The Spanish Electricity Industry: *Plus ça change…*

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In this paper we describe the Spanish electricity industry and its current regulatory regime. Special emphasis is given to the description and discussion of market design issues (including stranded cost recovery), the evolution of market structure, investment in generation capacity and network activities. We also provide a critical assessment of the 1997 regulatory reform, which did not succeed in introducing effective competition, but retained an opaque regulation which has been subject to continuous governmental interventionism. Furthermore, the implementation of the Kyoto agreement could show the lack of robustness of the regulatory regime.

1. INTRODUCTION

Competition is good for society because it increases efficiency and it is good for consumers because they benefit from efficiency gains through price cuts. This general principle could well have applied to the Spanish electricity industry, if only effective competition had been introduced. In 1997, the Spanish regulatory authorities reached an agreement with the electricity companies to reform the industry,[1] starting on 1 January 1998. The main innovation introduced by the new regulatory regime was the reliance on a spot market (dominated by two large producers) as a way to allocate production and determine wholesale prices. Nevertheless, the industry remained heavily regulated in ways that made the wholesale market unable to transmit efficiency signals. Regardless of market prices, what consumers end up paying and firms receiving is ultimately determined

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1. Protocolo para el Establecimiento de una Nueva Regulación del Sistema Eléctrico Nacional, December 1996; (text, in Spanish, available at http://www.unesa.es/documentos_regulacion/Pro11-12.zip).

by regulated tariffs, set by the government on a multi-year basis. Hence, contrary to the authorities' claims, the reduction in retail prices since the 1997 reform (a 16.6% in nominal terms, and a 35.6 % in real terms) does not prove its success.[2] Rather, we argue that the retail price decrease hides the lack of a real reform.

This paper describes the Spanish electricity industry and its current regulatory regime. Section 1 focuses on electricity generation, whereas Section 2 deals with network activities, namely transmission, distribution and interconnection. Section 3 concludes with some remarks concerning the evolution of the industry.

2. ELECTRICITY GENERATION IN THE SPANISH ELECTRICITY INDUSTRY

Since 1998, electricity is traded in a spot market with features similar to many electricity markets around the world. Still, this market has several specificities worth emphasising in order to understand the way competition among the electricity producers takes place.

2.1 Supply and demand for electricity

Spain is a peninsular system with weak interconnections (see section 2.1 below). Essentially, electricity is produced by four vertically integrated incumbent firms: Endesa, Iberdrola,[3] and two smaller competitors, Unión Fenosa, and Hidrocantábrico. Gas Natural, the most important gas producer in the country, has been the main, among the few, new entrants.[4] The generation mix is made of hydro power (27.9% of total capacity in 2003), coal (18.6%), oil-gas (15.3%), nuclear (12.1 %), CCGTs (6.8%), and renewable resources, of which wind is the most important (8.5 %).[5] Figure 1 below depicts the monthly evolution of electricity production in the Spanish electricity wholesale market from 1998 to 2004, disaggregated by technology type.

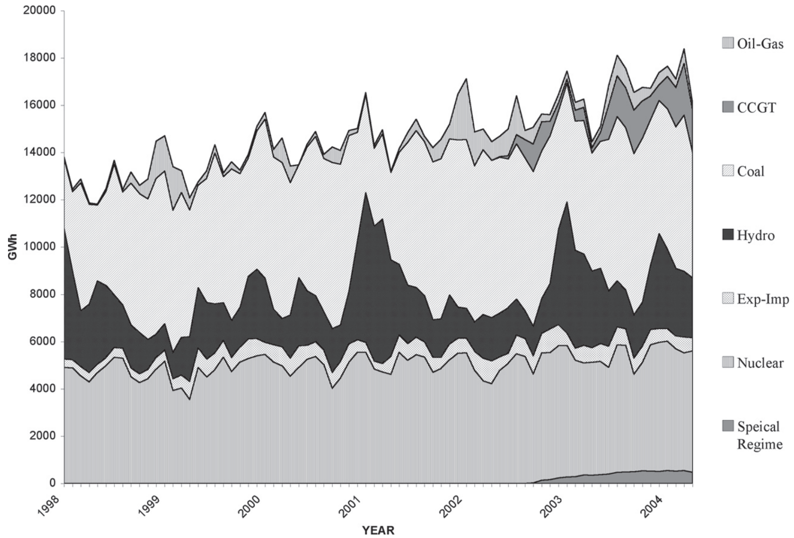
2. These price-cuts have been possible thanks to factors such as the reduction in interest rates over the period 1998-2003, a more intensive use of the existing capacity (to the extent that the system has been operating at weak reserve margins), a strong decrease in the costs of the regulated activities, and administrative decisions unrelated to any cost considerations (capacity payments have been reduced, tariff deficits have been passed to future years, etc.). Since 2002, the government has ruled that retail prices cannot increase by more than a 2% per year for the following eight years.

3. In 2003, Endesa controlled 37% of the total installed capacity and 40.5% of the production in the pool. These figures were respectively 39% and 36.7% for Iberdrola.

4. There are new players in the industry. Nevertheless, we find it inappropriate to consider them as new entrants to the extent that they have entered by taking control of already existing companies. For instance, the Italian and Portuguese incumbents, ENEL and EDP, have acquired Viesgo and Hidrocantábrico. There have been other, strictly speaking, new entrants, who are currently involved into the construction of new plants that are not yet operating. Some of these new entrants (ENRON, AES, TXU, etc.) have already sold their projects to existing companies. The CCGT plant Bahia Bizkai Gas is operating since the beginning of 2004, and 25% is owned by Iberdrola.

5. Data source: "Informe sobre le operación del sector eléctrico en 2003", Red Eléctrica de España.

Figure 1. Electricity production disaggregated by technology type in the Spanish day-ahead market, January 1998-April 2004



Data source: OMEL[6]

As can be seen from Figure 1, demand has exhibited a rapid growth. Since 1998, the average annual growth rate has exceeded 6 % (ranging from 2.7% in 2002 to 6.6% in 1998). Electricity demand typically peaks in winter, although summers register new records, due in part to the development of air conditioning. Over the day, the average demand pattern is quite volatile, with demand typically peaking at 9:00pm. There exist pumping stations (in 2003, these have represented 4.2% of total capacity) that increase the demand for thermal units at night and provide hydro electricity during the day when prices are higher.

2.2 Market design

The Spanish Electricity Market is organized as a sequence of markets: the day-ahead market, several intra-day markets that operate close to real time, and the ancillary services market.[7] Participation in these markets is not compulsory, as market participants are allowed to enter into physical bilateral contracts.

The day-ahead market, which concentrates most of the volume of trade, is composed of 24 hourly markets that clear once a day. On the supply side, the Spanish

6. Before 2002, the Special Regime was discounted from the distributors' demand and hence does not appear in the graph (see Royal Decree 841/2002, 2 September 2002).

7. See "Electricity Market Activity Rules" (April 2001), available in English at http://www.omel.es/ es/pdfs/EMRules.pdf.

electricity producers and the external agents, if not tied to a bilateral contract, submit supply functions specifying the minimum price at which they are willing to produce a given amount of output from each of their production units. Supply functions have to be non-decreasing and can include up to 25 price-quantity pairs per production unit. They can also include several conditions such as 'minimum income', 'indivisibility', 'load gradient', and 'scheduled shutdown'. The demand side is made of distributors who purchase the electricity demanded by the non-eligible consumers at regulated tariffs, the retailers who sell electricity to the eligible consumers at unregulated prices, the eligible consumers who choose to participate directly into the pool, and the external agents. They submit demand functions specifying the maximum price at which they are willing to purchase a given amount of electricity. The demand functions can include up to 25 price-quantity pairs.[8]

Once the supply and demand bids have been submitted, the market operator (Compañía Operadora del Mercado de Electricidad, OMEL) constructs a merit order despatch by ordering the supply and demand bids in ascending and descending order, respectively. The despatch and the equilibrium prices are determined through market clearing, i.e. by computing the intersection between the industry supply and demand curves. Conditionally on being despatched, the price to be received or paid by the market participants is set according to a uniform-price auction. Namely, irrespectively of their bids, the price they receive (if producers) or pay (if distributors, retailers or eligible consumers) is set equal to the highest accepted supply bid (the so-called System Marginal Price).[9]

Once the day-ahead market closes, the System Operator (Red Eléctrica de España, REE) studies the feasibility of the despatch and, on the basis of the bids submitted by market participants in the day-ahead market, modifies it by adding or removing the energy required to solve the congestion.[10] The production units used to solve the transmission constraints are paid their own bid, whereas the units which are displaced from the despatch do not receive any payment at all. The extra-costs for solving the constraints are recovered though a lump-sum, and hence do affect the value of the SMP.[11] The System Operator also runs several

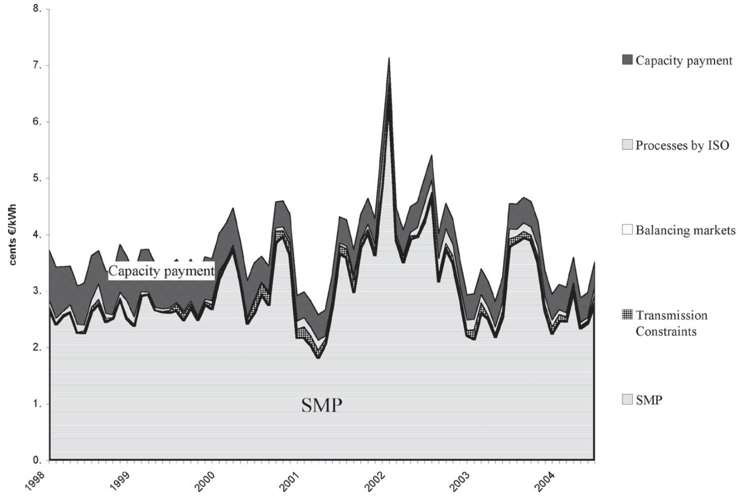
8. The distribution companies acquire the energy demanded by the consumers subject to regulated tariffs. Hence, they typically act as price takers and submit flat demand schedules at the price cap, 18.03 c€/kWh.

9. In its monthly report, the market operator publishes a table showing by colours which technology has been the "price-setter", that is the technology called last in the merit order to match demand in each day-ahead market. It is interesting to notice that at peak hours, the hydro technology (including pumping stations) almost always sets the price, thanks to its flexibility.

10. In most cases, congestion problems give rise to pockets of local market power, in which there is a single company capable of solving the transmission constraint. See the Conclusions for more on this.

11. At the time of writing this paper, there is a Royal Decree subject to administrative approval aimed at modifying these market processes. The out-of-merit units capable of solving the congestion will submit additional bids, whereas the ones in-merit that have to be displaced will also submit additional bids (i.e. the minimum price they are willing to accept to be displaced). Surprisingly, demand will not be allowed to participate into these auctions, even though the outcome would be physically equivalent.

Figure 2. The evolution of final prices in the Spanish Electricity Industry (c€/kWh), January 1998-June 2004



Data source: OMEL

markets in which production units compete to commit their capacity to provide ancillary services when needed.

Following these procedures, market participants may adjust their positions in either direction (e.g. producers may submit purchase bids if they expect to be short, and distributors, retailers and eligible consumers may submit sale bids if they anticipate to be long) in a sequence of six intra-day markets. The bidding and market-clearing processes in these markets are similar to the ones in the day-ahead market. In particular, all units are bought or sold at the highest accepted bid.

Last, the System Operator runs several markets that allow market participants to overturn any potential deviation with respect to their previously undertaken commitments.

The so-called *final price* of electricity comprises the equilibrium prices in the previously described markets and the per-kWh costs of running the technical processes needed to balance the system. Furthermore, the final price includes a capacity payment. The average capacity payment per kWh paid by consumers is currently equal to 0.481 c€/kWh, though it was initially set at 0.785 c€/kWh and subsequently reduced to 0.697 c€/kWh (see Figure 2).[12] In

12. The structure of the capacity rates paid by the different consumers is very opaque, and it is subject to periodical revisions. For instance, these rates depend on whether the consumer buys electricity through a distributor or directly into the pool. For the latter, the capacity rates vary across the day in ways that depend, among others, on the type of access tariff they are subject to (see UNESA 2004). The total value of the capacity payment paid by a consumer is equal to his demand times the rate that applies at each moment.

order to be entitled to receive capacity payments, a production unit must bid into the wholesale market (those units subject to bilateral contracts and the external agents do not have the right to receive capacity payments).[13] The total amount of capacity payments paid by consumers is shared among the units entitled to them in the following way. First, the production units in the so-called "Special Regime" (mainly cogeneration and renewable energy) are paid a capacity payment equal to 0.9015 c€/kWh times their production. The residual amount of capacity payments is shared among the remaining production units, proportionally to their capacities (corrected by the unit's availability rate in the current month).[14]

Figure 2 depicts the evolution of the final price in the Spanish electricity market from January 1998 to June 2004, and decomposes it into its different elements. As can be seen, prices seem to be rather stable during the first two years of operation (1998 and 1999),[15] with the average final price moving around 3.6 c€/kWh, approximately equal to the implicit price-cap imposed by the payment of stranded costs (see section 1.3 below). From 2000 onwards, price volatility increases and so does the average price. This has been explained by several factors, notably the uncertainty as to whether the European Commission would consider the CTCs as State Aids and hence ban them, and the tight capacity margins that arise due to the steep increase in demand coupled with the lack of new investments, and a sequence of cold winters and droughts (especially during the last months of 2001 and the first months of 2002). From 2002 onwards, the surge in new investments, particularly in CCGTs, contributed to bring prices down.

2.3 Competition Transition Costs (CTCs)

Under the previous regulatory regime, firms took their investment decisions in the framework of a National Energy Plan (PEN) and their revenues were set according to some pre-determined "standard costs" in ways that induced

13. It has been argued that the fact that firms are entitled to receive capacity payments only if the participate into the day-ahead market has discouraged firms from entering into physical bilateral contracts, even though these are permitted.

14. In computing capacity payments, the capacity of the hydro units is a function of their production in the previous years.

15. A closer look at the evolution of prices during 1998 shows the occurrence of five to six short periods of very low prices, even below the costs of the thermal plants. Fabra and Toro (2004) perform an empirical analysis of the pattern of prices and market shares. They find that the evidence is consistent with theories of tacit collusion under imperfect monitoring. In particular, they find that the periods of low prices are statistically and economically significant (i.e. unexplained by factors such as change in cost or hydro conditions), and that the signs and magnitudes of the trigger variables coincide with those expected by game theory. In particular, they find that an increase (reduction) in the market share of Endesa (Iberdrola) increases the likelihood of switching to a low price regime in the following period.

similar incentive properties as Yardstick Competition.[16] The Law passed in 1997 entitled the incumbent generators to some additional payments to compensate them from their stranded costs,[17] i.e. the difference (possibly negative) between the value of the standard costs and the expected payments that each of them would have in the market place. These payments were referred to as "Competition Transition Costs".[18]

2.3.1 The mechanism

The 'Protocol' signed between the government and the electricity companies in December 1996 (see footnote 1) states that 'the electricity companies shall receive during a transition period a fixed payment which shall be computed as the difference between the average revenues of the tariff and the regulated costs. The net present value of this amount will not exceed 1,988,561 million pesetas (€11,951.49 Million). If the generation cost exceeded 3.61 c€/kWh, the excess would be deducted from the above-mentioned amount'.

These 'Competition Transition Costs', are computed as follows. In a given year, the total amount paid to the whole industry in terms of CTCs is the residual amount left after deducting from the tariff revenues the costs of the regulated activities (distribution and transmission), the subsidies to the consumption of national coal, and the costs incurred by the distribution companies from purchasing the electricity in the pool. Each generator entitled to these payments receives a fixed proportion of the residual amount: Endesa's CTC share was set equal to 51.2%, Iberdrola's was 27.1%, Unión Fenosa's was 12.9% and Hidrocantábrico's was 5.7%.[19] In this way, the industry total revenues (summing market revenues and CTC payments) are fixed through the choice of the regulated tariff, regardless of the level of pool prices. Still, the companies are not indifferent about the level of prices, as long as their market shares differ from their CTC shares (see 1.3.2. below).

16. The "standard costs" were initially based on audited costs. However, regardless of any potential changes in actual costs, firms' per-unit revenues were determined on the basis of the standard costs. Since any potential efficiency gains would not reduce their revenues, firms faced the right incentives to incur in cost-reducing activities. Furthermore, it was in the firms' interest to report any cost reduction, as this would alter the merit order used by REE to determine the production of each individual unit. See Crampes and Laffont (1995) for more on this. Fabra-Utray (2004) and Arocena and Waddams (2001) report evidence on the increase in productive efficiency achieved by the Spanish electricity generators from 1988 to 1998, while this scheme applied.

17. The Energy Commission (CNSE, 1997) argued as follows: 'the introduction of competition needs to be gradual, and firms need to be helped to adapt to the new situation. This aid should guarantee firms financial viability and be consistent with a decreasing pattern of the final tariff to consumers'.

18. Capacity payments also contribute to cover firms stranded costs. However, whereas capacity payments are received by all available units, only the incumbent generators are entitled to receive CTCs.

19. During 1999 only, the mechanism worked differently. The companies agreed to give 16% of the total CTC entitlement up in exchange to being allowed to cash 64% (€ 5.8 billion) by issuing an equivalent amount in securities on the market; the final tariff would include an extra 4.5% levied to support these costs. The remaining 20% would still be determined by difference, in the same way as described above.

Several objections were made to these payments. First, the government was criticized for the lack of transparency in the method used to compute them. Second, the regulatory authority chose an exogenous and fixed baseline price, 3.61 c€/kWh, to compute the CTCs to be paid to all the plants, under the claim that it represented the expected costs of the marginal units (CCGTs) and hence the price in a competitive market. The expectation that the average price received by all plants would be 3.61 c€/kWh could only be a matter of luck: what if gas prices, an important determinant of the marginal costs of the peaking technologies, unexpectedly rose or decreased? What if the forecasts on demand, expected hydro, entry or capacity decisions were flawed? What if – as it is the case- the average price earned by the several technologies differed, due to their different positions in the load curve and number of hours during which each operates? What if the market did not drive prices to the system marginal cost? Pretending that 3.61 cents of c€/kWh was based on any cost considerations was, at best, a leap of faith. Still, it has not been a matter of luck that prices have varied around the baseline price. Rather, it has been the almost inevitable outcome of the incentive structure – a matter that the authorities seemed to have overlooked, or at least, did not make explicit.

What is then the effect of these payments on firms' bidding incentives and why is it not surprising that the authorities' predictions turned out to be so accurate? Would have it been inconsequential that the baseline price had been set at a different level?

2.3.2 The effects of CTCs on bidding behaviour

As described above, the incumbent generators have three main sources of revenues: market revenues, CTCs, and capacity payments. For the sake of simplicity we will only focus on the first two. A firm's market revenues depend on its market share, and it is an increasing function of the pool price. A firm's CTC payments, on the other hand, depend on its CTC share, and these are smaller the higher the pool prices (the residual amount left to distribute in terms of CTCs decreases as pool prices go up).

The effects of CTCs on bidding behaviour are similar to the ones that arise in all markets where a major part of production is subject to 'Contracts for Differences' (see Newbery 1998). Establishing the analogy between the two is straightforward: a firm subject to CTC payments supplies its output in exchange of the market price, and receives the difference between the 'contract price', i.e. the regulated tariff, and the market price, for the 'quantity contracted', which is given by its allocated CTC share. Formally this can be written as

$$\pi_i = pq_i + (\tau - p)\, Q\alpha_i - C_i(q_i) \tag{1}$$

where the profit of firm i, denoted π_i, is expressed as a function of the pool price p, firm i's production q_i, the regulated tariff paid by final consumers τ, the total quantity demanded Q, firm i's CTC share α_i and firm i's cost function C_i. Dividing the above equation by total quantity Q, we can express it in terms of firm i's market share $m_i \stackrel{def}{=} \frac{q_i}{Q}$:

$$\frac{\pi_i}{Q} = p(m_i - \alpha_i) + \tau\alpha_i - \frac{C_i(m_i Q)}{Q} \qquad (2)$$

We see that an increase in the pool price p has a positive effect on the firm's profits that is proportional to its market share, m_i, and a negative effect that is proportional to its CTC share, α_i. Thus, whether a firm is better off or worse off when the pool price increases depends on the difference between its market share and its CTC share, $m_i - \alpha_i$. If this difference is positive, the firm stands at a net selling position and hence it is better off the higher pool prices are. On the contrary, if this difference is negative, an increase in pool prices reduces the firm's CTC revenues more than it increases its market revenues. Hence, firms face a conflict of interest as to the level of prices.

The recent debate in the sector has made this conflict explicit. Iberdrola (whose CTC share is below its market share, and who has already recovered most of its CTC entitlement) and Gas Natural (with no CTC entitlement) have advocated the elimination of the CTC payments, while the remaining companies (specially, Endesa, whose CTC share considerably exceeds its market share and who has not still recovered a large fraction of its CTC entitlement) have opposed it (see EL PAIS, November 18, 2003 and July 29-30, 2004).[20] Furthermore, Iberdrola's incentives to get rid of the price-cap implied in the CTCs are enhanced by the fact that it reduces the ability of its hydro units from exploiting their competitive advantage.

Using a similar specification, it is possible to derive a firm's profit maximizing supply function, i.e. price-quantity pairs that maximize a firm's profits for all the possible realizations of the residual demand function that it might face (see Fabra and Toro 2004). The intersection between the firm's profit-maximizing supply functions and its residual demand must be at points such that the following condition is satisfied:

$$\frac{p - c_i}{p} = \frac{1}{\gamma_i} \frac{m_i - \alpha_i}{m_i} \qquad (3)$$

where c_i is the firm's marginal cost, and γ_i is the elasticity of the residual demand curve faced by the firm. Note that the above equation implies that a firm will optimally operate at prices below marginal costs whenever its CTC share exceeds its market share, and at prices above marginal costs otherwise.

20. The divergence between market shares and CTC shares across companies is explained by the type of technology units they own. For instance, Endesa was entitled to receive more stranded costs and was expected to receive lower market revenues given that its technology mix is mainly thermal, whereas the contrary was true for Iberdrola, with a large hydro capacity.

This fact has also created some controversy in the sector. Gas Natural has recently complained that "wholesale prices are being manipulated ..., and are set below costs"; "even though Gas Natural has not mentioned a single company, it has implicitly accused Endesa and, to a lesser extent, Fenosa and Hidrocantábrico" (see EL PAIS July 29-30, 2004). Following these complaints, the National Energy Commission, CNE, has agreed to open up an investigation (see EL PAIS, August 13, 2004). Our analysis suggests that what Gas Natural has denounced as an anticompetitive practice, is just the outcome of the incentive structure created by the CTCs.

The way in which the CTCs were computed had two further effects on firms' bidding incentives. First, the Law fixed a maximum amount of CTCs to be earned over the transition period. This implicitly set a price floor, as the reduction of prices below the level that would result in firms receiving the maximum entitlement would not be compensated by an increase in CTCs. Second, the Law also established that all the revenues exceeding 3.61 c€/kWh would be deducted from a firm's maximum entitlement. Clearly, this played the same role as an implicit price cap (and hence a focal price) as long as firms believed in the government's commitment to pay all the CTC entitlement during the transition period. Indeed, in 1999, when the European Commission questioned the legality of the CTCs under the consideration that they were State Aids, this mechanism lost effect and prices started to increase (see Figure 2).[21]

2.3.3 The future of CTCs

The likely evolution of prices once the transition period ends in 2010 remains an open question. So far, mark-ups have not been excessive (they have even been negative at times, see Fabra and Toro 2004) because of two main reasons. First, as already argued, prices have been implicitly capped through CTC payments. And second, given that the regulated tariffs for final consumers are relatively low, those consumers that participate directly into the pool have a safeguard and can always go back to the tariff as soon as wholesale prices increase. This has implied an extra (implicit) cap on wholesale prices.

However, once the CTC mechanism comes to an end (and once the regulated tariffs to final consumers disappear), a market that is dominated by two large producers controlling more than 80% of total production should result in high prices. The question is whether this will be sustainable, taking into account that a great part of consumers will still be subject to regulated tariffs.[22] Given the

21. The controversy over the CTCs ended on July 25, 2001, when the European Commission (Filings NN/49/99 on "Regimen Transitorio del Mercado de Electricidad") stated that, "… even if the CTC mechanism could include state aid elements … the Commission considers that such elements would be compatible with the EU Treaty".

22. Since 2003, all consumers are free to choose their electricity retailer. However, switching rates are very modest. In 2003, 99.73% of consumers were under the tariff system and consumed 69% of the total energy. The remaining 0.27% of consumers purchased their electricity in the liberalised market and consumed 31% of the energy (Comisión Nacional de la Energía, 2004).

past experience and the history of governmental interventionism, the question is: which new regulatory measure will the government add to the so-called market to restrain firms from raising prices?

In this context of uncertainty and controversy regarding the CTCs, the Kyoto agreement has come into play. By 2008-2010, the implementation of the Kyoto agreement will change the operating costs of the thermal plants, as these will have to partially internalize the costs of emissions (net of the emission rights that they will receive at zero cost). This will have several effects on the performance of the market. On one hand, this increase in costs will most likely lead to an increase in the equilibrium prices, which are used to determine the payments received by every despatched unit. Furthermore, the current merit-order will be altered, and this will change the expected production of the different technology units. Hence, the hydro and nuclear units will increase their ability to recover their stranded costs through the market, whereas the conventional thermal units will reduce their ability to recoup them in ways that were unforeseeable at the time the amount of the CTC entitlement was set. Consequently, the implementation of the Kyoto agreement will invalidate the criteria used by the authorities to determine the total amount of CTCs and its distribution across companies, set seven years ago. Somewhat surprisingly, this observation has been absent from the debate about the implementation of the Kyoto agreement. Had this issue been raised, it would have opened up a real Pandora's Box of issues related to the lack of robustness of the current regulatory regime.

2.4 Evolution of the market structure

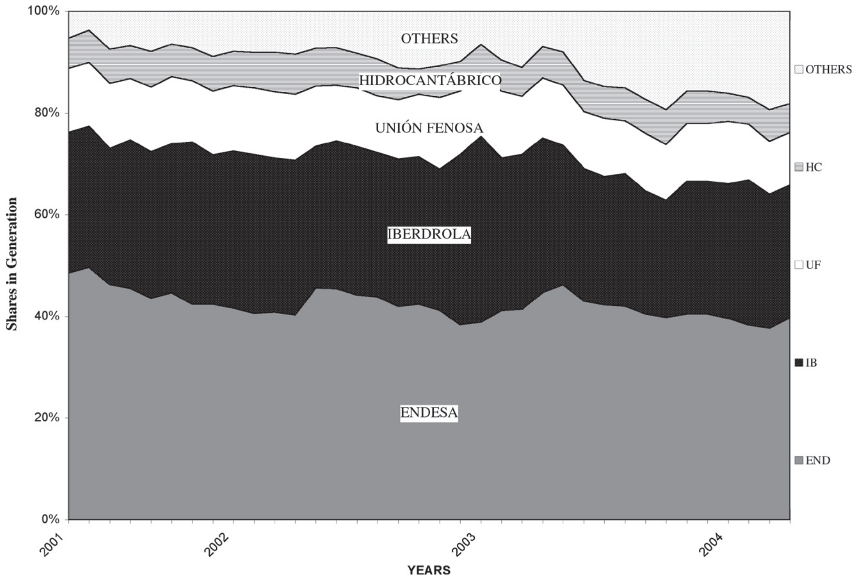
The structure of the Spanish electricity market has been subject to an intense process of change during the last decade. Nowadays, there are four main electricity companies, two of which, Endesa and Iberdrola, control 80% of the generation and distribution assets. There is also a high degree of vertical integration[23] and tight links between the Spanish electricity generators and the primary fuel providers (coal, gas and oil).[24]

Figures 3 and 4 depict firms' market shares in the Day-Ahead Market from May 2001 to April 2004, both from the supply side (generation) and from the

23. An important feature that is worth emphasising is that distribution operators remain strictly regulated in all respects- i.e. not only as owners of the 'wires' but also as buyers and sellers of electricity (see section 2.2 below). The fact that distributors charge a regulated rate to final consumers and buy electricity from the pool at the equilibrium market price should not lead to conclude that, as in other markets, distributors have a potential profit margin to make from buying energy at prices below the default rate. This is important to determine firms' net-positions, and hence their bidding incentives. Needless to say, this does not imply that vertical integration is innocuous. For instance, through the effect of switching costs, the customers of the distribution companies will likely become captive customers of their subsidiary retailers, thus giving the incumbent firms a competitive advantage over new entrants.

24. Some electricity generators own coal mines, have shares in gas and oil companies, and are directly involved in the construction of pipelines and refineries. Furthermore, their objective is to become active players in the gas market. For instance, Iberdrola's objective for 2006 is to control 20% of the gas market (see Iberdrola's corporate web page).

Figure 3. Firms' market shares on the supply side in the Spanish day-ahead market, May 2001-April 2004



Data source: OMEL

demand side (distribution, retailing and pumping storage).[25] We can see that the incumbent firms remain dominant over the period. Endesa and Iberdrola's market shares decrease slightly, and Unión Fenosa's and Hidrocantábrico's remain stable. The small firms (both in generation as well as in retailing) manage to slightly increase their market shares over time. Among these, the most important ones are Viesgo (whose assets were divested from Endesa) and Gas Natural.

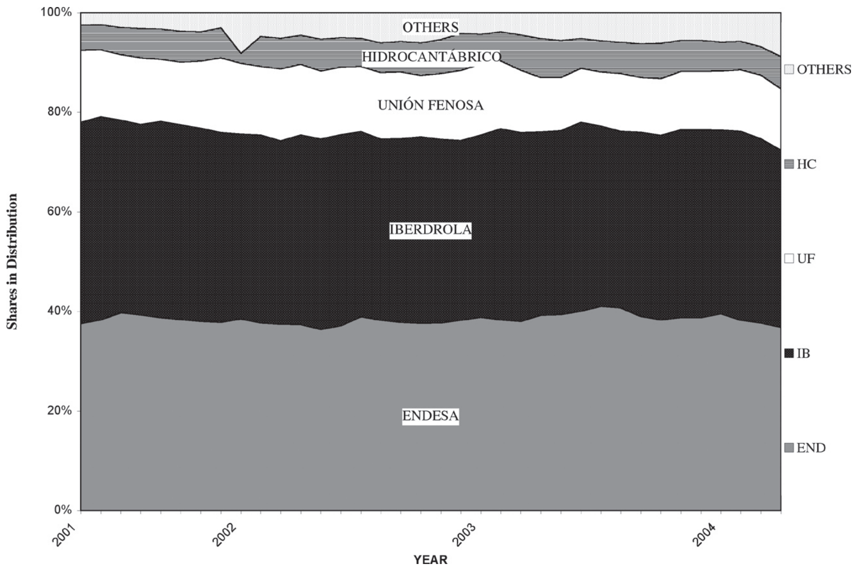
Prior to 1998, the industry was considerably more fragmented than it currently is. The regulatory uncertainty, coupled with the government's explicit support,[26] strengthened firms' merger incentives. Both Endesa – a public company at that time – and Iberduero (the predecessor of Iberdrola) embarked on an aggressive policy of acquisitions and take-overs of their smaller competitors. Endesa acquired a myriad of regional electricity companies (ENHER, Unelco, GESA, ERZ, Electra de Viesgo, Saltos del Nansa, and Sevillana de Electricidad), whereas Iberduero merged with Hidrola (leading to the creation of Iberdrola).

The process of mergers, acquisitions, and alliances did not end after the change in the regulatory regime. In 2000, Unión Fenosa launched a hostile take-over over its smaller competitor, Hidrocantábrico. The Government, following the

25. Market share data are not available for previous periods.

26. In 1996, the government allowed Endesa to merge with Sevillana de Electricidad and FECSA in order to increase its value before privatization.

Figure 4. Firms' market shares on the demand side (distribution, retailing, pump storage) in the Spanish day-ahead market, May 2001-April 2004



Data source: OMEL

reports by the Energy Commission and the Competition Court, did not approve the take-over, arguing that it would weaken competition. Up to very recently, Hidrocantábrico has been subject to a continuous process of buy-outs and alliances: it was first bought by Electricidade de Portugal (40%) and EnBW (35%), and since July 2004, EdP controls 95% of Hidrocantábrico after acquiring EnBW's stocks (see EL PAIS, July 30, 2004).

In October 2000, Endesa and Iberdrola planned to merge. The objective was two-fold. The firms sought to obtain some liquidity without losing their strategic position; they also tried to diversify their business towards other areas of economic activity and towards international markets.[27] The parties themselves accepted that significant divestments of generation and distribution assets were necessary to conform with regulatory and competition policy requirements. They proposed to sell some 16,000 MW of generation capacity, and hence retain approximately 50% of total industry capacity, in addition to divesting a small proportion of their distribution assets, and to reducing their share in the retail supply market. The merger proposal then opened an interesting debate on the set of ex ante constraints

27. Supporting this claim is the fact that, once the Competition authorities modified the merger project, Endesa sold through an auction its company Electra de Viesgo (2,500 MW in generation assets, and distribution and transmission assets associated with 500,000 customers).

that should be placed on the asset divestments to ensure that the merger/divestment process would not weaken competition. In particular, the emphasis was on two sets of questions: Should smaller firms in the market be permitted to purchase significant shares of these assets, or should the assets be mainly reserved for new entrants? What should be the mix of technologies retained by the merged firm? These questions were not given a clear-cut answer as the government, after consultation with the Competition Court and the Energy Commission, required severe remedies which made the plan unprofitable from the point of view of the merging companies. Consequently, Endesa and Iberdrola decided to withdraw their plan.

On March 10, 2003, the public bid that Gas Natural launched for 100% of Iberdrola's shares re-opened the controversy concerning mergers in the Spanish electricity industry. Iberdrola is the second largest firm in the electricity sector and is the one with the most balanced technology mix. Iberdrola's hydro capacity confers on it the ability to greatly influence market prices and places it in a dominant position in the market. Gas Natural is the dominant player in the gas sector, controlling 70% of the market. Also, it has been the main 'new' entrant into the electricity sector, with a strong commitment to invest in CCGTs and to fiercely compete at the retail level by bundling electricity and gas.

The merger proposal, which would have resulted in the fifth largest energy company in the world, with a € 33 billion total stock value, thus represented an ambitious attempt to vertically integrate both the gas and electricity sectors. The National Energy Commission decided to block the merger authorisation on the basis that it would have had a deep impact on the regulated gas and electricity distribution sectors.[28]

2.5 Investment in generation capacity and resource adequacy

The change in the regulatory regime not only implied that transactions would be organized through market mechanisms, but also that investment decisions would no longer be defined in the framework of the National Energy Plan. Market participants alone now face the full risk and cost of their investment decisions.[29]

The new regulatory environment inherited the uneconomic excess capacity that was built during the previous regulatory regime. Still, capacity reserves have been rapidly absorbed due to the steep increase in demand over the recent years (see Figure 1) and the lack of new investment. Two facts stand out as possible causes. First, the regulatory uncertainty induced firms to 'wait and see' before building any new generation plant. Second, the Royal Decree 6/2000 did not allow the incumbent generators with shares above 30% to construct new plants. As the experience has

28. Since very recently, Endesa and Gas Natural are involved in merger talks. The Ministers of Economics and Industry have openly declared that they would not be against it (see EL PAIS, May 28, 2004).

29. Investments in generation are subject to administrative licensing, which requires that the investor shows expertise and financial viability, and meets safety and environmental criteria.

demonstrated, this was a regulatory mistake that delayed the operation of new plants (mainly, by Endesa) precisely when they were most needed.

During the winter of 2000-2001, a particularly humid season (20% above the historical average) hid the tight capacity margins under which the system was operating. However, a particularly cold and dry winter drove electricity demand above installed capacity. On the 17th of December 2001, the problems became public knowledge when the System Operator had to force rolling blackouts in the central region of Spain in order to avoid the collapse of the system. The deep and well-founded worry that the stability of the system was still at risk, allowed the regulatory authorities to request firms to carry about all the investment plans that had previously been announced (probably, some of these announcements were not backed by a real commitment but rather, responded to strategic reasons). In 2002, 2.800 MW of new capacity entered into operation, 800 belonging to Iberdrola and 800 to Gas Natural. These, together with an exceptionally intense humid season, contributed to cover the peak of demand that was registered during the last days of 2002 and the first months of 2003 (on January 14, 2003, demand peaked at 37.000 MW). In 2003, three new CCGT plants have increased the total installed capacity by 1600 MW.

Parallel to the experience in other electricity markets, the bust in the investment cycle has been followed by a boom, which is based on the construction of new CCGT plants (see Table 1). They offer the best prospects among all the technologies available to the Spanish electricity generators, not only in terms of their average costs, but also in the light of the reduction of emissions needed to comply with the Kyoto agreement. It is thus not surprising that Gas Natural, which benefits from its activity in the gas market, has been one of the first and most active operators in building new plants. The incumbent firms' incentives to invest in CCGT plants are also extremely powerful. From the point of view of the large incumbent firms, losing the opportunity to invest would mean a loss in dimension, relative size, and most certainly, competitiveness. The smaller companies, Hidrocantábrico and Union Fenosa, need to invest in order to improve their position in a system that is close to being a duopoly, as well as to protect their independence.

Table 1. CCGTs Construction Plans in the Spanish Electricity System (MW)

Owner	**Year in which in the CCGT plants become available**			
	2004	**2005**	**2006**	**2007**
ENDESA	—	400	400	1,200
IBERDROLA	1,600	1,200	800	800
UNIÓN FENOSA	—	1,200	2,400	800
HIDROCANTÁBRICO	—	—	800	400
GAS NATURAL	800	—	3,200	800
OTHERS	800	2,285	3,085	5,200
TOTAL	3,200	5,085	10,685	9,200

Source: CNE

Still, even this surge in investment does not seem to be enough to absorb the expected increase in demand. The estimates based on the new investment plans and forecasted demand, show that the ratio of the reserve margin over the installed capacity is expected to shrink below its current level by 2010 (from 6.5% nowadays to 4.6 % in 2010 as shown in Table 2). While it is true that there is time to start the construction of new plants that could be ready by 2010, the recent experience has shown an artificial inflation of projects, in the sense that not all the construction plans for which authorisations have been requested have actually gone through. At this point, it is unclear which of these two effects will dominate. This situation could be improved by the development of interconnection capacity, especially with France. But this is highly unlikely, as the next section argues.

Table 2. Installed Capacity, Load and Reserve Margins in Spain and Portugal

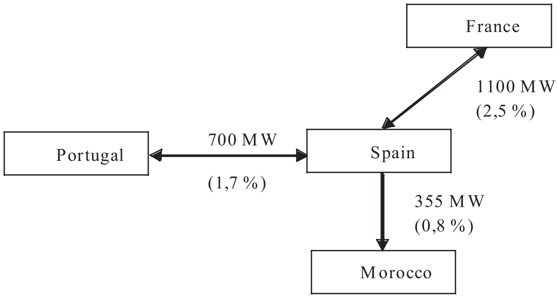
	2004	**2006**	**2008**	**2010**
Power Data (GW)				
Hydro	22.5	22.8	22.9	23.2
Nuclear	7.6	7.6	7.5	7.6
Thermal	31.4	35.2	37.3	39.3
Renewable	6.6	10.1	12.9	15.9
Installed Capacity	68.1	75.7	80.6	86.0
Guaranteed Capacity	51.5	55.7	58.2	60.1
Load	47.1	49.8	52.8	56.1
Reserve Margin	4.4	5.8	5.4	4.0
Interconnection capacity (with France and Portugal)	1.8	2.4	3.0	4.1
R. Margin / I. Capacity (%)	6.5%	7.7%	6.7%	4.6%
Inter. Cap./I. Capacity (%)	2.6%	3.2%	3.7%	4.8%
R. Marg.+Inter.Cap./I. Cap. (%)	**9.0%**	**10.8%**	**10.4%**	**9.4%**

Source: UCTE

3. NETWORK ACTIVITIES: INTERCONNECTION, TRANSMISSION AND DISTRIBUTION

In this section, we will explain how the Spanish grid is connected to the neighbouring systems (section 3.1) and the economic principles that command the operation of the transmission and distribution activity (section 3.2).

Figure 5. Commercial capacity of interconnections (% of installed capacity)



Data source: OMEL

3.1 Interconnection

In the former organizational framework, where competition was not the industry's driver, interconnectors were mainly viewed as security devices. Most national or regional electric systems were independent from each other and interconnection links had been designed to help bordering systems in case of emergency. Of course, since the links were available, they also were used under normal circumstances. In Spain, imported energy was already part of the centrally despatched resources in the pre-1998 system. Symmetrically, the interconnectors remain emergency devices under the new organizational framework. For example, in December 2000, after the storm that isolated the South-west part of France from the remaining part of the French grid, the Spanish electricity generators contributed to the stability of the damaged Southern French network and to the supply of energy to the French consumers.

In the new liberalized framework, competitive pressure should come either from the multiplication of independent generators (possibly through mandatory divestiture) or from abroad, thanks to interconnectors. However, in Spain competition cannot arise from abroad. Indeed, when Unión Fenosa tried to absorb Hidrocantábrico in 2000 and when Endesa tried to absorb Iberdrola in 2001 (see section 1.4 above), the Competition Court (*Tribunal de Defensa de la Competencia*) rejected the merger plans on the basis of a narrow definition of the relevant market: "it may be that, in the long run, the geographical relevant market will be the Iberian peninsula; at the moment, it is limited to the Spanish peninsula". Since these decisions, things have evolved institutionally, but not technically. Essentially, the Spanish electricity market remains isolated (see Figure 5).[30] In 2003, imports represented 4.3 % (8,547 GWh) of the total

30. In Figure 5, commercial capacity is defined as physical capacity less security capacity. Note that the connection with Morocco is exclusively used for exports.

electricity production,[31] which is a small number compared to the share of the four large electricity generators.

The European directive 96/92 states that Network Operators determine the use of interconnectors on the basis of objective, transparent and non discriminatory criteria, which is not easy to implement when network operators belong to national incumbents, big vertically integrated generators. No unbundling is required for ownership, only independent management and accountancy. Anticompetitive allocation of interconnectors is under the threat of articles 81 and 82 of the EC treaty,[32] but competition restrictions could be unavoidable to recoup the costs of the investment in new links. The new European regulation on cross-border exchanges in electricity (EC 1228/2003) edicts general principles on the building and the management of interconnectors, in particular regarding the rules of access and the use of the revenues resulting from the allocation of interconnection. It allows some exemptions from regulation for independent investors in new interconnectors and in significant increases of capacity in existing interconnectors. The exemptions are conditional to the fact that "the investment must enhance competition in electricity supply". This is an explicit acknowledgement that it is competition in energy supply that matters, not competition in the use of a specific type of equipment, local or remote.

3.1.1 Interconnection between Spain and France

The interconnection between Spain and France takes place through two 400 kV lines, two 220 kV lines, one 132 kV line and one 110 kV line. The interconnector capacity with France could be much larger than it currently is.[33] Actually, several projects have been abandoned or delayed because of political decisions taken under the pressure of environmental activists.

The best known case is the abandonment in 1996 of the 400 kV line planned to cross the central Pyrenees, which proved to be highly damaging for the Spanish electricity system (Fabra Utray 2004, p. 341). After the breach of the contract signed between Red Eléctrica and Electricité de France, EDF was obliged to pay compensatory fines to REE, which amounted to €1.81 Billion payable from 1997 to 2010. The breach of the contract also obliged EDF to upgrade the existing lines as well as to decrease the coefficients of the two-part tariff paid by REE to buy electricity from France. These two elements contributed to the reduction in the Spanish wholesale electricity prices.

The agreement signed between REE and EDF also included a commitment to build a new interconnection line before 2006. If the line was not opened in December 2006, it was agreed that the firm responsible for the delay

31. On the average, 8 % of European electricity trade is executed through interconnectors.

32. The European Commission has examined the use of interconnection capacity between France and Spain.

33. See the forecast for 2010 in Table 2.

would compensate the other with an annual payment of €8.26 Million during the following ten years. Given the opposition of the French public opinion,[34] it seems quite likely that the line will not be built.[35]

3.1.2 The 'Tripartite Agreement': REE, EDF and EDP

It is noteworthy that in 1990, REE, EDF and EDP signed an agreement for exchanging energy. Under this agreement, EDF opened access to 385 MW of capacity to REE, whereas REE opened access to 301 MW of capacity to EDP (excluding at most 200 hours per year of interruption). This tripartite agreement was necessary to implement any bilateral agreement between France and Portugal given the intermediary position of Spain. Also in 1990, France and Spain reached an agreement by which REE was free to access 1000 MW of capacity (now reduced to 500 MW) as if REE were a French domestic subscriber. This was the first international contract based on virtual capacity, i.e. on the whole French electricity system rather than on the energy provided by some specific plants (Fabra Utray 2004, p. 184-5).

3.1.3 The Iberian Electricity Market

On the 14th of November 2001, the Portuguese and Spanish governments signed an agreement aimed at progressively creating a single market, named the Iberian Electricity Market (Mibel). The Mibel was expected to start operating in April 2004 (but the opening has been delayed until July 2005), with the objective to guarantee all agents established in both countries access to the Iberian Market Operator (Omel and its Portuguese counterpart, Omip, are expected to merge into the Omi by April 2006) and to the interconnections with third countries under free and equal bilateral trading conditions. Interconnection between Spain and Portugal takes place through two 400 kV and three 220 kV lines, which can take up to a maximum 3300 MW in thermal capacity.[36] The indicative value of the capacity available for commercial purposes varies, according to the system operators, between 550 MW (summer, from Portugal to Spain) and 850 MW (winter, from Spain to Portugal). The values recorded during 2001 fell somewhere between 50 MW and 1500 MW. The "Collaboration Protocol" on Mibel does not consider the possibility of relying on one single transmission operator. Red

34. On the project of a very high voltage line across the eastern part of the frontier between France and Spain, see Commission Nationale du Débat Public, http://www.debat-liaison-tht-france-espagne.com (all files are in French).

35. Contrary to official announcements, it is not true that the construction of this line was decided in 2001 to counter-balance EnBW's stake (a subsidiary of EDF) in Hidrocantábrico. The building of the line was already decided since the 1997 REE-EDF agreement, while the financial operation of EnBW had been cleared by the European Commission in pursuance of the 1989 text on merger regulation.

36. For details, see CNE and ERSE (2002).

Eléctrica de España (REE) and Rede Eléctrica Nacional (REN) have to coordinate the planning and expansion of the transmission networks, as well as to harmonize the operation procedures, particularly the resolution of congestion.

3.2 Transmission and distribution

The Spanish electricity network is made of 53,716 km of transmission lines.[37] Red Electrica de España (REE) has been the main transmission owner since it was created in 1985, owning 98% of the 400 kV lines and 26%-36% of the 220 kV lines until 2002, when it further acquired the 220 kV lines belonging to Endesa and Unión Fenosa. Iberdrola's transmission network was sold to a subsidiary of Red de Alta Tensión (Redalta) but REE reached an agreement by which it became the owner of 25% of Redalta. To prevent abuse of dominant position (REE is a private firm),[38] Red Eléctrica has to respect and enforce the procedures for access to the transmission grid as defined by the Royal Decree 1955/2000. The other main relevant texts are the Royal Decree 2819/1998 that defines the economic scope of transmission and distribution activities in order to guarantee a high degree of service quality and the Royal Decree 1164/2001 that fixes the tariff rules for access to the networks of transmission and distribution of electricity.

The regulation system for transmission and distribution is based on an average-price cap. The formula for rewarding transmission and distribution firms as well as the formula for the prices to be paid by users are fixed administratively.

A. Consider first the revenue of the network operators.

A.1 The revenue of the transmission firm *i* in year *t* is[39]

$$R_{it} = \overline{R}_{it} + I_{it} + N_{it} \tag{4}$$

where R_{it} is the cost corresponding to the equipment of firm *i* installed up to December 1997 and globally re-evaluated by a $RPI - X$ factor with $X=0.6\%$ for each year during the period 2003-2006 (*RPI* is the acronym for Retail Price Index). Table 3 shows the initial value for the cost (= revenue) of transmission firm *i* in 1988, i.e. $R_{i,1988}$.

I_{it} stands for the cumulative cost corresponding to the equipment installed between 1998 and $t - 1$. Each item is re-evaluated by the same factor $RPI - X$,

N_{it} is an incentive revenue paid to firm *i* in year *t* to reward the availability of its equipment during year $t - 1$.

37. These are figures on December 31, 2003. The length are respectively 16 560 Km at 400 kV, 16 242 at 220 kV and 20 914 at 132-110 kV.

38. The capital of REE is mainly held by SEPI, a public firm (28.5%), and the four largest generators (Endesa, Iberdrola, Hidrocantábrico and Unión Fenosa, each for 3%, i.e. the legal cap). The remaining 59.5% is free float in the Spanish stock market.

39. For details, see article 4 of the Royal Decree 2819/1998.

Starting from 507 M€ in 1998 (see Table 3), the transmission costs have reached 833 M€ in 2004 (of which 625 M€ are for Red Eléctrica de España). After Article 7 of the mentioned Royal Decree, the costs corresponding to new equipments include “costs necessary to develop the transmission activity”.

A.2 For distributors as a whole, the revenue in year *t* is given by

$$R_{dt} = R_{dt-1} \times (1+RPI) \times (1+ \frac{\Delta D}{D} \times F) \tag{5}$$

Table 3. Transmission costs, as set in 1998 ($\bar{R}_{i,1998}$ in millions of euros)

Transmission firm *i*	M€	Percentage
Iberdrola, S.A.	79.32	15.64
Unión Eléctrica Fenosa, S.A.	25.59	5.05
Compañía Sevillana de Electricidad, S.A.	31.81	6.27
Fuerzas Eléctricas de Cataluña, S.A.	19.53	3.85
Empresa Hidroeléctrica del Ribagorzana, S.A.	24.49	4.82
Hidroeléctrica del Cantábrico, S.A.	2.55	0.50
Electra de Viesgo, S.A.	4.89	0.96
Eléctricas Reunidas de Zaragoza, S.A.	6.39	1.26
Endesa, S.A.	5.43	1.07
Red Eléctrica de España, S.A.	307.24	60.57
Total	507.24	100.00

Source: Annex 1 of RD 2819/1998.

where $\frac{\Delta D}{D}$ is the rate of increase in demand (or 0 if there occurs a decrease) and $F \leq 0.4$ is an efficiency factor. According to Article 21 of RD 2819/1998, the share of this total amount allocated to each distributor is decided yearly by the energy ministry (for 2004, see Table 4). Actually, the allocation procedure is far from discretionary. It follows some established rules such that the share to each distributor is fairly stable from year to year.

These two reward schemes have an incentive component. For transmission, incentives come from the fact that operators are residual beneficiaries of any cost reduction below the revenue cap. For distribution, note that an increase in demand does not provoke a proportional increase in revenue. This is not surprising since an increase in demand does not create the need to increase the distribution costs by the same amount. In these network activities, most costs are fixed. Hence, absent structural congestion, extra demand can be accommodated with the same equipment, i.e. at a low cost. The efficiency component of the revenue mechanism relies on the possibility for the revenue-setter to arbitrarily fix the weight of the

Table 4. Distribution revenues in 2004 (millions of euros)

Iberdrola Distribución Eléctrica, S. A. U.	1,042,952
Unión Fenosa Distribución, S. A.	477,749
Hidrocantábrico Distribución Eléctrica, S. A.	90,062
Electra de Viesgo I, S. A.	79,783
Endesa	1,132,736
Sociedad Coop. Valenciana Ltda. Benéfica de Consumo de Electricidad *San Francisco de Asís*	124
Total	2,823,406

Source: Annex VIII of RD 1802/2003

demand increase, *F*, as long as it is not above 40%. This type of mechanism probably explains why distributors have become more efficient, as Griffel-Tatjé and Lovell (2003) have shown by comparing observed costs of distribution and virtual costs derived from an ideal network designed without the burden of history. An additional reason is that the revenue mechanism does not provide explicit revenues to promote investment,[40] so that distributors have the incentive to accommodate more demand without developing their lines. This lack of incentive to invest is efficient in the short run when the networks are oversized, but it will be damaging in the long run if it results in structural congestion.

B. We now consider the tariff paid by the users of the network. The Law 54/1997 that liberalized the electricity industry sets that (at least) yearly the government fixes the average or reference tariff (art. 17). The basic definition of the tariffs appears in the Royal Decree 1164/2001 and the 2004 tariffs are set by Royal Decree 1802/2003. The access prices vary with voltage level and are made of an energy term and a power term.[41] The low voltage tariff (below 1kV) distinguishes a "simple tariff" (for power below 15kW) with an optional peak / off-peak hour system and a "general tariff" where the energy and the power terms of the bill can take three different values depending on time and season. In the high voltage tariff (between 1kV and 36kV), users of the transmission network with a contractual power below 450 kW pay tariffs that vary according to three periods. Above 450 kW or above 36kV, users of the grid are subject to a six-period tariff with very high differences depending on hours and seasons.

All these access tariffs are computed to recoup the variable cost for transmitting and distributing electricity, plus a series of fixed costs, either born by the transmission and distribution companies or attributable to general services (OMEL, CNE, CTC, etc), plus the extra cost due to the "Special Regime" (cogeneration and renewable energy).

40. Article 18 of RD 2819/1998 loosely refers to a ministry decision to design an incentive mechanism for the development of the distribution network.

41. Plus, if relevant, a term for reactive energy.

Given the importance of fixed costs, the (second) best solution should consist of either Ramsey linear prices or non-linear tariffs.[42] As they are, the Spanish tariffs look like an attempt to mimic both. Indeed, Ramsey prices are highly discriminatory since they would allocate all the costs of the network in proportion to the inverse of the elasticity of demand. Charging Ramsey prices would result in high unit prices for energy and transmission paid by households and low unit prices for industrial consumers, since the former are less price-responsive than the latter. But discrimination is forbidden by Law. One solution could be to allocate all the costs at the same price, with the effect of reducing efficiency since there is the additional constraint to make all prices equal. Rather, the traditional solution is based on "cost causality". It consists in separating the electricity grid into several components (e.g. high voltage and low voltage equipment) and allocating the costs only to the users that can be identified. Since the large consumers only use the high voltage grid, they only have to pay for the costs of the high voltage grid. In contrast, the households receive energy that has been transmitted through all the wires; therefore, they must pay for all the infrastructure costs. As compared with second best, here again there is a decrease in the social performance since there are now several budget constraints instead of one. Which system is less damaging for the society depends on many parameters. Here we just observe that the standard practice of cost-causality is not the only solution. At best, we can interpret the segmentation of clients on the basis of the voltage connection as an attempt to approximate the price differential that would result from second best prices.

Consider now the energy and power components of the tariff. Efficient pricing would command hourly prices for both energy and transmission. Only very large consumers have meters able to keep the track of hourly consumption. For most consumers, only cumulated consumption is metered. With standard meters, the operators are unable to distinguish between a consumer who withdraws 1 kW of energy during each hour of the day and the consumer who withdraws 24 kW during one hour and 0 kW during the remaining 23 hours. Yet, the two types of consumers create different costs of generation and transmission. The capacity term of the tariff is aimed at discriminating among them. For a given quantity of energy, "irregular consumers" must be charged proportionally more than regular consumers. If the energy component of the tariff is the same for all, the capacity component must be increasing with capacity. In the above example, the unit price of capacity paid by the irregular consumer must be larger than 24 times the unit price of capacity paid by the regular consumer. But it is also possible to charge a higher price of energy combined with a less than proportional price of capacity.

Note that these tariffs with two components (energy and capacity) are incorrectly named two-part tariffs. Actually, they are multi-linear prices without any fixed component. Adding a true fixed part, depending neither on energy nor on capacity, would give an additional degree of freedom to operators to approximate second best pricing.

42. See Crampes (2003).

4. CONCLUSIONS AND FINAL REMARKS

In 1997, the Spanish Government agreed with the electricity companies to reform the electricity industry. Regulation, it was claimed, would be replaced by competition, and this alone would drive electricity prices down and would allow market participants to make more efficient investment and consumption decisions. However, as we have argued in the preceding paragraphs, the so-called market, as it has been implemented, is not such. Regardless of market prices, what consumers end up paying and firms receiving is ultimately determined by regulated tariffs, which are set by the government on an annual basis, and in a non-transparent manner. Also, the new system has failed in attracting new entry, and in promoting the efficient amount of investment needed to guarantee adequate reserve margins. The government has additionally undermined attempts to change the market rules and has blocked several merger proposals. Some have viewed this as a lost opportunity to enhance competition, as it could have been used to de-concentrate the market structure through the imposition of adequate divestment requirements on the merging firms.

We would like to close this paper by highlighting a series of critical topics concerning the current and future performance of the industry.

Governmental Interventionism

Governmental interventionism and lack of transparency have reigned in the Spanish electricity market over the recent years. Instances of this are the determination of the Competition Transition Costs (CTCs) on the basis of fuzzy criteria, the payment of a capacity payment at a rate which is periodically changed in a non-transparent manner, the settlement through the CTC system of an implicit price cap on the energy traded in the pool, and the systematic policy against mergers (Unión Fenosa- Hidrocantábrico, Endesa-Iberdrola, Iberdrola-Gas Natural), which could have been used, through divestment requirements, to de-concentrate the market structure and increase the number of competitors.

Generators' Market Power

Several anticompetitive practices aimed at altering the competitive equilibria in the wholesale market have been observed. For instance, in 1998, the pattern of prices was characterized by the occurrence of five to seven price wars, unrelated to cost shifts, which can only be explained on the basis of strategic considerations (Fabra and Toro 2004). Similarly, during 1999, the response of prices to the conflict arising from Brussels regarding the legality of the CTCs showed that firms were able to alter the market equilibrium through their bidding strategies. Very recently, (see EL PAIS and Cinco Días, July 8, 2004), the Competition Court has imposed the maximum fine on Endesa, Iberdrola and

Unión Fenosa for abuse of dominant position on November 2001, when wholesale prices tripled with respect to their normal level. The Court argued that those firms had made use of their local market power by bidding higher prices when the transmission lines were congested.[43] While these episodes might be regarded as anecdotes, they provide some evidence of firms' ability to exercise market power. Arguably, further attempts to exercise market power may have been mitigated by the implicit price caps imposed by the CTCs and the regulated tariffs. However, the question remains as to the competitiveness of the market once the CTC mechanism comes to an end and the regulated tariffs disappear. Furthermore, the efforts of the National Energy Commission (CNE) to implement market reforms that limit the ability of the main producers to exercise unilateral market power have been undermined by the Government (Wolak 2004).

Entry

Entry has been dissuaded by the incumbent firms. This has mainly been achieved by the strategic announcement of new investment plants that have never been carried out. The existence of CTCs has represented an additional barrier to entry to potential entrants (which are not entitled to these payments) given that they induce the incumbent generators to reduce prices below the level that would make entry profitable. Indeed, Gas Natural has publicly complained about the existence of CTCs, which, it believes, distort the functioning of the wholesale market, and induce firms to set very low prices that make the new plants unprofitable (see EL PAIS, July 29, 2004).[44]

Investment

Investment in generation capacity has been suboptimal, with no new plant entering into operation from 1998 to 2002 despite the steep increase in demand. The system has operated below acceptable adequacy indexes since 2000. The rolling blackouts that the System Operator had to enforce in December 2001 to avoid the collapse of the system exemplified this. Exceptionally wet seasons and favourable weather conditions have stopped the problems from being more severe. Despite these facts, new interconnectors have not been built, and most probably, they will not be built in the short run. On the one hand, French green activists have systematically blocked any project to install new lines; on the other hand, REE has not shown much enthusiasm on those projects, probably because of its shareholders.

43. Endesa has local market power in Andalusia and Catalonia; Iberdrola on the East coast, and Unión Fenosa in the Central region of Spain.

44. Note that the fact that the incumbent firms find it profitable to invest on CCGTs does not necessarily imply that investment by new entrants, with no portfolio of other plants, ought to be profitable as well.

The Kyoto Agreement

The Kyoto agreement, via its effect on firms' costs and market prices, will alter firms' ability to recover their stranded costs. Hence, it will invalidate the criteria used by the government to set and distribute the CTCs. Somewhat surprisingly, this observation has been absent from the debate about the implementation of the Kyoto agreement. Had this issue been raised, it would have opened up a real Pandora's Box of issues related to the lack of robustness of the current regulatory regime. Today, the Kyoto agreement has uncovered the flaws of the regulatory system, technology changes will do so tomorrow, while the continuing volatility of oil and gas prices will highlight its lack of robustness.

To conclude, behind its apparent success, the current regulatory system hides several flaws and it is unsustainable as it stands. The need for reforms becomes more urgent the closer the end of the CTC system approaches. De-concentrating the market structure, by increasing the number of generators through divesture and by encouraging new investment and entry, is one structural solution, but a change in the rules will likely be needed as well. We believe that a political debate about the future of the Spanish electricity system has to be opened.[45]

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