	(0.000)***	(0.000)***	(0.000)***	(0.000)***	(0.000)***

Notes: p-values are reported in parentheses,
***, **, * denote rejection of the null hypothesis at 1%, 5% and 10% levels, respectively

Hence the variables in the regression equation, which individually contain unit roots, seem to have a cointegration relation, i.e., a long-run equilibrium relationship. As we are interested in the average relationship across firms, panel statistics are more relevant for our case. The Westerlund (2007) cointegration test, rather than being based on residual dynamics, is a structural-based test and therefore does not impose any common factor restrictions.

The Westerlund panel statistics reject the null hypothesis of no cointegration at 1%, suggesting that there is strong evidence for a possible common relationship between the marginal cost, the bidding quantities and all fossil fuel prices for the panels under study –

group 1, group 2 and group 3. It provides the explanation that the residual-based test requires the long-run cointegrating vector for these variables in levels to be equal to the short-run adjustment process for the variables in differences. Because the Akaike optimal lag and lead search is time-consuming when combined with bootstrapping, we kept the short-term dynamics fixed (Westerlund, 2007).

5.3 *Long-run and short-run results*

The long-run relationship can also be specified with the marginal cost as the dependent variable, in which case the relationship resembles the fossil fuel prices and bid quantities in market relationship.

Table 3 Estimated coefficients for the long-run – DOLS model

ECM for group 1	*ECM 1*	*ECM 2*	*ECM 3*	*ECM 4*	*ECM 5*	*ECM 6*
LnMC	1	–0.021	–0.005	0.165	–0.037	0.097
		[–7.8***]	[–2.03]**	[39.3]***	[–16.8]***	[19.7]***1
LnBrentP	0.153	–0.139	1	1.600	0.822	0.459
	[11.3]***	[–22.4***]		[165.7]***	[162.3]***	[40.2]***
LnCoalP	0.037	0.032	0.429	1	–0.368	–0.126
	[23.6]***	[4.43]***	[63.9]***		[–61.8]***	[–9.44]***
LnFuelP	–0.36	–0.013	0.955	–1.590	1	0.197
	[–10.9]***	[–0.76]	[62.7]***	[–61.7]***		[6.45]***
LnGasP	0.097	0.054	0.104	–0.028	0.063	1
	[7.9]***	[9.7]***	[20.1]***	[–2.96]***	[13.7]***	
LnQs	–0.009	1	–0.017	0.018	0.005	0.030
	[–.055]		[–2.3]***	[1.46]*	[0.74]	[2.12]**
ECM for group 2	*ECM 1*	*ECM 2*	*ECM 3*	*ECM 4*	*ECM 5*	*ECM 6*
LnMC	1	0.812	–0.032	0.171	–0.037	–0.004
		[105]***	[–17.9]***	[58.18]***	[–16.8]***	[–1.06]
LnBrentP	–0.363	0.170	1	1.593	0.822	0.430
	[–36.5]***	[9.75]***		[242.5]***	[162.3]***	[52.9]***
LnCoalP	0.660	0.055	0.442	1	–0.368	–0.066
	[56.7]***	[2.66]***	[93.2]***		[–61.8]***	[–6.89]***
LnFuelP	0.122	0.153	0.955	–1.600	1	0.211
	[4.61]***	[3.28]***	[88.28]***	[–90.8]***		[9.67]***
LnGasP	–0.097	0.161	0.102	0.021	0.063	1
	[15.6]***	[10.2]***	[28.0]***	[3.54]***	[13.7]***	
LnQs	0.069	1	0.002	–0.000	0.005	0.002
	[15.6]***		[0.89]	[–0.15]	[0.74]	[0.66]

Notes: *t* statistics are between brackets,
***, **, * denote levels of significance of 1%, 5% and 10% levels, respectively

Table 3 Estimated coefficients for the long-run – DOLS model (continued)

ECM for group 3	*ECM 1*	*ECM 2*	*ECM 3*	*ECM 4*	*ECM 5*	*ECM 6*
LnMC	1	1.187	–0.025	0.168	0.001	0.021
		[226.7]***	[–17.]***	[70.37]***	[0.43]	[7.16]***
LnBrentP	–0.156	0.113	1	1.596	0.824	0.445
	[–19.38]***	[–19.7]***		[293.1]***	[281.8]***	[67.]***
LnCoalP	0.551	–0.278	0.438	1	–0.387	–0.084
	[58.2]***	[–19.7]***	[113.0]***		[–112.]***	[–10.79]***
LnFuelP	–0.068	0.021	0.954	–1.600	1	0.200
	[–3.17]***	[6.49]***	[108.1]***	[–109.]***		[11.2]***
LnGasP	–0.036	0.101	0.106	0.007	0.062	1
	[–4.9]***	[9.35]***	[35.4]***	[1.42]*	[23.3]***	
LnQs	0.064	1	0.001	–0.005	0.000	0.001
	[14.9]***		[0.58]	[–1.73]**	[0.07]	[0.15]

Notes: *t* statistics are between brackets,
***, **, * denote levels of significance of 1%, 5% and 10% levels, respectively

We will now explore the multivariate long-run relationship between marginal cost, fossil fuel prices and portfolio bidding quantities and also the speed of adjustment λ for the different firm groups. The computed *t* values for tests of parametric restriction on the ECM, relating to dynamic ordinary least squares (DOLS), are given in Table 3. The parameters λ come back to long-run equilibrium levels once they violate the long-run equilibrium relationship. These parameters are of particular interest as they have important implications for the dynamics of the power plant marginal costs of electricity in the wholesale market. The negative sign of the estimated speed of adjustment coefficients are in accordance with the convergence toward long-run equilibrium.

We estimate the long-run equation using DOLS, as recommended in Kao and Chiang (2001), with 36 lags and 36 leads. We tried many combinations of lags and leads and chose the ones above because it minimises the Akaike information criterion (AIC). We tested the hypothesis H_0: $\beta_j = 1$. The t-test rejected the hypothesis at 1%, which implies that, on average, the marginal cost in each of an operator's power plants adjusts more than fully to fossil fuel price shocks and electricity quantities bidding in market auction in the long run.

5.3.1 Interpretation of long-run results

The estimated long-term cointegration equations ECM1 and ECM2 seek to validate the hypothesis whether the international commodity prices affect the cost and the quantity traded in the market by technology type or are the production marginal costs of and commodity prices that influence the transactioned amount game. Regarding equations ECM3 to ECM6, the aim is to validate the hypothesis if bid quantities in the electricity market and production marginal costs influence the demand and prices of each of the commodities in international markets.

In the two long-run relationships (ECM1 and ECM2), where fossil fuel prices are endogenous to the cointegration vector, for group 1 (Endesa, Iberdrola), the wholesale bid quantities are exogenous to the cointegration vector for its non-significance in ECM1. Then, we can assume that it is the marginal cost that moves to restore equilibrium. In ECM 2 and for the same group of electricity operators, the fuel prices seem to be exogenous to the cointegration vector. In this case it is the bid quantity that moves to restore balance. In the ECM1 and ECM2 for group 2 and group 3, the results indicate significance at 1% for the marginal cost elasticities and bid quantities concerning the commodity prices. The fossil fuel prices that most influence the marginal costs and bidding quantities (ECM 1 and ECM2) in group 1 (Endesa and Iberdrola) are the prices of Brent crude oil and coal, with higher marginal cost elasticity for the price of these two fuels for group 1 (respectively 15.3% and 3.7%). For the second group, while maintaining the order of importance of the two mentioned prices in the marginal cost elasticity, in the case of the, crude oil, gas and fuel have higher bidding quantity elasticity concerning fossil fuel prices, at 17%, 16.1% and 15.3% respectively (level of almost equal importance).

In order to evaluate the competitiveness of the production inputs, namely the existence (or not) of interdependence between the different commodities we used the remaining long-term dynamic relationships (ECM 3, ECM4, ECM5 and ECM6), where the bid quantities on the stock market also appear to be exogenous to the four cointegrating vectors for group 2 and exogenous at one co-integrating vector in the case of the Endesa and Iberdrola group. In these circumstances it is the prices of Brent crude oil, coal, fuel oil and gas that move respectively to restore the long-term balance. Thus there is evidence, for these relationships, that the commodity prices influence each other at a significance level of 1% in all groups of electricity operators. This bi-directionality effect, in the long run, is basically predictable by the inclusion of all commodities in the portfolio of utilised technologies used in electricity production.

These results confirm that for both, Endesa and Iberdrola, the main dominant firms in the market, the quantities supplied by thermal and hydro technology do not influence marginal costs, although these have a significant effect on the quantities bid in the market due to the raw-material (commodities) costs. Notwithstanding, for the other players under analysis there is a bidirectional effect between marginal costs by technology and quantities supplied to the market.

With regard to the price volatility of the commodities markets, it is possible to claim that for Group 1 (Endesa and Iberdrola) there is a significant effect of marginal costs by technology and the quantity supplied in the coal and natural gas market, two important inputs in the production of electricity for thermal power plants. Accordingly, the supply management and futures contracts decision-making in commodities markets have implications for the management of thermoelectric capacity, although Iberdrola make their market bids at lower prices especially when their supply is based on hydro and nuclear technologies and Endesa make their bids at higher prices, supplying from coal and CCGT technologies.

Another significant result in the long-term relationships is that marginal costs influence the evolution of each individual price of the commodity series and also confirm the bi-directionality effects for the Endesa and Iberdrola group (with marginal costs explaining 16.4% of the relative change in the price of coal and 9.7% of the relative change in the price of gas). In group 2 the marginal costs reveal no significant contribution to explaining the evolution of the price of gas, but contribute 17% to the explanation of the price of coal.

All the estimated long-term dynamic relationships reveal and confirm that coal technology is very important in explaining bid quantities at the wholesale price and also support the explanation of marginal cost evolution, confirming the results of the previous study.

The results indicate, for group 1, that 1% increase in Brent price, coal price and gas price causes increases of 13.5%, 38% and 19%, respectively, in power plant marginal costs.

It is noteworthy that the 1% increase in coal price had a larger positive effect on power plant marginal cost portfolio than gas price did. This is due to the high power plant marginal costs faced in portfolio bidding quantities.

5.3.2 *Interpretation of short-run results*

An implication of cointegration is that there must be causality in at least one direction. For this we estimate the following ECM panel, which gives the adjustment mechanism when power plant marginal costs, fossil fuel prices and bidding quantities deviate from the long-run equilibrium in the short run. We estimate the simple ECM for the long-run relationship explained in equations (1) and (2). The short-run equations are as follows:

$$\begin{aligned} Ln\Delta MC_{it} &= \alpha + \lambda ECM_{t-1} + \gamma_1 \Delta LnBrentP_{it} + \gamma_2 \Delta LnBrentP_{t-1} + \gamma_3 \Delta LnCoalP_{it} \\ &\quad + \gamma_4 \Delta LnCoalP_{t-1} + \gamma_5 \Delta LnFuelOilP_{it} + \gamma_6 \Delta LnFuelOilP_{t-1} + \gamma_7 \Delta LnGasP_{it} \\ &\quad + \gamma_8 \Delta LnGasP_{t-1} + \delta_1 \Delta LnQs_t + \delta_2 \Delta LnQs_{t-1} + \theta_1 \Delta LnMC_{it-1} + \mu_{it} \end{aligned} \tag{7}$$

and

$$\begin{aligned} Ln\Delta Qs_{it} &= \alpha + \lambda ECM_{t-1} + \gamma_1 \Delta LnBrentP_{it} + \gamma_2 \Delta LnBrentP_{t-1} + \gamma_3 \Delta LnCoalP_{it} \\ &\quad + \gamma_4 \Delta LnCoalP_{t-1} + \gamma_5 \Delta LnFuelOilP_{it} + \gamma_6 \Delta LnFuelOilP_{t-1} + \gamma_7 \Delta LnGasP_{it} \\ &\quad + \gamma_8 \Delta LnGasP_{t-1} + \delta_1 \Delta LnMC_t + \delta_2 \Delta LnMC_{t-1} + \theta_1 \Delta LnQs_{it-1} + \mu_{it} \end{aligned} \tag{8}$$

The errors for period $t - 1$ are estimated from the long-run equation (2), after imposing the DOLS estimates for fixed effects.

The coefficients are adjustment parameters and give the degree to which the respective left-side variables adjust in period t to disequilibrium shocks in period $t - 1$.

Equations (7) and (8) are dynamic, as they involve the first difference of the dependent variables and include the first difference of the independent variables because the right-hand side term is correlated with the first differenced error term. In Table 4, the error correction term is statistically significant, with an expected negative sign in all cases at a 1% significance level.

For a specific firm group, the equations (7) and (8) take specific forms depending on the statistical significance of the individual parameters in the abovementioned equations. We discuss this case below and also examine the implications for short-run movement or shocks from the causality point of view. Let us consider first the case of all groups for which not all the estimated parameters are significant in the case where the power plant marginal costs and bidding portfolio quantities are dependent variables. We have in the short run $\Delta LnMC_{it-1}$ and $\Delta LnQs_{it-1}$. This implies that any shock in $\Delta LnMC_{it-1}$ and $\Delta LnQs_{it-1}$ will cause a corresponding shock in $LnMC_{it}$ and $\Delta LnQs_{it}$. Hence, we have a very specific kind of power plant marginal costs to bidding portfolio quantities reverse causality for all firm groups. However, in this case the power plant marginal costs and bidding portfolio quantities causality is implemented by an additional autoregressive effect in the power plant marginal costs. This means that a sudden drop in the power plant marginal costs will have a lingering effect due to the significant autoregressive elements that generate the increase in the marginal costs' elasticity.

Table 4 Coefficients of dynamic short-run panel causality tests [equations (7) and (8)]

Long-run fixed effects coefficients	*Equation (7) group 1*	*Equation (7) group 2*	*Equation (7) group 3*	*Equation (8) group 1*	*Equation (8) group 2*	*Equation (8) group 3*
λ	–0.240	–0.206	–0.220	–0.149	–0.068	–0.052
	[–30.2]***	[–38.86]	[–49.6]***	[–22.5]***	[–20.9]***	[–22.3]***
Short-run fixed effects coefficients	*Equation (7) group 1*	*Equation (7) group 2*	*Equation (7) group 3*	*Equation (8) group 1*	*Equation (8) group 2*	*Equation (8) group 3*
γ_1	0.035	–0.114	–0.060	–0.017	0.014	0.007
	[0.71]	[–3.47]***	[–2.19]**	[–1.00]	[0.43]	[0.31]
γ_2	–0.011	0.068	0.040	–0.009	–0.010	–0.005
	[–0.35]	[3.10]***	[2.15]**	[0.73]	[–0.44]	[–0.32]
γ_3	0.188	0.173	0.018	–0.018	–0.063	–0.069
	[3.03]***	[4.17]***	[5.18]***	[–0.81]	[–1.53]	[–2.38]**
γ_4	–0.087	–0.099	–0.096	–0.002	0.020	0.024
	[–2.03]**	[–3.45]***	[–4.01]***	[–0.12]	[0.72]	[1.21]
γ_5	0.137	0.011	0.046	–0.008	0.026	0.002
	[0.87]	[0.11]	[0.53]	[–0.14]	[0.24]	[0.03]
γ_6	–0.066	–0.008	–0.024	0.004	–0.014	–0.001
	[–0.62]	[–0.12]	[–0.40]	[0.11]	[–0.19]	[–0.03]
γ_7	–0.066	–0.011	–0.028	0.014	–0.054	–0.036
	[–1.67]*	[–0.43]	[–1.29]	[0.99]	[–2.05]**	[–1.98]**
γ_8	0.023	0.009	0.015	0.006	0.041	0.033
	[0.89]	[0.51]	[1.05]	[0.69]	[2.32]**	[2.7]***
δ_1	0.410	0.109	0.124	0.050	0.134	0.134
	[8.55***	[8.07]***	[10.05]***	[8.93]***	[11.2]***	[16.1]***
δ_2	–0.211	–0.047	–0.059	–0.026	–0.077	–0.077
	[–6.75]***	[–5.81]***	[–7.44]***	[–7.2]***	[–10.2]***	[–14.6]***
θ_1	0.527	0.520	0.523	0.511	0.507	0.506
	[86.2]***	[113.2]***	[142.4]***	[71.9]***	[97.8]***	[118.5]***
α	–0.157	–0.323	–0.220	1.856	0.549	0.498
	[27.07]***	[–38.04]***	[–47.1]***	[22.5]***	[20.9]***	[22.3]***

Notes: *t* statistics are between brackets,
***, **, * denote levels of significance of 1%, 5% and 10% levels, respectively

Next, we consider the case in which $\Delta LnMC_{it}$ depends on fossil fuel prices. In the case of group 1, the associated parameters $\Delta LnCoalP_t$, $\Delta LnCoalP_{t-1}$ and $\Delta LnGas_{Pt-1}$ are significant at 1%, 5% and 10% respectively. In the case where $\Delta LnQs_{it}$ depends on fossil fuel prices, all the estimated parameters are not significant in firm group 1.

In group 2, the estimated parameters associated with $\Delta LnBrentP_t$, $\Delta LnBrentP_{t-1}$, $\Delta LnCoalP_t$, $\Delta LnCoalP_{t-1}$ are significant at 1% on $\Delta LnMC_{it}$ but not significant on $\Delta LnQs_{it}$. The larger the value of λ, the stronger is the significance of the variable $\Delta LnMC_{it}$ and $\Delta LnQs_{it}$ to the previous period's deviation from long-run equilibrium, if any. As the results show, the $\Delta LnMC_{it}$ in group 1 is 24%, in group 2 is 20.6% and in all firms in group 3 is 22%; for portfolio bidding quantities, group 1 is 14.9%, group 2 is 6.8% and group 3 is 5.2%. Comparing group 1 with group 2 implies, for group 2, that any deviation in the long-run equilibrium of the value of the power plant marginal costs (20.6%) and portfolio bidding quantities (6.8%) requires a much stronger long-run equilibrium to be restored.

We now consider three new multivariate relationships between Ln Brent price, fuel prices (coal, fuel oil, gas), power plant marginal costs and bidding portfolio quantities, as the following equation:

$$\begin{aligned} Ln\Delta Brent_t &= \alpha + \lambda ECM_{t-1} + \gamma_1 \Delta LnBrentP_{t-1} + \gamma_2 \Delta LnCoalP_{it} \\ &+ \gamma_3 \Delta LnCoalP_{t-1} + \gamma_4 \Delta LnFuelOilP_{it} + \gamma_5 \Delta LnFuelOilP_{t-1} \\ &+ \gamma_6 \Delta LnGasP_{it} + \gamma_7 \Delta LnGasP_{t-1} + \delta_1 \Delta LnMC_{it} + \delta_2 \Delta LnMC_{t-1} \\ &+ \theta_1 \Delta LnQs_t + \theta_2 LnQs_{t-1} + \mu_{it} \end{aligned} \tag{9}$$

and a multivariate relationship between Ln fuel oil price, fuel prices (Brent, coal, gas), power plant marginal costs and bidding portfolio quantities, as the following equation:

$$\begin{aligned} Ln\Delta FuelOilP_t &= \alpha + \lambda ECM_{t-1} + \gamma_1 \Delta LnBrentP_{it} + \gamma_2 \Delta LnBrentP_{t-1} \\ &+ \gamma_3 \Delta LnCoalP_{it} + \gamma_4 \Delta LnCoalP_{t-1} + \gamma_5 \Delta LnFuelOilP_{t-1} \\ &+ \gamma_6 \Delta LnGasP_{it} + \gamma_7 \Delta LnGasP_{t-1} + \delta_1 \Delta LnMC_t + \delta_2 \Delta LnMC_{t-1} \\ &+ \theta_1 \Delta LnQs_{it} + \theta_2 \Delta LnQs_{it-1} + \mu_{it} \end{aligned} \tag{10}$$

Table 5 Coefficients of dynamic short-run panel causality tests [equations (9) and (10)]

Long-run fixed effects coefficients	*Equation (9) group 1*	*Equation (9) group 2*	*Equation (9) group 3*	*Equation (10) group 1*	*Equation (10) group 2*	*Equation (10) group 3*
λ	–0.162	–0.161	–0.161	–0.027	–0.027	–0.027
	[–23.5]***	[–33.30]	[–40.8]***	[–9.6]***	[–13.7]***	[–16.8]***
Short-run fixed effects coefficients	*Equation (9) group 1*	*Equation (9) group 2*	*Equation (9) group 3*	*Equation (10) group 1*	*Equation (10) group 2*	*Equation (10) group 3*
γ_1	0.507	0.508	0.051	0.037	0.037	0.037
	[66.8]***	[94.6]***	[115.9]***	[6.0]***	[8.5]***	[10.5]***
γ_2	0.020	0.023	0.022	–0.017	–0.017	–0.017
	[0.91]	[1.48]	[1.75]*	[–4.3]***	[–6.1]***	[–7.5]***
γ_3	–0.016	–0.017	–0.017	–0.013	–0.013	–0.013
	[–1.07]	[–1.64]*	[–1.97]**	[–1.75]*	[–2.6]***	[–3.1]***

Notes: *t* statistics are between brackets,

***, **, * denote levels of significance of 1%, 5% and 10% levels, respectively

Table 5 Coefficients of dynamic short-run panel causality tests [equations (9) and (10)] (continued)

Short-run fixed effects coefficients	*Equation (9) group 1*	*Equation (9) group 2*	*Equation (9) group 3*	*Equation (10) group 1*	*Equation (10) group 2*	*Equation (10) group 3*
γ_4	0.328	0.327	0.328	0.005	0.006	0.006
	[6.02]***	[8.47]***	[10.4]***	[1.04]	[1.69]*	[1.96]**
γ_5	–0.187	–0.187	–0.187	0.501	0.501	0.501
	[–5.0]***	[–7.14]**	[–8.7]***	[59.1]***	[83.7]***	102.6]***
γ_6	–0.016	–0.016	–0.016	0.004	0.004	0.0039
	[–1.21]	[–1.71]*	[–2.08]**	[0.86]	[1.19]	[1.47]
γ_7	0.003	0.003	0.003	–0.002	–0.002	–0.002
	[0.36]	[0.52]	[0.61]	[–0.67]	[–0.94]	[–1.16]
δ_1	–0.001	–0.013	–0.009	0.001	0.000	0.001
	[–0.10]	[–3.04]***	[–2.5]***	[0.43]	[0.32]	[0.63]
δ_2	–0.001	0.006	0.004	–0.000	–0.000	–0.000
	[–0.26]	[2.29]**	[1.79]*	[–0.30]	[–0.32]	[–0.56]
θ_1	–0.005	0.001	0.000	–0.001	–0.000	–0.000
	[–0.31]	[0.14]	[0.05]	[–0.29]	[–0.15]	[–0.22]
θ_2	0.002	–0.001	–0.000	0.001	0.000	0.000
	[0.222]	[–0.18]	[–0.12]	[0.26]	[0.17]	[0.23]
α	–0.499	–0.536	–0.536	0.092	0.095	0.096
	[–23.5]***	[–33.2]***	[–40.7]***	[9.66]***	[13.7]***	[16.9]***

Notes: *t* statistics are between brackets,
***, **, * denote levels of significance of 1%, 5% and 10% levels, respectively

In the case in which the prices of Brent price and fuel oil are dependent variables, in the short-run, the mentioned variables significantly depend in their own past value $\Delta LnBrentP_{t-1}$ and $\Delta LnFuelOilP_{t-1}$. This implies that any shock in $\Delta LnBrentP_{t-1}$ and $\Delta LnFuelOilP_{t-1}$ will cause a respective shock in $\Delta LnBrentP_t$ and in $\Delta LnFuelOilP_t$. Hence, we have here a reverse Granger causality for all groups (1, 2 and 3).

Finally, we consider three new multivariate relationships between Ln coal price, fuel prices (Brent, fuel oil, gas), power plant marginal costs and bidding portfolio quantities, as the following equation:

$$\begin{aligned} Ln\Delta Coal_t = {} & \alpha + \lambda ECM_{t-1} + \gamma_1 \Delta LnBrent_{it} + \gamma_2 \Delta LnBrent_{t-1} + \gamma_3 \Delta LnCoalP_{t-1} \\ & + \gamma_4 \Delta LnFuelOilP_{it} + \gamma_5 \Delta LnFuelOilP_{t-1} + \gamma_6 \Delta LnGasP_{it} \\ & + \gamma_7 \Delta LnGasP_{t-1} + \delta_1 \Delta LnMC_t + \delta_2 \Delta LnMC_{t-1} \\ & + \theta_1 \Delta LnQs_t + \theta_2 \Delta LnQs_{t-1} + \mu_{it} \end{aligned} \tag{11}$$

and a multivariate relationship between Ln gas price, fuel prices (Brent, coal, fuel oil), power plant marginal costs and bidding portfolio quantities, as the following equation:

$$\begin{aligned} Ln\Delta GasP_t &= \alpha + \lambda ECM_{t-1} + \gamma_1 \Delta LnBrentP_{it} + \gamma_2 \Delta LnBrentP_{t-1} + \gamma_3 \Delta LnCoalP_{it} \\ &\quad + \gamma_4 \Delta LnCoalP_{t-1} + \gamma_5 \Delta LnFuelOilP_t + \gamma_6 \Delta LnFuelP_{t-1} + \gamma_7 \Delta LnGasP_{t-1} \quad (12) \\ &\quad + \delta_1 \Delta LnMC_t + \delta_2 \Delta LnMC_{t-1} + \theta_1 \Delta LnQs_{it} + \theta_2 \Delta LnQs_{it-1} + \mu_{it} \end{aligned}$$

Table 6 Coefficients of dynamic short-run panel causality tests [equations (11) and (12)]

Long-run fixed effects coefficients	*Equation (11) group 1*	*Equation (11) group 2*	*Equation (11) group 3*	*Equation (12) group 1*	*Equation (12) group 2*	*Equation (12) group 3*
λ	–0.034	–0.034	–0.034	–0.076	–0.076	–0.076
	[–9.63]***	[–13.7]***	[–16.8]***	[–14.9]***	[–21.2]***	[–26.0]***
Short-run fixed effects coefficients	*Equation (11) group 1*	*Equation (11) group 2*	*Equation (11) group 3*	*Equation (12) group 1*	*Equation (12) group 2*	*Equation (12) group 3*
γ_1	0.025	0.026	0.026	–0.027	–0.030	–0.029
	[1.65]*	[2.35]**	[1.65]***	[–1.20]	[–1.86]*	[–2.2]**
γ_2	–0.009	–0.010	–0.010	0.0189	0.020	0.020
	[–0.90]	[–1.33]	[–1.65]*	[1.25]	[1.9]*	[2.27]**
γ_3	0.499	0.499	0.499	0.006	0.009	0.008
	[57.1]***	[81.0]***	[99.2]***	[0.23]	[0.44]	[0.48]
γ_4	–0.097	–0.095	–0.095	–0.005	–0.007	–0.006
	[–2.09]**	[–2.88]***	[–3.55]***	[–0.27]	[–0.50]	[–0.57]
γ_5	0.054	0.053	0.053	0.034	0.036	0.035
	[1.71]*	[2.35]**	[2.89]***	[0.48]	[0.71]	[0.85]
γ_6	0.005	0.004	0.004	–0.021	–0.021	–0.021
	[0.43]	[0.52]	[0.66]	[–0.42]	[–0.61]	[–0.73]
γ_7	–0.001	–0.001	–0.001	0.050	0.050	0.050
	[–0.18]	[–0.18]	[–0.24]	[64.7]***	[91.7]***	[112.47]***
δ_1	0.012	0.009	0.010	–0.005	–0.004	–0.005
	[2.42]**	[2.45]**	[3.43]**	[–0.63]	[–0.76]	[–1.13]
δ_2	–0.008	–0.005	–0.006	0.002	0.001	0.002
	[–2.6]***	[–2.03]**	[–3.2]***	[0.34]	[0.37]	[0.60]
θ_1	–0.007	–0.007	–0.007	0.008	–0.014	–0.013
	[–0.47]	[–1.68]	[–1.81]*	[0.38]	[–2.36]**	[–2.23]**
θ_2	0.008	0.004	0.004	–0.025	0.004	–0.002
	[0.83]	[1.56]	[1.78]*	[–1.76]*	[–1.76]	[0.63]*
α	0.205	0.214	0.215	0.006	0.024	0.029
	[9.63]***	[13.77]***	[16.8]***	[4.84]***	[17.4]***	[22.8]***

Notes: *t* statistics are reported in parentheses,
***, **, * denote the rejection of the null at 1%, 5% and 10% levels, respectively

In the case in which the coal price elasticity and gas price are dependent variables, in all groups, in the short-run, the mentioned variables significantly depend in their own past value. This implies that any past shock will cause a respective shock in period *t*. Hence, in this case we have a reverse Granger causality.

6 Conclusions and policy implications

The main objective of this article was to analyse the ways by which marginal costs per power plant and strategic bidding behaviour in the wholesale Spanish electricity market can be exercised by Endesa and Iberdrola and by their main followers, Hidricantábrico, Unión Fenosa and Viesgo.

The results clearly indicate a differential impact of the fuel prices on the power plants marginal costs, with a positive effectiveness for gas power plants. On the other hand, the biggest negative impact on marginal costs is seen for coal technology. Accordingly, as a consequence of the characteristics of different production technologies, the set of marginal costs across the sample is based on coal power plants, although in group 1 (Endesa and Iberdrola – the dominant firms) the marginal costs are set predominantly based on gas power plants.

In general, as a result of the characteristics of different production technologies, for all the firms operating in the market and for the period under analysis, it is the coal plants that have greater weight in the sales bid. Consequently, given that Endesa provides about 57% of its electricity from coal and as Iberdrola is clearly dominant in hydraulic adjustable production, both groups typically determine the marginal pricing in the market. Finally, Endesa and Iberdrola are at the heart of the ‘gravitational centre’ in the Spanish wholesale market. Taken together, smaller electricity production companies and foreign operators are not in a position to set prices in most of the time periods.

Moreover, ECM panel does not confirm either short- or long-run Granger causality from power plant marginal costs to portfolio bidding quantities and to fuel prices, thus providing some evidence for the neutrality hypothesis. This means that the power plants marginal costs have a minor role in the determination of fuel prices in firm groups’ generators.

As such, the influence that low-marginal cost electricity made on ‘pool’ portfolio bidding quantities during the period 2002–2005 allows us to conclude that, as a general rule, the effect on low marginal cost causes a decrease in portfolio bidding quantities. It can also be concluded that an increase in the fuel prices in power plant marginal costs would be followed by a similar increase in the fuel price levels, because the setting of the marginal price would be shifted to the bidding quantities with higher power plant marginal costs.

Despite Endesa and Iberdrola’s dominant position, the quantities bid in the wholesale market are affected by the increase of the marginal costs of the power plants portfolio, especially when involving coal and gas technologies.

The increase or decrease in fuel prices may lead the weakening of the collective dominant position for bidding portfolio quantities. However, the results reveal a strictly conjectural situation, which does not significantly change the duopolistic structure of the reference market or the evaluation of the market power of its two main operators. It also does not change the comfortable situation of small operators as price takers. If generators bid at their marginal costs, we find that the changes to the capacity mix are much greater than the changes to the pattern of prices.

The results of the cointegration study also show that when the two dominant market players, Endesa and Iberdrola, increase the market price, their followers, Unión Fenosa, Hidrocantábrico and Viesgo tend to react by increasing their own production, partially offsetting the initial quantity reduction. However, as these followers operate in the market with their maximum capacity, they will not be able to increase production in the short term. For this reason, the energy offer of the dominant players, knowing that their followers are operating at their maximum capacity, produced from their key technologies, constitute a true duopoly, as the market power exercise seems plausible as a result of this duopolistic power.

If we add to this problem the supply of raw materials, the commodities as production inputs for this group of followers, we witness a relevant and significant long-term unidirectional relationship between fuel and Brent prices and for the period under analysis, it is the prices of Brent moved to restore economic equilibrium. It may seem paradoxical and counter-intuitive but perfectly plausible if we think that in the demand side we have fossil fuels and this demand determines, in this way, the price of raw materials. If the demand increases, given a certain production capacity, fuel as well as raw-material become scarcer, which makes them both more expensive. What our results show is that demand has 'dictated' the price and there is little evidence that the supply has caused significant fluctuations in the price of Brent and then subsequently transmitted to Fuel price.

The management of production parks per technology is a key aspect of capital interest analysed in this article, as it is possible to conclude that Iberdrola, the market dominant company bidding from hydroelectric and nuclear plants, has flexible and easily adjustable production levels since the production of electrical energy from these plants can be started, changed and stopped almost instantaneously. On the other hand, operating costs for hydroelectric power plants are very low when compared to the thermal power plants, which is the base technology used by Endesa, another dominant competitor, since this latter technology is strongly dependent on the volatility of commodity markets and on the supply chain and production costs management.

In fact, the main difference between Iberdrola and Endesa is the opportunity cost, as the marginal value of water can be very high during droughts, whereas for Endesa has higher opportunity costs *vis-à-vis* its main rival hydro generator technology. The strategic behaviour of these two players is simple: even when both of them supply the market from conventional thermal power plants, they firstly analyse the price behaviour of the commodities market in order to infer if it is advantageous (or not) to implement and operate all their generators by technology type and to redirect their production capacity strategies, switching them on and off according to the type of generators and to the type of production technology and thus more or less dependent on other kinds of commodity.

The empirical results confirm the previous evidence, Fabra and Fabra-Utray (2009b) and suggest that the equilibrium price of the marginal cost function is determined by assuming that each plant operates independently in daily electricity market. As the number of operating plants is not infinite, each plant bids above its marginal cost. However, if the number of plants is high, which is usually the case in electricity markets, each plant in the daily electricity market follows supply function close to its marginal cost function. Furthermore, our results show that based on different conventional production technologies, there are differential impacts on sales bids in the wholesale market per production technology, in which CTC technologies do not exhibit important competitiveness gains regarding the most polluting technologies (coal technologies), but a preference for coal-based technologies. This evidence is an important contribution to justify that strategic investment decisions in renewable energies, as would be expected as a result of the European Directives 2001/77/EC and 2003/36/EC, show a weak and fragmented growth in the Spanish electricity market in period studied. Moreover, our results also contribute to clearly justify that Spain and the other Member States should have followed more objective and penalising goals and not merely indicative targets, such as those mentioned in the two aforementioned directives.

Taking this into account, one can understand the Energy-Climate Package 20/20/20, approved in 2008 and the subsequent Directive 2009/28/EC in times in which Spain is going an energy diversification process, with the production of energy from renewable sources in 2009 reaching approximately 26% of total production. These strategic changes Spain is going through show that it is essential to fulfil the short- and long-term policymaking plans for the development of the endogenous production potential of renewable energy in the production of electricity. As such, the electricity market should create favourable conditions, in terms of production costs and encourage the promotion of regional energy policies for electricity production from renewable sources, which should include significant endogenous resources from wind and solar production technologies.

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Notes

1 According to the Energy-Climate Package 20/20/20, approved in December 2008, the 27 EU countries, by 2020, are expected to reduce emissions of greenhouse gases by 20%, taking 1990 emissions as the reference, to reach 20% of renewable energy in the total energy consumption in the EU and to increase energy efficiency to save 20% of EU energy consumption.