Reports of the Public-Private Sector Research Center 1

# Competition and Regulation in the Spanish Gas and Electricity Markets

Giulio Federico and Xavier Vives

With the collaboration of Natalia Fabra

IESE Business School
University of Navarra
Public-Private Sector Research Center

Orkestra
BASQUE INSTITUTE OF COMPETITIVENESS
Deusto Foundation
University of Deusto

D.L.B-52.341/2008
ISBN: 84-86851-73-4

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# Competition and Regulation in the Spanish Gas and Electricity Markets

**Giulio Federico** and **Xavier Vives**,
Public-Private Sector Research Center,
IESE Business School

With the collaboration of:
**Natalia Fabra,**
Universidad Carlos III de Madrid

November 2008

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# Foreword

This report is the first in a series of regular reviews of the Spanish regulated sectors which the Public-Private Sector Research Center of IESE plans to publish in the future, as part of its ongoing work program. The series of Reports intends to contribute to the ongoing debate between practitioners, policy-makers and academics on the Spanish – and the broader European – regulated markets.

The present report is jointly published with the Instituto Vasco de Competitividad (IVC). The aim of this report is to provide a perspective on the status of regulation and competition in the Spanish gas and electricity markets that is grounded on the economic theory of industrial organisation, regulation and antitrust, and, at the same time, to review some of the most recent events in the sector.

The report has been written by Giulio Federico and Xavier Vives of the Public-Private Sector Research Center of IESE, in collaboration with Natalia Fabra of the Universidad Carlos III de Madrid. Natalia Fabra has contributed mostly to the analysis of forward contracts and capacity payments contained in sections 4 and 6, and provided extensive input on the rest of the report. The views expressed in the report reflect the opinions of the authors alone, and do not represent those of the institutions to which they are affiliated.

We would like to thank Miguel Angel Lasheras, Ignacio Pérez Arriaga and Nils-Henrik von der Fehr, who acted as external advisors, and Yoseba Peña Landaburu from the IVC, for making very useful suggestions to improve this report. We would also like to thank Rafael Durbán Romero (CNE), Javier de Quinto Romero and Ventura Rodríguez García (both from REE) for facilitating access to information and Gregorio Mednik and Juan Temboury for providing comments on a draft of the report. Pablo Salvador provided excellent research assistance, and Salvador Estapé and Berta Torres made a significant contribution to the processing of the manuscript and the production of the report.

Prof. Xavier Vives
Academic Director
Public-Private Sector Research Center
IESE Business School

Public-Private Sector Research Center

The Public-Private Research Center was established in 2001. Its mission is to foster cooperation between the private sector and public administration through research and education. The main objectives of the center are to promote high-quality scientific research about the business sector and public administration and to consolidate a group of international research excellence in the following fields: regulation and competition, innovation, and regional economics and industrial policy.

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Orkestra, Basque Institute of Competitiveness

Orkestra, Basque Institute of Competitiveness was created in 2006 by Deusto Foundation (University of Deusto) with the objective of providing support to public bodies, socio-economic agents and all the higher education centers in the Basque Country in aspects related to competitiveness. Its research focuses on four key areas: Clusters, Regional Development and Innovation; Entrepreneurship; Strategy; and Welfare.

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## Executive Summary

This report provides an overview of the main competition and regulatory issues in the Spanish gas and electricity markets, setting them in the broader context of the liberalisation of the European energy market. Public policy in energy markets needs to reconcile a number of different objectives, including security of supply, environmental considerations, domestic competition and international competitiveness of the overall economy. There is frequently tension between some or all of these objectives. This tension requires a coherent set of policies to alleviate the trade-offs that are involved.

The report primarily focuses on the regulatory and competition policy aspects of the Spanish gas and electricity markets. It does not seek to analyse all of the public policy issues which affect the Spanish energy industry. Its objective is to provide a comprehensive analysis of the current status of regulation and competition in the relevant markets, and to highlight areas where further progress is required.

Our analysis shows that competition in the Spanish energy market is gradually improving, in both gas and electricity. There has been significant growth by new entrants and smaller operators in some segments of the value chain, including most notably wholesale gas and electricity, and gas supply to industrial customers. There are, however, some critical competition and regulatory issues that are affecting the overall performance of the industry that have not been fully addressed to date. These include: an imperfect level of competition in several markets (due to a combination of ineffective regulation and market concentration); a distorted (and at times erratic) application of regulation and merger control in the sector (which at times has also placed artificial obstacles to restructuring in the market); high and growing levels of dependency on imported energy sources (in particular, gas); slow progress in effective liberalisation at the residential level; and the need to develop a coherent, market-based policy to encourage the right technology mix in electricity generation over the medium to long term.

## The European context

There has been an intense debate on the prospects for better regulation and more effective competition in the European energy industry in recent times. This has been partially driven by a rise in fuel prices (most notably oil and gas, but also coal) observed between 2004 and mid-2008 and the resulting increase in electricity prices, and also by a perceived lack of competition in the sector. European markets are also becoming increasingly dependent on imported gas (most notably from Russia, but also from other gas producers), which is raising critical issues of energy dependence and security. These issues also affect Spain, mainly through the impact of international oil prices on gas import prices (both for pipeline gas and liquefied natural gas, hereinafter LNG).

The European Commission Energy Sector Inquiry published in 2007 found evidence of ineffective competition in most European energy markets. This was attributed to a mixture of horizontal concentration in the liberalised segments of the value chain (gas procurement, electricity generation and retail supply), and also vertical integration across the value chain (most notably in electricity transmission and gas transportation). Whilst the horizontal issues highlighted by the European Commission also affect the Spanish market (both in gas and electricity), the primary vertical concerns raised by the Sector Inquiry are of less direct pertinence to Spain at present, given the ownership unbundling of both the Spanish electricity and gas national network operators. However, the attempt to introduce more effective separation between distribution and retail supply activities is also relevant to Spain and could reduce barriers to entry in the downstream markets. The European Commission has also initiated a drive towards greater antitrust enforcement in the energy sector (mainly in the form of investigations under Article 82 of the E.C. Treaty). This is leading to structural remedies in the sector being adopted in some countries which are likely to improve competitive outcomes over time. Similarly, merger control has been used as a relatively effective lever in some cases to obtain significant structural reforms. Some of these regulatory trends are also likely to affect the Spanish market in the future.

## The Spanish context

The general context of the Spanish gas and electricity markets differs in some respects from the European context. These include a very high level of electricity demand growth (which has in turn fuelled significant growth in gas demand), limited levels of interconnection with other European countries, and very high levels of dependence on imported energy (most notably gas and oil). In common with other European countries, the Spanish gas and electricity markets were also characterised by high levels of concentration at the outset of liberalisation.

The recent performance of the Spanish energy industry has been affected by these structural features, coupled with the regulatory framework put in place since liberalisation. The key trends which have characterised the recent evolution of the Spanish markets and which we review in this report include:

- The presence of significant regulatory distortions of competition in the market (most notably in the electricity market, especially at the retail level);

- Very significant growth in renewable generation (wind, and more recently, solar power);

- Rapid expansion of imports of LNG, and associated regasification infrastructure, making Spain one of the European leaders in this area; and

- Growing convergence between the gas and electricity markets, especially at the wholesale level through the very rapid growth of combined-cycle gas turbines (CCGTs). This is increasing the degree of competition in both markets (with Spain faring particularly well in the wholesale and industrial gas markets but not so well in electricity in relation to the European benchmark) but also making Spain more dependent on imported gas.

**Regulation in the Spanish energy sector**

Since the liberalisation of the industry in the late 1990s, there has been intense regulatory activity in the Spanish energy sector. As the report reviews, this trend has continued in the recent past, most notably in the electricity sector. One of the key and most topical policy issues in the electricity sector remains the growing shortfall between revenues from regulated tariffs and wholesale electricity prices. This so-called "tariff deficit" increased very significantly in 2005 and 2006 (when wholesale prices increased rapidly and retail tariffs did not adjust) and a similar outcome will also characterise 2008.

The government has introduced several reforms of the electricity generation sector in order to render it more competitive and to contain the tariff deficit. One of these measures (and the one most directly aimed at reducing market power) has been the introduction of virtual power plant (VPP) auctions on the two main incumbent generators (Endesa and Iberdrola). Spain is - together with Portugal - the only country in Europe where VPP auctions have been introduced as a regulatory measure to mitigate market power (rather than as a remedy following an antitrust procedure).[1] However, the size of this intervention is still limited (with less than 1.25 GW per company being auctioned by mid-2008, equivalent to less than 6% of the total installed capac-

1 Other countries - e.g. the United Kingdom and Italy - have, however, relied on physical divestments to reduce concentration in their generation markets.

ity of each of the affected companies). The reduced size of the VPP auctions (coupled with their short duration) is likely to render the measure relatively ineffective in practical terms.

The government also attempted to increase bilateral trading in the Spanish market by starting large procurement auctions for regulated electricity demand (so-called CESUR) in mid-2007. The economic analysis contained in this report suggests that these auctions are unlikely to have a strong pro-competitive impact in the market. However, over time these auctions could be used to render the market more contestable, and improve the process which determines regulated tariffs by reducing the volatility of the wholesale energy component (if longer-term procurement contracts are introduced).

Other significant reforms introduced by the government in the generation sector were the adoption of a new system for capacity payments in 2007, and the introduction of a windfall tax on the expected profits earned since 2006 by generators as a result of the introduction of the European Emission Trading Scheme (ETS).

Another recent regulatory initiative has been the reform of the mechanism for recognising and funding the electricity tariff deficit. The tariff deficit is now recognised ex-ante to distributors and reflected in the regulated component of the tariff (i.e. the access charge), which is reduced in line with the deficit. This should in principle allow independent retailers to compete with the (subsidised) regulated tariff. Whilst this reform is helpful, since it should allow for a degree of retail competition to develop, it still does not address the fact that retail tariffs do not cover wholesale prices, nor are they adjusted to fully reflect changes in these prices. At a time when international fuel prices are subject to large variations and are higher than the levels seen prior to 2005, retail prices need be adjusted in order to send the right economic signals to end consumers. Moreover, only retail tariffs that reflect market prices can allow for effective and sustained retail competition to develop in the market over time.

Resolving the issue of the electricity tariff deficit goes hand-in-hand with the need for a more competitive generation market and, perhaps, an improved market design. In this context, at the same time as recommending a significant increase in retail tariffs in mid-2008 to prevent a further increase in the tariff deficit, the sector regulator (the *Comisión Nacional de Energía,* CNE) also highlighted the fact that significant "infra-marginal" rents had been earned by some generation technologies (notably nuclear and hydro) as a result of the rise in fuel costs for price-setting technologies (which was especially marked until mid-2008). No specific policy recommendation was made by the CNE to address the issue which it raised.

**Competition policy in the Spanish energy sector**

Competition authorities have also continued to be active in the Spanish energy sector. The most notable recent interventions have been the competition assessment of the proposed merger between Gas Natural and Endesa (in late 2005/early 2006), and the four excessive pricing decisions in the electricity congestion market taken by the Competition Tribunal (now Competition Commission) between late 2006 and mid-2008.

Merger control in the Spanish energy sector has not been applied on a consistent basis in the recent past. Mergers between relatively small competitors (Unión Fenosa/Hidrocantábrico) were prohibited outright, whilst others (Gas Natural/Iberdrola) were blocked on ill-defined regulatory grounds. This trend continued with the merger assessment of Gas Natural/Endesa. Conflicting recommendations between the sector regulator and competition authorities were made on the merger, with the former recommending approving the deal with extensive conditions, and the latter in favour of outright prohibition (in spite of the possibility of applying structural remedies). The Spanish government (which at the time had the last word on merger decisions) followed the CNE's recommendations, with some modifications. Subsequent bids for Endesa by E.On and Enel/Acciona have meant that the Gas Natural deal (and associated remedies) did not go ahead. As a result of the Endesa case, the European Court of Justice, at the request of the European Commission, found that the regulatory powers of the CNE over mergers ("Function 14"), as expanded by the Spanish government in February 2006, violated European law since they were not proportionate to ensuring security of supply. The experience of the bids involving Endesa illustrated a potential paradox which can arise in relation to acquisitions by foreign state-owned firms: a country like Spain may privatise a firm like Endesa, supposedly for efficiency reasons, only to find that it may later revert to foreign public hands (with this happening without any violation of European competition law since the E.C. Treaty is neutral with respect to the form of property of firms). The issue is therefore whether a level playing field exists in the European market for corporate control in the presence of state-owned firms. The proposed merger between Gas Natural and Unión Fenosa (announced in August 2008) will be another important test case for the application of merger control in the Spanish energy sector.

The Spanish competition authority recently fined Viesgo, Iberdrola and Gas Natural for abuse of dominance in the market for the management of congestions on the electricity transmission network. These decisions highlight the fact that the Spanish authorities are also willing to apply abuse of dominance provisions in the energy sector, even in the difficult and contentious area of "excessive pricing" under Article 82 of the European Treaty. However the features of the market for congestion management are quite peculiar and these decisions by the competition authority are difficult to apply to the broader market for wholesale electricity (or to other energy markets with dominant firms).

## Evolution of the Spanish gas and electricity markets up to 2007

Our review of the evolution of the Spanish gas and electricity markets up to 2007 reveals the following:

**Wholesale gas**. Spain's reliance on imported LNG remains high, with LNG accounting for close to 70% of total gas imports in 2007. The role of LNG is allowing Spain to achieve significant diversification of its import sources (compared to most other European countries), with no import source accounting for more than 40% of total flows in 2007 and with a variety of other gas-exporting countries serving the Spanish market. Investment in LNG infrastructure is also increasing, with a sixth LNG terminal coming into commercial operation in Mugardos in 2007. This is in addition to the three terminals operated by the Transportation System Operator (Enagás) and the other two privately owned terminals (Bilbao and Sagunto). Gas procurement activities remain concentrated, with the incumbent supplier (Gas Natural) still accounting for roughly 60% of total gas imports into Spain. This share is declining, however, thanks to the growth of LNG imports controlled by other competitors.

**Wholesale electricity**. The power generation sector has been characterised by significant entry of CCGT and wind capacity in recent years by independent or smaller producers. This new entry has reduced the combined market share of the two largest generators (Endesa and Iberdrola) from 80% in the late 1990s to just over 60% in 2007 (in terms of conventional output, excluding special regime generation) and below 55% (including special regime generation). As a result of this entry, the two largest generators were almost no longer pivotal (i.e. required to meet a given level of demand) in 2007. However, the two main generators have remained jointly pivotal for a significant proportion of the time. Moreover, the wholesale electricity sector overall remains highly concentrated, as measured by the Herfindahl-Hirschman Index (HHI) of conventional capacity and output in 2007 (even though the level of the HHI has been falling over time, and is in the moderately concentrated region if one considers all producers in the Iberian market and/or generators in the special regime). The degree of concentration seen in the Spanish generation market is broadly in line with that of other large European countries (with the exception of the United Kingdom). Wholesale prices have fluctuated significantly in recent years, driven by variations in international fuel prices (mainly gas, coal and $CO_2$), and in the availability of hydroelectric generation. After a period of high prices in 2005 and 2006, prices dropped for most of 2007 (due to more contained gas prices, and very low $CO_2$ prices), but have increased again since late 2007. An integrated market was started with Portugal in July 2007, but Portuguese prices were significantly higher than those in Spain during the second-half of 2007 and into 2008, due to congestion on the interconnectors between the two countries. Significant entry by gas-fired and renewable generation (mainly wind and solar power) is set to continue in the near future, implying that under some scenarios CCGT capacity and special regime generation (which includes renewable sources) could jointly account for two thirds of the total market by 2011. Solar power has increased particularly rapidly in 2007 and into 2008 (due to large monetary incentives, which are set to be reduced from 2009 onwards, and also cost reductions).

**Retail gas**. Retail gas demand has increased rapidly in recent years, driven by the demand from the electricity sector (which more than doubled between 2004 and 2007). In terms of volumes, retail liberalisation is now extensive, with close to 90% of total demand paying market prices rather than regulated tariffs. Gas Natural's position in the liberalised gas market is also weakening, with its share of retail volumes dropping below 50% in 2005, and standing at 46% in 2007. This decline can mainly be attributed to the fact that electricity companies (most notably Iberdrola and Unión Fenosa) are self-supplying demand from their CCGTs. Gas Natural's position in the residential gas market, however, remains much stronger, by virtue of its extensive distribution network (covering more than 80% of gas consumption) and the fact that few residential customers (10% on average) have switched away from their incumbent supplier. The level of performance in retail gas competition in Spain (measured by switching rates) is, however, not dissimilar from most other European countries, some of which have even lower levels of effective switching at the residential level. It is also worth stressing that switching rates and retail market shares may be imperfect indicators of competitive conditions, since they do not directly reflect the prices and quality levels faced by consumers.

**Retail electricity.** Liberalisation of the retail electricity market has recently been hindered by the fact that tariffs were set below market prices, especially in 2005 and 2006. During these two years the electricity tariff deficit reached very high levels (i.e. 20%-30% of total regulated revenues) and was allocated to the energy component of the tariff, resulting in negative retail margins for suppliers offering market prices. The presence of the tariff deficit, and the way it was funded, resulted in a sharp decline in the proportion of the market that paid market electricity prices between 2005 and 2007. During the whole of 2007, less than 10% of customers and just over 25% of volumes were on market prices. This negative trend was partially reversed by the tariff reforms introduced in 2007 (which allocate the deficit to the regulated component of the tariff, allowing independent retailers to compete against the tariff in principle). Moreover in July 2008 standard regulated tariffs were abolished for high-voltage customers (accounting for close to 50% of total consumption). This measure can also be expected to speed up competition in retail electricity. As in the residential gas market, most customers who switch to market prices remain with their regional incumbent, meaning that in 2007 fewer than 5% of total customers were not supplied by the regional electricity incumbents. Again, as for the gas markets, it should be stressed that measuring competition in retail markets by considering only market shares and switching rates is imperfect.

## Open policy issues

There are a number of outstanding policy issues which we do not address in this report, but which are relevant issues for future analysis of the sector. These include: (a) the role to be played by nuclear and clean-coal generation in the future energy mix of Spain; (b) the appropriate policy to be taken towards renewable generation (including most notably wind and solar power), in

order to optimise the trade-off between the containment of wholesale energy costs and optimal energy diversification (which must reflect the actual and measured externalities associated with climate change, energy security and also other factors such as encouraging R&D and international competitiveness in new technologies); (c) the possibility of improving the design of the European Emission Trading Scheme; (d) the scope for the creation of a more effective wholesale gas market in Spain (for both spot and forward trades); (e) the appropriate regulation of network infrastructure (including the need to maintain correct investment incentives), and the related reforms of the remuneration of transmission and distribution activities introduced in Spain in early 2008; (f) the prospects for the development of effective retail competition in Spain, including the role to be played by well-designed tariffs of last resort in the context of retail liberalisation; and finally (g) the need to improve the pricing signals provided to end energy consumers (especially in electricity), including the development of more effective time-of-day pricing to stimulate greater demand-side responsiveness.

## Key analytical conclusions

Some key conclusions emerge from our review of the recent evolution of the Spanish gas and electricity markets:

**Trends in wholesale gas**. Competition in wholesale gas is progressing, thanks to the growth of independent LNG imports and CCGT demand supplied by firms other than the incumbent, Gas Natural. However, the overall position of Gas Natural remains significant, as measured by its share of total gas procurement. Whilst Spain's reliance on LNG makes it well placed to benefit from the prospect of greater gas-to-gas competition in the future, at present it remains directly exposed to fluctuations in international oil prices, which affect the cost of both LNG and pipeline gas imports.

**Competition in electricity generation**. Recent developments in the wholesale electricity market have reduced the market power of the two main incumbent generators. This is particularly the case thanks to the entry of CCGT capacity by independent generators, smaller electricity firms (mainly Unión Fenosa, but also EDP/HC and Viesgo) and the gas incumbent Gas Natural. On the other hand, the Spanish generator sector remains concentrated under some definitions of the relevant market and is weakly interconnected with other markets (France and Portugal). Continuing focus of the government and the regulator on potential market-power mitigation measures and improved interconnection is therefore still warranted.

**Gas electricity convergence**. Integration and linkages across the gas and electricity markets have increased considerably in recent years, thanks primarily to the rapid growth of the CCGT sector. This is a positive development for efficiency, because gas is a main input for electricity production, and for competition, since it is allowing the incumbent suppliers in both the gas and

electricity sectors to challenge the other market more effectively. However, greater convergence between the gas and electricity markets means that fluctuations in the wholesale gas price now affect the electricity market just as much as the gas market. There is therefore a need to further diversify primary energy sources in the electricity market.

**Generation market design**. Several of the recent measures introduced in the Spanish electricity market can be seen as attempts to improve the design of the generation market and to contain wholesale prices. These include the introduction of VPP and procurement auctions (CESUR) and the deduction of windfall gains due to the ETS. In principle, the measure that most directly addresses market-power concerns in generation is the introduction of VPP auctions. However, due to their limited size and specific design issues, these auctions are likely to have had a moderate impact on prices to date. The recent experience of other countries which have liberalised their energy markets (most notably the United Kingdom) also shows that structural reforms - rather than changes in market design - are the most effective ways of enhancing competition in generation markets. This is also likely to be the case in the Spanish context.

**Liberalisation of the residential energy markets**. Competition in the Spanish residential energy market remains weak and distorted. On average (at a national level) only 10% of residential customers have switched to alternative gas suppliers and fewer than 5% to alternative electricity suppliers. The electricity tariff deficit, coupled with the flawed design of the tariff up to 2006, has impeded effective retail competition in electricity. This has most probably had a knock-on effect in the gas market too, by rendering dual-fuel entry (i.e. the joint offer of both gas and electricity) more difficult. The prospect of effective liberalisation, including the lifting of price controls if sufficient competition were to develop, appears distant, at least for household consumers. Preserving a tariff of last resort for these customers would be in line with the provisions of the European Directives implemented in 2007, as long as it reflects market prices and does not distort competition.

**Regulatory instability**. The application of regulation and competition policy in the gas and electricity markets is still unstable, which is contributing to a high degree of regulatory uncertainty. This is the case in several areas, including merger control (which has not been applied on a consistent basis), the overall design of wholesale electricity markets (which has been subject to several interventions over the past few years), the determination of retail tariffs (which is not consistent with market-based mechanisms), and the policy towards incentives for renewable energy (which has not been stable over time - the example of persistent uncertainty over the remuneration for solar energy during the course of 2008 is a case in point). It is also important to bear in mind that regulatory uncertainty may harm not just energy firms but also consumers, especially those who need to make investments whose profitability depends on the price of energy.

## Policy recommendations

The policy recommendations that can be derived from our analysis of the recent performance of competition and regulation in the Spanish gas and electricity markets are the following:

- **Encourage a balanced energy generation mix and demand control using market-based tools**

  The Spanish energy market is currently heavily reliant on imported gas, and is directly exposed to variations in international gas (and oil) prices. In order to increase energy security and contain future energy costs, there is a need to further diversify energy sources. In practice this means continuing to encourage renewable energy, but balancing its costs by taking into account well-defined and measured positive externalities that can be associated with this type of generation. Mechanisms should also be explored to preserve the current role played by nuclear and coal power in the overall energy mix over the medium-term (as long as this can be shown to be cost-efficient and consistent with environmental objectives).

  Market-based measures to procure additional generation capacity should be considered to determine an adequate remuneration level for new capacity, promote an appropriate energy mix and also make the market more contestable.

  More decisive efforts to encourage energy savings and greater demand-side responsiveness to market prices are also required. Price signals for end consumers should be improved both in the short-term (by allowing for more effective time-of-day pricing) and also in the longer-term (by eliminating the electricity tariff deficit).

- **Adjust electricity retail tariffs to prevent a further accumulation of the tariff deficit, and provide the correct price signals to consumers**

  Regulated tariffs for electricity in Spain are still set below wholesale market prices. This is an unsustainable situation and does not send the correct market signals to end users for electricity consumption (at least over the medium/long term). The absence of time-of-use tariffs, coupled with the fact that retail prices have been kept artificially low for a significant period of time in Spain, is likely to lead to excessive demand levels and therefore require inefficient levels of installed capacity. The fact that regulated tariffs are below market-based prices has also distorted competition both in the retail electricity market (at least up until the end of 2006) and in the related dual-fuel market (thus affecting competition for residential gas customers).

  There is a critical need for retail tariffs to be adjusted according to a well-defined and credible timetable to bring them in line with market prices and prevent a further accumulation of the tariff deficit. This should be implemented at the same time as measures aimed at enhanc-

ing competition in the wholesale electricity market are strengthened. Over time, ending the policy of subsidising retail tariffs could – as a secondary objective - also allow for more effective and faster liberalisation of both the gas and electricity markets. Before lifting retail price controls, the regulator would, however, need to ensure that sufficiently intense competition is present between firms in the relevant downstream markets.

- **Render market power mitigation measures in the generation sector more effective**

  The market power mitigation measures introduced by the government in the generation market can be made more effective. This applies in particular to VPP auctions implemented since mid-2007. In order to be more effective, VPP contracts of a greater size and duration are required. On the other hand, procurement auctions like CESUR should not be seen as a market power mitigation measure (since participation by generators in this type of auctions is not compulsory). The mitigation of market power in the generation market is, however, probably less critical now than it was when the market was first liberalised, thanks in part to the growth of independent competitors.

- **Induce an efficient firm and market structure**

  Artificial legal and regulatory impediments to efficient corporate restructurings in the energy sector responding to technological and market trends or arising from the market for corporate control should be removed. Where possible, structural market reforms (including measures to favour greater interconnection with neighbouring countries, such as France and Portugal, and more significant domestic gas storage capacity) should be used to improve the functioning of the Spanish energy markets. Following the examples of regulators in other countries, and more recently the European Commission, both merger control and antitrust enforcement could be used more effectively in the future to obtain remedies that can improve the structure of the market, thus making competition more effective.

- **Improve regulatory stability**

  There have been a myriad of regulatory initiatives taken by the government over the past two years. These have increased regulatory instability and created a complex regulatory framework. There is a need to promote regulatory stability over time (to the benefit of both firms and consumers), at the same time as improving regulation where possible with selected and targeted policy measures. Competition policy towards the sector also needs to be applied consistently within the E.U. framework, and be based on sound effects-based economic principles - both in terms of merger control and antitrust enforcement. Merger policy should enable corporate restructurings that are consistent with effective domestic competition, and that can also allow energy companies to become more efficient and acquire critical scale on international energy markets (e.g. with enough size to secure input supply at reasonable prices). Similarly, regulatory compensation mechanisms for renewable energy (e.g. wind and

solar power) need to be set up on the basis of robust economic methodologies – this would also promote regulatory stability for new investments.

Finally, the policy towards regulated electricity tariffs should be used to achieve and maintain an efficient and competitive energy market, but not to pursue other objectives (such as inflation control).

# 1. Introduction

This report provides a comprehensive overview of recent developments in the Spanish energy market, whilst focusing on regulatory and competition policy issues. The aim of this report is to provide a perspective on the status of regulation and competition in the Spanish energy market that is fully grounded in the economic theory of industrial organisation, regulation and antitrust, whilst reviewing some of the most recent events in the sector. The report intends to contribute to the ongoing debate on the appropriate regulation of the Spanish – and the broader European – energy market taking place between practitioners, policy-makers and academics.

The structure of this report is as follows:

**Section 2** provides a brief overview of the main features of the gas and electricity markets, highlighting key aspects of these markets from an economic perspective, and areas where regulatory and competition issues are more likely to arise.

**Section 3** summarises the current regulatory debate on the energy market in Europe. We review the issues of energy dependence and security (discussing the recent evidence on energy import flows and infrastructure), and recent developments in the area of regulation and competition policy. This serves as a general background for the overview of developments in the Spanish market contained in the rest of the report.

**Section 4** contains a review and critique of regulation and competition policy in the Spanish energy sector. It discusses both the initial reforms introduced in the sector at the inception of liberalisation in the late 1990s, and the more recent measures introduced during the 2006-2007 period to accelerate liberalisation and address perceived regulatory shortcomings.

**Section 5** provides an analysis of the recent evolution of the gas and electricity markets in Spain. It focuses on the last four full years of data (2004 to 2007), and deals in turn with the wholesale gas and electricity markets, and with the retail markets in both sectors.

**Section 6** provides a more in-depth economic evaluation of two selected topics in wholesale electricity market design, which have attracted a significant amount of attention in Spain recently: the role of contracts (including VPP and procurement auctions) in influencing market outcomes, and the reform of the capacity payment mechanism introduced in the Spanish market in 2007.

**Section 7** contains our conclusions and policy recommendations on the key themes in the Spanish energy market reviewed in the report.

The **Annexes** contain additional regional information on the gas and electricity markets in Spain, and a list of the acronyms used in the main text.

## 2. Background: Competition in the Gas and Electricity Markets

This section of the report provides a brief overview of the main economic features of gas and electricity markets, and of the key competition issues that can arise in these markets. We will start by reviewing the gas market, and then turn to the electricity sector. We will also discuss the impact of greater convergence across the two markets.

### 2.1. Structure of the gas market

The gas market is organised in a vertical structure, where four distinct segments are typically distinguished: production, transportation (including storage), distribution and retail supply.

**Production.** The production stage can include both gas supply from domestic fields and imports from foreign countries. Gas can be transported from other countries either through pipelines or by sea in the form of liquefied natural gas (LNG). Pipeline gas is cheaper than LNG for shorter distances. However, LNG imports have increased considerably in recent times across Europe, and in particular in Spain, due to growing gas demand and reductions in relative LNG costs. Gas is typically imported on long-term take-or-pay contracts which underpin the sunk investments required for long-distance pipelines. At the European level, the price in most gas contracts is indexed to oil (which has traditionally been a substitute fuel for gas). Investment in LNG facilities is less market-specific, thus implying that LNG can be imported on more flexible contracts. The growth of LNG imports raises the scope for the future development of wholesale gas markets (or "hubs"), even in countries with limited gas production, and the prospect for "gas-to-gas" competition. At present, however, gas hub trading in Europe is relatively limited, with the main exception being the United Kingdom.

**Transportation (including storage) and distribution.** Once gas is produced or imported, it needs to be transported to consumers in a high-pressure network first, and then in regional distribution

pipelines. Gas can also be stored domestically (e.g. in depleted fields), in order to deal with fluctuations in gas demand across days and seasons. The transportation and distribution networks display the characteristics of natural monopolies, since they cannot be economically replicated. However, the fact that there are multiple regional distribution networks allows, in principle, for comparative (or "yardstick") regulation at the distribution level, and for the presence of a form of indirect competition.

**Retail supply.** The final stage of the vertical chain includes the marketing and sale of gas to end customers. Typically three customer segments are identified within this activity: sales to residential households, sales to industrial and commercial consumers, and sales to electricity generators that rely on gas (mostly combined-cycle gas turbines, CCGTs). This stage of the market is potentially competitive, since sunk costs in supply are relatively small, and multiple competing firms can co-exist.

### 2.2. Competition issues in the gas market

Gas markets are being liberalised across Europe. Liberalisation typically entails the introduction of competition in gas procurement and retail supply, and the establishment of third-party access to the network. In some countries (but not all), liberalisation has also led to the vertical ownership separation of the main network infrastructure (transportation and storage).

Liberalisation has resulted in both horizontal and vertical competition issues arising. The first relate to the potential lack of significant competition within the competitive segments of the supply chain (i.e. production and retail supply), and in some cases the need for continuing retail price regulation. Vertical issues can arise due to the potential foreclosure of entrants, primarily resulting from the vertical integration of the incumbent gas players across naturally monopolistic and competitive activities (e.g. transportation and retail supply).

The high concentration of gas importers, primarily for pipeline gas, can also give rise to material horizontal concerns in the upstream gas market. However, especially for the countries that rely primarily on imported gas (which is the case of Spain), these issues are largely outside the control of domestic governments (both in terms of regulation and competition policy).

Regulation and competition law enforcement in gas markets has therefore tended to focus on issues of vertical foreclosure. These can arise as a result of incumbents reserving the majority of import capacity for their long-term gas contracts and/or due to vertical integration between the different stages of the production and supply chain (including the network elements). The first form of foreclosure can be addressed through gas release programs and also through greater reliance on LNG imports (which can allow entrants to by-pass the existing import infrastructure). The second form of foreclosure is potentially harder to address, in

the absence of full ownership unbundling of the gas networks. As we will discuss in the next section of the report, much of the recent regulatory debate at the European level has centred on the need for appropriate unbundling of the gas transportation network, which in several European countries is still owned by the gas incumbents (who are also active in procurement and retail supply).

Moreover, the European Commission and some national competition authorities have increasingly applied abuse of dominance provisions (e.g. Article 82 of the E.C. Treaty) to foreclosure issues in gas markets (e.g. these have been examined Spain, Italy, Belgium and Germany over the past few years).

At the retail supply level, horizontal issues arise because of established incumbency positions, which can result in very high concentration levels (especially at the residential supply level). Entry in residential supply can be hindered by the presence of customer switching costs, and also the advantages enjoyed by the regional incumbents thanks to their ownership of the distribution networks (e.g. informational and brand advantages).

### 2.3. Structure of the electricity market

Like the gas market, the electricity supply industry is also structured in four vertical segments: generation (or production), transmission, distribution and retail supply.

**Generation.** Wholesale electricity can be produced using several generation technologies, which differ in terms of the primary energy source that they use (e.g. nuclear, hydro, coal, gas, oil, wind, etc.), their cost structures and their flexibility (e.g. their ability to modify production levels rapidly across different time periods). Electricity production can also be imported from abroad, depending on the size of interconnection with neighbouring countries. Given the special properties of the electricity generation market (and their implications for the development of competition in this sector), we will describe the main features of this market in more detail in the next sub-section.

**Transmission and Distribution.** Electricity that is generated domestically or imported needs to be transmitted from generation plants and international interconnection points to final customers. This takes place first through a high-voltage national transmission network and then through regional and local distribution networks.

**Retail Supply.** Supply to end customers includes the marketing, billing and provision of electricity to both low-voltage customers (primarily residential) and medium/high-voltage customers (industrial and commercial users).

As in the gas market, the generation and retail supply segments of the electricity vertical value chain are potentially competitive, whilst transmission and distribution (in each region) have natural monopoly features and need to be regulated. Retail supply also remains price regulated in several European countries (at least at the residential level).

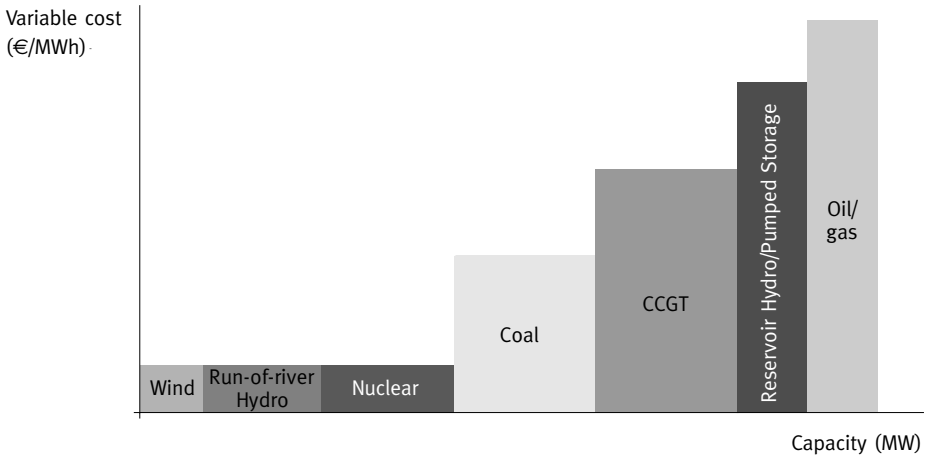
### 2.4. Special features of the electricity market

The electricity market is characterised by a number of specific features which affect both its market design and the nature of competition. The most notable feature is that, unlike gas, electricity cannot be stored on a significant scale and needs to be consumed instantaneously. The lack of storability, coupled with the fact that final electricity demand varies considerably during the day and across seasons, means that electricity production levels need to be able to adjust rapidly on an hourly basis and have to constantly match demand requirements. This implies that some generation capacity needs to be available primarily to meet demand peaks (but will not be needed at lower demand levels), and that prices can rise significantly during peak periods (to allow peaking capacity to recover both its fixed and variable costs). The fact that final demand does not respond significantly to price changes (typically because it does not face real-time prices due to the absence of hourly metering of consumption) accentuates the need for spare capacity during peak demand periods.

The features of the electricity market described above imply that a combination of power plants is used to optimally meet demand at any given point in time. Plants with high fixed costs and low marginal costs are used to meet baseload demand (i.e. the constant minimum level of demand across a time period, e.g. a year). Baseload plants typically include nuclear and run-of-river hydro plants, and renewable capacity which cannot be modulated (e.g. wind power). Plants with low fixed costs and high marginal costs (e.g. gas and/or oil turbines) are used instead to meet demand peaks. Reservoir hydroelectric power and pumped storage capacity are also used to meet demand peaks. Finally, plants with intermediate marginal and fixed costs (e.g. coal and CCGT plants) often operate as "mid-merit" generation (i.e. they do not produce in the periods of lowest demand, but generate in all other periods).

A "merit order" of plants of different technologies can therefore be constructed in generation markets, ranking capacity from the cheapest to the most expensive (in terms of variable costs). Fluctuations in relative fuel prices (including $CO_2$ emission costs) affect the position of different technologies in the merit order (and in particular can cause the relative position in the merit order of coal and CCGT to "flip"). A hypothetical generation merit order is shown in Figure 1.

*Figure 1: Hypothetical merit order in the generation market*




Source: Own analysis.

In the paradigm competitive generation market (i.e. one with low concentration levels), plants face incentives to offer their energy at variable cost during most hours of the year. Hourly prices are therefore set at the marginal cost of the most expensive plant in the merit order that is needed to meet demand in that hour (i.e. the marginal plant). Plants with lower marginal costs than the marginal plant can also produce during that hour and earn "infra-marginal rents" that allow them to recover their fixed costs (e.g. capital costs and fixed operation and maintenance costs).[2] At the very peak, prices need to rise above the variable cost of the marginal plant in that hour to allow it to recover its fixed costs, and can therefore reach (in the theoretical model) the maximum willingness to pay for electricity (i.e. the value of lost load or VOLL).

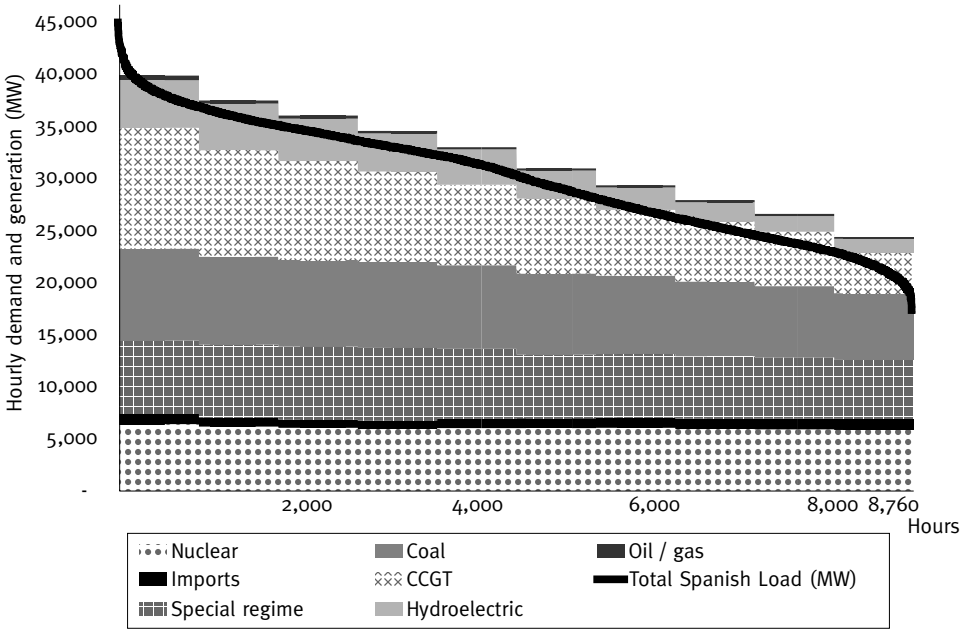
For a given generation merit order, the distribution of demand levels across a given time period (e.g. a year) will therefore affect the distribution of electricity spot prices. Both demand and prices can be described as annual "duration curves", i.e. plots of all the demand/price levels observed in a year (i.e. 8,760 hours), which rank hourly levels from the highest (0% duration or hour 1) to the lowest (100% duration or hour 8,760). The duration curves for Spanish load and generation by technology observed in 2007 are shown in Figure 2. To read the duration curve for total Spanish load, consider for example the point in the curve at hour 2,000 (i.e. duration of 2,000/8,760 = 23%). This shows a value for total load in 2007 of approximately 34,500 MW. This value corresponds to the 2,000$^{th}$ highest demand level of 2007, and also indicates that for 23% of the time in that year, demand levels exceeded 34,500 MW.

2. With free entry and exit in each technology, these infra-marginal rents will be exactly equal to the fixed cost associated with each technology, so that no excess profits are made. However, this need not be the case if there are barriers to entry/exit.

The duration curve shown in Figure 2 also indicates the average hourly output level of each production technology in each load decile. The different generation technologies are stacked up in approximate order of merit (i.e. from the lowest marginal cost technology – nuclear – to the highest – oil/gas turbines). The figure shows that the hourly output of the baseload generation in the order of merit (i.e. nuclear and special regime generation) was fairly flat across different duration levels (even though special regime generation is volatile around its mean) and that most of the systematic variation in demand levels across the year was met using CCGT and hydroelectric power.

Congestion on the transmission network can change the theoretically optimal merit order. In situations of network congestion, the operator of the electricity system (which is tasked with ensuring the perfect balance of demand and supply) will have to call on more expensive units located in the congested area to produce, instead of plants that are willing to produce electricity at a lower price in areas with surplus generation.

*Figure 2: Load duration curve in the Spanish generation market, 2007.*




Source: REE, own analysis.
Note: Special regime generation includes renewable output (e.g. wind and solar power) and co-generation. Hydroelectric power includes an element of run-of-river generation, which operates as baseload. Generation exceeds demand because of exports to other countries. Data on generation by technology is the average output level in each load decile.

## 2.5. Competition issues in electricity

Electricity markets can give rise to several competition issues, depending on their structure and market design.[3] The ones that have attracted the most attention, by both policy-makers and academics, are horizontal concerns in the generation market, resulting from industry concentration and from the specific features of this market. There can also be foreclosure issues due to vertical integration across different segments of the electricity value chain, and horizontal issues in retail supply.

### Competition in generation

In practice, the type of competitive bidding in generation described in the previous section is rarely observed in its purest form. Deviations from competitive pricing in generation markets can be explained by a combination of factors, which include:[4]

**Concentration.** Most national generation markets tend to be concentrated. Generators with several generation plants may therefore benefit from withdrawing[5] some of their capacity from the market (when this is technically feasible) in order to increase prices and benefit their remaining (infra-marginal) capacity. Moreover, portfolio generators may own plants which are close to each other in the merit order, thus allowing them to increase the bids of these plants in hours when they are (or expect to be) marginal without facing a significant risk of being undercut by a rival generator.[6]

**Capacity constraints.** Binding capacity constraints imply that smaller rivals may not be able to respond to an increase in market prices in some hours, thereby reinforcing the incentives faced by portfolio generators to raise prices. Similarly, "jumps" in the industry cost schedule due to the presence of different generation technologies can give incentives to generators to increase their bids or withdraw capacity in order to reach the next jump in the aggregate supply function.

**Transmission constraints.** Congestion in the transmission network (including interconnection with other countries) can also limit the ability of generators in some areas to respond to higher prices, thus allowing plants in congested regions to increase their bids.

**Low demand elasticity.** The fact that the price elasticity of demand tends to be low reinforces the market power of generators (as any model of oligopolistic competition would predict). The lack of storability exacerbates this issue, since it does not allow users to store electricity in low demand periods in order to shelter themselves from higher prices during peak periods.

3. For a review of these issues with particular emphasis on the Spanish market, see Vives (2008).
4. See OECD (2005) for a summary of these factors.
5. This strategy can be implemented by submitting high bids, for some plants, which exclude them from the economic merit order in the market, thereby inducing the market operator to call upon more expensive plants to produce (e.g. plants with higher fuel costs).
6. The European Commission Energy Sector Inquiry of January 2007 refers to these two strategies by portfolio generators as capacity withdrawal and "excessive pricing". In practice, a portfolio generator may find it optimal to engage in both types of strategy at the same time, choosing its optimal output along the residual demand curve that it faces.

**Entry barriers.** A number of entry barriers are present in generation markets, including the presence of sunk and long-lived investments, vertical integration (e.g. into network and/or retail activities), economies of scale in input procurement, and regulatory/environmental impediments to new-build in some types of generation technology (e.g. nuclear and hydro plants). These barriers mean that new entry may not provide a sufficiently strong disciplining effect on the market, at least in the short to medium term.

**Repeated interaction.** Competition in electricity markets is repeated very frequently (in some cases on an hourly basis) for an indefinite period of time. This may give firms the ability and incentives to tacitly coordinate their pricing.

These features of generation markets make them particularly prone to the exercise of market power, as has been noted by several commentators (see Borenstein and Bushnell (2000) and Wolak (2004)). A number of empirical studies have identified the presence of market power in some liberalised electricity markets.[7] Different methods are being used by competition authorities and academics to characterise and simulate market power in generation markets. These are summarised in Box 1.

In principle, the design of generation markets can be optimised in order to foster competition between firms. However, this is a complex area and there is still considerable debate on how the generation market should be designed to mitigate market power.[8] Issues in this debate include: the relative merits of establishing large, liquid spot markets as opposed to favouring bilateral contracting; the choice of trading rules in spot markets (e.g. uniform pricing vs. discriminatory pricing; hourly vs. daily bidding); the role to be played by contracts in mitigating power market in spot markets (including both stranded cost contracts, which seek to guarantee a certain level of revenues to incumbent firms in a liberalised market, and compulsory releases of "virtual capacity" to improve pricing incentives); the need for (and design of) capacity payment mechanisms to complement revenues from energy markets; and the relative merits of allowing vertical integration between generators and retailers. Section 6 of this report discusses those aspects of generation market design which have recently been reformed in Spain, i.e. forward contracts and capacity payments.

### Vertical competition issues in electricity

As in the gas market, liberalised electricity markets can also raise issues of vertical foreclosure. These can arise, for example, if the same firm controls essential infrastructure (e.g. the transmission network) and is also active in the liberalised segments of the value chain. This issue has been less prominent than in gas, however, partially because a slight majority of the EU15 countries

7. See, for example, Borenstein, Bushnell and Wolak (2002) for an empirical study of market power in the Californian market. Wolfram (1999) and Sweeting (2007) provide empirical estimates of market power in the British generation market. Mansur (2008), however, finds evidence of relatively limited market power in Pennsylvania, New Jersey and Maryland in the late 1990s.
8. For a review of some of these issues applied to the U.K. electricity market, see Newbery (2005). Fabra (2003), Federico and Rahman (2003), and Fabra *et al.* (2006) also study some of these issues in a theoretical setting.

(8 out of 15) have fully unbundled the electricity transmission network. Some Member States, however (most notably France and Germany), have not unbundled their electricity transmission networks. Section 3 of the report discusses the current European debate on the merits of ownership unbundling in the electricity market.

Vertical issues can also arise as the result of vertical integration between regional distribution and retail supply. This can raise barriers to entry in retail by, for example, giving the integrated retailer privileged access to information to the load profile of final users. This can strengthen incumbency advantages that are present in electricity retail markets due to the cost of switching between alternative suppliers and brand loyalty to the legacy supplier. In several European countries, regional concentration levels in residential electricity supply remain high, in spite of the fact that the market has been liberalised for some time. Vertical integration between generation and supply may also make entry by independent generators and retailers more difficult under some circumstances.

On the other hand, vertical integration across the competitive segments of the supply chain can be pro-competitive by mitigating incentives to exercise market power in the generation market (since the integrated firm is also a buyer in the wholesale market, and not only a seller).[9] Vertical integration between generation and retail can also increase the efficiency of retail pricing, reduce transaction costs and lead to more efficient risk management of wholesale price volatility.

### 2.6. Gas-electricity convergence

There is increasing convergence between liberalised gas and electricity markets convergence. This is being driven by two key factors. The first is that gas is becoming an increasingly important input for electricity generation through CCGTs. CCGT technology has relatively low capital costs and high efficiency rates. As a result, most of the new-build in liberalised electricity markets in Europe has been in the form of CCGT capacity (in addition to renewable generation). At current relative fuel prices, CCGTs are also often the marginal source of power in generation markets, implying that changes in gas prices have a direct effect on electricity prices.

The increasing role played by gas-fired generation has important implications for competition. At one level, it can allow incumbent electricity generators to build enough critical mass in terms of their gas procurement to be able to enter other segments of the retail gas market (e.g. the market for industrial consumers) and challenge the gas incumbent. Similarly, gas incumbents can successfully enter the generation market. This process of entry has been evident in the Spanish energy industry in both the gas and electricity markets, as discussed in this report (see Section 5).

9. For an empirical assessment of this effect, see Bushnell *et al.* (2008).

On the other hand, greater reliance on gas by electricity generation is creating a vertical link between the two markets which may hypothetically enable a gas supplier with market power to raise the costs of rival gas-fired generators. The potential for anti-competitive foreclosure arising from gas-electricity integration (which may or may not outweigh the efficiency effects of vertical integration) has been raised by competition authorities in a number of recent proposed gas-electricity mergers in Europe, including cases in Portugal (EDP/ENI/GDP), Hungary (E.On/MOL), Belgium (GDF/Suez), Denmark (DONG/Elsam/E2) and Spain (Gas Natural/Endesa). See Sections 3 and 4 for a review of these cases. However, the conditions under which such anti-competitive foreclosure can materialise are strict and may be difficult to obtain in practice.[10]

The second main driver of convergence between gas and electricity is the fact that both products can be offered to final consumers jointly, in the form of "dual-fuel" bundles. In some countries (most notably the United Kingdom), dual-fuel offers are allowing the gas incumbent to challenge the electricity incumbent at the residential retail level and vice versa. As we review in Section 5 of this report, this trend is also evident in Spain (but on a greatly reduced scale so far). Greater competition between the gas and electricity incumbents at the residential level can be positive, since it can allow a degree of competition to develop even in the presence of strong incumbency advantages in each product. On the other hand, it can also raise barriers to entry for independent retailers, by effectively forcing them to enter both the gas and electricity residential markets at the same time.

**Box 1: Measuring and modelling market power in generation markets**

Different structural indicators have been put forward to measure and monitor the presence of market power in generation markets. These include traditional indicators such as market shares and the Herfindhal-Hirschman Index (HHI), which measures the sum of the squares of the market share of each operator. These measures can give a first proxy for the potential of market power in generation, but crucially rely on the market being defined in the right way (so that market shares are meaningful). This raises issues of both product and geographic market definition (e.g. should the market be defined to include only potentially price-setting generation or all types of plants? Should different hours of the year be treated as different markets? Which countries/regions should be included in the market?).

Alternative measures of market power based on the concept of *pivotality* are also often used in electricity markets.* A generator is defined as *pivotal* when its capacity is required to meet a given (price-inelastic) level of demand, net of the total capacity of all other generators in the market. If demand is indeed totally price inelastic, a generator that is pivotal will be able to charge a very high price for the residual energy that it is required to produce in order to satisfy demand, and may therefore hold a significant degree of market power. Indicators of pivotality can be used to capture these types of

10. See the recent European Commission guidelines on non-horizontal mergers for a discussion of some of these issues.

situations and explicitly reflect the role played by the low price elasticity of demand and capacity constraints in determining market power.

The Pivotal Supply Index (PSI) measures the percentage of all hours in the year when a generator is pivotal. A similar (and slightly more sophisticated) measure is the Residual Supply Index (RSI), which measures, for a given generator and for each hour of the year, the total capacity available to rival firms, expressed as a percentage of total demand. If the RSI is less than 100%, the generator is pivotal in that hour. If the RSI is greater than 100% but still relatively low (say, below 110%[†]), the generator may still be able to exercise some market power and set prices that are above competitive levels.

Indicators of market power based on the notion of pivotality can be used to complement more traditional measures. However, they too have limitations. For example, in order to exercise its pivotality (i.e. set a price on the most inelastic segment of its residual demand curve), a generator may have to withhold a very significant share of its capacity. This may not be profitable or technically feasible. On the other hand, even a generator that is not pivotal may be able to exercise market power (i.e. offer some of its electricity above cost) in order to benefit from the resulting increase in the market price. Pivotality is therefore neither necessary nor sufficient for the exercise of market power in generation markets.

Ideally, simulation models based on economic theories of oligopoly interaction should be used to understand and measure market power in generation markets. A number of models have been used to simulate competition in generation markets. These include models that assume that players compete in output levels (*Cournot*), in smooth supply functions (*Supply Function Equilibria*), and in discrete price-quantity bids (*Bid Function Equilibria*).[‡] These models inevitably need to make relatively stylised assumptions to describe the operation of generation markets and results are sometimes sensitive to these assumptions. Nonetheless they all predict (not surprisingly) that in concentrated generation markets prices can rise considerably above competitive conditions (even in the absence of any tacit coordination) during peak demand periods. Properly calibrated simulation modelling can also be particularly useful to understand the possible effects of changes in market structure (e.g. as a result of mergers), and the potential impact of remedies (in the form of asset divestments and/or forward contract obligations).

* These have been recently used by the European Commission and by regulators in Spain, Italy, the Netherlands and various U.S. markets. See Twomey *et al.* (2005) for a review of these indicators.

† A market screening rule based on a threshold RSI of 110% has been proposed by Sheffrin (2002) using data from the California electricity market.

‡ Vives (1999) provides an overview of some of these models. Ocaña and Romero (1998) and Borenstein and Bushnell (1999) applied the Cournot model to the Spanish and Californian electricity markets, respectively. More recently, Moselle *et al.* (2006) performed a simulation of the Dutch market using the Cournot model. For examples of the Supply Function Equilibrium (SFE) model, see the early application to the British market by Green and Newbery (1992), and subsequent work by Kühn and Machado (2004) applied to Spain, and by Hortaçsu and Puller (2008) to Texas. The model with discrete price-quantity bids was first put forward by von der Fehr and Harbord (1993) and has been applied to the Spanish market by García-Diaz and Marín (2003) and de Frutos and Fabra (2008).

# 3. The Broader European Energy Context

The evolution of the Spanish energy market needs to be understood in the broader context of the international and European energy sector. This section of the report surveys the key trends in the European energy market, focusing in particular on its increasing reliance on imported energy sources (and associated implications) and on the drive by the European Commission to enhance competition in the sector through a mixture of regulatory and competition policy interventions.

## 3.1. European energy dependence and security issues

### Overall energy import dependence

The need for cost-effective and reliable sources of energy is one of the key challenges facing the European energy market. Input costs account for a significant proportion of final energy prices to consumers. An increase in these costs can quite easily offset any reduction in prices that can be achieved through better regulation and competition at a domestic level.

Variations in energy costs are of course hard to control for European policy-makers, since they are largely driven by exogenous factors. On the other hand, policy can affect some of the key decisions on energy mix (e.g. whether to actively promote nuclear energy or not), import sources (e.g. the extent to which imports should be geographically diversified) and energy conservation. Moreover, an understanding of likely future trends in energy security and availability can also affect other policy choices, e.g. with respect to renewable energy targets and the design of national energy markets.

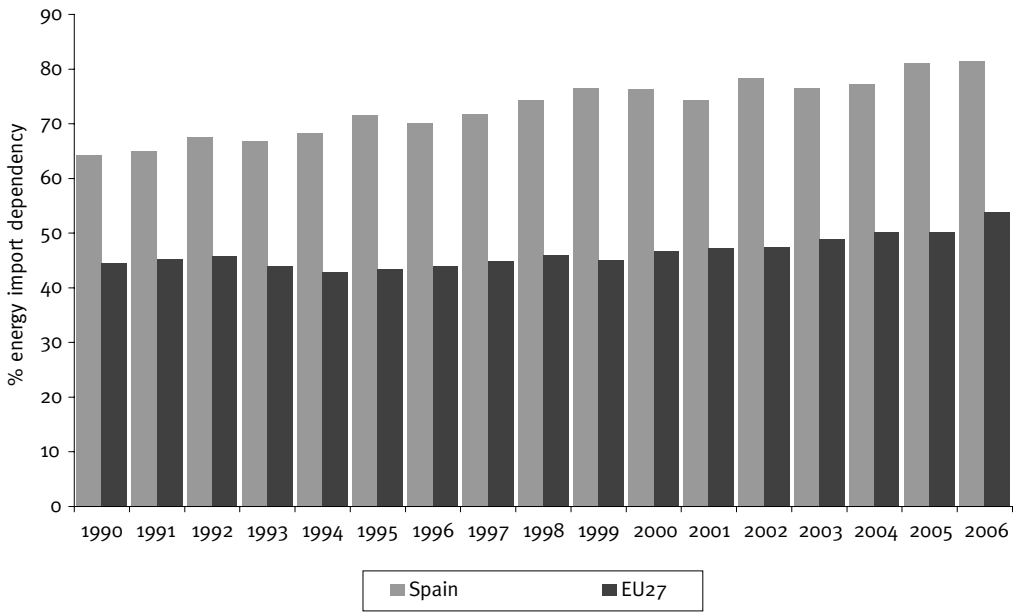
The European energy sector has recently been characterised by an increasing reliance on imported energy sources. Data published by the European Commission indicate an increase in

energy import dependence from 44% in 1990 to 54% in 2006 at the EU27 level (see Figure 3). The corresponding figures for Spain are significantly higher and also follow an upwards trend (with dependence increasing from over 60% in 1990 to over 80% in 2006). The current degree of import dependence is largely driven by imports of oil and gas, which respectively account for 84% and 61% of the consumption of each fuel at EU27 level. Spain entirely relies on imports for both oil and gas consumption (and also imports a significant amount of coal). This explains its higher import dependence relative to the European average.

### Gas dependence

The energy markets being surveyed in this report (the liberalised electricity and gas sectors) do not directly depend on imported oil to any significant extent. For example, the proportion of power generation that is oil fired stood at below 1% of total production in 2007 in Spain according to data from the electricity transmission system operator REE (see Section 5). Reliance on imported gas is therefore of more direct relevance to liberalised energy markets than oil dependence. On the other hand, given the pricing link that still exists between gas and oil imports, trends in the global oil market have important implications for the price of imported gas.

*Figure 3: Evolution of energy import dependence*

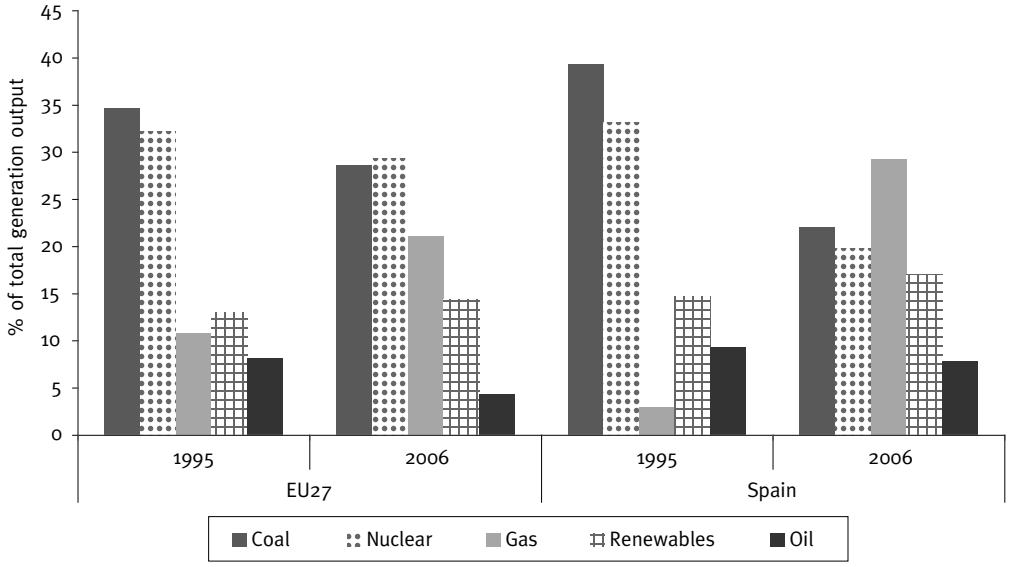



Source: European Commission, Eurostat, 2008.

Greater gas dependence has been driven by a very rapid increase in gas consumption in recent years. This has been in turn primarily due to the significant growth in the proportion of electricity generation that is gas fired. At a European level, the share of generation produced using gas as an input approximately doubled from 11% to 21% between 1995 and 2006 (see Figure 4). In Spain, this increase is even more pronounced, with aggregate gas-fired generation (including co-generation facilities) accounting for 30% of total generation in 2006, up from 3% in 1995.

The greater reliance of wholesale electricity on gas has been due to the very significant entry of efficient CCGTs in most liberalised energy markets. The OECD reports that more than two thirds of the total increase in generation capacity from 1990 to 2004 was gas fired, and that, in turn, 64% of the gas-fired capacity build was CCGTs. This trend is set to continue, with more than 60% of plants under construction in Europe as of 2006 being gas fired.[11] This increasing dependence on gas as an input, coupled with the fact that CCGTs are often the price-setting technology in liberalised generation markets, implies that the link between the gas and electricity markets is crucial to an understanding of the dynamics of both markets.

*Figure 4: Generation mix in the EU27 and Spain, 1995-2006*

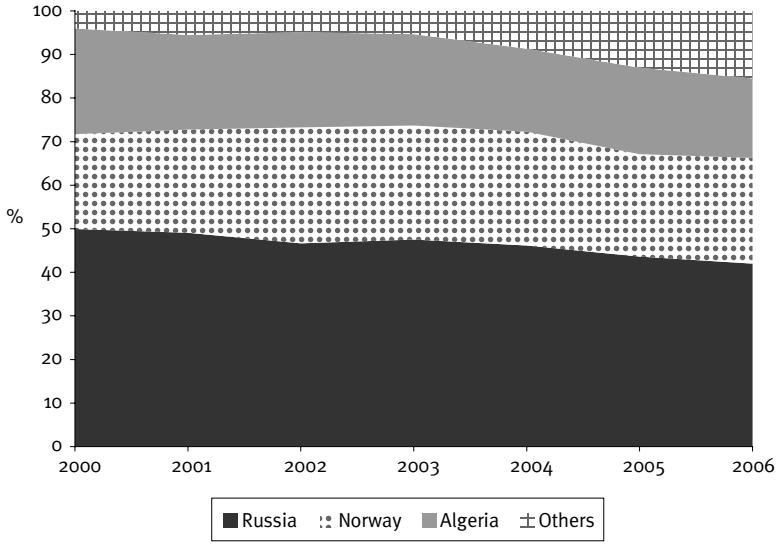



Source: European Commission, Eurostat, 2008.

Note: Eurostat's definition of renewable energy includes hydroelectric power, but excludes pumped storage.

11. See OECD, Natural Gas Market Review 2007.

*Figure 5: Gas import sources, EU27*




Source: European Commission, Eurostat, 2008.

Overall gas demand at the EU27 level increased by roughly a third between 1995 and 2006. This increase in demand (equivalent to approximately 117 billion cubic metres (bcm)) was entirely met by imports, with domestic production slightly declining over this period. In Spain the increase in gas consumption was much greater, with demand increasing four-fold (from less than 9 bcm in 1995 to 34 bcm in 2006), and total gas-fired electricity generation output increasing 18-fold.[12]

The increase in demand for gas at the European level (and in particular in Spain), coupled with the stagnation of the European production of gas (primarily from the United Kingdom and the Netherlands), has brought into sharp focus the role that imported sources of gas are playing in the European energy sector. As Figure 5 illustrates, the European Union (EU27) currently depends on Russia for the relative majority of its gas imports (42%), followed by Norway (24%) and Algeria (18%). This split has remained relatively constant over the past 5 years, with the most prominent trend being the recent rise of imports from other sources (notably, LNG).

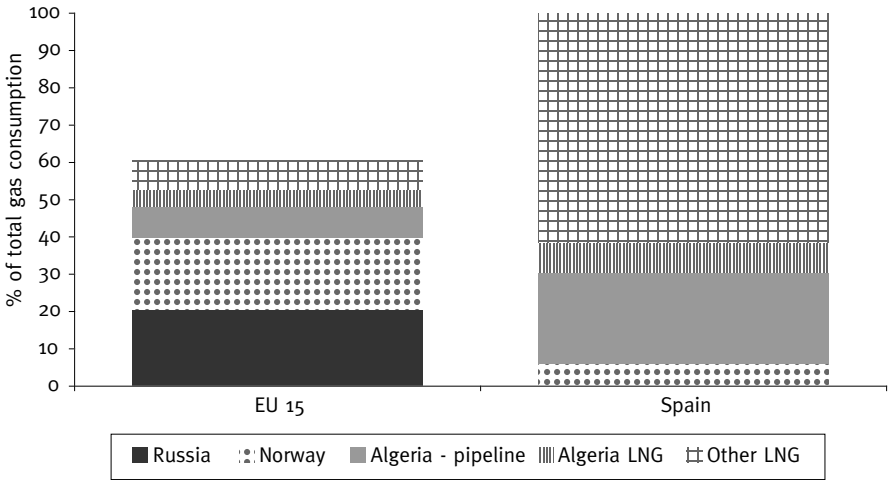
Figure 6 illustrates the relative dependence on imported gas of the EU15 countries and Spain. This reveals a stark difference in the current position of Spain relative to the rest of Europe, both because of a complete dependence on imported gas (100% for Spain vs. 60% for the EU15 as a

12. European Commission based on Eurostat 2008 figures.

whole) and because of the difference in the import mix. Spain primarily depends on LNG for its gas consumption (for close to 70% of its requirements), and its main source of imported gas is Algeria (accounting for more than a third of consumption).

By contrast, the EU15 countries import LNG for only 12% of total gas demand. Spain is, by some margin, the largest LNG market in Europe (defined as EU15), accounting for roughly 50% of total LNG imports in 2007.

*Figure 6: Gas import dependence, EU15 vs. Spain, 2007*

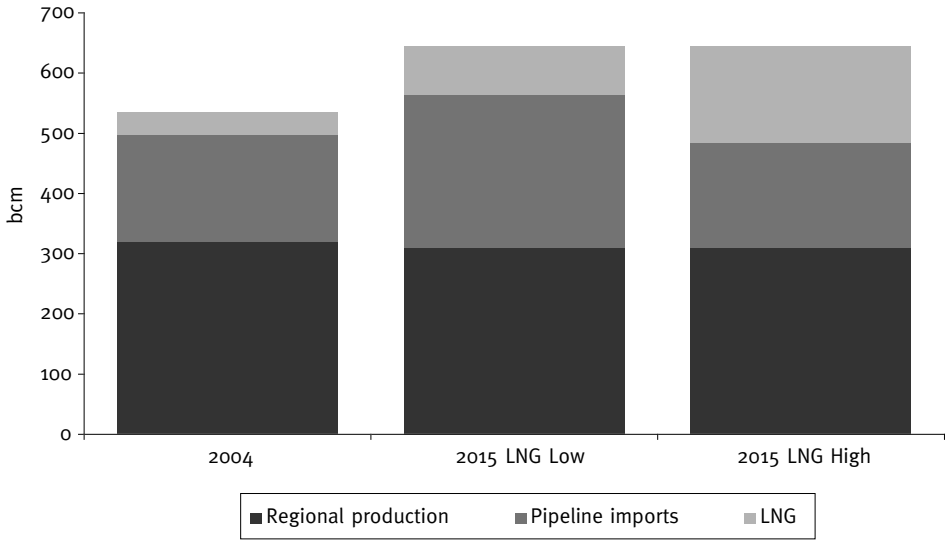



Source: BP Statistical Review of World Energy, 2008.

## Future trends in gas import dependence

Going forward, dependence on imported gas is set to increase. The OECD forecasts an increase in gas consumption in OECD Europe of more than 100 bcm (+20%) between 2004 and 2015, which is going to be met entirely by gas imports (see Figure 7). There is considerable uncertainty on how the higher level of imported gas is going to be allocated amongst different potential sources, with LNG potentially accounting for 40% to 100% of the increase. However, given the ongoing developments in new pipeline infrastructure (which we review below), it appears likely that both the levels of pipeline gas imports and of LNG imports will increase over time.

*Figure 7: OECD Europe gas demand forecasts, 2015*




Source: OECD Natural Gas Market Review, 2007.

The current levels of gas reserves in the main current suppliers of gas consumed in Europe (Russia, Norway, Algeria, the Netherlands and the United Kingdom) illustrate the key role that Russia is likely to play as a source of increasing gas pipeline imports in the future. Russia's gas reserves dwarf those of the other main gas suppliers to the European Union combined and currently stand at close to 45 trillion of cubic metres (tcm), as opposed to less than 10 tcm for Algeria, Norway, the Netherlands and the United Kingdom combined (see Figure 8). Reserves in some LNG-exporting countries, however, can match those of Russia, illustrating the potentially crucial role that LNG imports might be able to play as a competitive alternative to Russian gas. According to the data published in the BP Statistical Review, the countries that currently export only LNG to Europe[13] had reserves of 35 tcm in 2007, equivalent to 75% of Russia's reserves. Most of these reserves are accounted for by Qatar (26 tcm). The other potential exporter to Europe with large reserves of gas is Iran, with 28 tcm.

### Infrastructure developments

Some major gas pipeline projects are envisaged over the foreseeable future to meet Europe's greater reliance on imported gas. The European Priority Interconnection Plan reports that an additional 80 to 90 bcm of pipeline import capacity should enter into operation over the

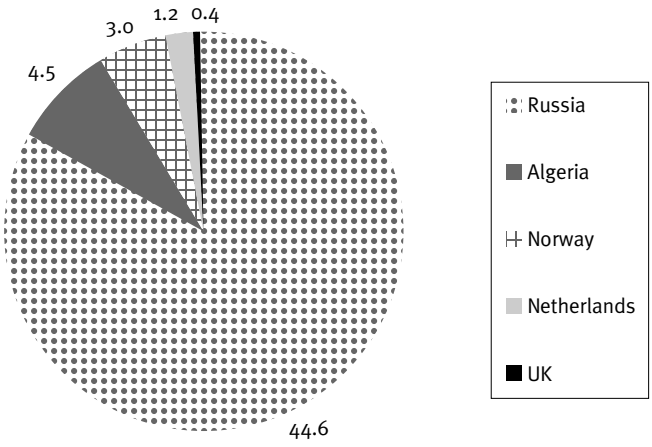
13. These include Trinidad and Tobago, Oman, Qatar, Egypt, Libya and Nigeria.

2010-2012 period – this is equivalent to up to 20% of total E.U. gas demand by 2010.[14] Even if a major pipeline does not come on stream (e.g. North Stream or Nabucco), the additional capacity would still be in excess of 50 bcm, which is the current European target for incremental capacity.

The most probable pipeline projects considered by the European Commission are summarised in Table 1. This also includes the South Stream project, which was not included in the European assessment of January 2007. As the table indicates, up to two thirds of the new capacity addition may be supplied by Russia, due to the potential development of two large pipelines (North Stream and South Stream). Competing gas pipelines (most notably Nabucco) would rely on gas from other sources in Central Asia and the Caspian, even though the exact composition of this incremental gas and its potential reliability remain uncertain.

The European Commission is also forecasting a major increase in LNG import capacity, from roughly 80 bcm in early 2007 to 135-140 bcm by 2010-2012, also in line with the target contained in the Priority Interconnection Plan. Spanish LNG terminals could account for up to a quarter of the total increase in import capacity (on the basis of OECD data, which envisages an additional 15 bcm of LNG capacity in Spain from 2006, including capacity at the Mugardos terminal, which came on line during 2007).

*Figure 8: Gas reserves of the main current suppliers to the European Union (trillion cubic metres)*




Source: BP Statistical Review of World Energy, 2008.

14. European Commission, Staff Working Document, "Priority Infrastructure Plan", January 2007.

*Table 1: Key gas pipeline infrastructure projects*

| Pipeline | Commissioning Date | Capacity into EU (bcm) | Primary EU destination | Primary supplier(s) |
|---|---|---|---|---|
| **North Europe Gas Pipeline (North Stream)** | 2010-2015 | 27.5-55 | Germany, Benelux, Sweden | Russia |
| **Medgaz** | 2009 | 8 | Spain, France | Algeria |
| **Transmed II** | 2008-2012 | 6 | Italy | Algeria |
| **Nabucco** | 2011 | 14-16 | Austria, South East and Central Europe | Turkmenistan, Azerbaijan, Iran |
| **Turkey-Greece Interconnector** | 2008-2011 | 11-12 | Greece, Italy | Azerbaijan |
| **South Stream** | 2013 | 30 | Italy, Central Europe | Russia |

Source: European Commission Priority Interconnection Plan, January 2007, for all projects except South Stream. Press articles for South Stream.

The European Commission Energy Sector Inquiry of January 2007 (hereinafter, the Sector Inquiry) also reports that as of 2006 there was 75 bcm of existing LNG capacity (of which more than 50% was in Spain), and that another 72 bcm was under construction (of which 13 bcm was in Spain).

Overall, the possible increase in pipeline and LNG capacity over the next 5 years or so amounts to 150 bcm, in excess of the increase in OECD forecast of increase in demand for 2015. Not all of the planned increase in capacity is, however, likely to come on stream. Competition and security in the European gas market would be enhanced if a balanced mix of the various gas import projects were to be realised, with a combination of both LNG and pipeline imports from new sources of gas (e.g. sources other than Russia and Algeria).

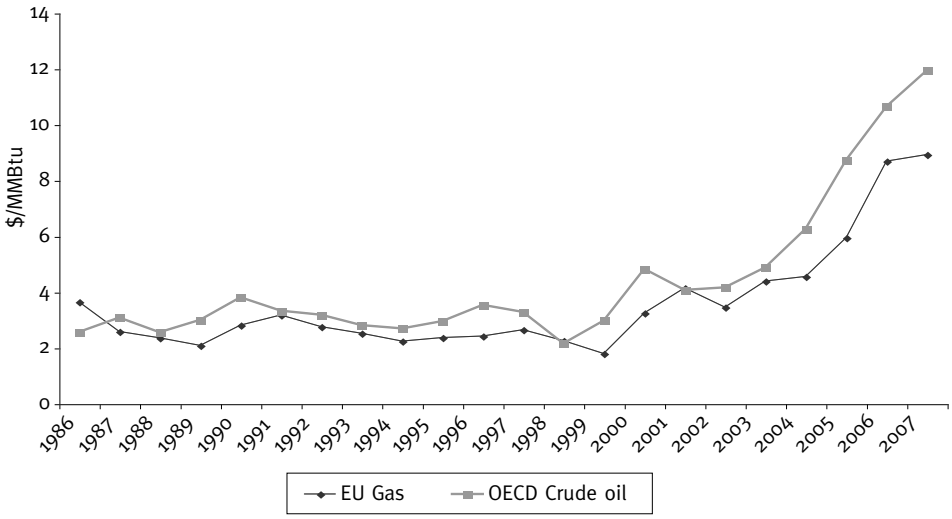
### Prospects for gas-to-gas competition

European gas import prices have risen sharply in recent years, as Figure 9 illustrates. On average, prices have increased 3-fold since 2000 in dollar terms (from $3.2/MMBtu to $8.9/MMBtu). This trend has followed closely the pattern of crude oil prices, as shown in the figure. During the first half of 2008 oil prices continued to increase (by roughly 50% compared to 2007), even though prices have fallen sharply since. International prices of coal (the other main fossil fuel used in electricity generation, besides gas) also increased sharply in 2007 and 2008, roughly doubling relative to the levels of 2004 and 2005.

The correlation in gas and oil import prices is the result of the widespread presence of oil indexation in gas import contracts. As the Sector Inquiry found, crude oil and its derivates (heavy fuel oil and gasoil) dominate price indexation in European gas contracts, accounting for close to 80% of changes in gas prices. The findings of the inquiry also indicated that indexation to oil is even stronger in the case of gas from Algeria (more than 90%) and from Russia (over 80%). Over the medium to long term there is a relationship between gas and oil, which can justify the inclusion of forms of oil indexation in long-term gas contracts.

Enhanced "gas to gas" competition would be required to lead to more competitive gas pricing for European consumers. Greater LNG imports may be able to facilitate the creation of a more liquid gas market in Europe (and integration into a global gas market), with a shift in reference price from oil to gas. However, this is likely to be a relatively slow process. The Sector Inquiry reports that by 2020 LNG spot trading may account for 30% of the global LNG market, with the rest of the market continuing to be based on long-term (and presumably oil-indexed) contracts.

*Figure 9: Evolution of gas and oil prices*




Source: BP Statistical Review of World Energy, 2008.

Possible moves towards a "gas OPEC" (i.e. a cartel of major gas-producing countries) would also reduce the scope for more competitive gas pricing in the future. With high prices, the impetus for such an initiative is likely to be muted, since gas price coordination can be achieved through indexation to oil. However, if oil prices were to continue to fall in the future (as they

have during the second half of 2008), it cannot be ruled out that more sustained attempts to coordinate international gas prices might be made.

### Environmental issues

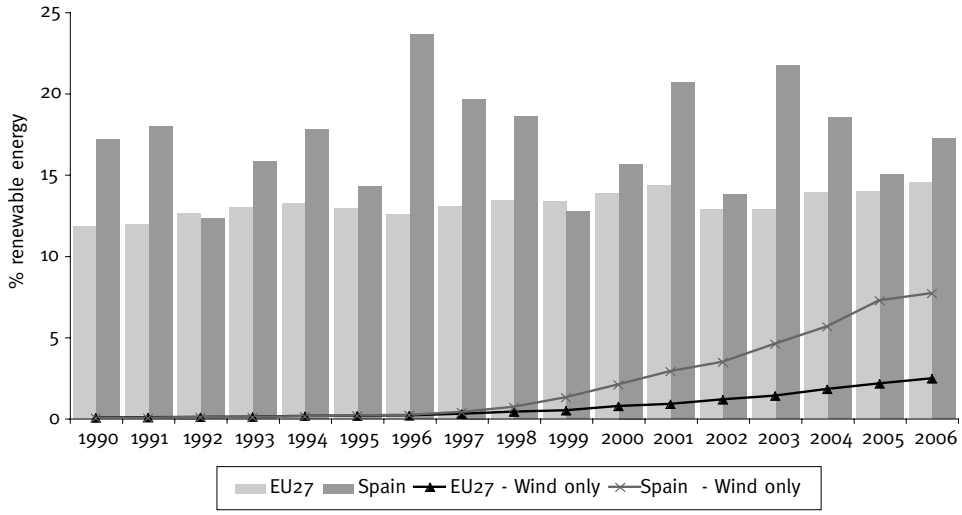
The desire and need to reduce gas dependency result in an important trade-off with climate change policy. This is because the considerable increase in gas consumption in recent years has been partially fuelled by the fact that gas is a cleaner technology for power generation than other forms of fossil-fuel generation (coal and oil). In particular, the start of the European Emission Trading Scheme (ETS) in 2005 has increased the relative cost (or opportunity cost) of coal-fired generation, accelerating a shift to gas-fired power. This trend is likely to continue in the current more stringent phase of the ETS (2008-2012) and in the third phase post-2012 (partially depending on the evolution of relative gas and coal prices). In order to reduce or contain future dependence on imported energy, climate change objectives will, however, need to be met in the future by reliance on alternative technologies, such as renewable energy (e.g. wind and solar power) and nuclear.

The share of renewable sources in electricity generation has been rising steadily but at a relatively slow rate in the past 15 years, as shown in Figure 10 for the EU27 and for Spain. Renewable energy at the E.U. level (including hydroelectric power) stood at 14.5% of total consumption in 2006, well below the 2010 target set by the European Commission of 21%. The share of renewable electricity in Spain is volatile, given the role played by hydroelectric generation (which is influenced by rainfall). Over the 2001-2006 period, this share averaged 17%, versus a 2010 target of 29%. Both the Europe-wide and Spanish targets are not going to be achieved by 2010, on the basis of the historical trend. Wind generation is, however, making an increasingly important contribution to meeting the target in Spain, accounting for almost 50% of total renewable generation. Section 5 provides more details on the recent evolution of special regime generation (including wind) in Spain.

The need to reduce carbon emissions and also avoid excessive reliance on imported gas means that nuclear power may acquire an increasingly important role in the future energy mix of a number of European markets. Several countries currently rely quite heavily on nuclear generation (this is the case in France and Belgium, but also in the United Kingdom, Spain, Germany, Sweden and Finland).[15] There is an ongoing debate in some of these countries on whether (and how) the role of nuclear power should be preserved, and possibly enhanced, in the future. Given the importance of nuclear generation in Europe at present, it is difficult to see how some of the key objectives of European energy policy (i.e. most notably the reduction in carbon emissions, and the desire to reduce energy dependency) can be achieved without preserving a material role for nuclear power in the future.

15. At the EU27 level, nuclear generation accounted for 30% of total electricity consumption in 2006.

*Figure 10: Share of renewable electricity in total generation*




Source: European Commission, Eurostat, 2008.

Note: Eurostat's definition of renewable energy includes hydroelectric power, but excludes pumped storage.

## 3.2. European competition and regulatory policy towards the energy sector: recent developments

There have been several significant recent developments in European competition and regulatory policy towards the energy sector. This section reviews and analyses the main recent initiatives taken by the European Commission in this sector. We will first describe the principal findings of the recent Energy Sector Inquiry, and then deal with the main policy instruments that the Commission has used so far to address perceived shortcomings in the market: regulatory reform, antitrust interventions and merger control.

### 3.2.1. The Energy Sector Inquiry

European competition policy in the energy sector was particularly active during the course of 2007. One of the main developments was the publication in January 2007 of the results of the Sector Inquiry. The Sector Inquiry was launched by the Commission in 2005 to study some of the alleged deficiencies of European energy markets, including recent rises in wholesale gas and electricity prices (which could not – according to the Commission – be fully explained by higher primary fuel costs and environmental obligations), persistent complaints about entry barriers, and limited possibilities to exercise customer choice.

The Sector Inquiry looked at both the electricity and gas sectors, and identified a number of issues of concern, as summarised in Table 2 below.

Most of the findings of the Sector Inquiry are not surprising. They primarily reflect the current structure of the energy markets in several European countries, both in terms of the vertical integration of infrastructure assets and potentially competitive activities, and in terms of the horizontal concentration of the wholesale and retail markets. These market structures were partly determined by policy decisions made by national governments when the energy industry was first liberalised.

*Table 2: Main findings of the European Commission's Energy Sector Inquiry of 2007*

| Issue | Findings |
|---|---|
| **Concentration** | High levels of concentration at all levels of supply chain. Pre-liberalisation positions substantially intact |
| **Vertical Foreclosure** | Infrastructure remains largely in the hands of incumbents, thus raising discrimination issues |
| **Market Integration** | Insufficient cross-border capacity to create integrated markets. Incumbents "stay at home" |
| **Transparency** | Lack of reliable and timely information to allow for healthy competition |
| **Pricing** | Lack of confidence that wholesale prices are the result of meaningful competition |
| **Retail contracts** | Long-term contracts between incumbents and customers can foreclose competition |

**Horizontal issues: concentration and interconnection**

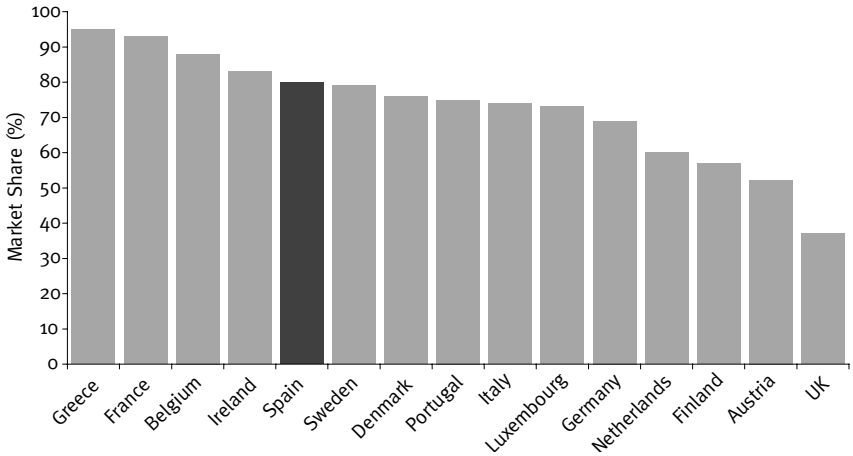
The most direct and easy-to-measure indicator of potential horizontal issues is the degree of concentration in liberalised segments of the markets (i.e. generation and supply). Recent comparative data published by the European Commission illustrate that concentration levels in most key European markets remain high, in both generation and supply (in particular supply to residential customers). These levels (as summarised by the combined market shares of the top three suppliers in each country) are shown in Figure 11 and Figure 12 for the year 2006. Spain remains amongst one of the most concentrated markets in both generation[16] and residential supply. However, in residential supply markets, national shares may not be representative of competitive

16. The findings of the London Economics study prepared for the Sector Inquiry confirm the relative position of Spain in terms of concentration in the generation markets, reporting that the average HHI in Spain over the 2003-2005 period was higher than in the United Kingdom, Germany and the Netherlands, but lower than in France.

conditions faced by customers, given the regional or local nature of competition (their use may therefore actually overstate the degree of competition in the market)[17]. Evidence on competition in the Spanish energy markets is analysed in more detail in Section 5 of this report).

The Sector Inquiry also provides additional information on horizontal issues in generation markets, including shares of price-setting capacity (which may give a better indication of market power than shares of total capacity), measures of "pivotality" of the major electricity generators (i.e. the percentage of hours when they are indispensible to meet total demand), and the extent of interconnection with neighbouring countries (which can reduce concentration in each country and also promote competition).

*Figure 11: Combined national market share of the 3 largest firms – electricity generation (2006)*

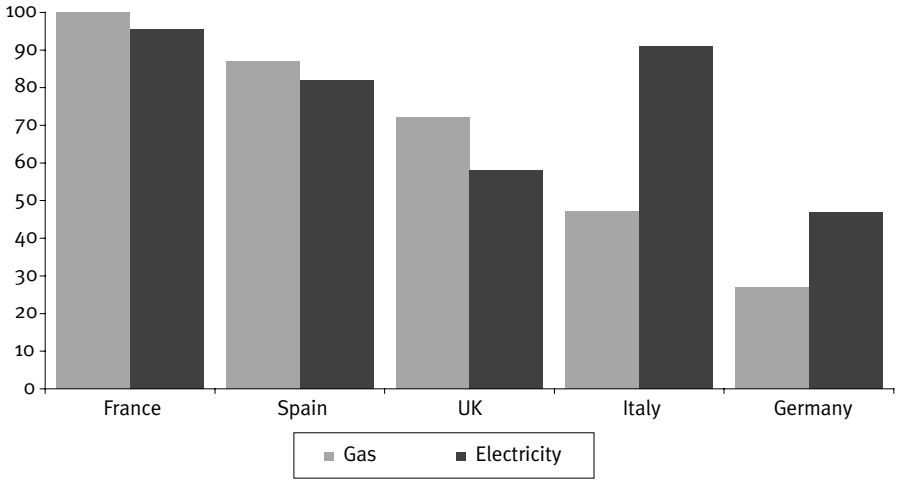



Source: European Commission.

Measures given for the Spanish market for all three indicators also indicate the likely existence of a degree of market power in the wholesale electricity market, due to the pivotality of the main generating companies during the 2003-2005 period, the limited amount of interconnection with other European countries (most notably France), and the share of marginal energy still accounted for by the incumbent generators (e.g. the Sector Inquiry reports that during the January-August 2005 period, the largest "price-setter" in Spain controlled more than 50% of the offers of electricity around the market-clearing prices for a third of the time). These issues are explored in more detail in Section 5 of this report.

17. Residential gas switching data published by the European Commission show very low levels of switching in Italy (cumulatively up to 2005) and Germany (in 2006) (see 2005 and 2008 European Commission Reports on Progress in Creating the Internal Gas and Electricity Market). This indicates that relatively low national concentration levels in residential gas supply reported for these two countries may not actually be representative of competitive conditions at a regional or sub-regional level.

*Figure 12: Combined national market share of the 3 largest firms - residential supply (2006)*




Source: European Commission.

**Vertical issues: unbundling electricity and gas transmission networks**

The other key concern highlighted in the Sector Inquiry is vertical foreclosure of new entrants through discrimination by integrated incumbents, and long-term contracts. Various foreclosure strategies are stressed in the Sector Inquiry, including quality discrimination, lack of effective access to infrastructure, discrimination in operational and investment decisions, and reductions in liquidity and market transparency.

The European Commission has identified the lack of effective unbundling of network infrastructure as one of the main factors behind vertical foreclosure. It has argued that in some markets national energy networks (electricity transmission, and gas transportation and storage) are not adequately separated from the competitive segments of the markets (generation and supply), in spite of the provisions of the current Gas and Electricity Directives of 2003. Under these Directives, Member States need to implement legal and management separation of network operators, meaning that the legal form, organisation and decision-making related to network operations need to be distinct from those relating to non-network activities. However, the Directives do not require full ownership unbundling, and allow network assets to be owned (and controlled) by entities with a presence in production and/or supply.

At present, a minority of EU15 Member States have imposed ownership unbundling of their gas networks (5 out of 15 countries), whilst a slight majority (8 out of 15) have implemented this measure in the electricity sector. One of the key regulatory measures proposed by the European

Commission in September 2007 was to move towards ownership unbundling in all Member States as the preferred regulatory option. We will review this regulatory initiative in Section (3.2.2) immediately below.

Spain has already implemented ownership unbundling of both the electricity and transmission networks and in this sense is an example of "best practice" in Europe. However, in its review of progress in implementing the Gas and Electricity Directives, the European Commission expressed concerns that ownership unbundling is incomplete in gas, as the network operator Enagás still buys and sells on the regulated market.[18]

### 3.2.2. Regulatory Reform

In September 2007 the European Commission put forward a third legislative package for the energy sector with specific proposals for new Gas and Electricity Directives. This package contained proposals under five main areas. Arguably the most important of these proposals and the one attracting the most attention involve network unbundling. We will focus on this specific aspect of the proposal in this section of the report.[19]

**The Commission's proposals on unbundling**

In its legislative proposals, the European Commission has expressed a clear preference for full ownership unbundling of network assets. Under the proposed legislation, Member States would need to ensure that the same person or persons cannot exercise control over a supply or generation undertaking, and at the same time exercise any rights over transmission activities. This would imply that divestments of network assets would need to occur in countries where these assets are still controlled by vertically integrated incumbents.

The proposals also provide for an alternative option in the form of an "Independent System Operator" (ISO). Under this derogation, integrated firms could retain ownership of network infrastructure but this would need to be managed by an ISO that performs the role of the network operator and is separate from the vertically integrated entity. Regulatory and monitoring provisions would be put in place to ensure the independence of the ISO.

Under the proposals, the current derogations for new infrastructure (e.g. electricity interconnectors and LNG terminals) would still apply. These stipulate that new infrastructure is exempt from regulated third-party access and ownership unbundling if it can be shown that new investment would not take place without the derogation, and that the derogation does not reduce competition.

18. European Commission, Staff Working Document, "Prospects for the internal gas and electricity market, Implementation Report", January 2007.
19. The other four areas are: regulatory oversight and cooperation, network cooperation, transparency, and access to storage and LNG facilities.

The European Commission's proposals also include a provision for the ownership of infrastructure assets by companies from non-E.U. countries. Under the draft legislation companies from third countries would be subject to the same unbundling requirements as E.U. firms and would need to show their independence from supply and/or production activities. Moreover, an agreement between the European Union and the third country would be required for a company from a non-E.U. country to acquire control of transmission assets in the European Union. This allegedly would ensure that all firms in the European energy market would act in accordance with the "market investor" principle (i.e. to prevent illegal state aid). This clause has been widely seen as an attempt to constrain the potential role that foreign energy groups (e.g. Gazprom) could acquire in European energy markets by purchasing critical infrastructure assets.

**Rationale for the proposals**

The European Commission's proposals for ownership unbundling are based on the vertical foreclosure concerns articulated in the Sector Inquiry. The Commission considers that without effective vertical separation, there is a risk of discrimination by incumbents both with respect to the access to the network and investment in the asset. Moreover, in the Commission's assessment, the legal and functional separation envisaged under the current Directive is insufficient to ensure the lack of discrimination, given the presence of an "inherent incentive" for vertically integrated companies to discriminate against competitors. This is why the Commission has proposed structural ownership unbundling as the primary solution to the vertical foreclosure problem.[20] More extensive functional separation in the form of an ISO is unlikely to be sufficient to fully address the vertical foreclosure concerns highlighted by the Commission.

In its impact assessment of the proposed legislation, the Commission presented some analysis of the possible effects of ownership unbundling relying on differences in competitive outcomes between countries which still have vertically integrated incumbents and countries which have opted for ownership separation. According to this analysis, the evidence shows that ownership unbundling has a beneficial effect on network investment, investment in LNG terminals, market concentration and prices.[21] Whilst some of the correlations presented in the analysis by the Commission may not reveal a robust causal link with ownership unbundling, at the very least the evidence does not appear to contradict the notion that vertical separation can have beneficial effects on competition in energy markets. Box 2 provides a high-level economic evaluation of the case for vertical separation in energy industries.

The European Commission's legislative proposals in favour of more decisive ownership unbundling of energy network assets have not been supported by all Member States. A number of countries led by France and Germany (and also including six smaller Member States) have opposed

20. See recitals (5)-(7) of the draft Directives presented by the Commission in September 2007.
21. See European Commission, Staff Working Document, "Impact Assessment, Accompanying the legislative package on the internal market for electricity and gas", 2007.

the Commission's plans for ownership unbundling and proposed a compromise solution based on stricter regulation of vertically integrated incumbents (a so-called "Independent Transmission Operator (ITO)" option). The E.U. Council of Ministers agreed on a third energy legislative package including this compromise in October 2008, which needs to be approved by the European Parliament. The position of opponents to the European Commission's initial stance has been somewhat weakened by the settlements offered by the German energy incumbents (E.On and RWE) in the context of Article 82 investigations by the European Commission (see below in this section for a brief account of these cases). As part of the settlements resulting from these investigations, E.On has agreed to divest part of its electricity transmission network and RWE has agreed to divest its gas network.

**Box 2: Economic assessment of vertical separation in the energy industry**

Economic theory suggests that vertical integration does not necessarily reduce competition in industries with a vertical structure. The case for vertical separation needs to be made on the basis of the specific facts of the industry one is considering. Moreover, the appropriate regulation of third-party access (TPA) can alleviate the competition issues raised by vertical integration.

Vertical integration can yield benefits to consumers by:

**Improving investment decisions** by facilitating the coordination of upstream and downstream parties, and mitigating so-called "hold-up" concerns. Hold-up of investment decisions can occur when investments in transaction-specific assets (e.g. a gas pipeline) are not made because an upstream investor is not sure that the downstream users will fully remunerate the investment ex-post, once the expenditure commitment has been made.

**Leading to better coordination** between upstream and downstream entities in terms of product development and innovation.

**Leading to more efficient pricing decisions** by reducing the margins that are charged at each stage of the vertical production process (elimination of "double-marginalisation" efficiency).

Effective regulation of the network can, however, replicate some of the efficiencies associated with vertical integration also within a vertically separated industry structure. In particular, price regulation of the network assets can partially remove inefficient margins at the upstream level even if the network is unbundled. This reduces the comparative gain from the elimination of double-marginalisation that can be associated with vertical integration.

Similarly, effective tariff regulation can allow an independent transmission owner to recover efficiently incurred investments in the network from users, thus reducing the risk of hold-up. Price regulation at the network level might also increase the incentives to engage in non-price discrimination for a network owner with downstream activities, thus providing an additional rationale for vertical separation. The derogation contained in the current and proposed European directives for larger and discrete investment decisions (such as interconnectors and LNG terminals) can also mitigate the incidence of inefficient hold-up and encourage specific investments where these are needed.

Especially in the gas sector, contracts can substitute for vertical integration and also incentivise efficient investment. Take-or-pay clauses in gas contracts are standard and can play an important role in facilitating upstream investment. Whilst the presence of these contracts can also lead to downstream foreclosure concerns, these are likely to be lesser than in the case of full vertical integration of upstream and downstream activities.

Opponents of ownership unbundling also argue that vertical integration can improve the bargaining power of European operators when negotiating with external suppliers of gas, and may therefore help reduce the cost of imported energy. However, even if this were true, the lessening of downstream competition associated with vertical integration may well outweigh any reduction in the cost of energy imports. In the absence of strong downstream competition, vertically integrated incumbents may face weak incentives to actually pass savings made on imported gas onto downstream customers.

There is a broad economic consensus in favour of vertical separation of network assets in the energy industry, which is often based on the economic arguments given above. The British experience in the gas sector, for example, shows that vertical integration retarded the process of liberalisation in the mid-1980s and in the 1990s. After several investigations by the U.K. competition authorities and the imposition of behavioural remedies, the incumbent gas operator eventually decided to vertically separate in 2000, leading to greater competition in the downstream gas market. The British experience is consistent with the policy direction adopted by the European Commission in the third legislative package.

### 3.2.3. Antitrust investigations

The European Commission also initiated a number of antitrust proceedings against companies in the energy sector, mostly during 2007 and 2008, following the results of its Sector Inquiry. These cases are summarised in Table 3 below. Most of these cases concern alleged abuses of dominance, under Article 82 of the E.C. Treaty. They are also mostly ongoing cases, with the exception of the Distrigaz and E.On cases, which have been settled through commitments.

*Table 3: Summary of antitrust investigations by the European Commission in the energy sector, 2007-2008*

| Company investigated | Description |
|---|---|
| **Distrigaz** | Foreclosure of Belgian gas market through long-term contracts with industrial customers. Remedied through commitment to 30% cap on long-term contracts in October 2007. |
| **E.On** | Alleged abuse of dominance in the German electricity market through capacity withdrawal and vertical foreclosure in the balancing market. In November 2008 the European Commission accepted E.On's committment to sell part of its electricity transmission system business and 5 GW of generation capacity to settle the case. |
| **E.On and GDF** | Suspected infringement of Article 81 in the form of a market-sharing agreement in the French and Germany gas markets. |
| **EDF** | Proceedings opened on long-term contracts with consumers of electricity in France, primarily with large industrial users. |
| **ENI** | Commission opened proceedings alleging capacity hoarding and strategic under-investment in transmission to foreclose the Italian gas market. |
| **GDF** | Proceedings opened for suspected foreclosure of the downstream market for gas in France through long-term reservation of network capacity and underinvestment in import capacity. |
| **RWE** | Proceedings opened for foreclosure of gas transport infrastructure in Germany. RWE has proposed to sell its gas network in Western Germany to an independent operator to settle this case. |
| **Suez** | Proceedings opened on long-term contracts with consumers of electricity in Belgium, primarily with large industrial users. |

Source: European Commission.

A number of general points emerge from the summary of antitrust cases presented in Table 3:

These cases relate only to vertically integrated incumbents that own network infrastructure at the same time as being active in competitive segments of the supply chain (production and/or supply). The Commission's focus in initiating antitrust investigations therefore appears consistent with the findings of its Sector Inquiry and the proposed third legislative package.

Most of the cases relate to non-price exclusionary abuse under Article 82 through a variety of potential foreclosure strategies, including discriminatory access, long-term contracts, hoarding and failure to invest in network facilities. It is notable that the case against E.On for capacity

withholding in the German market is the only case of potential exploitative abuse (i.e. setting prices that are too high and therefore anti-competitive). This is in line with standard application of Article 82, which tends to focus on exclusionary abuse.

The evidence so far is that the Commission will accept settling cases in exchange for significant remedies which can promote competition. This has been the case in the Distrigaz investigation (as a result of which Distrigaz´s contractual conduct will change, thus freeing up more gas in the downstream market) and has also taken place in the investigations of E.On and RWE in Germany, as a result of which the incumbents have offered to unbundle some of their network assets. This trend, if continued, would show that antitrust intervention may prove to be an effective instrument to achieve structural change and may be able to complement legislative reforms.

### 3.2.4. European merger control

The third key lever that the European Commission can rely on to ensure that energy markets function effectively is merger control. This tool is particularly important in the case of national mergers (i.e. mergers involving parties with significant overlaps in the same national market), since these transactions can raise the most problematic competition issues.

The European Commission has assessed four significant national energy mergers in the recent past, primarily affecting the Portuguese, Hungarian, Danish and Belgian markets. The first of these mergers, the proposed joint acquisition of the Portuguese gas incumbent (GDP) by the Portuguese electricity incumbent (EDP) and the Italian gas firm (ENI) was prohibited by the European Commission in late 2004. The other three mergers (E.On/MOL; DONG/Elsam/E2; and GDF/Suez) were all approved, subject to extensive remedies. These have included structural measures, such as the divestment of infrastructure assets (e.g. gas storage and transportation networks) and semi-structural interventions (most notably in the form of periodic gas releases).

Table 4 summarises the main features of the four national energy mergers evaluated by the Commission most recently.

These recent examples of European merger control in the energy sector are consistent with the competition concerns highlighted by the European Commission in its Sector Inquiry and its legislative agenda. All four mergers were seen as raising significant vertical foreclosure issues, partially arising from the lack of ownership unbundling. Moreover, material horizontal concerns were raised by the European Commission's evaluation, most notably in the GDF/Suez and EDP/ENI/GDP mergers.

The remedies imposed by the Commission in those mergers are also in line with the current European drive for regulatory reform. Ownership unbundling was part of the remedy package in all three of the mergers approved in 2005 and 2006 (and was also part of the proposed remedies in the EDP/ENI/GDP case). Significant releases of wholesale gas (to increase market liquidity)

and divestments at the wholesale gas and retail energy levels (as in the case GDF/Suez) were also included in the remedy package to address both vertical and horizontal concerns.

*Table 4: Recent merger cases in the energy sector evaluated by the European Commission*

| Case | Year | Outcome | Concern | Remedy - Infrastructure | Remedy – Gas and Electricity Release |
|---|---|---|---|---|---|
| **EDP/ENI/ GDP** | 2004 (on appeal: 2005) | Prohibited | Loss of potential competition; vertical effects | Unbundle gas transmission, storage and LNG* | Gas release + CCGT lease* |
| **E.On/MOL** | 2005 | Cleared with remedies | Vertical foreclosure | Unbundling of gas transportation and storage | Gas release (up to 14% of demand) |
| **DONG/ Elsam/E2** | 2006 | Cleared with remedies | Vertical foreclosure | Unbundling of gas storage | Gas release (up to 10% of demand) |
| **GDF/Suez** | 2006 | Cleared with remedies | Loss of direct competition; vertical foreclosure | Divest control of gas infrastructure | Divest largest gas wholesaler (Distrigaz) and 50% stake in downstream competitor (SPE) |

Source: European Commission.
* Based on the remedy offer made by the parties.

It should be recognised, however, that merger control is a restricted tool to improve competitive outcomes in energy markets. Merger remedies can, strictly speaking, only be used by competition authorities to restore competitive conditions to the pre-merger situation, rather than to improve it. It is therefore difficult to use merger commitments to increase the level of competition in liberalised markets and resolve pre-existing competition concerns.

On the other hand, in practice, merger control gives the European Commission (and other competition authorities) a fair amount of negotiating power in relation to the merging parties. This can allow it to push through structural measures that may be hard to achieve otherwise. Recent experience of merger control at the European level suggests that the European Commission has sought, where possible, to use this lever to obtain improvements in the structure of competition in the affected markets, rather than simply focusing on the direct harm to competition flowing from the mergers. This trend is likely to continue in the future, especially in the case of mergers in countries with no (or limited) ownership unbundling.

# 4. Regulation and Competition Policy in the Spanish Gas and Electricity Markets

This section of the report provides a review of regulation and competition policy in the Spanish gas and electricity sectors. Section 4.1 briefly summarises the main regulatory features of the market in the first phase of liberalisation (defined here as the 1998-2005 period). Sections 4.2 and 4.3 summarise the more recent developments in regulation and competition policy, respectively, focusing on those taking place in 2006 and 2007.

## 4.1. Background: liberalisation, regulation and competition, 1998-2005

The Spanish energy sector was liberalised in the late 1990s. The key pieces of legislation introduced to liberalise the industry were the Electricity Law (*Ley del Sector Eléctrico)* in 1997 for the electricity market, and the Hydrocarbons Law (*Ley de Hidrocarburos)* in 1998 for the gas market.

The main features of the regulatory reform of the industry, which we will deal with in turn below, were:[22]

(a) the creation of a wholesale electricity market,

(b) vertical unbundling of the gas and electricity networks, and

(c) a gradual liberalisation of the gas and electricity retail markets.

In addition, merger control by the competition authorities and the sector regulator played an important role in the later part of this period when three significant attempted mergers were

22. For an economic review of the main issues affecting the Spanish electricity market when it was liberalised, see Kühn and Regibeau (1998).

evaluated for their effects on competition and on regulated activities. These transactions were either rejected by the competent authorities or abandoned by the parties.

#### 4.1.1. Creation and design of the wholesale electricity market

One of the most contentious elements of the liberalisation of the Spanish energy industry was the creation of a market for electricity generation. This was partially due to the fact that the creation of the wholesale market was preceded by a process of consolidation[23], that created a concentrated market structure, with the two main incumbent companies (Endesa and Iberdrola) accounting for more than 80% of total output and capacity and with a relatively diversified generation mix.[24] To date, the wholesale market remains concentrated, in spite of significant entry by new generators and renewable sources of energy (see Section 5 for a detailed review of the current structure of the market).

The wholesale electricity market started on 1 January 1998. The key features of this market were as follows.

- A day-ahead electricity market (or "Pool") was created, where generators could bid their power for each hour of the following day. This market works as a uniform-price auction, with the price paid to all generators called to produce set equal to the most expensive bid that is accepted;

- A series of intra-day and balancing markets were also created to allow for balancing of the market in real time, resolution of constraints on the transmission network and the procurement of ancillary services (e.g. operating reserves) by the electricity transmission system operator (*Red Eléctrica de España* - REE);

- An administrative capacity payment (*garantía de potencia*) was set up to encourage new investment and also delay the retirement of existing plants;

- Generators were also free to trade bilaterally, therefore avoiding the day-ahead market – even though in practice the vast majority of power was transacted in the day-ahead market;[25]

- A stranded cost regime (*Costes de Transición a la Competencia* – CTCs) was introduced to compensate generators for investments made under the previous regulatory regime. A maximum amount of CTCs (initially set at €12 billion) could be paid out to companies under this arrangement during a transitory period lasting until the end of 2010. This amount was com-

23. In 1997 Endesa bought Fecsa, Sevillana, Enher and Viesgo (growing by roughly 16% in terms of its share of the market). Based on CNSE data published at the time, the HHI in generation increased by 1,400 (from roughly 2,200 to 3,600) between 1997 and 1998, leading to a highly concentrated market structure.
24. See CNE, "El funcionamiento del mercado eléctrico en el 1998", 2000.
25. For example, during the 2002-2005 period, the day-ahead market traded between 86% and 90% of total demand in the wholesale market.

puted assuming that market wholesale prices would equal €36/MWh.[26] Total CTCs payable each year out of this fund were set equal to the difference between industry net-back retail revenues[27] and wholesale prices (i.e. the lower the wholesale price, the higher the aggregate CTC payment, and vice versa). Each incumbent electricity utility received a proportion of the overall CTC payment, in accordance with pre-determined shares.[28]

The basic design for the Spanish market was partially based on other liberalised electricity markets (most notably those in the United Kingdom, Scandinavia, California and some other U.S. markets at the time). Like the U.K. model, the Spanish market effectively concentrated most liquidity in a single marketplace (creating a potentially visible and reliable price signal) and introduced a mechanism for remunerating capacity. Unlike the British market, however, in Spain generators could vary their bids hour by hour[29] and were also subject to a stranded cost recovery mechanism which reduced incentive to increase wholesale prices (as discussed immediately below).

The potential exercise of market power in the Spanish Pool has been a source of concern since the inception of the market. This was partially due to the concentration of the market at liberalisation (with an HHI in excess of 3,500) and to the specific features of the generation market which make it prone to the presence of unilateral and coordinated market power (see Section 2). The experience of other markets (most notably the United Kingdom during the 1990s) also suggested that an effective duopoly structure in generation is not conducive to competitive outcomes.

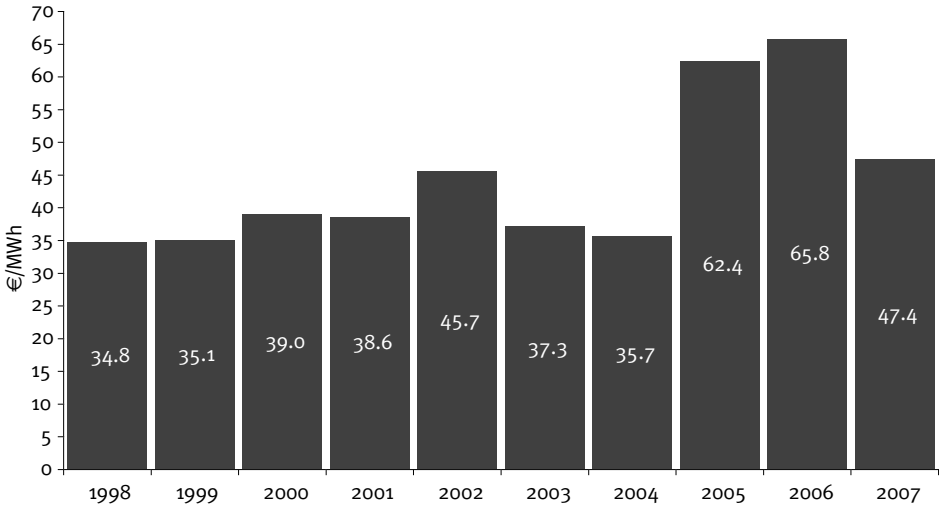
Market power in the Spanish Pool was partially mitigated at the outset by the presence of CTCs.[30] CTC payments were inversely related to wholesale prices, thus reducing the incentives to withhold output in order to push prices up (in effect, acting like a large contract-for-differences on the generators). This effect was particularly strong for companies with a share of the CTC fund that was in excess of its share of the generation market (e.g. this was the case for the largest generator, Endesa). The reference price of €36/MWh present in the CTC mechanism also acted as a "soft" price cap in the market (since the total CTC entitlement payable to each company over the entire transitory period until 2010 was adjusted downwards in the event that its average revenue in each year exceeded this level). The fact that each company's share of CTCs differed from its share of the generation market also led to asymmetric incentives in relation to wholesale prices. A company with a generation share in excess of its CTC share (most notably Iberdrola) would have a preference for higher wholesale prices. Conversely, a firm that was "long in CTCs" (most notably Endesa) would tend to favour lower wholesale prices to maximise its CTC revenues. Academic research indicates that CTCs did indeed affect bidding behaviour in the early years of the Pool, and resulted in conflicting incentives between the two main generators.[31]

26. The total amount of CTCs payable to each firm was adjusted downwards in the event that their average revenues from the wholesale market exceeded the €36/MWh threshold.
27. These were computed as the actual revenues from regulated tariffs minus regulated costs (largely distribution and transmission costs).
28. These were initially set as follows: 51% Endesa, 27% Iberdrola, 13% Unión Fenosa and 6% Hidrocantábrico.
29. This potentially increases the scope for market power as it allows generators to set bids that are optimal for each level of demand, rather than forcing them to bid a unique supply schedule for multiple demand levels (see, for example, Green and Newbery (1992)).
30. For a fuller description of the impact of this mechanism, see Crampes and Fabra (2005) and Fabra (2008).
31. See Fabra and Toro (2005) and Kühn and Machado (2004).

Prices in the early years of the generation market were indeed close to the €36/MWh cap, reflecting the impact of the CTC mechanism. In later years, however, the volatility of prices increased (both within the year and across years) and in some years (most notably in 2002 and again in 2005-2006), average prices exceeded the €36/MWh threshold by a significant margin. These price patterns are shown in Figure 13.

There are several reasons why prices over time exceeded the implicit cap put in place by the CTC arrangement. One is that the CTC mechanism lost effectiveness over time, as new generators with no CTC entitlements entered the market; regulated retail revenues declined as customers switched to market-set prices (thus reducing the total amount of CTC payments); there was regulatory uncertainty on the future rules for the allocation of the CTC fund[32]; and the incumbent generators (most notably Iberdrola) over time reached a point where they had already received a significant share of their initial CTC allocation (implying that the mechanism had a weaker effect on their pricing incentives in the spot market). The other basic reason is that costs varied over time (in particular due to the availability of hydroelectric energy, and an increase in gas and coal costs, including emission permits), implying that the €36/MWh price cap no longer represented a suitable benchmark for a competitive price. This was particularly the case in the 2005-2006 period, with wholesale generation costs well in excess of this level (see Section 5).

*Figure 13: Annual wholesale electricity prices in Spain, 1998-2007*




Source: REE and OMEL.

32. This uncertainty was partially driven in the late 1990s by the prospect that the European Commission might find that the CTCs represented illegal state aid.

The high electricity prices experienced first in 2002 and again in 2005-2006 effectively led to the collapse of the CTC mechanism (which was done away with in 2006 – see section 4.2 below) and to the emergence of a "tariff deficit" (resulting from the fact that regulated tariffs were not sufficient to cover the market price of electricity). Section 5 provides an empirical analysis of trends in the tariff deficit. These developments led policy-makers to look for alternative mechanisms to contain wholesale electricity prices and reduce the size of the tariff deficit, as we will discuss in Section 4.2.

#### 4.1.2. Network unbundling and regulation in Spain

The legislative framework adopted by Spain in 1997 for electricity and in 1998 for gas implemented the European directives that were applicable at the time (the Electricity Directive of 1996 and the Gas Directive of 1998). Under the European Directives, accounting separation of transmission and distribution from liberalised activities had to be implemented. Moreover, a system of third-party access to infrastructure (either regulated or negotiated) had to be introduced.

The Spanish framework actually went further then the European Directives. It did so by introducing regulated third-party access to the network, and by introducing legal separation of transmission in both gas and electricity. In electricity, ownership limits on the transmission system operator (REE) were contained in the Electricity Law of 1997 and third-party access had been in place before 1997. The ownership limits on REE meant that no individual shareholder could own more than 10% of REE's capital and that the electricity industry as a whole had to own a combined share of less than 40%.

Over time, ownership unbundling in electricity was tightened and it was also extended to the gas network operator (Enagás). The limit on individual shareholding in REE was reduced to 3% in 2002 and to 1% for electricity companies in 2005. In gas, a limit of 35% of any individual shareholder was introduced in 2000 and it was then lowered to 5% in 2003. Gas Natural currently owns 5% of Enagás.

These provisions have effectively implemented full ownership unbundling in both gas and electricity transmission in the Spanish market. They have therefore gone beyond the current Gas and Electricity Directives of 2003 and are likely to also exceed the unbundling requirements that will be included in the future European legislation on the subject, at least in the short run (see Section 3 for a review of recent regulatory developments in Europe).

In terms of the distribution networks, Spain initially implemented the softer legal and accounting separation contained in the Second Gas and Electricity Directives and introduced stronger functional separation in July 2007 (again in line with the directives).

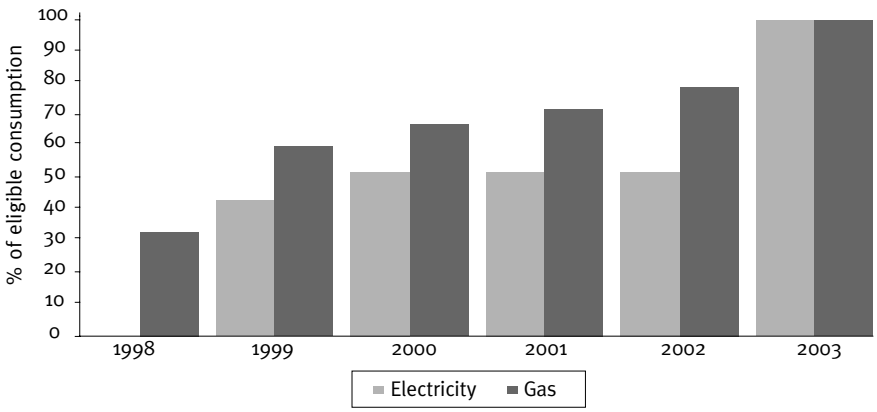
### 4.1.3. Retail liberalisation

The third main element of regulatory reform in the Spanish energy sector has been the liberalisation of the downstream retail market in both gas and electricity. This has again been in line with European legislation on the issue, which prescribed a calendar for the introduction of competition in the retail market in both sectors. Under the Second Gas and Electricity Directives, all industrial and commercial customers had to be free to choose their retail suppliers by July 2004 and household customers had to be in the same position by July 2007.

The Spanish government has introduced a faster liberalisation schedule than the one envisaged under the European Directives. This is summarised in Figure 14 below. Full retail liberalisation was introduced in both gas and electricity in 2003, with gas liberalisation generally proceeding faster than in electricity during the preceding years (due to the smaller share of household consumption in the gas market).

Making a customer eligible for retail competition is, however, only a pre-condition for effective competition in the retail sector. Indeed, as our empirical review in Section 5 shows, retail competition has been slow to develop in the Spanish residential energy sector in both gas and electricity. At the end of 2007, few customers had switched away from their incumbent supplier (fewer than 10% in gas and fewer than 5% in electricity). Competition in the electricity sector was particularly hindered by the presence of a large tariff deficit (as mentioned above and discussed in more detail in Section 5). Liberalisation in the industrial and commercial gas sectors has, however, been more effective, largely driven by LNG competition and the increase in gas consumption by electricity generators.

*Figure 14: Schedule of retail market liberalisation in Spain, 1998-2003*




Source: CNE.

### 4.1.4. Merger Control and Competition Policy

The application of competition policy has been active in the first phase of liberalisation of the energy sector, especially in the area of merger control. Three major mergers were assessed by the sector regulator and the relevant competition authorities in the period up to 2005. These cases are summarised in Table 5 below. We will discuss the mergers involving Endesa (which were evaluated by the competition authorities during the 2006-2007 period) in the next section of the report.

*Table 5: Merger control in the Spanish electricity sector, 2000-2005*

| Merger | Year | Main issues | Outcome |
|---|---|---|---|
| Unión Fenosa / Hidrocantábrico | 2000 | Horizontal effects arising from consolidation of third and fourth largest electricity company | Prohibited after a negative opinion by the Competition Tribunal *(Tribunal de Defensa de la Competencia - TDC)*, stressing the risk of coordinated effects. |
| Endesa / Iberdrola | 2001 | Horizontal effects from merger of first and second largest electricity companies | Abandoned by the parties due to the divestments imposed by the government. |
| Gas Natural / Iberdrola | 2003 | No decision by the competition authorities | Prohibited by the CNE due to effects on regulated activities (under "Function 14"). |

As Table 5 shows, none of the three mergers proposed in the 2000-2003 period eventually proceeded. This was largely due to regulatory interventions, either by the government (following the recommendation of the competition authorities) or by the Spanish sector regulator (CNE) under its power of review of the impact of mergers on regulated activities. The degree of caution showed by the competition authorities when looking at these mergers is understandable, given the concentrated structure of the affected markets prior to the merger (with the exception of the Gas Natural/Iberdrola decision by the CNE, which was not taken on competition grounds, but on regulatory grounds). However, merger control was not applied consistently to these transactions and merger remedies could have been used more effectively to improve the competitive structure of the markets and actually increase competition. Pro-competitive aspects of these transactions (e.g. the potential for efficiencies arising from vertical integration between gas and electricity) could have also been more explicitly recognised in the application of competition policy.[33]

Another significant competition decision in the energy sector in the first phase of liberalisation was the ruling by the TDC on the Gas Natural/Enagás matter in 2005.[34] This was an abuse of dominance case that related to the contractual relationship (the so-called *contrato deslizante*)

33. See Crampes and Fabra (2005) and Vives (2008) for a discussion of these mergers.
34. Tribunal de Defensa de la Competencia, "Resolución, Expediente 580/04, Gas Natural", June 2005.

between the network operator Enagás and the downstream incumbent Gas Natural in 2001, at a time when Gas Natural owned 100% of Enagás. The TDC found that Gas Natural had abused its vertical position by obtaining privileged access to Enagás's LNG import capacity through this contract, at the expense of its rivals in the downstream market. Gas Natural was fined €8 million for this abuse. This decision was subsequently annulled on appeal to the Audiencia Nacional in March 2007 on procedural grounds. Without commenting on the merits of the TDC's decision, this abuse case illustrates the potential vertical foreclosure effects that can arise when the network operator is vertically integrated into liberalised activities. Subsequent to this case, ownership of Enagás was effectively unbundled from Gas Natural.

### 4.2. Recent developments, 2006-2007: Regulatory reform

Several regulatory initiatives were taken by the government and the sector regulator during the 2006-2007 period. Some of these were driven by the need to comply with European legislation or a desire to amend the design of the market. Others were the result of the regulatory pressure arising from the failings of the current system, in particular the emergence of a very significant electricity tariff deficit in 2005 and into 2006, and the need to manage its consequences.

Table 6 provides a snapshot, in chronological order, of the key regulatory events of 2006 and 2007. We will comment below on the key regulatory changes, grouping them as follows:

a. Measures to manage the tariff deficit;

b. Market design reforms; and

c. Retail liberalisation.

#### 4.2.1. Measures to manage and mitigate the tariff deficit

The government took a number of regulatory measures over the 2006-2007 period which can be interpreted as ways to directly manage and mitigate the impact of the growing electricity tariff deficit in the market. These interventions are reviewed below. The first two measures that we analyse (the imposition of an administratively-determined price on "matching (or internal)" transactions within vertically integrated groups, and the clawback of windfall profits arising from the European ETS) sought to directly reduce wholesale prices in order to decrease the size of the tariff deficit. The third measure (the move towards the ex-ante recognition of the deficit) sought to reduce the impact of the deficit on the efficiency of the market. The fourth measure (the gradual increase in retail tariffs) aimed to absorb the deficit over time.

*Table 6: Main regulatory events, 2006-2007*

| Event | Date | Description |
|---|---|---|
| **Administrative price on "internal" trades in the electricity spot market** | February 2006 (RDL 3/2006), June 2007 (RD 871/2007) | An interim price of €42.35/MWh is set for internal transactions in the electricity day-ahead market within vertically integrated utilities (the final price was subsequently set at €49.23/MWh). This is a temporary measure in anticipation of the development of a new market design for bilateral trading. |
| **Abolition of CTCs** | June 2006 (RDL 7/2006) | Abolishes CTC mechanism. Also recognises that CTC distort market outcomes and are based on outdated assumptions. Final settlement of the CTC payments is still being debated. |
| **Development of forward markets (OMIP/ OMIClear)** | June 2006 (Orden ITC/2129/2006), December 2006 (Orden ITC/3990/2006), June 2007 (Orden ITC/1865/2007) | Sets minimum volumes to be purchased by distributors on the Iberian forward electricity market, progressively raising this amount from 5% of total regulated demand to 10%. |
| **Tariff revision for 2007** | December 2006 (RD 1634/2006) | De facto abolishes administrative price on internal transactions of integrated companies (as contained in RDL 3/2006). Recognises ex-ante tariff deficit for 2007, to be financed through auctions for future rights on retail and access tariffs. Introduces "additive" regulated tariff to allow for a sufficient retail margin (net of energy costs and access charges). |
| **VPP auctions** | December 2006 (RD 1634/2006), May 2008 (RD 324/2008), and Resoluciones de la Secretaría General de Energía | Introduces VPP auctions for Endesa and Iberdrola. Develops framework for VPP auctions and establishes amounts to be auctioned in each session (up to April 2009). |
| **Procurement Electricity Auctions** | February 2007 (Orden ITC/400/2007) and April 2007 (Resolución de la Secretaría General de Energía) | Establishes legal framework for procurement auctions by distributors, to commence by the second quarter of 2007. Develops detailed rules for first procurement auction. |
| **Adoption of E.U. Directives** | July 2007 (Ley 12/2007 and Ley 17/2007) | Implements functional separation of distribution network. Sets out timetable for introduction of tariffs of last resort in both gas and electricity. |
| **MIBEL** | July 2007 | Operational start of MIBEL |
| **Reform of capacity payments** | September 2007 (Orden ITC/2794/2007) | Develops revised system for electricity capacity payments. |
| **Deduction of windfall gains from ETS** | November 2007 (Orden ITC/3315/2007), and December 2007 (RDL 11/2007) | Establishes calculation for payment of windfall gains arising from the ETS during 2006. Establishes that deduction will also take place for the 2008-2012 period. |

Note: RD stands for Royal Decree (*Real Decreto*); RDL for Royal Decree Law (*Real Decreto-Ley*); and Orden ITC for resolutions of the Ministerio de Industria, Turismo y Comercio (Ministry of Industry, Tourism and Commerce).

- **Administrative price on "internal" transactions in the day-ahead market from March to December 2006**

In February 2006 the government imposed an administratively set price of approximately €42/MWh on volumes of energy in the day-ahead market that were effectively traded within the same vertically integrated group. These intra-group volumes were defined as the matching positions in the spot market between generation and regulated supply for each vertically integrated firm. Given that the four main utilities in Spain are vertically integrated and that regulated supply still accounts for a significant share of total supply, the volumes subject to this price represented a very significant amount of energy during 2006. This is shown by the fact that volumes effectively remunerated at market-based prices in the day-ahead market fell by almost 50% in 2006 compared to 2005 (even though most energy was still traded through the Pool).

The price set by the government was well below the average price observed in 2005 and the prevailing price in 2006 (which were both in excess of €60/MWh). The measure therefore directly reduced the energy costs faced by consumers. There is also some evidence (that we will review in Section 5) that this measure also reduced spot prices in the day-ahead market in the short term.[35] However, as a result of the imposition of a price control on intra-group trades, Iberdrola effectively exited the day-ahead market as of June 2006 by bidding its regulated demand requirements at a price level that was below cost. These demand requirements were then met in the balancing markets, where the price control did not apply. As a result, the price for balancing services (including congestion management) increased several-fold in the period between June and December 2006 (compared to prices during the first part of 2006), thus partially offsetting the impact of the measure on total wholesale costs.[36]

This measure appears to have been introduced as a temporary "fix" in order to mitigate market power in the day-ahead market and reduce the tariff deficit, before the development of a market design for bilateral trading. This was subsequently introduced during the course of 2007, as we will review below. However, as discussed in more detail in Section 6 of this report, it is unlikely that the introduction of bilateral trading (in the form of compulsory procurement auctions for a share of the regulated supply requirements) will substantially increase competition in the electricity wholesale market, at least in their current format.

- **Removal of "windfall gains" from the introduction of the European Emission Trading Scheme (ETS)**

The government announced a measure to remove the windfall gains arising from the operation of the ETS in February 2006 (to be applied retrospectively to the whole of 2006). The intervention

35. This is to be expected, since fixing a price on intra-group trades reduced the size of infra-marginal gains made by generators as a result of any given increase in the spot price, thereby reducing the incentives to raise prices.
36. For a further discussion of this regulatory intervention, see Fabra (2008).

was subsequently extended to the 2008-2012 period (which corresponds to the second phase of the ETS), even though the exact modalities for its application have not been defined yet.

The idea behind this intervention is to remove from generators the windfall gain[37] created by the internalisation of emission costs and the fact that some emission permits were handed out for free.[38] The ETS scheme has set a market price for carbon emission permits since 2005. Incumbent generators also receive free emission permits, until 2011. The presence of a market for carbon emission implies that generators should be expected to reflect the opportunity cost of carbon in their variable cost of production (since if they do not generate, they can re-sell their free permits in the market that has been created for carbon allowances). The resulting increase in the market price for electricity will affect all of the generator's output (including the part that is covered by free allowances and also output by generation technologies that do not require permits). This can be expected to result in a windfall gain for the producer.

The precise mechanism introduced by the Spanish government to remove windfall gains made in 2006 is summarised in Box 3 and Figure 15. The formula used by the government applies a windfall tax to generators with free permits (in proportion to the free permits that they have received and their emission factor – i.e. the amount of permits needed to produce) and to generators in the ordinary regime which do not need carbon permits (e.g. nuclear and hydroelectric power), but which also benefited from the increase in electricity prices resulting from the ETS.[39]

It is important to recognise that the source of the windfall gain does not lie in any form of abusive pricing behaviour by generators. Each generating plant should be expected to reflect the entire opportunity cost of carbon emissions (even if these are handed out for free) for the scheme to be effective and signal a scarcity of $CO_2$. The windfall gain results, instead, from the basic features of generation markets (i.e. the fact that prices are set by the marginal source of generation, potentially benefiting infra-marginal sources too), coupled with the design of the ETS, which allocated significant amounts of free permits to generators. This windfall gain would be present also in the absence of any market power in the electricity wholesale market.[40]

37. A windfall gain can be defined as an increase in profits for firms that arises from an exogenous regulatory intervention (i.e. in this case the creation of a market price for carbon emissions, and the allocation of free permits).
38. As we will discuss below, both conditions are necessary for windfall gains to arise for all types of generation technologies (including thermal plants).
39. Generators in the special regime were excluded from this intervention even though those that sold their energy in the market also benefitted from a windfall gain due to the introduction of the ETS.
40. Variations in infra-marginal rents (which share some similarities with the changes in generation profits due to the ETS) can commonly arise in liberalised electricity markets, when the cost of some technologies change over time, but not the cost of others. For example, higher fuel prices for price-setting thermal technologies (gas and/or coal) typically result in gains to technologies with low marginal costs (nuclear and hydro). In May 2008 the CNE provided an indicative computation of the gains made by nuclear and hydro technology as a result of higher fossil fuel prices that ranged between €770 million and €1.4 billion for the third quarter of 2008, depending on whether the assets are considered amortised or not (see CNE, "Precios y costes de la generación de electricidad. Informe complementario a la propuesta de revisión de la tarifa eléctrica a partir del 1 de Julio de 2008", May 2008).

**Box 3: The clawback on ETS windfall profits applied in Spain for 2006**

Royal Decree Law 3/2006 established that windfall gains made during 2006 due to the allocation of free carbon permits under the ETS would have to be paid back by generators. The rules for the computation of this clawback mechanism were subsequently set out in November 2007 (ITC/3315/2007).

The mechanism that has been implemented by the Spanish government seeks to remove windfall gains from both non-thermal generators (that do not need carbon permits) and thermal generators:

**Non-thermal generators** (e.g. nuclear and hydroelectric power) have to pay back an assumed increase in power prices due to the ETS multiplied by their actual output level. The assumed increase in power prices was computed assuming that a CCGT with a specific emission factor (defined as *EFm* and set at 0.365 tonne/kWh) set the price in all hours of the year and that it fully passed through the increase in cost it faced as a result of the ETS. This increase in cost reflects the increase in the opportunity cost of generation due to the presence of a market price for $CO_2$ under the ETS.

**Thermal generators** had to pay back an amount proportional to the amount of free carbon allowances received. The computation for this payment also assumed that the electricity price would be set by a CCGT with an emission factor of *EFm*. The payment by a thermal generator *i* was set equal to the market value of the free allowances received by that generator (evaluated at the market price for $CO_2$) multiplied by the ratio of the emission factor of the notional price-setting CCGT (*EFm*) and the emission factor of generator *i* (*EFi*).

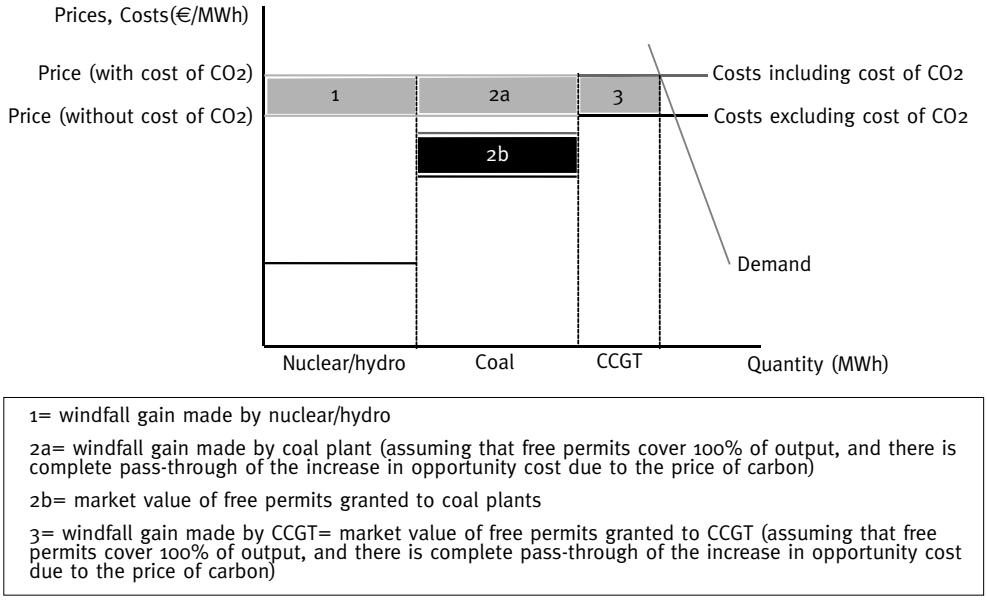
- If $EFi = EFm$ (e.g. in the case of a CCGT with the same emission factor as the notional CCGT assumed in the mechanism), then the payment equals the market value of the free permits.
- If $EFi > EFm$ (e.g. in the case of a coal plant that emits more than a CCGT), then the windfall gain is assumed to be lower than the market value of the free permits and less needs to be paid back. This recognises the fact that a coal plant that is not price setting will receive a windfall gain that is determined by the increase in costs faced by a price-setting plant and not by the increase in its own variable costs (see illustration in Figure 15).

The formulae used for 2006 correctly capture the windfall gains made due to ETS if the following conditions hold:

- Prices are always set by a CCGT with an emission factor equal to the assumed level of 0.365 tonne/kWh.
- Price-setting CCGTs face incentives and are able to fully pass through the increase in variable costs due to the ETS.
- For the case of a thermal generator with emission factor in excess of 0.365 tonne/kWh (e.g. a coal plant), free allowances exactly cover the output of the plant. This is a reasonable assumption for Phase I of the ETS (2005-2007), as shown by excess of allowances in this phase of the ETS, which led to a collapse in $CO_2$ prices during 2007.

If these conditions do not hold, the formulae will not give an accurate measure of the windfall gain and may over- or under-estimate it. Figure 15 illustrates the principle behind the mechanism that was implemented for 2006.

*Figure 15: Illustration of assumed windfall gain due to ETS (assuming competitive behaviour in generation market)*




Source: Own analysis.

Removing the windfall gain from the ETS reduces the energy expenditure of consumers (depending on the allocation of the windfall tax). The measure can therefore benefit consumers and can be used to reduce the cost of energy at a time of increasing fuel prices. However, an intervention to remove windfall gains from ETS such as the one implemented in Spain raises a number of issues:

**The measure is applied ex-post.** The ex-post application of a windfall tax is potentially problematic if generators have made plant-specific investments in the expectation that the plant would have earned profits from the increase in spot prices due to the ETS and from the allocation of free carbon allowances. Those investments may no longer be profitable if the windfall gain is removed. The ex-post intervention therefore contributes to regulatory uncertainty and may discourage efficient investments over time.[41]

41. In Spain this risk may have been mitigated by the fact that the windfall tax was announced just over a year after the start of the ETS (and the establishment of a market price for $CO_2$). On the other hand, the application of ex-post interventions by the regulator can still raise uncertainty about the recovery of any other future investment.

**Estimating actual windfall gains for thermal generators is not straightforward.** The precise size of the windfall gain made by thermal generators (i.e. coal and gas-fired plants) will depend on a number of empirical conditions which are hard to measure for the regulator. These include the identity of the plants that set the market price in the wholesale market, the degree of pass-through of a given cost increase (i.e. the extent to which plants will be able to profitably increase their bids in the market as a result of the increase in variable costs) and the amount of carbon allowances needed by each plant net of the free allocation. The formulae used by the government to estimate the size of the windfall gain in 2006 are necessarily simplified and unlikely to precisely reflect the size of the windfall gain made by generators (see Box 3). Whilst some of the assumptions used in the Spanish mechanism are conservative (e.g. the assumption that a relatively clean technology is always price-setting), others are not (e.g. the assumption of full pass-through of the cost increase due to the ETS).

**Windfall gains on non-thermal generators are also removed.** Plants that do not generate carbon emissions (e.g. hydroelectric and nuclear plants) also make a windfall gain from the introduction of the ETS, since this increases marginal electricity prices in many hours without affecting their costs. The windfall gain made by non-thermal generators is actually unrelated to the presence of free carbon allowances and would also be realised in the absence of any such allowances. By taxing non-thermal windfall gains, the Spanish government therefore extended the scope of its intervention to all windfall profits resulting from the ETS (and not just those due to free allowances).

**Use of the windfall tax.** In Spain the proceeds of the windfall tax on ETS have been indirectly used to reduce the tariff deficit on regulated tariffs and effectively subsidise electricity consumption. This does not appear to be consistent with one of the aims of the ETS, which should be to *increase* the price of thermal electricity and signal to society the externality associated with $CO_2$ emissions. A more efficient outcome would be achieved by restructuring electricity tariffs to reduce fixed charges paid by consumers using proceeds from the windfall tax, but keep marginal electricity prices at market-based levels, thus preserving adequate signals for energy efficiency.

- **Reforms of the electricity tariff deficit**

The way in which the tariff deficit is recognised and financed was also reformed in 2007. The main features of the reform include: (i) an ex-ante recognition of the tariff deficit in an "additive" structure for regulated tariffs and access charges; and (ii) the introduction of auctions to finance the tariff deficit.

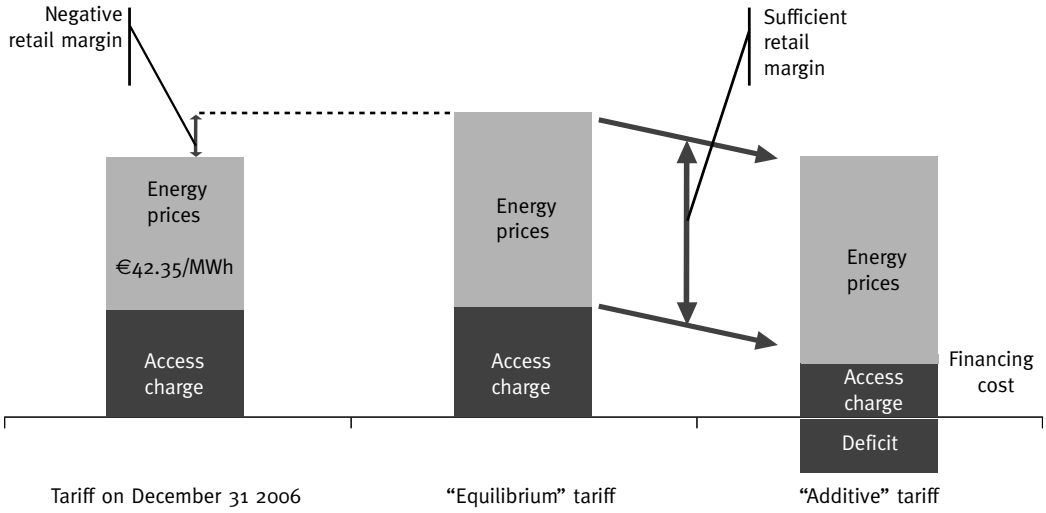
**Introduction of additive tariffs**

The recognition of an expected shortfall of total revenues in relation to total costs when regulated tariffs and access charges are set (i.e. ex-ante) has allowed the introduction of "additive" tariffs. These tariffs fully reflect the expected cost of energy in the wholesale market. The ex-

ante deficit then measures the expected shortfall between total revenues and total cost. This is in turn allocated to the regulated element of the tariffs, i.e. the access charges. This means that the access charges paid by retailers active in the liberalised market are reduced to reflect the presence of the deficit. The purpose of this measure is to allow for a sufficient downstream margin for retail supply, thereby enabling independent retailers to compete against the regulated tariff.

This mechanism is illustrated in Figure 16, sourced from the CNE. The first column in the figure ("Tariff at 31/12/2006") shows the regulated retail tariff that was set by the government for 2006, with an assumption that wholesale energy costs during 2006 equal €42.35/MWh. Actual energy costs in 2006 were significantly higher than this level, resulting in a higher required "equilibrium" tariff (shown in the second column). The difference between the 2006 tariff and the equilibrium tariff represent the tariff deficit. This deficit in turn results in negative retail margins for suppliers in the liberalised retail market. In order to preserve an adequate downstream retail margin, the additive tariff (third column) recognises a tariff deficit ex-ante and sets regulated access charges below cost (whilst allowing actual wholesale electricity prices to be reflected in the tariffs). Retailers therefore pay a lower access than what would be required to cover all access costs and as a result are able to compete with the regulated tariff without incurring a loss.

*Figure 16: Introduction of additive electricity tariffs in 2007*




Source: CNE, Ministerio de Industria, Turismo y Comercio.

A move to additive tariffs is positive, since it can help insulate competition in the retail market from the adverse effects of the presence of a tariff deficit. There is some evidence that retail competition increased during 2007 as a result of this reform (see Section 5), at least in terms of overall electricity volumes in the liberalised market (which increased from 22% in the second half of 2006 to 30% in the second half of 2007).

**Tariff deficit auctions**

The ex-ante recognition of the tariff deficit in 2007 was accompanied by auctions to finance it. The primary objective of these auctions is to allow the utilities to recover the entirety of their recognised regulated network costs, rather than effectively forcing them to finance the tariff deficit through their revenues. A secondary aim is to establish the financing cost of the tariff deficit and to provide a public signal of whether the markets had confidence in the design of the electricity market, and expected the deficit to be clawed back through future increases in retail tariffs (or reductions in wholesale prices).

Three auctions for the ex-ante deficit have thus far taken place, in November 2007 and in June and September 2008. The first and third auctions were cancelled due to insufficient interest from the capital markets and a general lack of credit in the market. The second auction did not assign the entire deficit that was being allocated. General conditions in the financial markets also affected the outcome of this second auction.

- **Increases in retail tariffs**

The fourth general measure followed to mitigate the impact of the tariff deficit since early 2007 has been the increase in retail tariffs. The tariff increases have, however, been insufficient to prevent the emergence of a deficit in each year and, therefore, an accumulation of the deficit over time. Over the course of 2007, prices were increased by roughly 6%, but a tariff deficit was still observed (in spite of the fact that wholesale prices were relatively low). This is shown in more detail in Section 5. Projections for 2008 indicate that a large tariff deficit will be present by the end of the year, due to high wholesale electricity prices and relatively modest increases in tariffs (+3.4% in January 2008 and a further 6% in July 2008, below the levels required to cover prevailing energy procurement costs and prevent a further increase in the tariff deficit[42]).

42. The CNE had recommended an increase of 11.3% in June 2008 to prevent an increase in the tariff deficit above the levels forecast ex-ante at the end of 2007. In September 2008 the CNE recommended a further increase in retail tariffs of between 3%-10% to prevent an increase in the tariff deficit (also computing that the increase required to eliminate the current deficit would be in the 27%-35% range, excluding the clawback of windfall gains from the ETS in 2008).

### 4.2.2. Reforms of the design of the wholesale electricity market

- **Virtual Power Plant (VPP) and procurement auctions**

The Spanish energy regulators have focused a significant part of their recent reforms of the wholesale electricity market on the promotion of forward contracting.[43] This was already clear in Law 36/2003, where a number of economic measures were announced, including some which led to the creation of electricity forward markets in Spain. In 2006 these reforms were put into practice through an obligation on electricity distributors to contract 5% of their regulated requirements through the forward markets created under MIBEL;[44] this obligation increased to 10% in 2007 and 2008, and it will remain in place until the formal disappearance of the regulated retail market in January 2009. These measures seek to improve market liquidity and provide more reliable pricing of forward contracts.

Moreover, in 2007 two additional forms of forward contracting were introduced: procurement auctions for regulated demand, known as CESUR (*Contratos de Energía para el Suministro de Último Recurso*) and Virtual Power Plant (VPP) auctions, known in Spain as EPEs (*Emisiones Primarias de Energía)*.[45]

**Procurement auctions (CESUR)**

Distributors must buy in the procurement auctions (CESUR) a significant share of demand from customers who are still on regulated tariffs, roughly 30%-40% to date. These volumes must be bought forward, for the three- (or six)-month period that follows the auctions.[46] Sellers in these auctions include generators, independent retailers, large consumers, and other agents, thus allowing arbitrage across multiple markets (as will be discussed below).[47]

There were five CESUR auctions between June 2007 and June 2008, taking place every three months (a sixth auction was held in September 2008, which we will not analyse here). In the first three auctions only a quarterly baseload contract was offered. In the fourth and fifth auctions a six-month baseload contract was also added. So far, no product with volume risk (i.e. whose volumes changes with variations in underlying demand) has been auctioned, even though it is likely that such products will be introduced in the future.

43. These reforms have promoted contracting in addition to the forward transactions which take place through organized exchanges.
44. The futures markets under MIBEL are run by OMIP (for trading) and OMIClear (for clearing). These came into operation in July 2006. There are two types of contracting modalities: through explicit auctions or via continuous trading. Explicit auctions (in which Spanish and Portuguese suppliers of regulated customers participate) currently concentrate most of the trading volumes.
45. CESUR are regulated through Order ITC/400/2007. EPEs are regulated in Royal Decree 1634/2006 (for the period between June 2007 and June 2008) and in Royal Decree 324/2008 (as of September 2008).
46. Details on the auctions are available at *www.subasta-cesur.eu*. Similar auctions have been held in several markets of the U.S. (e.g. Massachusetts, Maryland, New Jersey, Illinois and Ohio). See Loxley and Salant (2004) for a description of these procurement auctions.
47. The consortium FORTIA formed by energy-intensive consumers has participated in the last two VPP auctions. Agents that buy VPPs can also resell the capacity at the procurement auctions that take place a few days later.

The auctions are run as descending price auctions, that is, the auctioneer sets a price and producers need to declare how many MW they are ready to sell at each price. If supply exceeds demand at a given price, prices drop in subsequent rounds until demand equals supply. If both the quarterly and six-month products are auctioned at the same time, the auction closes when there is no excess supply for either product.

Once the auction closes, sellers and buyers sign physical bilateral contracts with each other, on a pro-rata basis, as a function of the quantities sold by each generator and of fixed shares of volumes for electricity distributors in Spain and Portugal.[48] The costs of procuring energy in these auctions are treated as regulated costs and are used to inform the regulated retail tariff. In the future, it is envisaged that mechanisms similar to the CESUR auctions will be used to determine the level of the tariffs of last resort. Table 7 summarises the results of the five CESUR auctions held up to June 2008.

*Table 7 CESUR auctions*

| | **First** | **Second** | **Third** | **Fourth** | | **Fifth** | |
|---|---|---|---|---|---|---|---|
| **Date** | 19/06/2007 | 18/09/2007 | 18/12/2007 | 13/03/2008 | | 17/06/2008 | |
| **Period** | JUL-SEP 07 | OCT-DEC 07 | JAN-MAR 08 | APR-JUN 08 | APR-SEP 08 | JUL-SEP 08 | JUL-DEC 08 |
| Volume (MW) | 6,500 | 6,500 | 6,500 | 3,500 | 3,500 | 1,800 | 900 |
| Price (€/MWh) | 46.27 | 38.45 | 64.65 | 63.36 | 63.73 | 65.15 | 65.79 |
| Rounds | 25 | 15 | 14 | 16 | | 12 | |
| Participants | 25 | 26 | 24 | 26 | | 25 | |
| Sellers | 21 | 18 | 23 | 26 | | 21 | |

## Virtual Power Plant (VPP) auctions

The regulator has imposed VPP auctions on Endesa and Iberdrola, which are defined as "dominant firms" according to Spanish legislation (i.e. their market share exceeds 10%).[49] VPP auctions imply the obligation to auction the right to use a fraction of the firms' generation capacity. They do not entail a change of control or ownership of specific assets, nor are they associated with specific plants.[50] Hence, they have a purely financial effect (independently of whether gen-

48. These shares are set by the government. Until the fourth CESUR, the share of demand across distributors was set as follows: Endesa 35%, Iberdrola 35%, EDP 12%, Unión Fenosa 11%, Hidrocantábrico 4%, Viesgo 3%. In the fifth auction, the shares were set as follows: Endesa 29%, Iberdrola 40%, EDP 12%, Unión Fenosa 6%, Hidrocantábrico 12%, Viesgo 1%.
49. The other so-called "main" operators in the market (EDP/HC and Unión Fenosa) cannot participate in these auctions as buyers.
50. In some cases, like in the Netherlands and Alberta (Canada), VPP auctions have been linked to the production of specific plants.

eration capacity needs to be nominated before the spot market opens), i.e. they affect the payments for energy, but not actual production.[51]

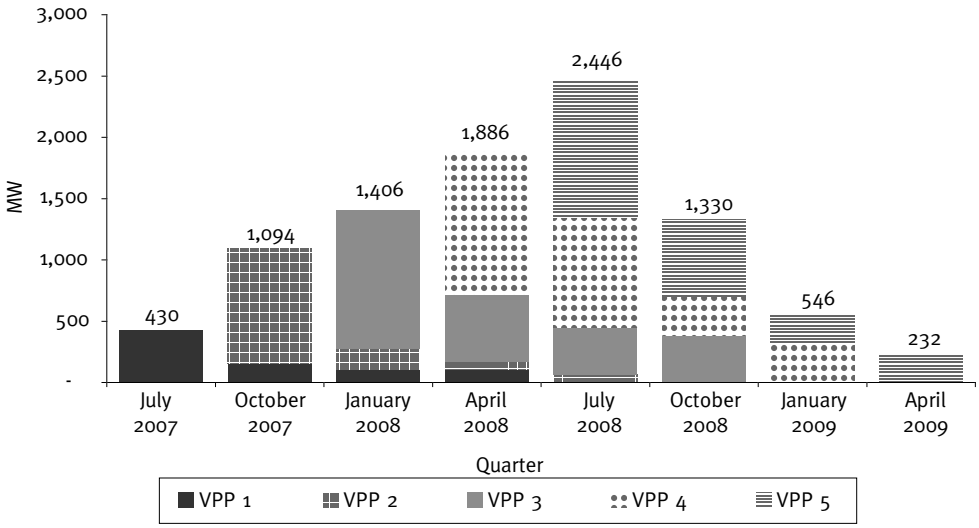
VPP auctions have been employed in various European countries (France, Belgium, the Netherlands, Ireland and Italy), in the United States and in Canada with different objectives: as merger remedies (e.g. in the cases of EDF/EnBW in France and Nuon/Reliant in the Netherlands), following antitrust investigations by the competition authorities (e.g. ENEL in Italy) and as a measure to promote forward contracting and mitigate market power (e.g. in Spain and Portugal). Spain and Portugal are the first countries in Europe to introduce VPP auctions as a regulatory measure to improve competition, rather than as a remedy in the context of an antitrust procedure.[52]

VPP auctions were already envisaged in the Electricity Law of 1997 (as later amended), which allowed the government to establish compulsory electricity auctions for dominant operators (up to a maximum of 20% of the firm's capacity). The White Paper on the reform of the regulatory framework for electricity generation in Spain that was commissioned by the Spanish government in 2005[53] also recommended using VPP auctions. The White Paper estimated that the volumes required to mitigate market power in 2008 were of approximately 4-6GW for each of the two main generators (Endesa and Iberdrola).[54] However, the volumes auctioned in practice have been much lower than those recommended by the White Paper (or allowed under Law 54/1997). No VPP session has auctioned more than 600 MW per firm, whilst the total amount of capacity simultaneously subject to VPP auctions per firm has not exceeded 1.25 GW to date. This represents less than 5% of total installed capacity in the case of Iberdrola and less than 6% for Endesa.

The amounts released during the auctions held up to June 2008 are illustrated in Figure 17 below. Further VPP auctions are scheduled for the periods starting in October 2008 and April 2009. These two additional auctions will each release a total of approximately 1.1 GW of annual capacity. Depending on the final distribution of the annual and semi-annual products, these additional sessions imply that the level of capacity subject to VPP auctions for Endesa and Iberdrola could amount to approximately 1.2 GW on average until the third quarter of 2009 (i.e. roughly similar to the level reached in July 2008).[55]

51. Recent reforms of VPP auctions have also simplified procedures by allowing the options to be settled for differences (with respect to spot prices).
52. In other countries (e.g. the United Kingdom and Italy) outright divestments of generation assets have been used to make the market more competitive.
53. See Perez-Arriaga *et al.* (2005).
54. The objective of VPP auctions recommended in the White Paper was that no operator controlled more than 19% and 22% of total capacity in baseload and peak demand periods, respectively. These limits were computed using a simulation model of the Spanish generation market. The resulting volumes for the VPP auctions were computed as 4,180 MW (Endesa) and 3,267 MW (Iberdrola) in baseload periods, and 4,934 MW (Endesa) and 5,870 MW(Iberdrola) in peak periods. It also recommended that, for these contracts to mitigate market power, they should have a minimum duration of 3 years.
55. This estimate assumes that the overall amounts auctioned in the two sessions will be spread equally between the annual and semi-annual products.

*Figure 17: Quarterly capacity affected by VPP auctions (baseload and peak products combined)*




The five VPP auctions that took place between June 2007 and June 2008 ran according to the following arrangements. The regulator determined the amount of "virtual capacity" to be auctioned in each session, divided in lots of 2 MW each. Two products were auctioned (baseload and peak) with three delivery periods (quarterly, semi-annual and annual). The baseload contract is a call option which can be exercised during all hours of the delivery period, whilst the peak option can only be exercised between 8 a.m. and midnight of each weekday (excluding public holidays). Each product has a strike price, which is set by the regulator the day before the auction. The holder of the option pays the strike price to the generator whenever the option is exercised.[56] The option price is determined in the auction (which follows an ascending price format).[57]

From the point of view of the buyer of the option, the price of the option and the strike price effectively represent the fixed and variable cost of the "virtual" plant that is being temporarily acquired. However, there are important differences which distinguish virtual plants from physical assets. These include the fact that the owner of the virtual plant does not bid its energy in the spot market. This means that the VPP holder is not an active operator and simply receives a financial flow once the spot market price is set (conditionally on the option being exercised). The VPP auctions by reducing the volumes of sales which receive spot market prices, have the

56. In several of the auctions the strike price was so low that the baseload option was always exercised ex-post (i.e. the strike price was always below the spot price).
57. The format of the VPP auctions is more complex than those of the CESUR since more products are auctioned at the same time (baseload and peak for three different delivery periods).

potential of mitigating firms' incentives to increase spot prices. However, they do not alter the incentives of the acquiring parties, unless the virtual capacity is held by firms which also own assets in the market.[58] Section 6 of this report focuses on the potential impact of VPP auctions on firms' bidding behaviour and market outcomes.

The VPP auction design described above has recently been modified. The new design, first applied in the last quarter of 2008, suppresses the quarterly product, reduces the number of auctions to be held each year and introduces the possibility that the exercise of the options can be implemented financially (simply on the basis of the difference between the spot price and the strike price in each hour of the delivery period).

Table 8 sets out the results of the five VPP auctions held until June 2008 (a sixth auction was held in September 2008, but is not analysed here).[59]

*Table 8: VPP auctions (quarterly baseload product only)*

| | First | | Second | | Third | | Fourth | | Fifth | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Date** | 13/06/2007 | | 13/09/2007 | | 11/12/2007 | | 11/03/2008 | | 10/06/2008 | |
| **Delivery** | JUL-SEP 07 | | OCT-DEC 07 | | JAN-MAR 08 | | APR-JUN 08 | | JUL-SEP 08 | |
| **Product** | Base | Peak | Base | Peak | Base | Peak | Base | Peak | Base | Peak |
| **Volume (MW)** | 274 | 2 | 674 | 100 | 566 | 20 | 268 | 0 | 446 | 40 |
| **Exercise price (€/MWh)** | 17 | 52 | 22 | 51 | 38 | 51 | 36 | 63 | 39 | 55 |
| **Option price (€/MW/month)** | 20,000 | 2,310 | 11,840 | 1,001 | 12,832 | 2,151 | 17,000 | 3,400 | 19,000 | 6,100 |
| **Implicit price (€/MWh)** | 44.78 | 58.56 | 38.44 | 53.84 | 55.82 | 57.11 | 59.61 | 72.66 | 65.39 | 72.33 |

Note: Results refer to prices and volumes for the quarterly baseload products. Half of the total volumes are assigned to Endesa and the other half to Iberdrola.

58. As discussed in Section 6 of the report, VPP auctions can also potentially affect the incentives of the VPP holders by reducing barriers to entry. However, it is unlikely that the current VPP auctions as implemented in Spain play such a role.
59. Since the buyers of the VPP pay both a fixed fee for the option and a variable exercise price, the table shows a total implicit price. This is computed as the sum of the exercise price and the option fee divided by the total number of hours in which the option can be exercised. This calculation may underestimate the actual price of the energy acquired in a VPP auction if the option is exercised in fewer hours than the maximum that is allowed (since each MWh would reflect a higher share of the fixed option fee).

## Comparison between VPP and CESUR auction results

Table 9 compares the prices of the first four procurement and VPP auctions (for the quarterly baseload products sold in each auction). These prices are also compared to average spot prices during the delivery periods, and to the spot and forward contract prices traded the day before the VPP auction was held (on OMIE and OMIP, respectively).

*Table 9: Price comparison (€/MWh) between VPP auction, CESUR and the OMIP and OMIE markets*

| | VPP | CESUR | Spot OMIE | Future OMIP | | Spot OMIE* |
|---|---|---|---|---|---|---|
| | Implicit price | | Quarterly average | | Day before | Day before |
| JUL-SEP 07 | 44.78 | 46.27 | 36.43 | FTB Q3-07 | 44.96 | 48.66 |
| OCT-DEC 07 | 38.44 | 38.45 | 47.93 | FTB Q4-07 | 39.27 | 37.01 |
| JAN-MAR 08 | 55.82 | 64.65 | 65.86 | FTB Q1-08 | 60.05 | 50.08 |
| APR-JUN 08 | 59.61 | 63.36 | 56.92 | FTB Q2-08 | 60.13 | 59.42 |

Note: The VPP auction price refers to the quarterly baseload product (assuming that the baseload option is always exercised). The CESUR price refers to the quarterly product. The Spot OMIE quarterly average is the simple average of hourly prices in Spain during the delivery period. Future OMIP and Spot OMIE* refer to forward and spot prices set the day before the VPP auction took place. Note that CESUR auctions were held some days after the VPP auctions.

The results show that the VPP auction and CESUR prices follow relatively closely those of traded future prices in OMIP (with the exception of the third VPP auction and the third and fourth CESUR auctions, where deviations from the corresponding future prices exceeded 5%). The relative convergence between market prices and those set in the auctions should not be surprising, given the arbitrage possibilities that exist across the different types of contracts.

However, there have been systematic differences between the prices in the CESUR and VPP auctions. In particular, VPP auction prices have always been lower than the CESUR prices. This appears to indicate that arbitrage possibilities between the two auctions have not been fully exploited, i.e. it would have been profitable to buy more energy in the VPP auctions to sell it in the CESUR. From Endesa's and Iberdrola's perspective, it has been less profitable to sell energy in the VPP auctions than it would have been to sell it in the CESUR (assuming that they would have voluntarily sold energy in the CESUR and that greater participation in these auctions would not have lowered the price).

On the other hand, the comparison between CESUR and VPP auction prices versus spot market prices is not systematic: for the first and fourth auctions, CESUR and VPP auction prices exceeded the average spot price during the relevant quarter, but the opposite took place for the second and third auctions. Again, this should be expected, as in the case of any standard insurance contract.

- **Reform of capacity payments**

Capacity payments to electricity generators were reformed in 2007. A new system of capacity payments (*pagos por capacidad*, set out in Orden ITC/2794/2007) substituted the former one (the so-called *garantía de potencia*) that had been in place since 1998.

The new capacity payments distinguish between two concepts: availability in the short to medium term; and investment in the longer term. The mechanism for remunerating availability has not been specified to date.[60] The intention behind this payment is to provide the transmission system operator with a mechanism that can incentivise availability by generation plants when the system requires them the most. The payment for investment (referred to as an "investment incentive") is instead confined only to new conventional generation plants with a capacity of more than 50 MW. Significant additional investment activities on existing plants (e.g. the fitting of FGD on coal plants – see Orden ITC/3860/2007) can also benefit from the investment incentive.

The investment incentive is computed as a decreasing function of a reserve index (or *índice de cobertura*), defined as the ratio between total available capacity and peak demand (see Figure 18). This index is computed when the investment is made. If the index is at or below 1.1 (i.e. the reserve margin is 10% or less), each new MW of capacity will receive an annual amount of €28,000 for the first 10 years of operation of the plant. For example, a new 400 MW plant would receive a total payment of €112 million. If the reserve index is greater than 1.1, then the annual payment for each MW of new capacity is reducing at a linear rate using the following formula: $193{,}000-150{,}000 \times IC$ (where $IC$ denotes the reserve index). For example, if the reserve margin were 11%, then the payment for each additional MW would be €26,500 (less than the €28,000 computed above). In general, each percentage point increase in the reserve margin leads to a reduction in the capacity payment of 1,500€/MW/year. The investment incentive cannot be negative, implying that if the reserve index reaches a level of approximately 1.29, new generation capacity will not receive any payment for the investment.

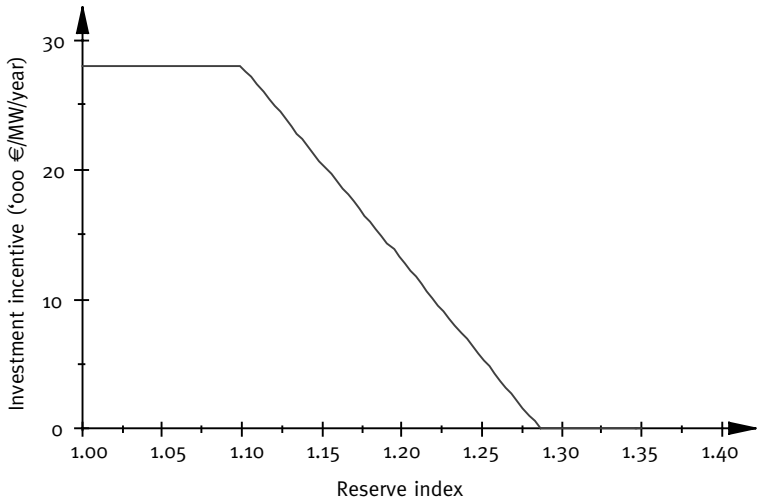
It is also worth noting (as we will further comment in Section 6) that the new regulation also envisages the possibility that the regulator (i.e. the Ministry of Industry, Tourism and Trade in this case) could procure new capacity in the future through capacity auctions.

In summary, there are two main changes introduced by the new capacity payments (relative to the previous arrangements): the distinction between a payment for availability and one for investment; and the method for computing the investment incentive, which is a decreasing function of the reserve index. There are also other implicit differences between the two systems, such as the fact that the new capacity payments introduce a degree of asymmetry in the remuneration

60. In March 2008, the transmission system operator submitted a proposal to the CNE for the determination of availability payments. The CNE has estimated the following payments for availability of services during the third quarter of 2008: 2.45 €/MWh for hydroelectric energy, 5.48 €/MWh for CCGT, and 0.81 €/MWh for coal.

of generation plants as a function of when they come on line[61] and as a function of the generation technology (to the extent that simultaneous investments mainly focus on a single technology, as has been the case in recent years through the entry of CCGTs).[62]

*Figure 18: The Investment Incentive*




However, the new system also preserves some characteristics of the previous arrangements: first, both systems are based on the premise that the remuneration of generation plants should include not only a payment for energy, but also payments for being available (we will comment further on this point in Section 6 of this report). Secondly, both mechanisms rely on administratively set prices for capacity, through which the regulator seeks to provide sufficient incentives for the market participants to invest until the desired reserve margin is achieved. Last, both systems induce weak incentives for plants to be available when the system needs them the most (which we will also discuss in Section 6).

- **MIBEL**

The third important market design reform implemented in the Spanish (and Iberian) wholesale electricity market in 2007 was the operational launch of the *Mercado Ibérico de Electricidad* (MIBEL) on 1 July 2007. MIBEL is operated in accordance with a "market splitting"

61. This includes the fact that existing plants will not receive any payment for investment, whilst new plants will receive a payment that depends on the value of the reserve index at the time of their entry (which is unlikely to be constant through time).
62. Recent changes to the previous capacity payment had already introduced explicit asymmetries between generation technologies. For example, thermal plants were treated differently than hydroelectric plants, and nuclear capacity no longer received a capacity payment. However, all thermal technologies received the same payment, independently of when they came into operation.

mechanism. This means that when interconnection capacity between Spain and Portugal is not congested, a unique spot price is determined across the two countries. This is set on the basis of the bids submitted by generators in both countries and total demand at the Iberian level. If the transmission capacity is congested, however, the market splits into two sub-markets, each of which sets its own spot price on the basis of bids and demand in that country (including imports/exports to the other market).

In practice, given the different cost structures of the wholesale markets in Spain and Portugal and the amount of interconnection capacity (an average of roughly 1.1 GW of import capacity into Portugal in 2007), MIBEL has experienced market splitting for a significant amount of the time since July 2007. As we review in Section 5, the spot market price between Portugal and Spain has differed in approximately 80% of during the July-December 2007 period, and average Portuguese spot prices have been almost 25% higher than Spanish prices over this period. Overall, during the whole of 2007, interconnection with Portugal was fully congested in almost 60% of hours, and average utilisation of the interconnector was of approximately 80%.

Therefore, whilst MIBEL has established the mechanism for integration between the Spanish and Portuguese markets to take place, effective integration across the two markets has not been fully achieved yet. Greater interconnection capacity between the two systems is required for full market integration to take place. The expectation is also that, over time, the convergence of market design across the two systems (e.g. the harmonisation of trading rules and of the mechanism for capacity payments) should also lead to greater convergence in market structures and technology mixes, and allow for the creation of an effective single Iberian market.

#### 4.2.3. Further liberalisation of the retail market

The third main element of the regulatory reforms recently implemented in Spain was the establishment of a timetable for further liberalisation of the retail market over the 2008-2011 period. This reform intends to fully implement the E.U. Directives on electricity and gas, and achieve a more effective liberalisation of the energy retail markets.

In electricity, a timetable for the gradual withdrawal of regulated tariffs and the introduction of Tariffs of Last Resort (TLR) was set. These tariffs represent the maximum price to be applied as a default to consumers who do not choose an electricity or gas supplier in the liberalised market. The timetable set out in the law envisages the following:

**July 2008:** disappearance of main regulated tariffs for high-voltage consumers

**January 2009:** disappearance of regulated tariffs and introduction of TLR

**January 2010:** TLR applicable only to low-voltage consumers

**January 2011:** TLR applicable only to low-voltage consumers with capacity of less than 50 kW (primarily domestic customers).

This timetable implies that full retail competition will apply to all non-domestic customers by 2011. This should mean that the presence of a subsidised retail tariff will no longer distort retail competition for these customers. The same is not the case for domestic customers, since the presence of a TLR that is below cost could still distort retail competition after 2011.

A faster liberalisation schedule was set out for the gas market, as follows:

**July 2007**: disappearance of retail tariffs for all customers with pressure above 4 bars (basically non-domestic demand).

**January 2008:** disappearance of regulated tariffs and introduction of TLR for customers with pressure below 4 bars

**July 2008:** TLR applicable only to consumers with consumption of less than 3 GWh/y

**July 2009:** TLR applicable only to consumers with consumption of less than 2 GWh/y

**July 2010:** TLR applicable only to consumers with consumption of less than 1 GWh/y

Whilst in principle this schedule allows for faster liberalisation of the gas sector relative to electricity, in practice the consumption thresholds that have been set for the application of the TLR imply that most of the residential gas sector will still be eligible for the TLR in July 2010. In the absence of significant additional switching in the residential gas market by 2010, one would expect the TLR to apply to a significant proportion of this market over the short to medium term.

The laws implementing the European Directives have also established a supervisory body (the *Oficina de Cambio de Suministro*) designed to facilitate the process of customer switching in the gas and electricity residential markets.

## 4.3. Recent developments, 2006-2007: Competition policy

### 4.3.1. The Endesa "merger saga"

The most significant recent event in the area of merger control in the Spanish energy market has been the long-lasting process surrounding the takeover of Endesa. This was initiated by the bid launched by Gas Natural in September 2005. It has only ended recently, with the acquisition of Endesa by the Spanish group Acciona and the Italian electricity incumbent Enel, and the finalisa-

tion of an asset sale agreement with the German utility E.On (which had previously also made a bid for Endesa).

Table 10 describes the main features of the three separate merger processes that have involved Endesa since late 2005. Only the first (the bid by Gas Natural) was under the jurisdiction of the Spanish government, which cleared the deal subject to a number of remedies (see below). The bids involving E.On and Enel were instead assessed by the European Commission, given their significant cross-border dimensions. Under the E.C. Merger Regulation, the European Commission took sole jurisdiction of the competition assessment of these two bids, and did not impose additional conditions beyond those put forward by the parties. The Spanish sector regulator, however, imposed additional conditions on both transactions, partially relating to issues of energy security in Spain. These conditions were imposed under the so-called "Function 14" of the CNE's statutory powers, as amended by the government in February 2006.[63] The European Commission referred the Spanish government to the European Court of Justice (ECJ) over the conditions imposed on the E.On bid, and the ECJ found that these conditions broke E.U. law, as summarised in the table below. In a separate judgement, in July 2008, the ECJ also found that Function 14 of the CNE (as amended by the Spanish government in 2006) violated European law, and was not proportionate to the Spanish government's objective of ensuring security of energy supply.[64]

The conflict of the ECJ with the CNE over the decisions in relation to the E.On bid for Endesa continued with the Enel/Acciona bid, illustrating the potential tension between a national government trying to protect energy security and national firms when foreign state-owned firms (or firms with some state protection) are involved in takeovers of domestic firms. State-owned firms are not subject to the market for corporate control and tend to be less efficient (although this depends on the degree of market competition). The potential paradox is that a country like Spain may privatise a firm like Endesa, supposedly because of efficiency reasons, only to find that later on it reverts - at least partially - to public foreign hands. This may happen without any violation of European competition law since the E.C. Treaty is neutral with respect to the form of property of firms. The level playing field for corporate control in the European market may be distorted in the presence of state-owned firms. This is because, state-owned firms cannot be taken over, may have objectives other than profit maximisation and may present a conflict of interest in regulated sectors (since the public sector is on both sides of the regulator-regulated relationship).

63. The amended Function 14 allows the CNE to authorise acquisitions involving assets in the Spanish energy industry (also by foreign companies with no presence in Spain) and impose conditions to maintain a number of objectives, including the security of energy supply.
64. In September 2008 the CNE decided not to apply the amended Function 14 of its mandate to the merger between Gas Natural and Unión Fenosa, due to the judgement of the ECJ.

*Table 10: Description of the Endesa mergers*

| Transaction | Date of announcement/ bid | Date of competition approval | Remedies |
|---|---|---|---|
| **Gas Natural/ Endesa** | September 2005 | February 2006 (Spanish Council of Ministers) | The Spanish government imposed several remedies to prevent a reduction in competition – see separate table below. |
| **E.On/ Endesa** | February 2006 | April 2006 (European Commission) | No remedies imposed by the European Commission.<br><br>The CNE imposes significant remedies initially (July 2006), including plant divestments. The CNE remedies were subsequently scaled down (November 2006).<br><br>The European Commission referred the matter to the European Court of Justice, which found in March 2008 that the conditions imposed by the CNE under Function 14 were contrary to E.U. law. |
| **Enel/ Acciona/ Endesa** | March 2007 | July 2007 and June 2008* (European Commission) | The transaction includes the sale of Viesgo and further generation assets of up 1.4 GW to E.On.**<br><br>The European Commission did not impose further remedies.<br><br>The CNE imposed additional remedies in July 2007. The European Commission opened infringement proceedings against these remedies. |

* The transaction was approved again in June 2008 due to changes in the divestments agreed upon with E.On.

** These assets include: Los Barrios (570 MW), Tarragona 1 (400 MW) and drawing rights on nuclear power (up to 450 MW).

Whilst the E.On and Enel/Acciona bids raised important jurisdictional issues on the application of competition policy in the European energy sector (as reviewed above), the most interesting competition issues were actually raised by the first bid for Endesa by Gas Natural. This merger would have brought together the largest gas and electricity firms in Spain and raised several competition concerns, both of a horizontal and vertical nature.

The remedies that were initially proposed by Gas Natural and those that were finally imposed by the Spanish government are summarised in Table 11.

*Table 11: Key remedies in the proposed Gas Natural/Endesa merger*

| Competition issue | Remedies proposed by Gas Natural | Remedies imposed by Spanish government |
|---|---|---|
| Horizontal effects in wholesale gas | Divestment of Endesa's participation in LNG plants | Same as Gas Natural proposal |
| Horizontal effects in wholesale electricity | Divestment of 3.1 GW of existing plants (largely coal) to Iberdrola<br><br>Divestment of 1.2 GW of CCGT projects (0.8 GW to Iberdrola) | Divestment of 4.3 GW of existing plants, including at least 1.2 GW of flexible generation (CCGT or hydro)<br><br>Acquisition by Iberdrola subject to separate competition assessment |
| Horizontal effects in retail gas and electricity | Divestment of Endesa's portfolio of liberalised gas customers, and Gas Natural's portfolio of liberalised electricity customers | Same as Gas Natural proposal |
| Horizontal effects in gas distribution | Divestment of gas distribution network in Valencia, Murcia and Madrid (1.2 million points) to Iberdrola | Divestment of gas distribution networks with at least 1.5 million points, creating at least two new operators |
| Vertical foreclosure effects | None | Gas release auctions (including sale of Endesa's gas import contracts) |

Gas Natural had proposed relatively extensive remedies, with one of their key features being that several of the assets to be divested post-merger would have been purchased by Iberdrola (Endesa's largest competitor in the electricity market). This would have been likely to reduce the pro-competitive impact of the proposed remedy package (by increasing concentration levels relative to a counterfactual where the divestments would have gone to an independent or smaller buyer).

After an in-depth investigation, the majority opinion of the TDC recommended that the merger should be blocked (in spite of the possibility of applying structural remedies to the transaction). However, the Spanish government approved the deal in February 2006 subject to a revised remedy package, which was similar in many aspects to the one that had been recommended by the CNE in its advisory opinion on the competition aspects of the merger. The most notable features of the remedies imposed by the government are summarised in Table 11. These included:

(a) the exclusion of Iberdrola as the identified buyer of the divested assets. Iberdrola would have to have purchased these assets through a separate competition procedure, which would have presumably resulted in additional remedies (or a prohibition of Iberdrola as a suitable buyer) in order to preserve the effectiveness of the original remedy package;

(b) the increase in the size of the divestment package in the generation market (from 3.1 to 4.3 GW of existing plants), and the additional condition that 1.2 GW of these divestments would have to be flexible (or price-setting) generation in order to offset the loss of competition from Gas Natural's generation portfolio in the price-setting segment of the electricity merit order;

(c) the inclusion of a significant gas release program (roughly up to 10% of the domestic market at the time) in order to mitigate potential foreclosure effects flowing from the gas market to the electricity market; and

(d) the absence of a structural measure which would have prevented the creation of double incumbency situations in the gas and electricity retail markets in those regions where Gas Natural owned the gas network and Endesa the electricity network (this affected most notably Andalusia and Catalonia). The only measure that was put forward to address the barriers to entry created by the double incumbency situation was the establishment of an independent entity to facilitate customer switching in areas were the merged entity would have owned both the gas and the electricity networks.

### 4.3.2. Excessive pricing in the Spanish electricity market

The second important recent development in competition policy in the Spanish energy market was the series of decisions issued by the TDC (and later by the newly created *Comisión Nacional de Competencia*, CNC) on excessive pricing in the wholesale electricity markets. These cases are important since there tend to be very few cases at a European level of dominant companies being fined for charging excessive prices (i.e. setting prices that are seen as "too high" in relation to a competitive benchmark). They may therefore form an important precedent (at least in the energy sector).

These decisions relate to the wholesale market for electricity congestion management. This market is run by the transmission system operator (REE) after the day-ahead market in order to resolve congestions on the transmission network. In this market, REE identifies the transmission congestions that may affect the dispatch resulting from the day-ahead market and accepts bids from plants that are required to relieve the congestions (i.e. plants which are located in the congested areas, but whose bids were not accepted in the day-ahead market). Plants that are asked to produce in the congestion market used to be paid the bid for providing congestion management services which they submitted in the day-ahead market until mid-2005. The rule was subsequently changed and plants can now change their bids for providing congestion management services.

In the four decisions over the 2006-2008 period, the TDC/CNC found that three operators (Viesgo in the first decision, Iberdrola in the second and third, and Gas Natural in the fourth) had abused their dominance in the congestion management market by overpricing their offers. The details of these four cases are set out in Table 12 below. As it shows, the decisions relate to a time period between December 2002 and February 2005, before the design of the market for congestion management was changed.

*Table 12: Summary of excessive pricing cases on the electricity congestion market, 2006-2008*

| Case | Outcome | Period examined | Main findings |
|---|---|---|---|
| **TDC, December 2006** | Viesgo fined €2.5 million | February 2002- May 2003 | "Self-exclusion" from day-ahead market through high bids within specific period (late December – late February)<br>Bids are well above revealed costs<br>Change in bids across periods examined<br>Finds excessive prices by Viesgo's plants during 14 days over the period examined |
| **TDC, March 2007** | Iberdrola fined €39 million | December 2002 – December 2003 | "Self-exclusion" from day-ahead market when price is low (Dec. 2002-May 2003; Nov.-Dec. 2003)<br>Bids are above revealed costs (40%-120% mark-ups) during self-exclusion periods<br>Exiting the daily market allows Iberdrola to preserve or augment its average revenues<br>Does not accept that cost of technical dispatch is higher than revealed cost, nor that intra-day prices are below cost<br>Self-exclusion strategy is abusive |
| **CNC, February 2008** | Iberdrola fined €15.4 million | July 2004 – February 2005 | "Self-exclusion" from day-ahead market by Castellon 3<br>High bids distort outcome of day-ahead market<br>No objective justification for high bids<br>Self-exclusion strategy is abusive |
| **CNC, April 2008** | Gas Natural fined €1.5 million | January-June 2004 | "Self-exclusion" from day-ahead market by San Roque 1<br>No objective justification for bids above market prices<br>Self-exclusion strategy is abusive |

Source: TDC/CNC.

These abuse decisions are primarily based on a concept of self-exclusion from the main day-ahead market by the plants which are subsequently called to produce to relieve transmission congestions. The competition authority found this self-exclusion to be abusive since in the market for congestion management the demand faced by the plants was practically inelastic (i.e. by virtue of their geographical location, the plants knew with sufficient certainty that they would be required to produce). This in turn allowed the generators to submit bids which were well above their costs and the prevailing spot market prices, thereby earning excessive profits.

What is notable, however, about at least some of the abuse periods identified by the Spanish competition authority is that these were periods typically characterised by low spot prices (this was the case, for example, during the late 2002 to late 2003 period considered in the Viesgo and first Iberdrola case). According to some of the cost data used in the decisions, spot market prices were not sufficient to cover the variable costs of the plants under examination during some of the abuse periods. These plants were therefore excluded from the day-ahead market, but were at times still required for congestion resolutions. This is consistent with the main role of the market for congestion management, which is designed to enable the system operator to rely on plants which are too expensive to be dispatched in the unconstrained day-ahead market, but which are actually necessary to resolve congestions.

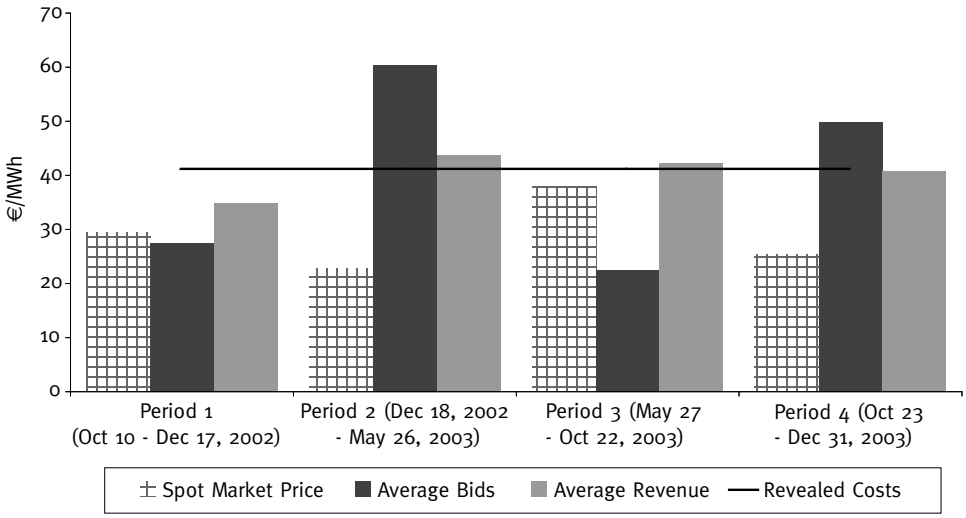
"Self-exclusion" from the day-ahead market therefore cannot be seen as an abuse *per se*.[65] Generators may, however, still be in a position to abuse their dominance in the market for congestion management by submitting bids which are well above the overall cost of providing the service. Dominance in this market is likely (given the localised nature of transmission congestions) and market forces often may not be able to constrain potential abuse of this market power.

However, measuring the cost faced by a plant for providing congestion relief for the purposes of establishing whether an excessive price is being charged is not straightforward. A plant called in the congestion management market will typically be asked to produce for a limited number of hours on any given day and will seek to recover its overall cost of operation (including start-up costs or losses made on the intra-day market to avoid starting up) using the bids submitted to the electricity transmission system operator. Evidence of relatively high bids submitted in the congestion management market (relative to prevailing spot prices or variable costs) is therefore not sufficient on its own to determine whether there has been an abuse. This can be illustrated by the data used by the TDC in its decision on Iberdrola of March 2007, which are reproduced in Figure 19. These data show, for four distinct periods, the average bids submitted by Castellon 3 (a CCGT plant owned by Iberdrola) in the day-ahead market[66], its average revenues (including revenues from congestion management and from the intra-day market), prevailing spot market prices and the revealed variable cost for the plant used by the TDC. The TDC found that the plant abused its market power during the second and fourth period since its bids in the day-ahead market were well above its costs and above spot prices too. However, as the figure shows, these bids were observed in a period with low spot prices, which were well below the variable cost attributed to the plant. Moreover, whilst the bids submitted to the market by the plant were relatively high (€50-€60/MWh), the actual average revenues earned by the plant were significantly lower during the two periods (€41-€44/MWh) and only marginally above the level of revealed costs.[67] A finding of excessive prices in these circumstances appears to be questionable.

65. Similarly, bidding above marginal costs in a situation where bids determine the remuneration received by a plant (i.e. in a pay-as-bid system) and in the presence of fixed costs is not sufficient evidence of excessive pricing.
66. Given the prevailing market rules at the time, these are the same bids used for the resolution of congestions.
67. Average revenues for the plant were presumably below its bids because of the much lower revenues earned by the plant in the intra-day market in order to achieve a technically feasible dispatch.

The excessive pricing cases considered by the TDC/CNC since late 2006 illustrate the fact that demonstrating the existence of abusive pricing in the energy market is potentially a very complex exercise and subject to several pitfalls. It also reveals the limits of applying ex-post competition policy to address some of the structural problems affecting energy markets (such as the existence of transmission constraints and market power more generally).[68] In cases such as this one, applying a well-designed regulatory solution ex-ante (e.g. establishing a regulated price as is the case in several U.S. power markets in the form of "reliability" contracts with the transmission system operators) may be superior to relying on market mechanisms and the application of ex-post competition law.

*Figure 19: Bids, revenues and costs of Castellon 3 (Iberdrola), examined in the first Iberdrola case (March 2007)*




Source: TDC.

68. See Hellwig (2008) for a general discussion of the applicability of abuse of dominance cases to electricity generation markets.

# 5. Recent Evolution of the Spanish Gas and Electricity Markets

This section of the report provides an overview of the recent evolution of the Spanish gas and electricity markets. We focus on the most recent publicly available data, including data from the last full year of the market (2007). The section first reviews evidence from the wholesale markets for gas and electricity, and then turns to the corresponding retail markets.

The review of competition conditions contained in this section of the report is based on published data made available by the energy sector regulator (CNE), the gas and electricity transmission system operators (Enagás and REE) and by the companies themselves. Most of these data relate to the market shares of each firm in the various gas and electricity markets, and allow us to construct fairly reliable indicators of concentration in each market. However, market share and concentration indicators are inevitably imperfect measures of competition conditions since they do not incorporate information on the actual terms offered to consumers (e.g. in relation to price and quality of service). Therefore, they can only be used as a first screen of potential competition issues (as is the case in antitrust and merger control cases undertaken by competition authorities), rather than to reach definitive conclusions on the extent of competition present in a market. Nonetheless, within the constraints on data availability present in the Spanish gas and electricity markets (which are common to other European energy markets), we believe that the review of concentration indicators contained in this report can still be useful to understand the recent evolution of competition in Spain, and to place them in the broader context of the European energy industry.

## 5.1. Wholesale gas

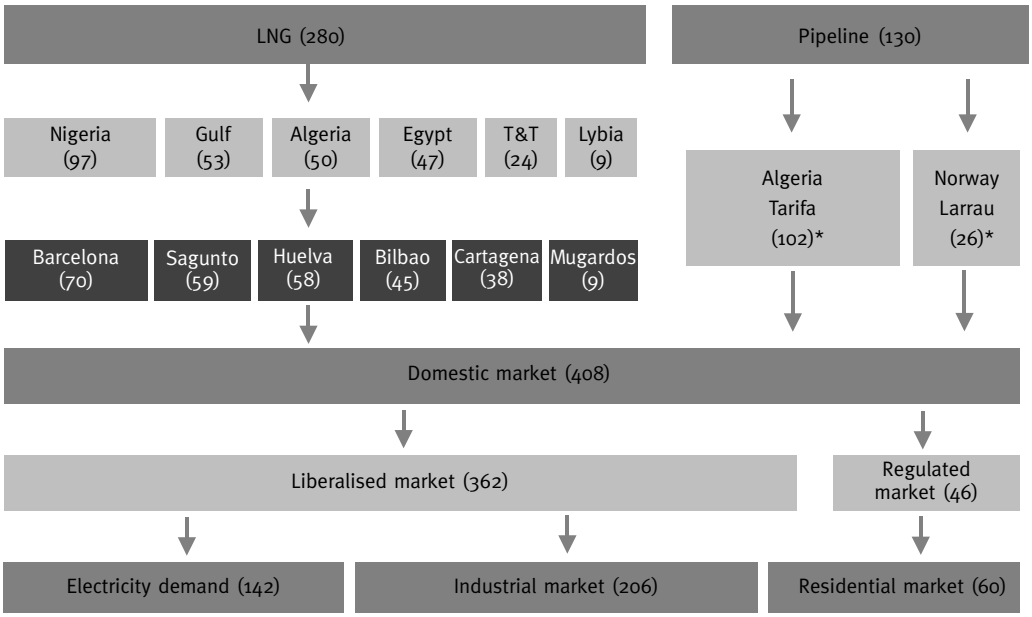
The Spanish wholesale gas sector has undergone a period of radical change in recent years. This has been driven by the very rapid growth of LNG imports, coupled with a significant increase in gas demand from the electricity sector. As a result of these developments, Spain has access to a well-

diversified portfolio of gas import sources in comparison with other European countries. On the other hand, given the absence of domestic gas production, Spain relies entirely on imports for its gas consumption and is fully exposed to variations in international wholesale gas prices.[69]

### The structure of the Spanish wholesale gas market

Figure 20 below summarises the structure of the Spanish gas market. Spain is practically entirely reliant on gas imports for its gas consumption. There were two sources of gas imports in 2007: pipeline gas from Algeria and Norway; and LNG from six foreign countries (the largest of which was Nigeria in 2007). LNG is then regasified at six LNG terminals in the Spanish territory. Pipeline and LNG imports served a national gas market of roughly 410 TWh in 2007 (approximately 35 bcm). As will be discussed in more detail in Section 5.3 below, most of the retail market is served on market-based prices, with a small proportion (mainly in the residential market) that is still on regulated tariffs. An important component of total gas demand (more than one third) is represented by demand from the electricity sector for CCGT generation (See Section 5.3 for further details on electricity gas demand).

*Figure 20: Flows in the Spanish gas market (figures in brackets in TWh)*



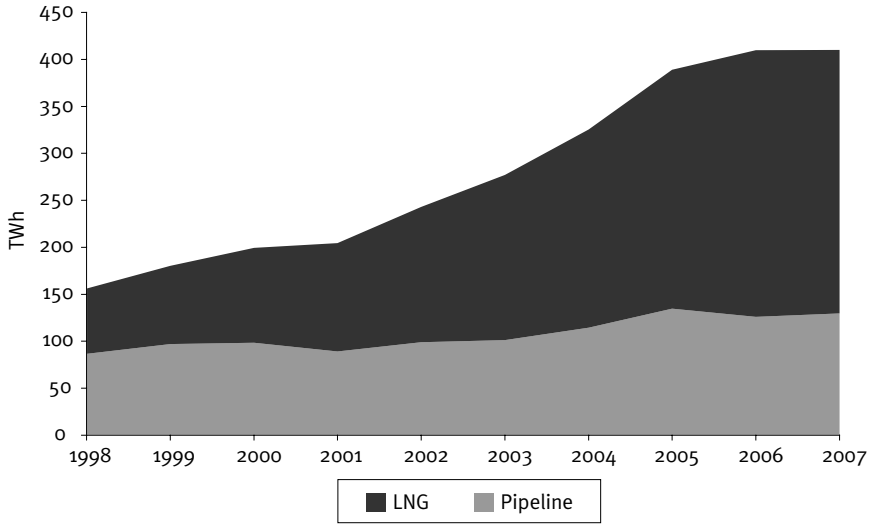

* Excludes transit gas to third countries, domestic production and domestic storage flows.
Source: Enagás.

69. A map of the Spanish wholesale gas market is included in Annex 2 of this report.

### Trends in LNG vs. pipeline gas

LNG imports have grown at a very rapid rate in the recent past, increasing 4-fold between 1998 and 2007, and meeting more than 80% of the growth in overall demand for gas imports over this period. This trend is illustrated in Figure 21. LNG currently accounts for close to 70% of total gas imports into Spain. As reviewed in Section 3, this share is much higher than the equivalent level in other major European countries. At the EU15 level, LNG accounted for only 12% of total consumption and 20% of non-E.U. imports. Figure 21 also shows that overall gas imports into Spain increased more than 2.5-fold between 1998 and 2007.

*Figure 21: Trends in pipeline and LNG imports, 1998-2007, TWh*




Source: CNE, Enagás.

### Gas import mix

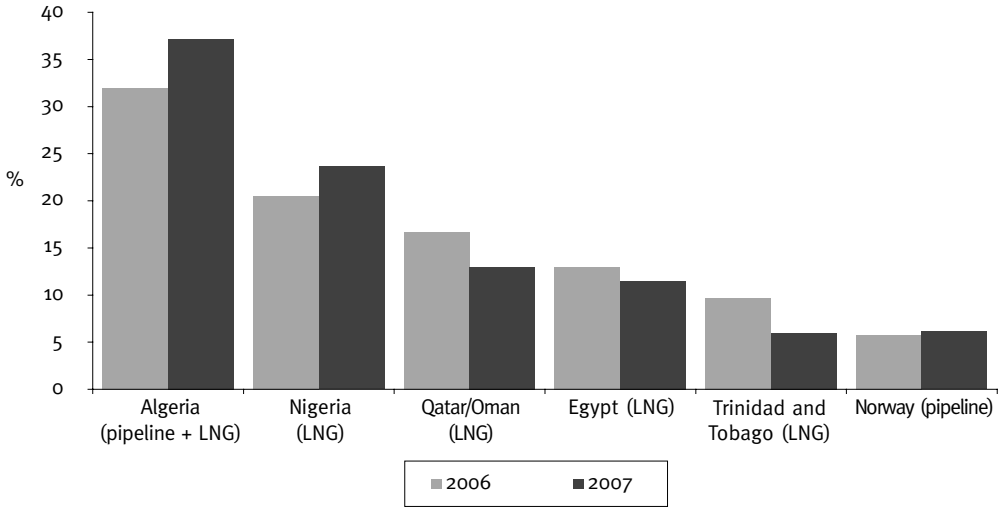
The growth of LNG in Spain has diversified its import mix in recent years. This is because LNG can be transported economically over longer distances than pipeline gas, and therefore has a more global reach. In spite of this trend, Algeria remains the main gas supplier to Spain, with an overall share in excess of 35% in 2007 (including both pipeline gas and LNG), as illustrated in Figure 22. The next four largest exporters (Nigeria, Qatar/Oman, Egypt and Trinidad and Tobago) are, however, all based on LNG exports. The top six exporters account for practically all of Spain imports. Whilst this represents a more diversified import mix than other European countries (some of which are heavily reliant on Russian gas), Spain's gas import flows are still relatively concentrated. However, Spain's reliance on LNG sources gives it more flexibility in its gas procurement relative to countries which rely more on pipeline imports. Import shares varied

between 2006 and 2007, with the most notable changes being the increase in imports from the top two gas exporters (Algeria and Nigeria) and a corresponding reduction in imports from the Gulf and Trinidad and Tobago.

### Domestic gas infrastructure

The key entry points for pipeline gas in Spain are Tarifa (which imports gas from Algeria) and Larrau (importing gas from Norway). There are also currently six LNG terminals in Spain. The relative importance of these entry points in 2006 and 2007 is summarised in Figure 23. The main import infrastructure remains the gas entry point at Tarifa (accounting for a quarter of all imports). The LNG terminal in Barcelona was the largest importer of LNG in 2007, followed by Sagunto, Huelva, Bilbao and Cartagena. Imports to Mugardos were relatively limited due to the fact that this terminal started commercial operations in late 2007.

*Figure 22: Shares of Spanish gas imports by exporting country, 2006-2007*

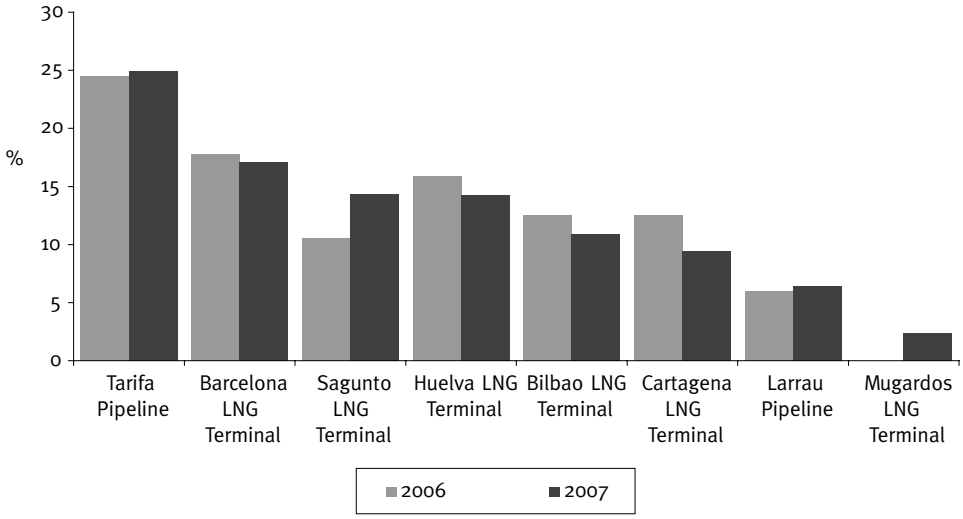



Source: Enagás.

Table 13 summarises some of the key features of the six LNG terminals currently in operation in Spain. The three oldest and largest terminals (in terms of capacity) are those owned by Enagás, the TSO, which also owns the bulk of the transportation network. Enagás's LNG terminals have a lower load factor (i.e. the percentage of capacity that is utilised over the year) than the two independently owned terminals in Bilbao and Sagunto. Three of the incumbent electricity firms (Iberdrola, Endesa and Unión Fenosa) have important stakes in the three independently owned

LNG terminals, reflecting the fact that they are important sources of gas for CCGT generation in the electricity sector. Total LNG regasification capacity stood at roughly 57 bcm by the end of 2007 in Spain. According to European Commission data (published in the Sector Inquiry) this represented more than a third of the total LNG capacity in operation and under construction at the EU25 level at the end of 2006.

*Figure 23: Share of gas flows at LNG and pipeline entry points*




Source: Enagás.

The other important gas infrastructure facilities in Spain are the underground storage sites. There are only two such facilities in Spain, in Gaviota and Serrablo, both of which are managed by Enagás. These have very limited gas storage capacity in relation to the size of the overall Spanish market. Total storage capacity at these sites (including only usable gas) is roughly 27.5 TWh[70], in an overall market in excess of 400 TWh. Inflows and outflows from these sites during 2007 were 9 and 13 TWh, respectively, thus making a limited contribution to providing flexibility to the overall system. LNG terminals and imports play an important complementary role in the provision of flexibility in the market. Storage capacity at the six LNG terminals was approximately 15 TWh by the end of 2007. LNG storage is, however, less effective than underground storage since inflows of gas can only go in one direction (i.e. from the tank to the high-pressure network).

70. CNE, "Informe Marco Sobre la Demanda de Energía Eléctrica y Gas Natural, y su Cobertura, 2007", January 2008.

*Table 13: Spanish LNG terminals*

| LNG Terminal | Owner | Year of commissioning | Output 2007 (TWh) | Capacity 2007 (TWh) | Load factor (%) |
|---|---|---|---|---|---|
| Barcelona | Enagás | 1969 | 70 | 178 | 39% |
| Huelva | Enagás | 1988 | 58 | 147 | 40% |
| Cartagena | Enagás | 1989 | 38 | 131 | 29% |
| Bilbao | Bahía de Bizkaia Gas (25% Iberdrola) | 2003 | 45 | 85 | 53% |
| Sagunto | SAGGAS (42% Unión Fenosa Gas, 30% Iberdrola, 20% Endesa) | 2006 | 59 | 82 | 72% |
| Mugardos | Reganosa (21% Endesa, 21% Unión Fenosa Gas) | 2007 | 9 | 43 | 21% |
| **Total (TWh)** | | | **279** | **666** | **42%** |
| Total (bcm) | | | 24 | 57 | 42% |

Source: Enagás.

The growth of LNG infrastructure and imports in Spain is also contributing to the development of domestic gas trading. In 2007, the volume of gas traded over the counter (OTC) represented close to 110% of total gas consumption (based on data published by the CNE). This percentage increased further in the first months of 2008. Most of these volumes were traded at the six LNG plants. This trading activity is also contributing flexibility to the system. The absence of a transparent gas wholesale price is, however, likely to be limiting the effectiveness of risk management in the gas market.

### Shares of gas imports by firm

Gas Natural remains the main importer of wholesale gas into Spain. Detailed gas import data published by the CNE when it reviewed the Gas Natural/Endesa merger[71] showed that Gas Natural imported 230 TWh of gas into Spain in 2004, equivalent to over 70% of total retail gas demand in Spain at the time. Gas Natural's gas imports included gas supplied to Enagás for the regulated gas market (met through the Maghreb pipeline gas contract), and also gas supplied to other energy retailers (most notably Iberdrola and Bahía de Bizkaia Electricidad) active in

71. CNE, "Informe de la CNE sobre el proyecto de concentración consistente en la adquisición del control de Endesa S.A. por parte de Gas Natural SDG, S.A. mediante oferta pública de adquisicion de acciones", December 2005, p. 137.

the liberalised gas market. The next largest gas importer in 2004 was Iberdrola (with a share of 8.3%), followed by BP (5.7%) and Unión Fenosa Gas (4.2%).

Gas procurement volumes by firm at the same level of detail are not publicly available for more recent years. However, data published by Gas Natural in its 2007 Annual Report indicate that it imported 246 TWh of gas into Spain in 2007, equivalent to 60% of total gas consumption. Of this amount, 33 TWh was for supply to other energy companies for their own retail sales in the liberalised market, and 45 TWh for the regulated market. Whilst Gas Natural's absolute level of gas procurement increased over the 2004-2007 period, its share of the market fell due to the increase in the size of the CCGT market and the fact that some generators (most notably Iberdrola and Unión Fenosa) directly imported gas for their plants. The growth in the gas consumption of Iberdrola's and Unión Fenosa's CCGTs alone can be estimated to represent roughly 50% of the increase in gas sales not accounted for by Gas Natural over this period.

### Wholesale gas prices

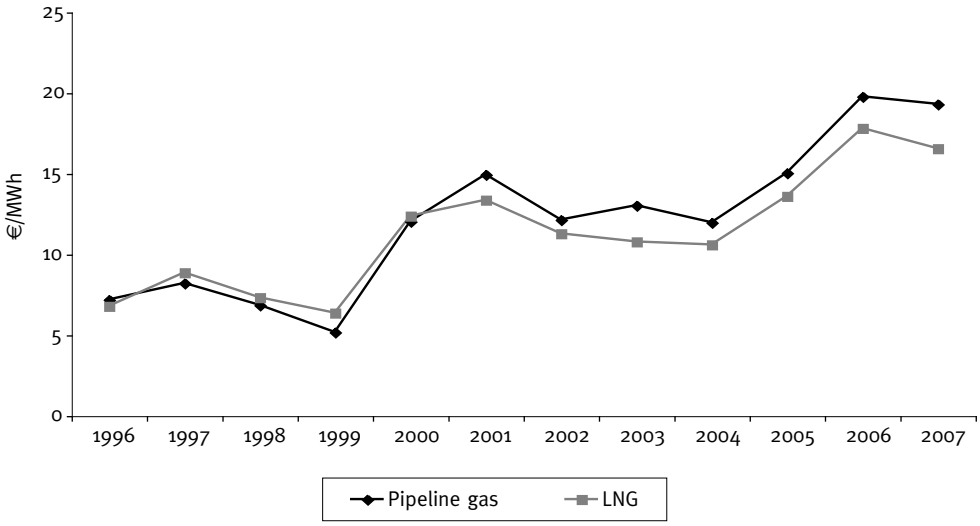
Spain's practically complete dependence on imported gas means that Spanish wholesale gas prices are determined on the international gas market, rather than through the interplay of domestic competitive forces. This exposes Spanish gas consumers to large variations in wholesale gas prices, most of which can be explained by changes in international oil prices (for the reasons set out in Section 3 above). Whilst international gas-to-gas competition may emerge in the future (especially in relation to the LNG market, which is more fragmented), this has yet to happen to a significant extent.

Figure 24 summarises recent trends in Spanish gas import prices, expressed in €/MWh. This trend has closely followed the patterns observed in the international gas market. As the figure shows, LNG import costs have tended to be at a slight discount to pipeline gas costs (at least based on the data reported by the International Energy Agency (IEA)), but the trends over time are very similar.

One of the most noticeable recent trends that can be observed in Figure 24 is the sharp increase in Spanish gas import prices in 2005 and 2006. This was partially reversed during 2007 (due to a lower increase in oil prices during 2006 and the appreciation of the euro), but has resumed even more dramatically during the first half of 2008. Spot gas on major European gas exchanges (the United Kingdom, Belgium and the Netherlands) was trading at above €25/MWh in mid-2008. Future contracts for delivery in the end of 2008 were trading at even higher levels (between €35-€40/MWh) in mid-2008, due to exceptionally high oil prices (which have, however, sharply declined since then).[72] International gas prices directly feed into gas import prices in Spain for both pipeline gas and LNG. As we will discuss in the next sub-section of this report, this has important implications for the electricity sector, given its increasing reliance on gas-fired generation.

72. See CNE, "Informe 24/2008", 25 June 2008.

*Figure 24: Spanish gas import prices (€/MWh)*




Source: OECD/IEA.

New gas infrastructure

A number of new gas infrastructure projects are planned in Spain in the foreseeable future. The main pipeline project is the Medgaz pipeline, which will connect Spain and Algeria. According to the latest information published by the CNE (in August 2008), Medgaz is projected to come into commercial operation in mid-2009, with an initial capacity of 8 bcm (equivalent to close to a quarter of total gas demand in 2007). In spite of the coming on line of Medgaz, the CNE does not forecast a significant increase in the relative reliance on Algerian gas in the future, partially due to the growth of demand and of other sources of imports.[73] According to the CNE's projections, Algerian gas could account for 35% of total demand in 2009, and 37% in 2011 (slightly above the levels observed in 2007).[74]

Additional LNG facilities are also planned over the 2008-2012 period. The most imminent are expansions at the plants in Barcelona, Cartagena and Sagunto, which according to the latest projections prepared by the CNE in May 2008 would increase total system throughput capacity by 850,000 $Nm^3$/hour or 7.4 bcm per year (equivalent to approximately a 13% increase) by the end of 2010. The planned expansion at the Bilbao terminal and new LNG plants at El Musel,

73. See CNE, "Informe marco sobre la demanda de energía eléctrica y gas natural, y su cobertura, 2007", January 2008.
74. Increased reliance on Algerian gas may raise the issue of whether Sonatrach (the Algerian gas producer) should be allowed to enter the Spanish gas retail market, for fear of anti-competitive foreclosure effects. Foreclosure of competitors however appears unlikely to result since a significant part of the market is not supplied by Sonatrach and because – at least initially – Sonatrach would have a very reduced downstream position (which would reduce potential incentives to foreclose rival retail suppliers).

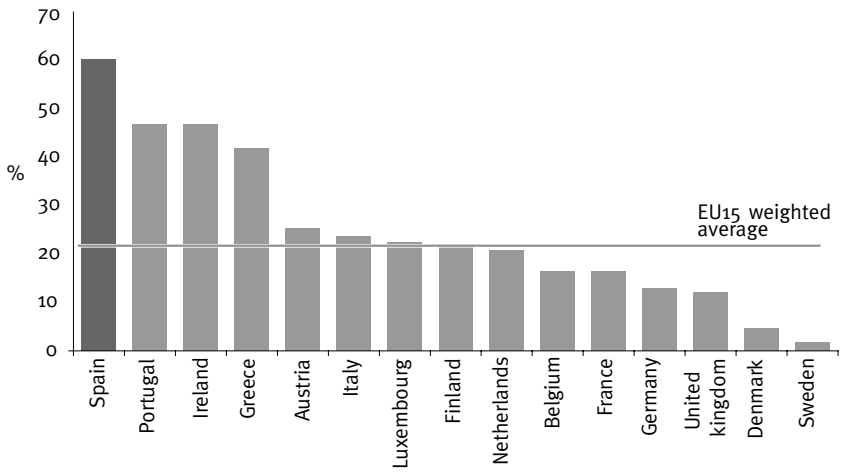
Tenerife and Las Palmas de Gran Canaria could increase total throughput capacity by a further 1,620,000 $Nm^3$/hour or 14.1 bcm per year by the end of 2012 (leading to a cumulative increase in LNG capacity relative to 2007 of close to 40%).

A number of additional gas storage projects are also planned in Spain (including facilities in Marismas, Poseidon, Yela and Castor, and expansion in Gaviota). On aggregate these projects would significantly increase storage capacity in Spain. However, the CNE has recently reported that all of these projects are suffering significant delays and that no additional capacity will be on line before the end of 2010.[75] This represents a critical issue in a system like the Spanish one, which relies entirely on imported gas, and which currently has very limited storage capacity.

## 5.2. Wholesale electricity

This sub-section of the report provides an overview of the key market developments in the Spanish (and Iberian) wholesale electricity market over the 2004-2007 period. We will comment on the evolution of capacity and output mix, on market shares by firm and other indicators of market power, on the evolution of wholesale prices and costs, and on new investments in the sector.

*Figure 25: Growth in electricity consumption, 1997-2006, EU15*



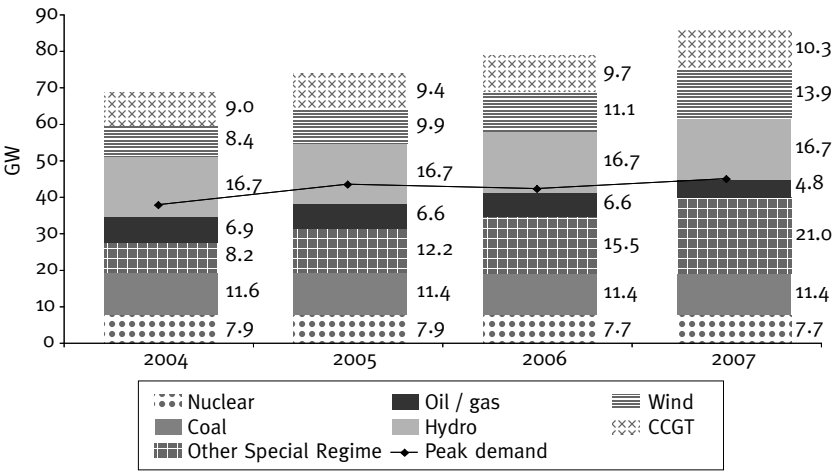

Source: European Commission, Eurostat, 2008.

75. CNE, "Décimo informe semestral de seguimiento de las infraestructuras referidas en el informe marco sobre la demanda de energía eléctrica y de gas natural y su cobertura", May 2008.

### 5.2.1. Demand growth

One of the most notable features of the recent evolution of the Spanish electricity market has been the very high levels of demand growth experienced since the liberalisation of the sector. During the 1997-2006 period, overall electricity consumption in Spain grew by 60%. This is well above the EU15 average growth of 20% and a higher level of growth than in any other country in the EU15 (see Figure 25). Such a high level of growth has required a considerable amount of new generation capacity, as we illustrate below. REE also reports that over the past four years (2004-2007), the cumulative growth of electricity demand in Spain stood at just below 15%, much higher than in other major European countries (e.g. growth in France, Germany and Italy was in the 2%-6% range).

*Figure 26: Installed generation capacity by technology, mainland Spain*




Source: REE.

### 5.2.2. Current capacity and output mix

**Total levels and evolution**

Total installed generation capacity in mainland Spain reached 86 GW by the end of 2007, up from less than 70 GW in 2004. Most of this growth was due to new CCGTs, which increased from 8 GW to 21 GW over this period (an increase of more than 150%), and wind generation (increasing from 8.4 GW to almost 14 GW). This growth was partially offset by the retirement of older and less efficient oil/gas plants (reducing from 7 GW in 2004 to 5 GW in 2007). Figure 26 summarises these trends. The figure also shows the level of peak demand in the system over the relevant period.

Peak demand was roughly 45 GW in 2007, well below installed capacity. However, "reliably available capacity" (as defined by the UCTE in its supply margin assessment[76]) stood at roughly 53 GW (based on UCTE's estimates for January 2008). Net of load and of load management, this yields a level of residual capacity of 10 GW, which is still above the adequacy reserve margin computed by the UCTE of 5.5-7.4 GW.[77]

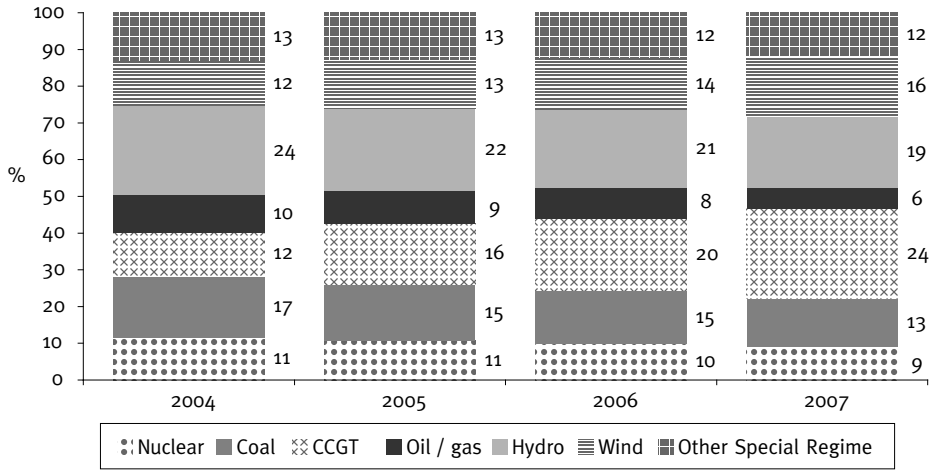
Figure 27 and Figure 28 show the share of installed capacity and output in Spain during the 2004-2007 period. CCGT capacity doubled its share of both capacity and output over this period (from 12% to 24%). In terms of output, CCGT generation was just behind coal in 2007 (accounting for 24% of output versus 26% for coal), but has overtaken it during the first eight months of 2008 (reaching 33% of output over this period). Wind generation in 2007 accounted for 16% of capacity, but only 10% of output (due to its low load factor). The same consideration applies to hydroelectric power and to generation from oil/gas turbines. Nuclear generation still accounts for a significant share of total output in Spain (20% in 2007), even though this share is declining over time, due to the increase in total domestic output.

Overall, special regime generation (including wind, solar, small hydro and co-generation capacity, among others) grew to 28% of total installed capacity by the end of 2007, as a result of the favourable remuneration paid to this type of generation.[78] Whilst most special regime generation is accounted for by wind power, a particularly noticeable increase has recently been seen in the amount of solar generation. Solar capacity increased more than four-fold between 2006 and 2007, and is projected to exceed 1,500 MW of installed capacity by the end of 2008 (well above the objective of 371 MW initially set by the government). This increase has been induced by a generous retribution for this type of energy under Royal Decree 661/2007 (which applied only until the end of September 2008). Remuneration for future solar capacity (e.g. from 2009 onwards) will be reduced by 25% and will be subject to annual quotas.[79]

Without a proper empirical analysis of the positive externalities associated with renewable generation (e.g. in terms of environmental effects, import security, R&D and the international competitiveness of Spanish firms active in this area), it is also hard to evaluate whether the very rapid increase in renewable generation observed in Spain over the past few years has been cost-effective and therefore efficient. In the future there is a need to base the subsidies paid to renewable generation on a more economic assessment of its social benefits in order to avoid under- or over-investment in this type of technology. Market-based mechanisms (e.g. procurement auctions) could also be used to elicit more information on the true costs of generating renewable power.

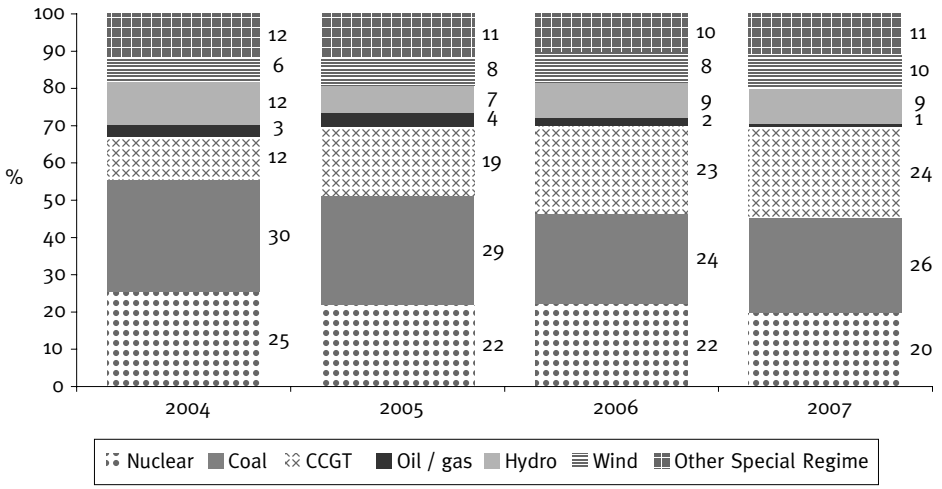
76. This definition adjusts for the actual availability of each type of generation technology.
77. See UCTE, "System Adequacy Forecast Report 2008-2020", January 2008.
78. According to data published by REE in its 2007 annual review of the electricity market, the average cost of special regime generation was close to €80/MWh during the 2003-2007 period, almost 50% above the average wholesale price over the same period.
79. See Royal Decree 1578/2008, approved on 26 September 2008.

*Figure 27: Shares of installed capacity by technology, mainland Spain*




Source: REE.

*Figure 28: Shares of domestic generation output by technology, mainland Spain*

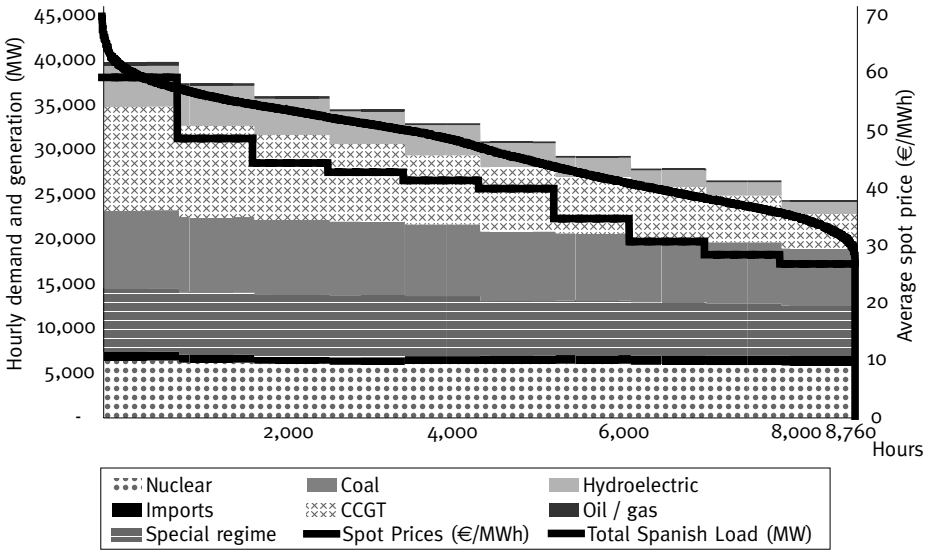



Source: REE.

**Production profile of each generation technology in 2007**

The output profile of each generation technology differs depending on its relative costs and its operational characteristics. This can be illustrated for the Spanish market in 2007 by considering the load duration curve shown below as Figure 29 (this was already included in Section 2 of the report to illustrate the general economics of power markets). This curve shows hourly data on total Spanish demand (or load) in 2007, ranked from the highest to the lowest demand hour of the year. The figure also plots average hourly production levels for each generation technology, at each decile of the load duration curve (from the top 10% of hours to the bottom 10%). Hourly production levels for each generation technology are "stacked" underneath the load duration curve in the approximate merit order prevailing in 2007, starting from the cheapest (and less flexible) source of generation (nuclear and special regime) to the most expensive (older and less efficient oil/gas turbines). Hydroelectric generation is also shown at the top of the duration curve since, to the extent that it can be stored (in reservoirs or through pumped storage facilities), this type of generation will be allocated to the highest demand/price hours of the year. Figure 29 also includes a duration curve for spot prices, showing the average price observed in the day-ahead market at each decile of the load duration curve. As should be expected, overall there was a positive relationship between prices and demand in 2007, reflecting the fact that more expensive generation is required to meet higher demand levels.

*Figure 29: Spanish load duration curve in 2007, and corresponding average production levels and average spot prices*




Source: REE, OMEL, own analysis.
Note: The duration of spot prices shows the average spot price realised in each decile of load (from the top 10% to the lowest 10%).

Figure 29 also shows that nuclear and special regime average generation levels were not positively correlated with demand (even though special regime generation is very volatile around its mean, due to different wind conditions). Coal generation was also fairly flat across the year, whilst most of the "system flexibility" (i.e. the increase in demand that needs to be met from the lowest to the highest demand levels) was provided by CCGT and hydroelectric generation.

This is shown more precisely by the data shown in Table 14, which contains the average hourly generation level of each technology, grouped by decile of demand. Total hourly demand increased by roughly 17 GW from the lowest 10% of hours to the highest 10% during 2007. 45% of this increase was met using CCGT output and an additional 19% using hydroelectric power (both shares are well in excess of the shares of total generation plus imports accounted for by these two technologies). Coal generation was the only other technology to contribute more than 10% of the total system flexibility needs in 2007.

*Table 14: Average generation levels by technology in each demand decile (from highest to lowest), GW, 2007*

| Demand Decile | Hydro-electric | Nuclear | Coal | Oil/Gas | CCGT | Imports | Special Regime | Domestic Demand |
|---|---|---|---|---|---|---|---|---|
| **1st** | 4.6 | 6.4 | 8.8 | 0.4 | 11.6 | 1.0 | 7.1 | 38.4 |
| **2nd** | 4.5 | 6.1 | 8.4 | 0.3 | 10.2 | 0.9 | 7.0 | 35.7 |
| **3rd** | 4.1 | 6.0 | 8.3 | 0.3 | 9.5 | 0.8 | 7.0 | 34.2 |
| **4th** | 3.6 | 5.9 | 8.2 | 0.2 | 8.7 | 0.8 | 7.0 | 32.7 |
| **5th** | 3.4 | 6.0 | 8.0 | 0.2 | 7.7 | 0.9 | 6.7 | 31.2 |
| **6th** | 2.7 | 6.0 | 7.8 | 0.2 | 7.2 | 0.9 | 6.1 | 29.0 |
| **7th** | 2.1 | 6.0 | 7.5 | 0.2 | 6.3 | 1.0 | 6.1 | 26.9 |
| **8th** | 1.9 | 5.9 | 7.1 | 0.2 | 5.7 | 1.0 | 6.0 | 25.2 |
| **9th** | 1.5 | 5.9 | 6.8 | 0.2 | 5.2 | 1.0 | 5.9 | 23.6 |
| **10th** | 1.4 | 5.8 | 6.4 | 0.2 | 3.9 | 1.1 | 5.6 | 21.3 |
| Difference between 1st and 10th decile ("flexibility") | 3.2 | 0.6 | 2.4 | 0.3 | 7.7 | -0.1 | 1.4 | 17.2 |
| % system flexibility | 19% | 3% | 14% | 2% | 45% | -1% | 8% | 100% |
| % total net generation + imports | 9% | 19% | 24% | 1% | 24% | 3% | 20% | |

Source: REE, own calculations.

5.2.3. Generation capacity and output by firm

Table 15 and Table 16 set out the position of the main firms in the Spanish mainland market in terms of total installed capacity and generation output in 2007 (based on data from the transmission system operator REE and from the companies' own reporting). Iberdrola was the largest firm in terms of installed capacity, with 26 GW of installed capacity. More than half of this capacity is accounted for by hydroelectric capacity (9 GW) and CCGT (close to 6 GW). Endesa was the second generating company in terms of capacity, with close to 22 GW (and considerably less hydro and CCGT than Iberdrola, but with more coal capacity). Unión Fenosa was the clear number 3 player in the Spanish market (with over 9 GW of capacity), followed by EDP/HC and Gas Natural, with roughly 4 GW each. Independent generators accounted for over 18 GW of capacity – primarily special regime (over 14 GW) but also with an important element of CCGT (4 GW).

*Table 15: Installed generation capacity by firm and technology at the end of 2007, mainland Spain, ordinary and special regime generation (GW)*

| | Iberdrola | Endesa | Unión Fenosa | EDP/HC | Gas Natural | Viesgo | Others | Total |
|---|---|---|---|---|---|---|---|---|
| Coal | 1.2 | 5.6 | 2.1 | 1.5 | | 0.9 | | **11.4** |
| Oil/gas | 1.8 | 1.9 | 0.8 | | | | 0.3 | **4.8** |
| CCGT | 5.6 | 2.4 | 3.5 | 0.8 | 3.7 | 0.8 | 4.1 | **21.0** |
| Nuclear | 3.3 | 3.6 | 0.6 | 0.2 | | | | **7.7** |
| Hydro | 8.8 | 5.4 | 1.8 | 0.4 | | 0.7 | | **17.1** |
| Special regime | 4.9 | 2.9 | 0.4 | 1.4 | 0.4 | | 14.2 | **24.2** |
| **TOTAL** | **25.8** | **21.7** | **9.2** | **4.3** | **4.0** | **2.4** | **18.6** | **86.2** |
| Market share | 30% | 25% | 11% | 5% | 5% | 3% | 22% | 100% |

Source: REE, companies' websites, own estimates.
Note: Excludes the effects of the Enel/Acciona/Endesa operation, which took place in 2008.

In terms of output, the relative rankings in the market differ, since Endesa was clearly the largest generator, with 82 TWh in 2007. This is due to the relatively high load factor achieved by its coal plants and the low load factor of Iberdrola's hydroelectric capacity. Iberdrola produced 68 TWh in 2007, followed by Unión Fenosa with 36 TWh, and EDP/HC and Gas Natural with roughly 17.5 TWh each.

*Table 16: Generation output by firm and technology at the end of 2007, mainland Spain, ordinary and special regime generation (TWh)*

| | Iberdrola | Endesa | Unión Fenosa | EDP/HC | Gas Natural | Viesgo | Others | Total |
|---|---|---|---|---|---|---|---|---|
| Coal | 7.1 | 36.6 | 12.9 | 10.8 | | 4.5 | | **71.8** |
| Oil/gas | 0.3 | 0.4 | 0.3 | | | | 1.4 | **2.4** |
| CCGT | 13.8 | 8.5 | 14.3 | 2.0 | 16.5 | 0.0 | 13.1 | **68.1** |
| Nuclear | 23.2 | 25.8 | 4.7 | 1.3 | | | | **55.1** |
| Hydro | 14.0 | 7.1 | 3.0 | 0.8 | | 1.0 | | **26.0** |
| Special regime | 9.4 | 3.8 | 1.0 | 2.7 | 0.8 | | 38.6 | **56.3** |
| **TOTAL** | **67.8** | **82.3** | **36.1** | **17.6** | **17.4** | **5.5** | **53.0** | **279.8** |
| Market share | 24% | 29% | 13% | 6% | 6% | 2% | 19% | 100% |

Source: REE, companies' websites, own estimates.
Note: Excludes the effects of the Enel/Acciona/Endesa operation, which took place in 2008. Data refer to gross generation (i.e. generators' own consumption and pumped storage demand are not netted out).

The figures presented above do not take into account the transfer of assets from Endesa to E.On/Viesgo which was implemented in mid-2008 as a result of the agreement between Enel, Acciona and E.On/Viesgo. This transfer could reduce Endesa's conventional generation capacity by up to 1.4 GW[80] and its conventional output in 2007 by approximately 10 TWh (considerably narrowing the differential with Iberdrola in output terms). E.On/Viesgo would remain the sixth player in the Spanish market following the asset transfer, but would be very close to both EDP/HC and Gas Natural in terms of capacity and output. The proposed merger between Gas Natural and Unión Fenosa would further affect these figures.

### 5.2.4. Indicators of competition in the wholesale electricity market

In what follows we will provide an overview of the performance of some of the standard indicators that are typically used in wholesale electricity markets to offer an initial indication of the degree of competition in a market and of the potential for market power. Such indicators can be computed according to a number of different hypothetical product and geographic market definitions. In our analysis of market shares and concentration indicators we consider four possible market definitions:

**a "wide" market definition,** which includes all generation in the Iberian Peninsula and all types of generation plants (both ordinary generation and special regime generation);

80. However, including Acciona's renewable assets in Endesa's portfolio more than offsets this reduction in terms of overall capacity (i.e. capacity including special regime).

**a "narrow" market definition,** which excludes Portugal and special regime generation; and

**two intermediate definitions,** which add either Portuguese output or special regime generation to the narrow market definition.

Given the characteristics of special regime generation (illustrated above) and the current level of congestion with Portugal (which we will review below), the narrow market definition that only looks at conventional generation in Spain is arguably more appropriate to understand competitive conditions in the Spanish generation market than the alternative (and wider) definitions.[81] In particular, excluding special regime generation may be appropriate for an analysis of market power since this technology is not flexible (i.e. it cannot respond to an increase in wholesale prices and it cannot be withheld from the market), does not participate in price setting to a significant extent and is currently relatively unconcentrated. Including it in the market definition would therefore overstate the competitive constraint faced by larger players with price-setting capacity. This approach is broadly consistent with the analysis undertaken by the CNE in its analysis of the Gas Natural/Endesa merger (in December 2005), where concentration indicators were constructed with respect to "flexible capacity". This was defined as total capacity net of special regime, nuclear and run-of-river hydro.[82]

However, it is important to bear in mind that non-flexible generation can affect the conduct of generators that also own flexible generation, since it contributes to the size of any infra-marginal gains made by these generators as a result of an increase in prices. A detailed simulation model of the market would be required to account for this effect (for a discussion of these models, see Box 1). In the absence of a simulation, it is difficult to fully capture this effect by relying only on concentration indicators, which are inevitably imperfect proxies of the competition conditions in the market.

As we will show below, excluding Portugal from the relevant geographic market definition also appears appropriate based on 2007 data, given the high levels of congestion of the interconnection capacity between Portugal and Spain and the fact that Portuguese wholesale electricity prices have been significantly above Spanish prices.

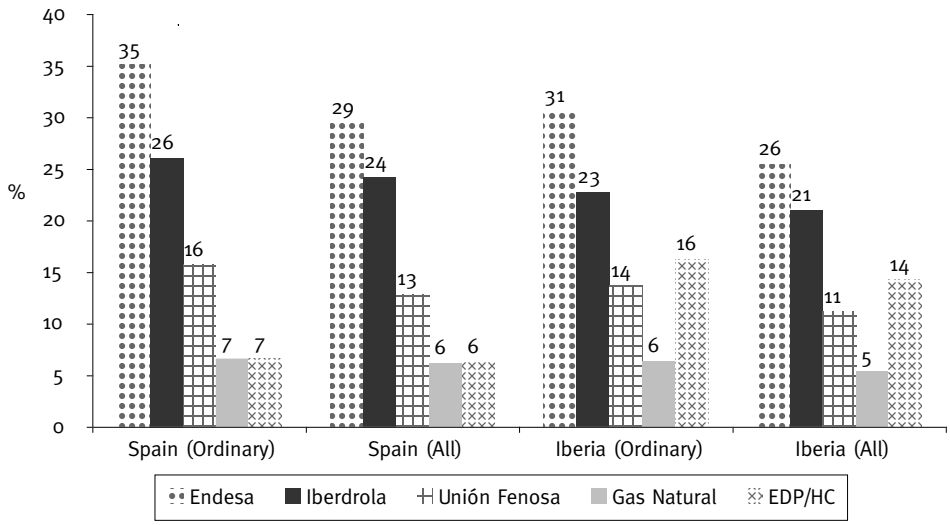
### Output shares and C2 indicators

Figure 30 shows generation output shares for the top five firms in the Spanish generation market in 2007 under the four definitions of the market discussed above. The shares of the top two firms

81. In some hours, even narrower geographical market definitions may be considered if the domestic transmission network is congested.
82. The OECD's review of competition issues in the electricity sector (see OECD (2005)) also supports this definition of the relevant market in electricity generation. For simplicity, we do not remove nuclear and run-of-river hydro from the "narrow" market definition that we consider. This also follows convention in Spain, which has tended to look at market shares in terms of ordinary capacity in the past. It is also practical since precise data on run-of-river hydro by firm is not publicly available. Moreover, the fact that the ownership of nuclear and run-of-river hydro is relatively concentrated implies that including these sources of generation in the HHI is likely to provide a more realistic depiction of the potential for market power (since it captures the incentives resulting from the ownership of greater infra-marginal output on firms that also control price-setting capacity).

(Endesa and Iberdrola) are highest under the narrowest definition ("Spain (Ordinary)") and lowest under the widest definition ("Iberia (All)"). The market leader in output terms (Endesa) had a share of 35% in 2007 under the narrow definition – this drops to 26% under the wide definition. Accounting for the transfer of assets to E.On/Viesgo could lower Endesa's share under the "Spain (Ordinary)" definition of the market to 31% (using 2007 output data). As the data illustrates EDP/HC's position grows considerably under an Iberian market definition, given its significant presence in Portugal. In an Iberian market, EDP/HC becomes the third generator, ahead of both Unión Fenosa and Gas Natural.

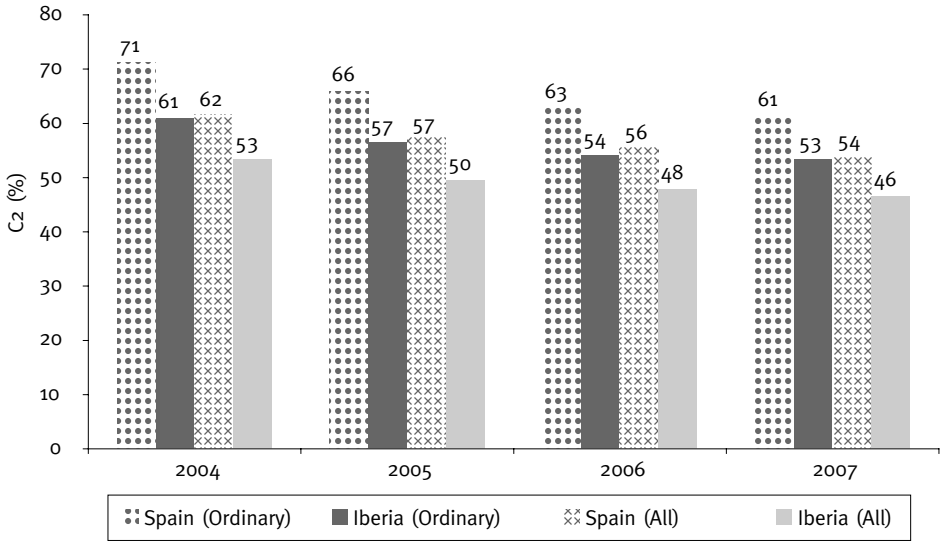
*Figure 30: Output shares by firm, 2007*




Source: REE, REN, companies' websites, own calculations.

Figure 31 shows the combined market share of the top two firms in the market (the C2 indicator) over the past four years. Even under the narrow market definition (including only ordinary capacity in Spain), the combined share of Endesa and Iberdrola dropped from 71% to 61% between 2004 and 2007 (and from 80% in the late 1990s). The main driver for this decline in the C2 share was the entry of CCGT plants not owned by the two main incumbents – notably those of Unión Fenosa (that has gained 3.4 percentage points in terms of its conventional output share since 2004), Gas Natural (which has experienced a gain of 4.6 percentage points since 2004) and independents (which have grown by 3.3 percentage points since 2004). Endesa and Iberdrola, however, still control a significant share of total conventional generation in Spain.

*Figure 31: C2 indicators, generation output*




Source: REE, REN, companies' websites, own calculations.

**HHI levels**

The extent of concentration of the Spanish generation market can also be illustrated by considering the HHI (which is a measure given by the sum of the squares of the market share of each participant). Standard thresholds used by competition authorities (e.g. the European Commission, the U.K. Office of Fair Trading and the U.S. Department of Justice) refer to HHI values of 1,800-2,000 to indicate a highly concentrated market. As Figure 32 shows, the HHI for 2007 remained above 2,000 under the narrowest definition of the market ("Spain (Ordinary)"), but was below 2,000 under the other three market definitions. The HHIs in terms of capacity were higher in 2007 (e.g. 2,340 in the Spanish market for ordinary generation). HHI levels for ordinary generation remained above 2,000 even accounting for the transfer of assets from Endesa to E.On/Viesgo, both in terms of output and capacity.

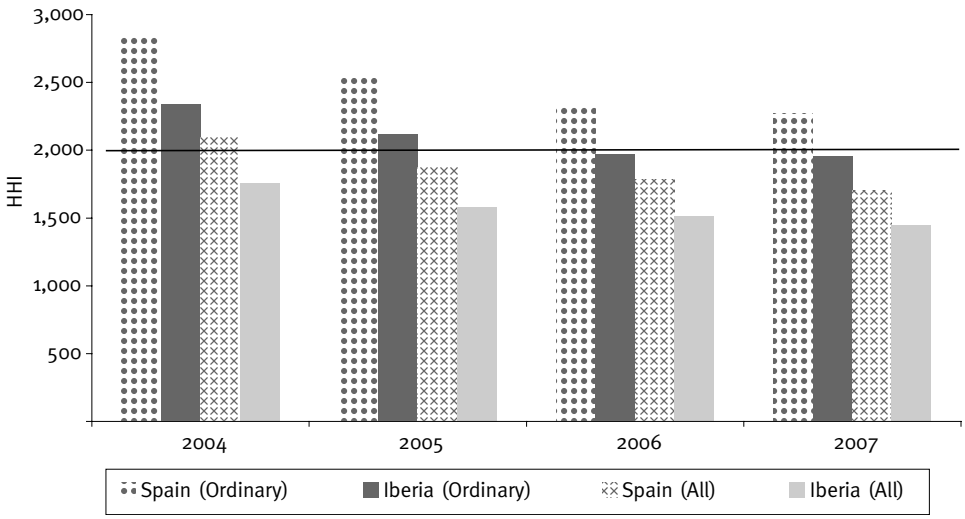
However, HHI measures have fallen considerably in the last four years, primarily as a result of the decline of the combined share of the two main generators and the corresponding growth of smaller players using CCGT generation. As a result of CCGT entry, the HHI for CCGT output was in 2007 considerably lower than the HHI of total ordinary output (1,600 for CCGT vs. 2,270 overall), and the two main firms in this segment were actually Unión Fenosa and Gas Natural (i.e. not the largest firms overall). This has been a helpful development, given that CCGTs are a relatively strategic asset in the market (together with hydroelectric generation), as shown by their

contribution to total system flexibility, and their role in setting market prices. An increased level of competition at the margin can be expected to have constrained the market power of the main generators by making the residual demand that they face more elastic.[83]

**Analysis of generator "pivotality"**

The analysis of pivotality in generation markets is sometimes employed as a complementary measure of market power, in addition to more traditional structural indicators such as the HHI. This approach considers the extent to which the largest firms in the market are *pivotal*, i.e. they are actually required to meet a given level of demand once one subtracts the available capacity of all other generators. Pivotality therefore means that a generator faces a very inelastic residual demand (defined as total demand minus residual supply) in some hours of the year. Section 2 of this report provides a more extensive review of market power indicators (including measures of pivotality) in generation markets.

*Figure 32: HHI levels in the generation market, output terms*




Source: REE, REN, companies' websites, own calculations.

83. Some commentators have argued that concentration in the marginal (or price-setting) segment of the overall industry supply curve is important to understand overall market outcomes. For example, Newbery uses the HHI of coal-fired generation to illustrate the presence of market power in the British market in the 1990s, when coal plants were frequently price-setting (see Newbery (2005)). The OECD (2005) also presents an analysis that shows that competition between marginal units can have a significant impact on market prices. Market shares of price-setting units are also typically used in generation markets to indicate the potential for market power (e.g. the U.K. regulator used to report this measure prior to the abolition of the Pool, and the Italian market operator currently uses this indicator).

However, it is important to bear in mind that pivotality is not a *sufficient* condition for the exercise of market power by a generator, since it may still not be optimal for a firm to withhold the amount of generation required to reach the inelastic part of its residual demand curve. Moreover, it is also not a *necessary* condition for the presence of market power, since a generator may still find it profitable to increase its bids above costs even when its demand is not totally inelastic.

Box 4 illustrates the results of a pivotality analysis performed for both Endesa and Iberdrola in 2006 and 2007, using hourly demand and generation data for Spain. The analysis shows that pivotality levels were relatively high in 2006. This is particularly the case for Iberdrola, which was pivotal for close to 10% of total hours of that year. The corresponding level for Endesa was lower (6.4%) due to its lower overall levels of generation capacity. Pivotality levels, however, dropped considerably in 2007 to 1.5% for Iberdrola and 1% for Endesa.

The reduction in pivotality is consistent with the decline in the C2 and HHI measures summarised above. It does not mean, however, that market power was necessarily absent from the Spanish generation market in 2007. Endesa and Iberdrola in particular would still face a fairly inelastic residual demand also in hours in which they are not pivotal. This can be shown, for example, by reference to the RSI, which represents an alternative indicator of market power in generation markets. The RSI measures the ratio of the residual supply faced by a firm and total demand in an individual hour. A RSI of below 1 therefore indicates that a firm is pivotal, that is, the capacity available to other generators is not sufficient to meet total demand. Low levels of the RSI (e.g. a threshold level for the RSI of 1.1 has been suggested by some commentators) are still consistent with the presence of significant market power (see discussion in Section 2). In 2007 the RSI of each firm remained low (i.e. below 1.1) for a fairly high number of hours (9% in the case of Endesa, 11.5% in the case of Iberdrola).

Moreover, Endesa and Iberdrola were still jointly pivotal for most hours in 2007 (i.e. their combined residual demand was very inelastic). Standard models of oligopoly interaction (e.g. the Cournot model and also other simulation models – see Box 1) indicate that firms can achieve prices above cost when they jointly face an inelastic demand even in the absence of any form of coordinated pricing.[84]

### 5.2.5. Prices

This sub-section of the report summarises the evidence on wholesale electricity prices in Spain over the 2004–2007 period (for a longer overview of price developments, see Section 4).

Figure 34 shows the level of final prices in the market, by component. As commented above, prices reached high levels in 2005 and 2006 as a result of high fuel costs and fairly dry hy-

84. This does not mean that there is an abuse of market power or that prices are "excessive" from the point of view of competition law.

**Box 4: Pivotality analysis for Endesa and Iberdrola, 2006-2007**

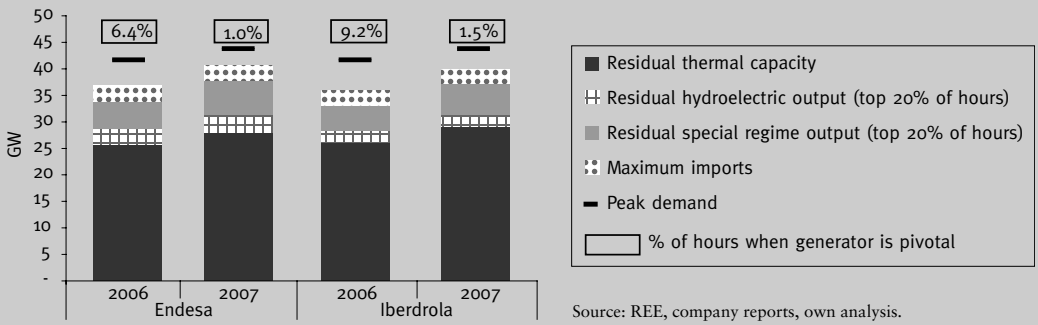
The way to compute a pivotality indicator for a firm in a given time period (e.g. a year) is to calculate the maximum capacity not controlled by that firm (i.e. residual supply) and then compare it to aggregate demand in each hour of that time period. If one assumes that demand is perfectly price-inelastic, then a firm is pivotal whenever aggregate demand exceeds the residual supply it faces (i.e. its residual demand is positive at all price levels). The number of hours in which demand exceeds the capacity of a firm's rivals therefore determines the number of hours in which that firm can be considered pivotal.

Figure 33 plots the results of a pivotality analysis for both Endesa and Iberdrola for 2006 and 2007, using hourly generation and demand data for both years. The analysis computes the residual supply faced by each firm (i.e. the amount of total capacity that they do not control) by breaking it into four sub-components: residual thermal capacity, residual hydroelectric generation, residual special regime generation, and imports.

- The residual thermal capacity faced by each firm is computed as its rivals' total installed thermal capacity times the average availability factor for each thermal technology in each year.
- In the case of hydroelectric and special regime generation, the volumes available to each firm's rivals are computed as the actual average output of these technologies in the top 20% of hours of each year (ranked in terms of overall demand), net of the share of these technologies controlled by the firm. This captures the average amount of hydro and special regime actually available in peak demand conditions (when a generator may be pivotal).
- The maximum hourly import flows in each year are also added to the levels of residual capacity faced by each firm (this is a conservative assumption, given that Spain was a net exporter during this period).

Maximum (or peak) demand in each year is also shown in Figure 33 as a reference. The fact that maximum demand was always above residual supply for the four cases considered in the figure shows that both Endesa and Iberdrola were pivotal for at least one hour (i.e. the peak demand hour) in both 2006 and 2007. The box above each bar also indicates the total number of hours in each year in which aggregate demand exceeded the residual supply faced by each firm (expressed as a percentage of the total number of hours in the year). This percentage represents the PSI for each firm in each year.

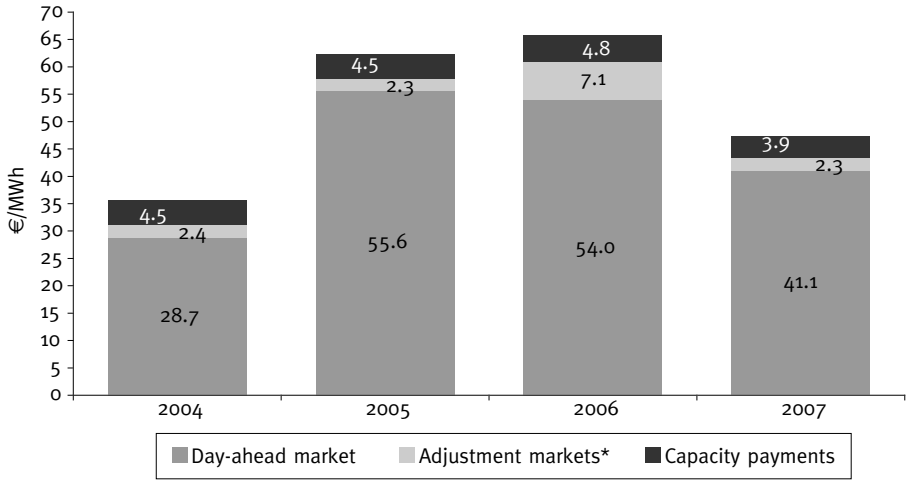
*Figure 33: Pivotality analysis for Endesa and Iberdrola in 2006 and 2007 (Spanish market)*




Source: REE, company reports, own analysis.

droelectric conditions (especially in 2005). Wholesale prices almost doubled between 2004 and 2005, and remained at above €60/MWh in 2006. The other notable price development in 2006 was the high cost associated with balancing, ancillary and congestion management services. This trebled between 2006 and 2007 as a result of the large shift of volumes to these markets which took place following Iberdrola's response to the government fixing the price of matching upstream and downstream positions in the electricity spot market in RDL 3/2006 (see Section 4 above). Electricity prices dropped considerably in 2007, due to lower fuel prices (especially the price for carbon emissions, which dropped to zero as a result of the excess in free allowances, and the lack of bankability across phases in the ETS). However, prices towards the end of 2007 increased again due to higher oil, gas and coal prices, and relatively low levels of hydroelectric output. This upwards trend in wholesale prices continued into 2008.

*Figure 34: Annual wholesale electricity prices in Spain, 2004-2007*

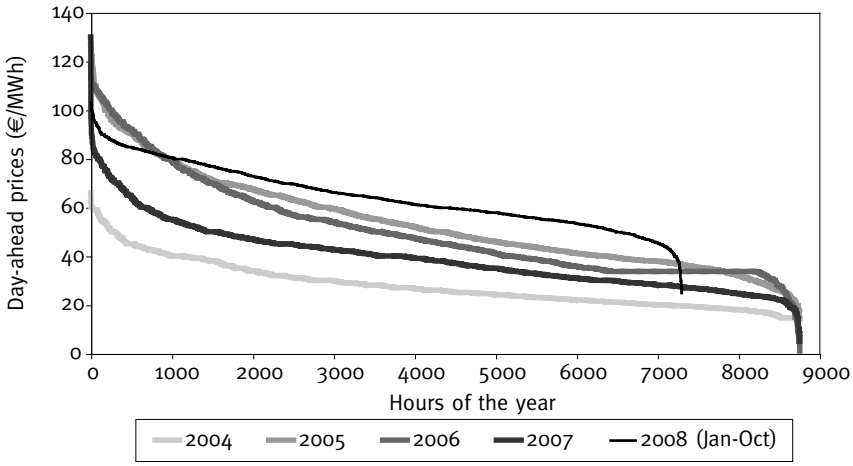



Source: REE.
* Adjustment markets include intra-day, congestion and balancing markets, and also the cost of imports from France managed by REE in some years.

Figure 35 shows the duration curves for day-ahead prices in the Spanish market during the 2004-2007 period and also includes a series for the first 10 months of 2008. Duration curves plot prices for all 8,760 hours of each year, ranking them from the highest-priced hour to the lowest. The price point corresponding to hour 1 in each year therefore represents the maximum price that was realised in that year. Similarly, the price corresponding to hour 1,000 in each year represents the 1000$^{th}$ highest price observed in that year.

The duration curves show that prices in 2005 and 2006 were higher than in 2004 and 2007 across the entire duration (i.e. even in baseload hours), and were also slightly peakier. In 2007 a parallel shift downwards in the duration curve was observed. Prices for the first 10 months of 2008 were close on average to the highest annual prices in both 2005 and 2006. The average final price during the January-October 2008 period was of €69/MWh, slightly above the level of the equivalent period in 2006.

*Figure 35: Price duration curves, day-ahead prices, January 2004 – October 2008.*




Source: OMEL.

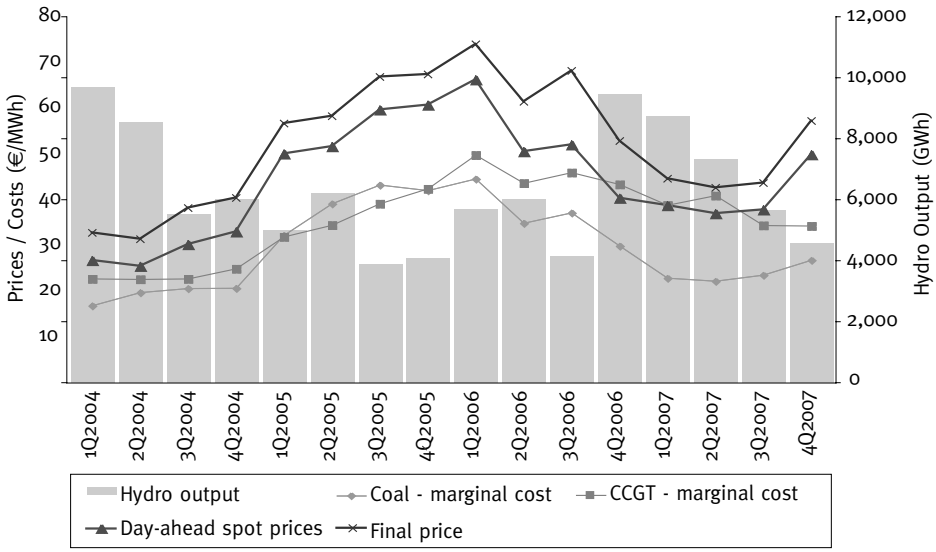
Finally, Figure 36 presents a quarterly analysis of wholesale prices, comparing it to the trends in estimated fuel costs for coal and CCGT plants (including $CO_2$ emission costs), and in total hydroelectric output. This chart shows a broad correlation between prices and costs, with fuel costs increasing sharply between the end of 2004 and the end of 2006, and hydroelectric output also being fairly low until the third quarter of 2006. Day-ahead prices also dropped sharply in the second quarter of 2006 after the imposition of the measure on "matching" trades in the wholesale market (RDL 3/2006). However, final prices increased again in the third quarter of 2006, as volumes shifted out of the day-ahead market as a result of this intervention. As stated above, prices dropped sharply in 2007 as a result of lower fuel costs (especially for coal, including $CO_2$) and more hydroelectric energy. The steep increase in prices in late 2007 can be partially explained by the rise in crude oil prices in the second half of 2007 (prices rose by 20% in euro terms compared to the first half of 2007), which had a significant impact on European spot gas

prices at the end of 2007 (and into the first half of 2008).[85] Similarly, coal prices increased by close to 50% between September 2007 and early 2008.[86]

### 5.2.6. Price-setting trends

An important indicator to understand the nature of competition in generation markets is given by the identity of price-setting units and other plants that are near the margin. This is because competition at the margin will determine the elasticity of residual demand faced by each firm and will therefore affect their pricing incentives.

*Figure 36: Quarterly evolution of prices, fuel costs for coal and CCGT plants, and hydroelectric output*




Source: OMEL (prices), REE (hydroelectric output), IEA (imported coal and gas costs), Datastream ($CO_2$ prices).
Note: Assumes notional thermal efficiencies of 36% for coal technology and 52% for CCGT. Coal and CCGT fuel costs include the cost of $CO_2$ emission permits.

Figure 37 plots the percentage of hours in which each major technology set the price in the Spanish day-ahead electricity market. The most notable trend in recent years has been the growth of CCGTs as the price-setting technology in Spain. This partially reflects the growth of CCGTs in

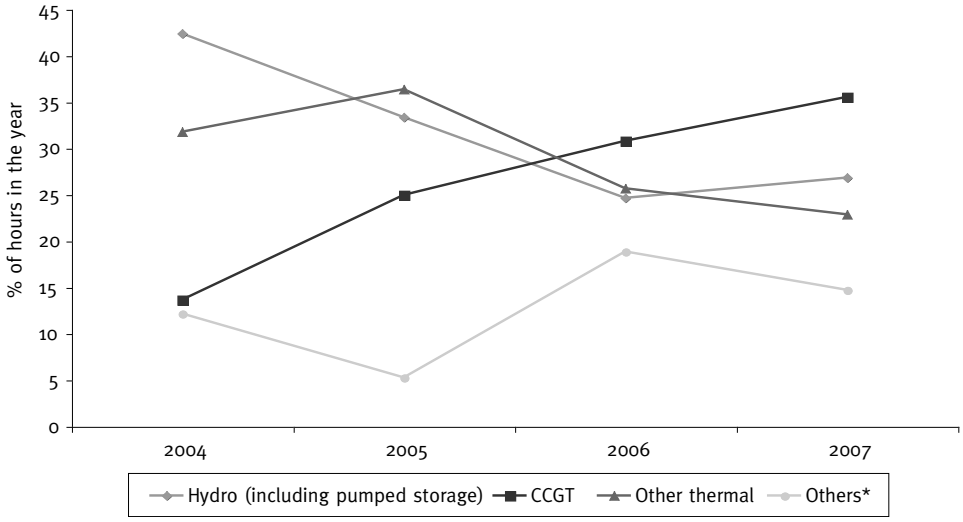
85. The increase in spot gas prices does not appear to be fully reflected in the IEA series for LNG import prices used in Figure 36, which only shows a moderate increase at the end of 2007. Nonetheless, it may have affected the marginal cost faced by some CCGTs in Spain.
86. See CNE, "Propuesta de revisión de la tarifa eléctrica a partir del 1 de Julio de 2008", May 2008.

total generation output. The fact that CCGTs' share of price setting is well above their share of output (e.g. 36% vs. 24% in 2007) shows that this technology is particularly marginal in the market (and can therefore confer a degree of market power to owners of this technology).

Hydroelectric energy also remains a very important source of marginal energy, setting the price during 27% of hours in 2007 according to OMEL data. However, bidding behaviour by CCGT and other thermal plants also affects the prices determined when bids by hydroelectric plants are notionally setting the market price (i.e. they are the last bid to be accepted by the market operator). This is because the opportunity cost of using a given amount of reservoir hydroelectric energy over a period of time is effectively determined by the cost of the thermal plant that it is displacing when it chooses in which hours to produce. Competition between CCGTs and other thermal plants will therefore also affect the spot price in those hours when hydroelectric units are setting the price.

The trend shown in Figure 37 has continued into 2008, with CCGTs setting the price 46% of the time in the January-August period (above its share of output during this period of 33%) and hydro setting it 27% (much above its overall output share of 8%). By contrast, special regime generation only set the price 2% of the time during the first eight months of 2008, in spite of accounting for 23% of output.

*Figure 37: Percentage of time in which each technology sets the price*




Source: OMEL.
* Others include special regime generation, imports and demand-side bidders.

Additional data published by OMEL since July 2007 also show that CCGT energy accounts for the clear majority of the total energy that is offered and accepted at a bid that is close (i.e. within 5%) to the system marginal price. These data indicate that during the second half of 2007 and the first half of 2008, CCGTs accounted for two thirds of the energy offered and accepted at 95% or more of the marginal price in each hour.

Whilst the role played by CCGTs in setting and affecting the electricity system marginal price is good for competition in the generation market (since this section of the merit order is not highly concentrated at present), it also makes the electricity market more directly exposed to the international wholesale gas market and in turn to the oil market. The strategic role played by CCGT plants therefore raises even further the importance of the role played by issues of energy security and diversification in the effective functioning of the electricity market in Spain.[87]

### 5.2.7. Energy trading by market

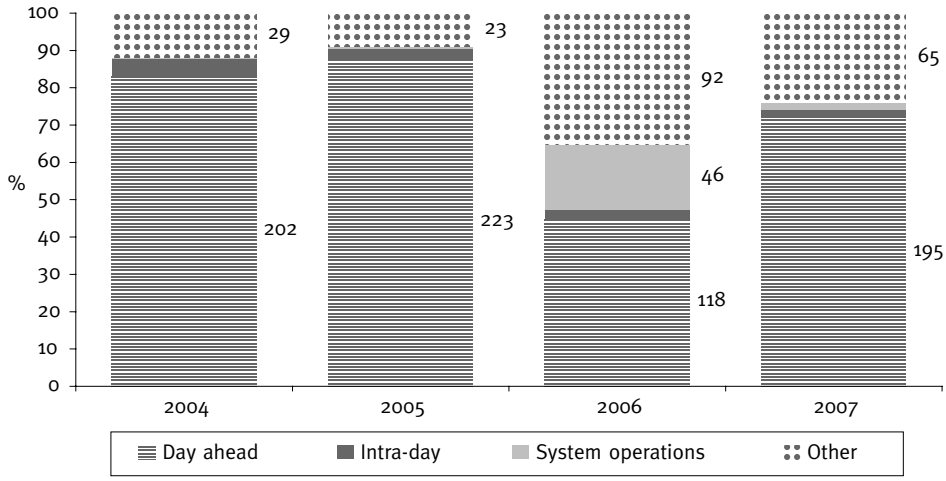
The Spanish electricity market has traditionally been characterised by the key role played by the day-ahead spot market and by the correspondingly low shares of bilateral trades. Recent trends in shares of trading by market are shown in Figure 38. In 2004 and 2005 the day-ahead market accounted for 80%-90% of total demand in the market. This, however, changed drastically in 2006, when the government effectively removed significant volumes from the day-ahead market and "converted" them into bilateral contracts through RDL 3/2006 (see the discussion of this measure in Section 4). The shares of total volumes effectively traded in 2006 dropped to below 50%, whilst both bilateral trading (shown as the residual "Other" in the figure) and system operations (e.g. primarily balancing and congestion management) increased very significantly. The predominant role of the day-ahead market was partially restored in 2007 as a result of the abolition of the measure on bilateral contracting in March 2007. However, the creation of the CESUR auctions is also likely to have diverted some volumes away from the day-ahead market, during the second half of 2007. The share of volumes not physically transacted in the spot market is set to increase in 2008 since CESUR auctions will apply to the entire year.

### 5.2.8. Interconnection and MIBEL

Interconnection between the Iberian Peninsula and other electricity systems (most notably France and Portugal) remains limited. Average import capacity from France was only slightly above 1,000 MW in 2007, which is less than 3% of peak demand. Imports from France amounted to 5.5 TWh in 2007 (and were at roughly similar levels in preceding years), equivalent to 2% of electricity demand. Overall, however, Spain was an electricity exporting country in the 2004-2007 period, primarily due to the considerable level of exports to Portugal. These reached a level of 7.5 TWh in 2007, equivalent to 15% of total demand in Portugal. Recent trends in net export flows from Spain are summarised in Figure 39.

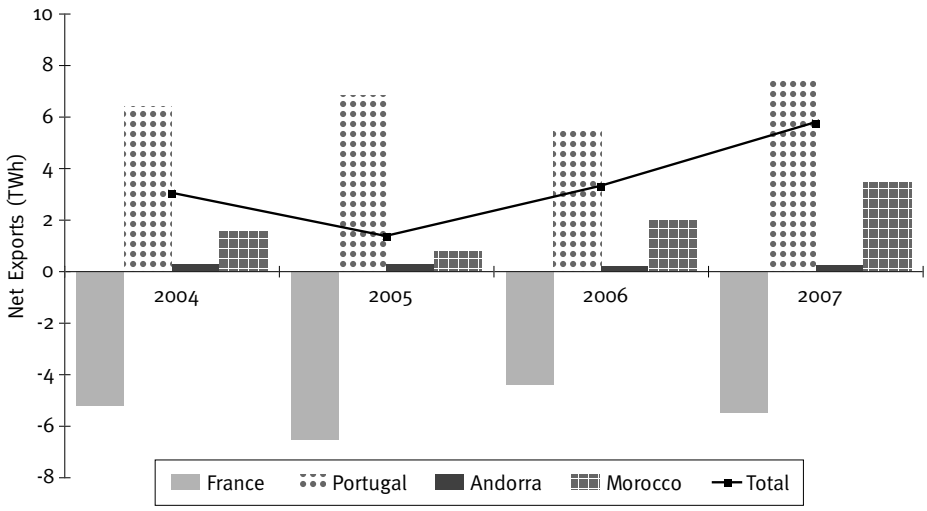
87. Moreover, as recently argued by Newbery (2008), the ETS may amplify the effects of gas prices on electricity prices (through the price of $CO_2$) and may also enhance the market power of gas suppliers.

*Figure 38: Energy volumes (TWh) and shares of total demand in each electricity wholesale market, 2004-2007*




Source: REE, OMEL, own calculations.

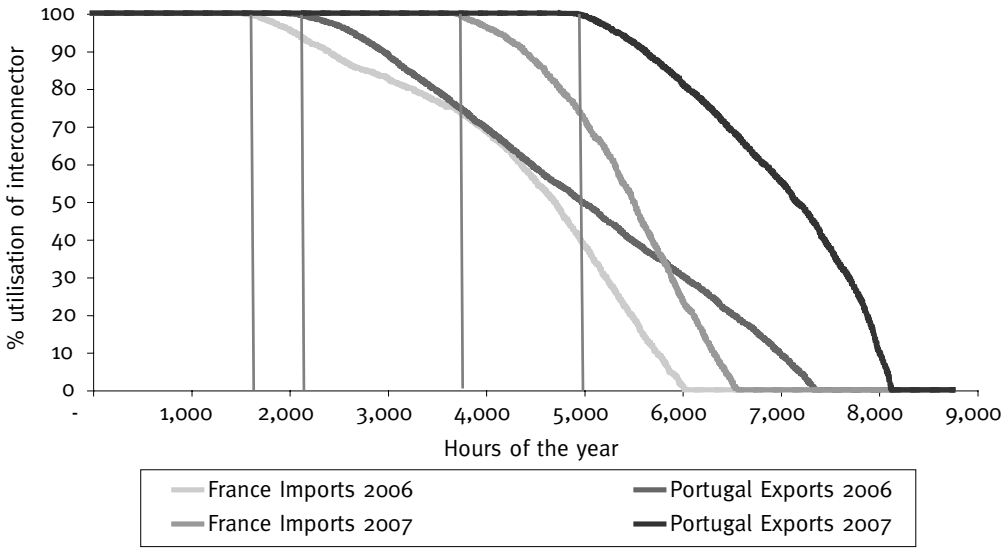
*Figure 39: Net import/export flows from/to Spain, 2004-2007*




Source: REE.

Due to the relatively limited size of the interconnection links and the asymmetries between the technology mix, the interconnectors between Spain and both France and Portugal were often congested during 2007. This was particularly the case for Portugal, where the interconnector was fully congested for roughly 5,000 hours in 2007 (i.e. close to 60% of the time).[88] The average export utilisation of the interconnector with Portugal stood at 80% in 2007 (up from 57% in 2006). The interconnector with France was less congested (40% of the time) and had an average import utilisation of 62%. The duration curves of utilisation on the Portuguese and French interconnectors (in export and import mode, respectively) are illustrated in Figure 40. These show the levels of utilisation (or congestion) on each interconnector for all 8,760 hours of the year, ranking hours from the one with the highest congestion level (i.e. 100%) to those with the lowest congestions levels (i.e. 0%).

*Figure 40: Duration curves of utilisation levels on the French and Portuguese interconnectors with Spain, 2006 and 2007*




Source: REE.

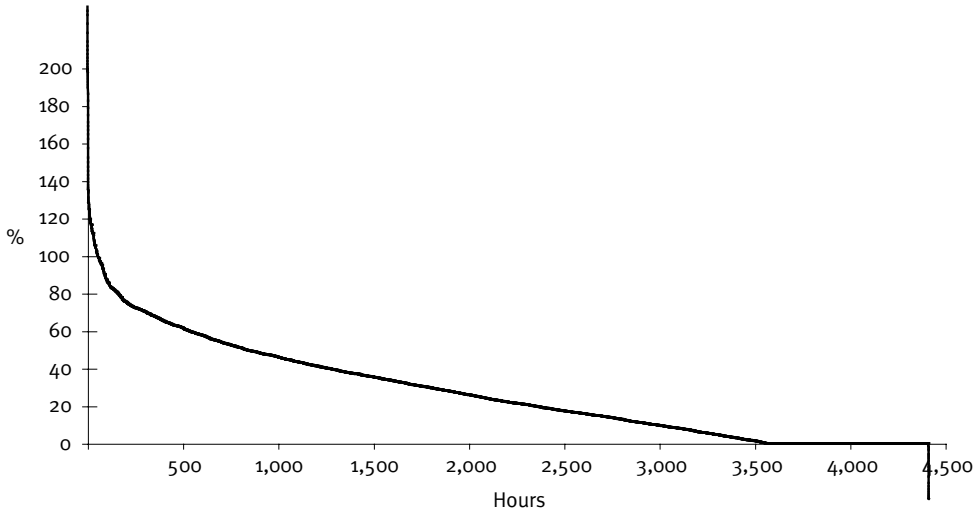
The high levels of congestion with Portugal show that effective integration between Spain and Portugal as part of MIBEL had not yet taken place in 2007. This has also become evident since the effective launch of MIBEL in July 2007, and the creation of a single wholesale market,

88. The average available commercial capacity of the Portuguese interconnector for export mode stood at roughly 1,100 MW in 2007.

with market splitting during hours of congestion on the interconnector. The average Portuguese day-ahead wholesale price during the July-December 2007 period has been 24% higher than Spanish prices. Figure 41 shows the duration of the hourly price differentials between Portugal and Spain for all the hours between 1 July 2007 and 31 December 2007 (i.e. 4,416 hours), ranked from the hour with the highest differential to the one with the lowest. As the duration curve shows, the differential between prices in Portugal and Spain reached very high levels during the second half of 2007, with Portuguese prices 50% or more above Spanish prices for roughly 20% of the time.

The level of interconnection between the Spanish market and neighbouring markets remains low in comparison with other major European countries. In January 2008, total peak import capacity in Spain amounted to 7% of peak load, well below the corresponding levels for Italy (13%), France (14%) and Germany (13%-23%), but above the value for the British market (3%).[89] Plans are in place to increase interconnection capacity between Spain and other countries. For example, the interconnector with France is due to be almost doubled in size in 2011.

*Figure 41: Hourly duration curve of percentage differential between the Portuguese and Spanish day-ahead electricity price, July – December 2007*



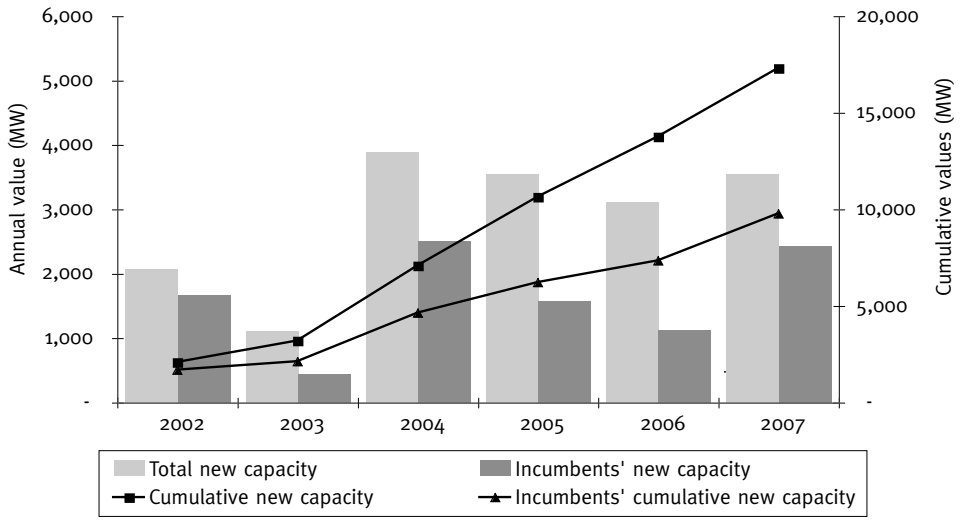

Source: OMEL.

89. Based on UCTE data for January 2008 (published in the System Adequacy Forecast 2008-2010), and NGT and ETSO data for Great Britain.

### 5.2.9. Investment in new generation capacity

There has been considerable net investment in new generation capacity in Spain over the past few years. This has mostly consisted of investment in new CCGT and wind generation. Figure 42 summarises the annual and cumulative new addition of ordinary capacity in Spain over the 2002-2007 period. Investment was particularly high over the 2004-2007 period, with an average 3.5 GW of net capacity added every year. Cumulative investment by the end of 2007 reached more than 17 GW, equivalent to almost 40% of peak demand in 2007. A significant share of the new additions in capacity (close to 60% by the end of 2007) was made by the incumbent electricity companies (defined in the figure below to include the top four firms). Entry by non-incumbents was primarily driven by the investment of Gas Natural in CCGTs (which is in turn the incumbent in the gas market). Investment in special regime capacity over the 2002-2007 period amounted to 11 GW. Most of this investment (9 GW) consisted of wind generation.

*Figure 42: Net capacity additions in Spain, 2002-2007 (conventional capacity only)*




Source: REE.
Notes: Incumbents are defined to include Iberdrola, Endesa, Unión Fenosa and EDP/HC.

### 5.2.10. Looking forward: projections for future investments in generation capacity

According to the current forecast produced by the CNE[90], investment in new capacity is set to continue over the 2008-2011 period. The "pessimistic" scenario of the CNE envisages an additional 9 GW of CCGT entry by the end of 2011, and 8 GW of wind generation (relative to the

90. See CNE, "Informe Marco Sobre la Demanda de Energía Eléctrica y Gas Natural, y su Cobertura, 2007", January 2008.

levels at the end of 2007). These additions would more than compensate for a reduction in coal and fuel-oil capacity (-2 GW and -4 GW, respectively). Based on the UCTE forecasts of system adequacy for early 2013, the amount of net new entry envisaged under the pessimistic scenario of the CNE would be sufficient to meet the adequacy reference margin (reaching the required levels of capacity by the end of 2011).

A notable feature of the CNE's projections for new CCGT investment is that incumbent generators are set to account for a significant share of new CCGT projects over the short to medium term. Of the possible 5.6 GW of new CCGT capacity which could enter the Spanish market over the 2008-2009 period (according to the projections of published in January 2008), Endesa and Iberdrola account for over 40% and Gas Natural for close to 40%. More independent entry is projected beyond 2009, but all of it may not take place (especially under the "pessimistic" scenario developed by the CNE). It therefore appears unlikely that new CCGT entry alone will be able to significantly reduce the current levels of concentration in conventional capacity in Spain over the next few years.

Based on the CNE projections, the fuel mix will evolve over time, whilst accentuating some of the trends that are already present in the market (i.e. the growth of gas-fired and renewable technology). According to the projections for 2011 (under the "pessimistic scenario" for ordinary capacity), CCGT technology will account for 30% of total installed capacity in 2011 (up from 24% in 2007) and wind generation for over 21% (relative to 16% in 2007). Overall special regime generation will stand at 36% of total capacity and 31% of output. This includes 2 GW of solar power by 2011, which, however, seems conservative, given the fast growth experienced by this technology in 2007 and 2008, and the regulated quotas for the 2009-2011 period established by the government in September 2008.

CCGT capacity plus special regime capacity could therefore account for two thirds of the market in 2011 (compared to just a quarter of the market 10 years earlier, in 2002). It is unclear whether the rapid increase in renewable generation implied by these projections accords with the positive externalities (primarily environmental) associated with this source of electricity.

These future trends are likely to strain the wholesale electricity system, since special regime generation is significantly less flexible (i.e. it cannot adjust its output level depending on market conditions) than ordinary capacity and more subject to exogenous shocks which the overall market system needs to adjust for. The current role played by CCGT generation in providing overall flexibility to the market will therefore become even more critical. This in turn will make the generation market even more dependent on the wholesale gas market, implying that the latter will need to be able to cope with more significant fluctuations in gas demand (further raising the importance of procuring adequate gas storage facilities).

Over the medium term the retirement of some coal plants (which may be accelerated by the fact that carbon allowances will no longer be free after 2013) is likely to further increase the depend-

ence of the market on gas (both in terms of overall volumes and flexibility). Greater reliance on gas-fired generation might be avoided, however, if "clean coal" technologies (e.g. through carbon capture and sequestration) were to develop sufficiently fast in the near future.

Looking even further forward, the retirement of the current fleet of nuclear generators will pose a difficult challenge for the system as a whole. It is hard to see at present how the current role played by nuclear power in providing base load generation can be filled by relying only on thermal or renewable technologies, since this would increase the dependence on these technologies to a level which appears either unfeasible or excessive.

### 5.3. Retail gas

Evolution and composition of demand

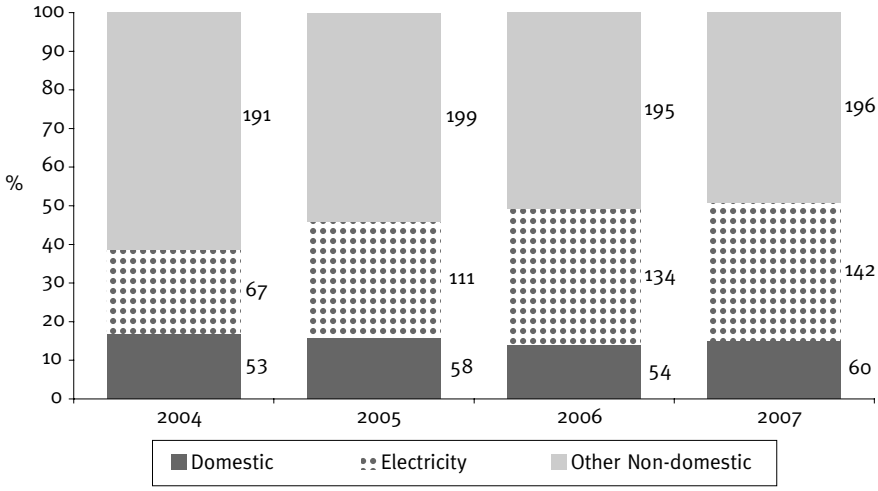
Final demand for gas in Spain has increased rapidly during the past four years. Over the 2004-2007 period, demand grew by almost 30%. This growth rate was primarily driven by the increase in consumption from the electricity sector, which more than doubled (from 67 TWh in 2004 to more than 140 TWh in 2007). Demand from the electricity sector accounted for 36% of total demand in 2007. Figure 43 illustrates the trends and composition in total gas demand over the 2004-2007 period.

Evolution of the liberalised gas market

The growth of gas demand from the non-residential sector partially explains the fact that a significant majority of gas consumption in Spain currently takes place at market-based prices, since regulated tariffs no longer apply to this segment of the market. By the end of 2007, close to 90% of total demand was accounted for by the non-regulated sector.

However, if one considers only the residential sector (i.e. households with relatively low gas consumption), then switching rates are much lower. Just over 40% of the residential market has switched to market-based prices in energy terms and less than 40% in terms of customer numbers. The switching rate in the gas market is, however, much larger than in the electricity sector, as discussed below in this section. This can be attributed to the fact that switching in the electricity supply sector has been impeded by the presence of a significant tariff deficit (implying that retail electricity tariffs are below market retail prices). As discussed more extensively below, most of the switching in the gas market has been to the incumbent distributor in each region and not to a new entrant.

*Figure 43: Composition and volumes (TWh) of gas demand*




Source: CNE; Enagás (for the electricity component).
Note: Excludes customers with own LNG tanks (*plantas satélites*).

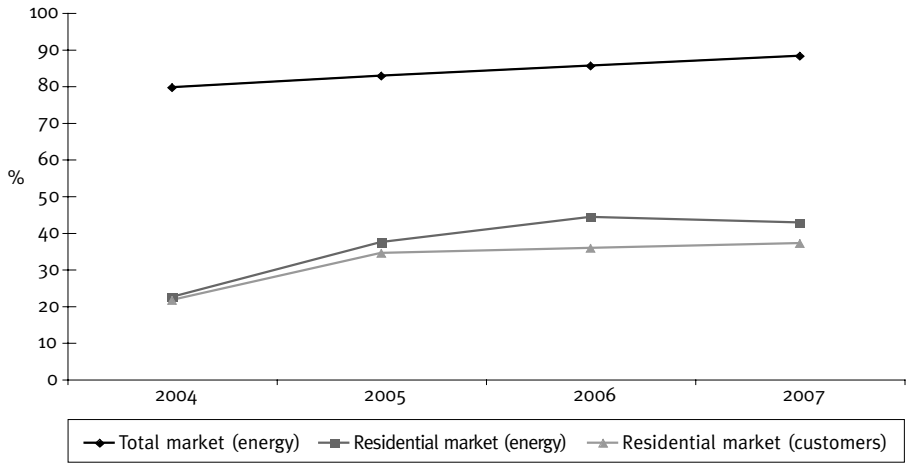
## Overall national market shares

There are three main incumbent gas distributors in Spain: Gas Natural (which has a widespread national presence, with more than 85% of connections and 82% of gas consumption on regulated tariffs), Endesa (present in Aragón and Extremadura, with a national share of 7% of the regulated market) and Naturgas (which is part of the EDP/HC group, and is active in Asturias and the Basque Country, with a national share of 11% of the regulated market). A map of gas distribution networks by region is included in Annex 2 of this report.

More players are active in the segment of the gas market that has switched to market-based prices. Competition in this market has been driven by the non-residential sector (most notably consumption by CCGTs), which accounts for a significant share of total gas consumption in Spain, as shown in Figure 43.

National shares in this market over the 2004-2007 period are summarised in Figure 45. This shows Gas Natural's share in energy terms progressively declining from over 50% in 2004 to 46% in 2008. The fastest-growing supplier was Unión Fenosa Gas, which almost trebled its market share over this period. Whilst data on market share by customer group is not available for the most recent period, Unión Fenosa Gas's growth appears to have been driven primarily by the supply contracts to Unión Fenosa's CCGTs.

*Figure 44: Share of gas market at market-based prices*




Source: CNE.

Gas Natural has historically also lost market share in the market for large industrial gas consumers, excluding CCGTs. In 2004, Gas Natural had roughly 50% of this market, slightly below its overall national market share (and well below its share of gas distribution connections to this customer group). This reflects the fact that this part of the market is relatively more contestable than other segments (e.g. residential supply), and is able to benefit from the availability of competitive gas to other suppliers in the form of LNG.

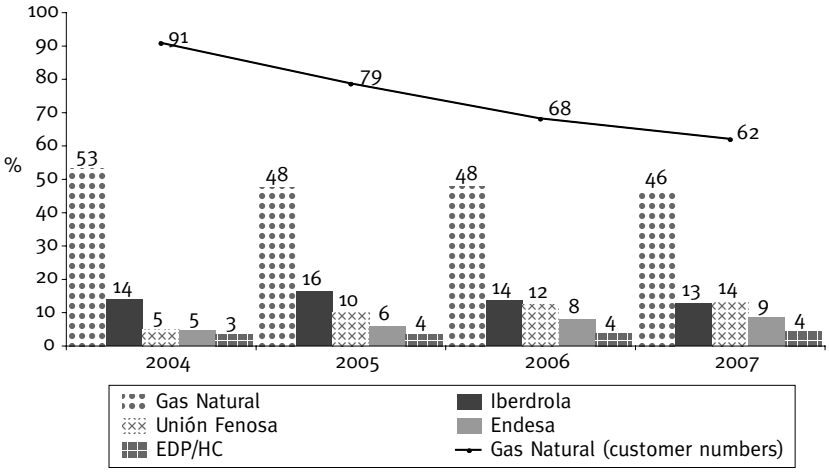
Gas Natural's share in terms of customers in the liberalised market is higher than its share of volumes, due to its relatively stronger presence in the residential market. The decline in the share of liberalised customers has been faster, however, than the corresponding fall in the share of volumes. This is mainly due to the fact that the number of liberalised customers grew very rapidly between 2004 and 2007 (from 1.2 million in 2004 to 2.4 million in 2007), and Gas Natural progressively captured a smaller share of these consumers (at a national level).

### Switching patterns and regional shares in the residential gas market

Positions in the residential gas market are more concentrated than what is suggested by the overall market shares given in Figure 45. This is partially indicated by the fact that Gas Natural's share in terms of customer numbers (shown in the line above the bars) sits well above its share of total consumption, and still exceeded 60% in 2007.[91]

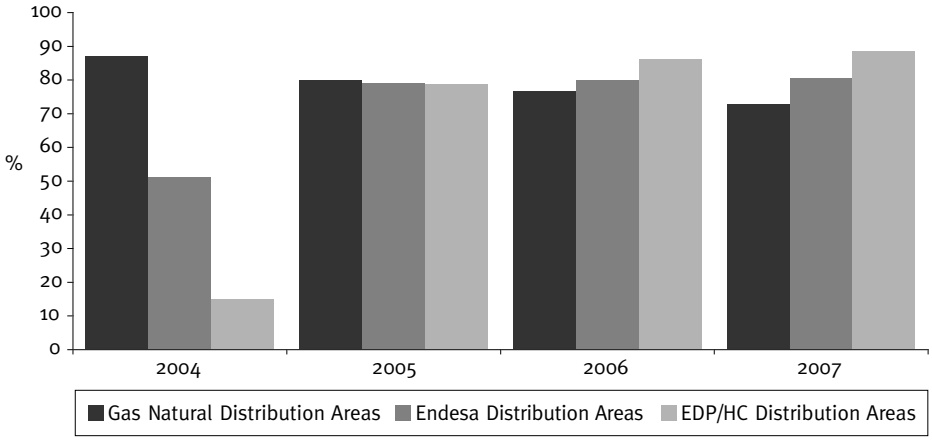
91. Given that residential customers account for the vast majority of total customers in the gas market, shares of total liberalised customer numbers can be used as a good proxy for market shares in the residential sector.

*Figure 45: Shares of the national market on market-based prices (by consumption - and by customer numbers for Gas Natural only)*




Source: CNE.
Note: Gas Natural's shares of customer numbers relate to the annual average level in each year.

*Figure 46: Gas retail fidelity rate by number of liberalised customers*




Source: CNE.

The market for residential customers also has a clear regional dimension, largely driven by the presence of the pre-existing incumbency positions of the local gas distributors. Moreover, most of the customers who switch from the regulated tariffs to market-based prices actually remain with the local supplier, as shown in Figure 46. Fidelity rates[92] were above 70% for the three main gas distributors in 2007 and, in the case of Gas Natural, have remained above this level since 2004.

However, it is important to note that high fidelity rates (and high market shares in general) do not necessarily mean that competition is weak and that customers are not being offered competitive terms by incumbent firms. More analysis is required to support such a conclusion. In the absence of such an analysis, switching rates necessarily provide only a necessarily imprecise indication of competitive conditions. For example, in the presence of credible potential competition (e.g. in the form of attractive dual-fuel offers by the electricity incumbents and vice versa), the incumbent may still offer competitive deals to retain its customer base.

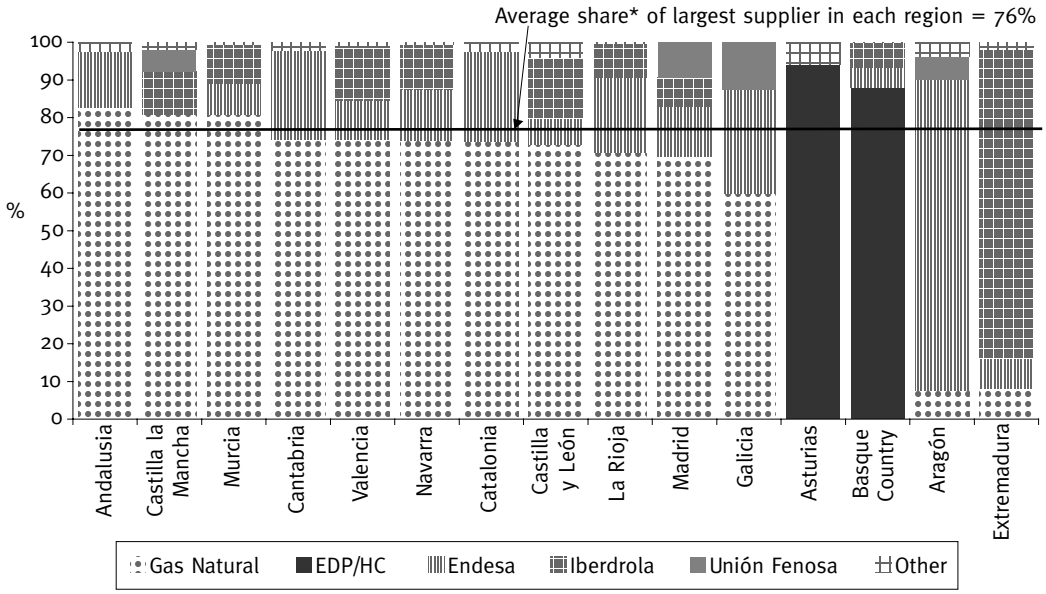
Looking at the market on a region-by-region basis reveals stronger incumbency positions in favour of the gas distributors and more concentrated markets than what would appear from simply considering national market shares. Regional market share data published by the CNE for 2007 show that the largest supplier in each region held a share of those customers who had switched to market-based prices in excess of 75% on average (see Figure 47). With the exception of Extremadura, the largest gas supplier is also the owner of the gas distribution network.[93] Coupled with the fact that more than 60% of customers are still supplied by the gas distributor on regulated tariffs (as shown above), this evidence shows that on average fewer than 1 in 10 customers in each region is supplied by a company other than the incumbent gas supplier. This is also illustrated in Figure 48, which shows that switching to gas retailers other than the incumbent remained low in 2007 (at or below 10%) for all distribution networks. Switching to the liberalised market was high in the EDP/HC regions (most notably in the Basque Country), but the majority of these switchers are still supplied by the incumbent gas distributor.

The large variations in regional market shares indicate that the relevant geographic market in residential gas supply is most probably regional, not national. A regional definition of the market recognises the fact that the presence of regional gas distribution companies (coupled with vertical integration between distribution and supply activities) gives an incumbency advantage to the legacy regional supplier and creates regional barriers to entry.

However, a regional definition of the market does not fully agree with some of the more recent competition policy precedents in this sector, which have defined national gas (and electricity) markets for the part of the market that has switched to market-based prices[94], whilst recognising the presence of local elements to competition for residential customers.

92. These rates measure the proportion of switchers to the liberalised market who switch to the local gas distributor.
93. The situation in Extremadura is not representative because only 2% of the market has switched to market-based prices in that region.
94. See, for example: TDC, "Gas Natural/Endesa, C94/05", January 2006; and CNE, "Informe de la CNE sobre el proyecto de concentración consistente en la adquisición del control de Endesa S.A. por parte de Gas Natural SDG, S.A. mediante oferta pública de adquisición de acciones", December 2005. However, in its decision on Endesa/Iberdrola in January 2001, the TDC found regional (or even local) markets for retail electricity.

*Figure 47: Regional gas market shares by number of customers*



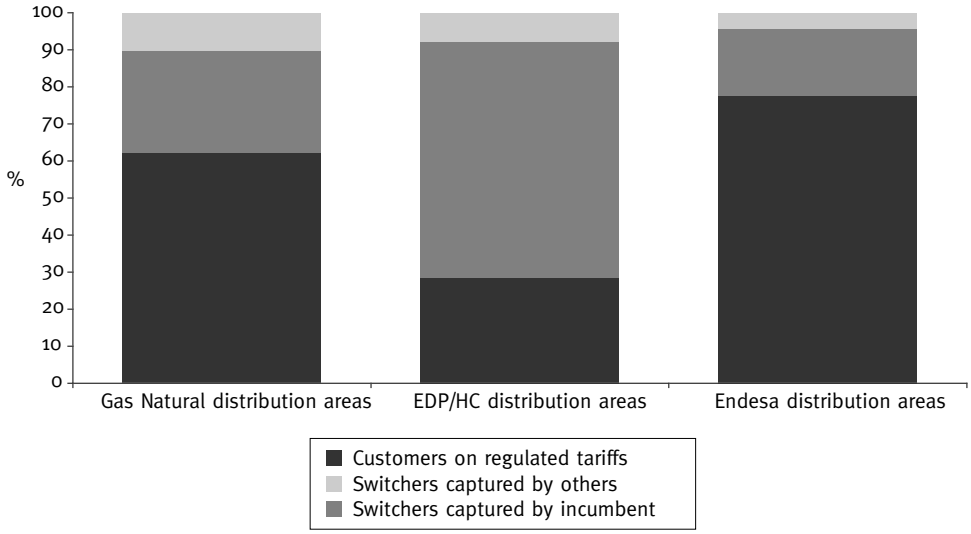

* The average share is weighted by the number of customers on market prices in each region.
Source: CNE.

The regional analysis also shows that the main rival to the gas incumbent tends to be the incumbent electricity supplier (i.e. the company that owns the local electricity distribution network). This is quite clearly the case for Endesa in Andalusia and Catalonia, and also applies to Iberdrola's position in Castilla La Mancha, Castilla y León, Valencia and Murcia. This suggests the presence of a potentially close link between competition in the gas and electricity residential markets, through competition in dual-fuel offers.

Dual-fuel competition has been one of the main drivers of competition in other liberalised markets. For example, in the United Kingdom the main gas supplier, British Gas Trading, is also the largest electricity supplier, with over 20% of the national market in mid-2008. Electricity firms (with no incumbency positions in the gas distribution market) are also very active in the residential gas market and currently account for more than 50% of all domestic gas customers (indicating a much more competitive structure than in Spain).[95]

95. See the report by the British national regulator, Ofgem, "Energy Supply Probe, Initial Findings Report", October 2008. This report shows that regional markets in the United Kingdom are more concentrated than the national gas and electricity markets (as is also the case in Spain). At the regional level, the electricity incumbent supplier is the largest competitor to the gas incumbent, and vice versa. On average, in mid-2008 in each region of the United Kingdom, 70% of gas and electricity customers were served by one of the two incumbent energy suppliers. Consistent with this, two thirds of all customers who consume both electricity and gas were on dual-fuel tariffs in December 2007.

*Figure 48: Switching patterns of gas customers by distribution area, 2007*




Source: CNE.
Note: Endesa's distribution areas are defined as including the whole of Aragón and Extremadura.

The link between the retail gas and electricity markets also implies that the particularly problematic development of competition in the electricity retail sector (which we will review in the section below) is also likely to be negatively affecting the pace of competition in the gas market.

### European comparison

The relatively slower development of competition in residential gas (at least when measured by market shares and switching rates) than in the industrial and CCGT segment seen in Spain is in line with the experience of most other major European countries, with the notable exception of the United Kingdom.

The latest benchmarking information published by the European Commission[96] reveals very low switching rates in residential gas in the main European countries (including Germany, France and Italy), with the only exception being the United Kingdom (where switching rates of close to 50% of domestic and small business customers were already achieved by the end of 2004). Switching rates for industrial customers are higher in Spain than in other major European economies, again with the exception of the United Kingdom.

96. See the European Commission 2005 and 2008 Reports on Progress in Creating the Internal Gas and Electricity Market.

Primarily because of Spain's successful liberalisation of the industrial gas market (including the CCGT segment), the preliminary 2006 rankings produced by OXERA for the U.K. Department for Business, Enterprise and Regulatory Reform[97], place Spain as the most competitive gas market in Europe, second only to the United Kingdom.

## 5.4. Retail electricity

### Recent evolution and composition of electricity retail demand

Electricity demand increased at a steady rate during the 2004-2007 period, going from 215 TWh in 2004 to 238 TWh in 2007 (an 11% increase). Just below half of current electricity demand is low-voltage demand. The residential sector accounts for just above 30% of total demand, with the remainder made up of industrial and commercial usage. Figure 49 summarises the recent trends in the level and composition of electricity retail demand in Spain.

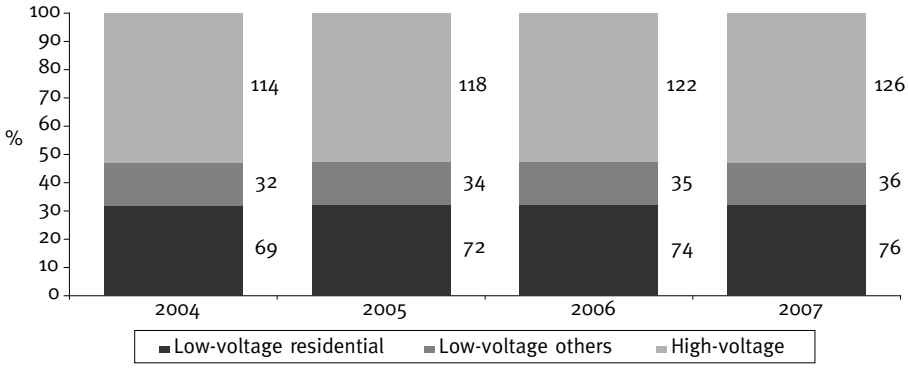
### Evolution of the liberalised electricity market

Only a small proportion of the total retail electricity market had switched to market-based pricing by the end of 2007. Figure 50 plots the evolution of the share of the market on market-based prices over the 2004-2007 period. As this figure shows, by the end of 2007 fewer than 10% of customers consumed electricity on market terms. In terms of electricity volumes, the relevant share was higher (above 25%), but significantly lower than the levels achieved early in the period (e.g. in 2005 this share stood at above 35%). This indicates that a considerable number of large consumers of electricity switched back to consuming on regulated tariffs in 2006. There was a recovery in the second half of 2007, however, as shown by the fact that the share of total volumes on market prices rose from 22% in the second half of 2006 to roughly 30% during the second half of 2007 and the first half of 2008. The abolition of the standard high-voltage tariff from July 2008 has further increased the share of volumes on market prices in 2008 (e.g. customers on standard high-voltage tariffs accounted for close to 50% of total volumes during the first half of 2008).

The reasons for the recent poor performance of the electricity retail market in terms of switching to market-based prices and for the deterioration in 2006 are well known: wholesale electricity prices increased significantly in 2005 and 2006 relative to previous years (as shown above), and regulated tariffs were not adjusted accordingly. This meant that regulated tariffs were effectively set below market prices during this period (and into 2007), thus implying that independent retailers could not compete with the regulated prices offered by the incumbent suppliers.

97. OXERA, "Energy market competition in the European Union and G7: preliminary 2006 rankings". Prepared for the Department for Business, Enterprise and Regulatory Reform, October 2007.

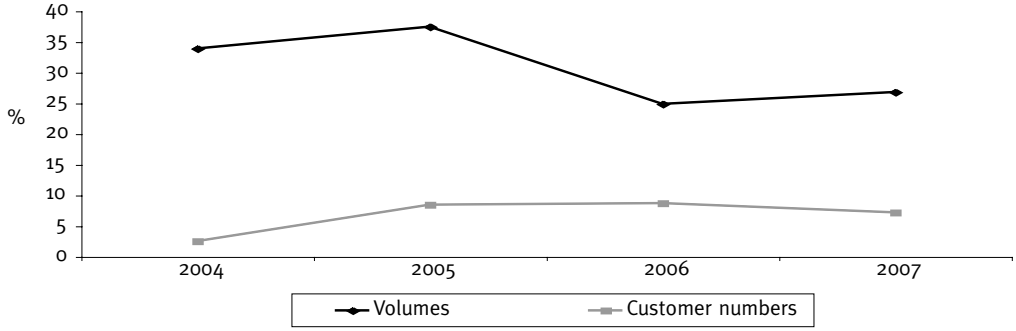
*Figure 49: Composition and volumes (TWh) of electricity demand*




Source: CNE. Low-voltage split estimated for 2007.

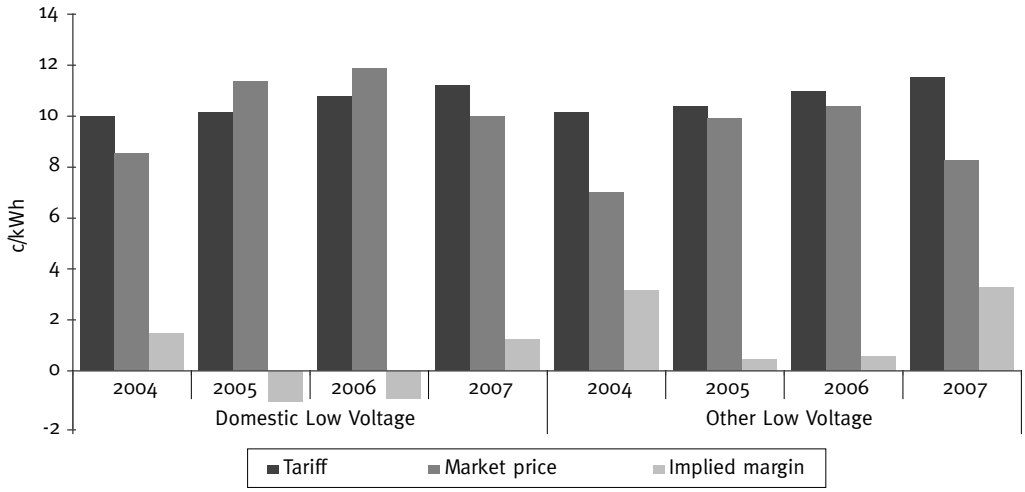
The fact that the implied market-based retail margins were negative in 2005 and 2006 is evident from Figure 51. This compares the regulated tariff for low-voltage customers with a notional market price, simply defined as the wholesale energy price (adjusted for the load profile) plus access prices. Market prices were above regulated tariffs in both 2005 and 2006 for domestic low-voltage consumers, thus implying that suppliers had to incur losses at the retail level in order to compete with the regulated tariff. Implied retail margins were just above zero for other low-voltage customers but were small and unlikely to cover retail costs. Margins improved in 2007 (especially for non-domestic customers) but regulated tariffs still implied a tariff deficit as shown below. Given the introduction of an additive tariff in 2007 (see discussion in Section 4 above), independent retailers should, in principle, be on a level playing field with incumbent distributors and be in a position to compete with the regulated tariff.

*Figure 50: Share of electricity retail market on market-based prices*



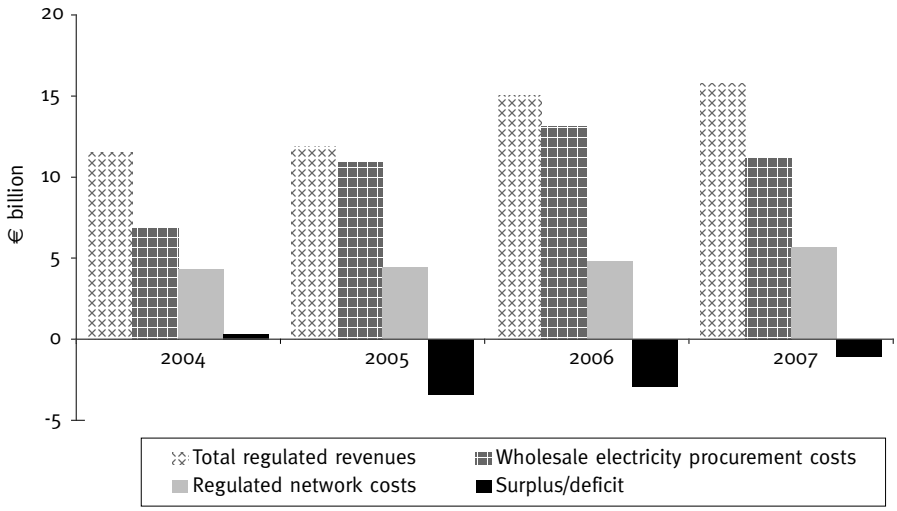

Source: CNE.

*Figure 51: Implied retail margin at market-based prices (access costs plus wholesale energy cost)*




Source: CNE, own calculations (including estimates for 2007).

*Figure 52: Evolution of the regulated tariff deficit, 2004-2007*




Source: CNE.

The CNE reports data on the regulated tariff deficit on an annual basis. The values for the 2004-2007 period are shown in Figure 52. The tariff deficit is defined as the difference between overall revenues from customers on regulated tariffs and overall costs for these customers, computed as the actual electricity procurement costs for distributors (these primarily consist of wholesale electricity prices) plus recognised regulated costs for transmission, distribution and retail activities.[98] As the data show, there were considerable deficits in 2005 and 2006 (between 20% and 30% of total revenues). In spite of the lower wholesale prices, there was also a deficit in 2007 (equal to 7% of revenues). Tariff deficits were also experienced between 2000 and 2002, during another period of relatively high wholesale prices. As of the end of 2007, the overall nominal deficit (including all past annual deficits) stood at roughly €9 billion, equivalent to more than 50% of overall regulated revenues in that year.[99] An additional tariff deficit of close to €5 billion was recognised ex-ante for 2008. A tariff deficit of € 6.7 billion has been forecast for the whole of 2008.[100]

### Competition in the retail electricity market

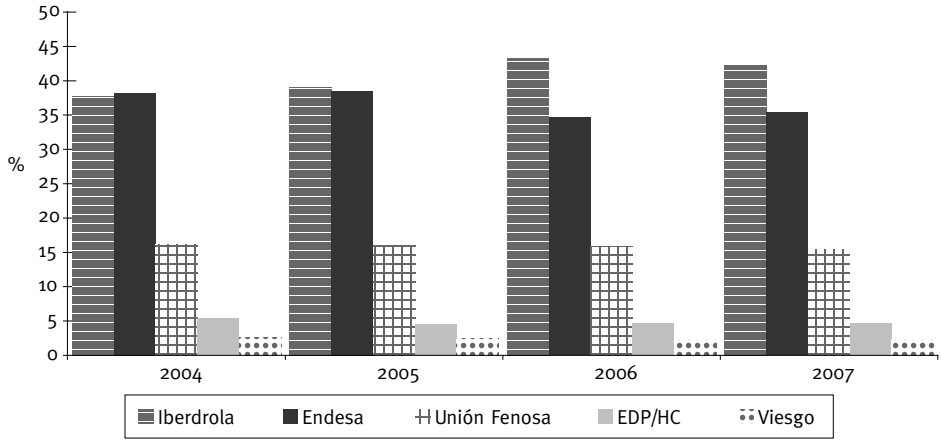
Competition in the retail electricity market has clearly been significantly affected by the presence of a deficit on regulated tariffs. This has slowed down migration to market-based prices and has led operators to adopt different strategies in the overall retail market.

Figure 53 and Figure 54 illustrate the market share trends in the regulated and free segments of the retail market. As the figures show, in reaction to high wholesale prices, Iberdrola partially withdrew from the liberalised market (at least up to 2007) and appears to have effectively migrated some of these customers back to the regulated tariffs more extensively than its competitors. As a result, Iberdrola was the leading supplier in the regulated market in 2007 (at the national level) and only the fourth-largest supplier in the market for customers who consume at market-based tariffs. By contrast, Endesa has kept a significant presence in the liberalised market, with its national share currently standing at over 50% (up from 35% in 2004).[101] Other operators (most notably EDP/HC) have grown considerably in market share terms since the emergence of a considerable tariff deficit.

A noticeable recent trend in market shares is the relative decline of the most active new entrant in electricity retail, Gas Natural. Gas Natural's share in terms of customers peaked at close to 20% at the end of 2006 but declined to 11% by the end of 2007, presumably also in reaction to the presence of negative margins in the liberalised supply business.

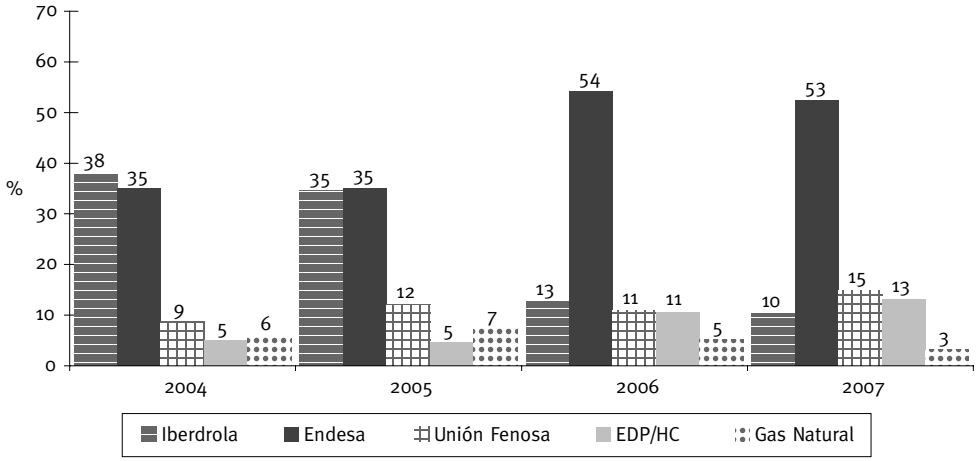
98. Other smaller regulated costs are also included in this calculation.
99. These figures are based on estimates provided by the CNE and exclude the recovery of windfall gains due to the ETS.
100. CNE, "Propuesta de revisión de las tarifas de acceso para 2009 y revisión de las tarifas integrales vigentes para el primer trimestre de 2009", November 2008. This forecast for the deficit was higher than the level projected at the beginning of the year and greater than the deficits of any other previous year. The CNE estimated that an increase in residential tariffs of over 30% would be necessary to avoid a tariff deficit in 2009. The CNE also estimated that the recovery of windfall gains from the operation of the ETS could reduce the projected deficit for 2008 by €1.45 billion.
101. In terms of customer numbers, Endesa's national share is even higher (60%), thus reflecting the fact that some of its competitors (most notably Unión Fenosa and EDP/HC) have focused on the larger electricity consumers and not on the residential market.

*Figure 53: National shares of the market on regulated tariffs (energy terms)*




Source: CNE.

*Figure 54: National shares of the electricity market on market-based prices (energy terms)*




Source: CNE.

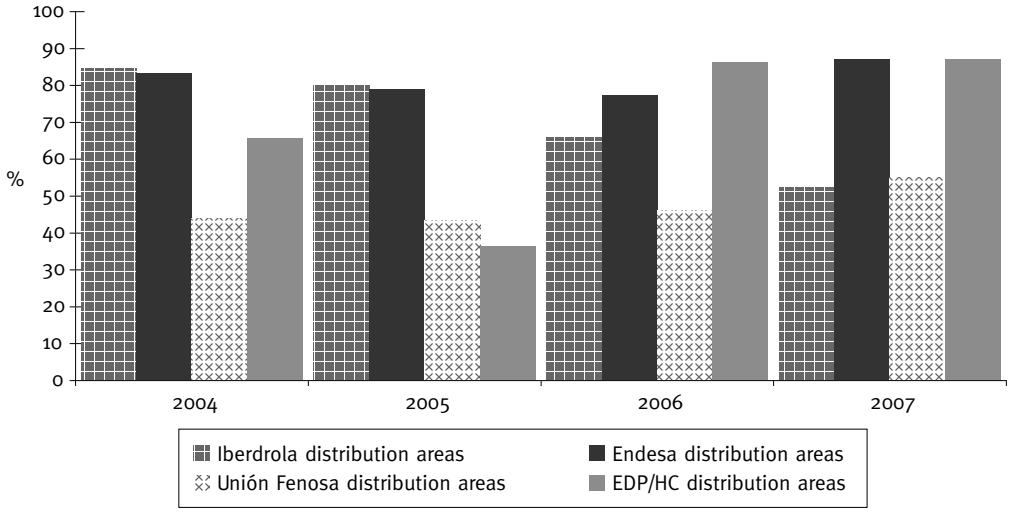
## Electricity retail competition at a regional level

As in the case of gas, competition in electricity retail is better understood at the regional rather than the national level. This is due to the presence of different electricity distributors in each

region, with associated incumbency positions in retail supply. Endesa is the electricity distributor in Andalusia, Catalonia, Aragón and Extremadura (50% of the network). Iberdrola owns the distribution network in Castilla y León, parts of Madrid, Murcia and Valencia. A map of the regional electricity distribution networks is included in Annex 2 of this report.

Regional market shares are not published by the CNE. However, regional incumbency positions can be measured by reference to the fidelity rates that are published by the CNE, i.e. the shares of customers on market-based tariffs that have switched to the supply business of the local distribution company in each region. Fidelity rates over the 2004-2007 period are shown in Figure 55 below for the four main distributors. As the figure illustrates, fidelity rates are very high in the case of Endesa and EDP/HC (over 80%), and considerably lower for Iberdrola and Unión Fenosa. However, it is also the case that in the Iberdrola and Unión Fenosa distribution areas, switching to market-based tariffs is considerably lower than in the Endesa and EDP/HC areas (5% of all customers vs. 9%-11%). Overall, the presence of high fidelity rates and low switching to the market imply that the overwhelming proportion of customers (in excess of 95% in each distribution area on average) are still served by their incumbent suppliers.

*Figure 55: Fidelity rates by distribution area (customer numbers)*




Source: CNE.

Analysis of the shares of customers in each distribution area also shows that Gas Natural has a relatively wide national market presence (which reflects its extensive gas network). Gas Natural is the clear number two electricity supplier in the Endesa areas and was also the second supplier

in the Iberdrola areas until the end of 2006 (Gas Natural was the third electricity supplier in the Iberdrola areas, just behind Endesa, in 2007). Gas Natural's success (relative to other electricity entrants) illustrates the fact that regional incumbency positions matter in competition for retail customers, both in gas and electricity. It also shows the potential for dual-fuel competition in Spain. The presence of the electricity tariff deficit has, however, impeded the growth of effective dual-fuel competition at least up until the recent reforms of the tariff design.

### European comparison

The performance of the Spanish electricity retail market is relatively poor compared with other European countries in terms of switching rates and market shares. According to the benchmarking information published by the European Commission, switching rates for large business customers at the end of 2004 were lower than in the United Kingdom, Germany and Italy, but higher than in France. In residential electricity the relative ranking was surprisingly better, but this finding is likely to be affected by the fact that the definition of switching used for Spain included customers that simply changed tariffs for the same supplier. More recent data published by the European Commission for 2006 are less comprehensive, but show relatively low switching rates in residential electricity in Spain (5%) and even lower rates for Germany and France. The preliminary 2006 rankings produced by OXERA for the U.K. Department for Business, Enterprise and Regulatory Reform[102] find that Spain is the third-least competitive electricity market in their sample, only superior to Portugal and Ireland (the sample excludes France). This ranking includes the performance in the generation market as well.

102. OXERA, "Energy market competition in the European Union and G7: preliminary 2006 rankings", Prepared for the Department for Business, Enterprise and Regulatory Reform, October 2007.

# 6. Economic Analysis of Recent Wholesale Electricity Reforms in Spain

This section of the report contains a more in-depth economic analysis of two selected topics in electricity wholesale markets: the impact of contracts and procurement auctions, and the role of capacity payments. These issues are topical in Spain, given the recent reforms implemented by the government in this area, as reviewed in Section 4 of this report.

## 6.1. Contracts, procurement auctions and competition

A necessary (but not sufficient) condition for markets to work well is the absence of significant market power. In other words, for markets to efficiently allocate resources, firms have to truthfully reveal their costs in their price offers. Nevertheless, some companies may have incentives to raise prices above marginal costs in order to increase revenues from their infra-marginal production (i.e. low cost generation capacity that is offered in the market), even if part of their marginal production is displaced by other companies.

The analysis of the determinants of firms' incentives to exercise market power is complex. However, the relationship between a firm's market share and its incentives to raise prices above marginal costs is simple and robust: the bigger the firm's market share, the greater its incentives to exercise market power.[103] This is so since raising prices is more profitable the greater the firm's infra-marginal production, whilst the cost of losing marginal production is the same regardless of the firm's size. A larger number of competitors, which should dilute market shares, make the market more competitive and thus potentially improve its performance.

Making the market less concentrated is probably the most effective way to enhance competition in imperfectly competitive markets. This view is generally shared by both academics and competition policy authorities (e.g. in general, competition authorities prefer structural remedies to behavioural ones in antitrust and merger cases). However, regulators often lack the power to apply structural remedies. This explains why regulators in energy markets have often resorted to

103. This does not imply that the relationship between concentration and equilibrium prices necessarily goes in the same direction. See, for example, Vives (1999) and García-Díaz and Marín (2003).

imposing forward contract obligations on dominant producers as a way to mitigate their incentives to exercise market power.

Forward contracts do not change the distribution of assets across firms. However, by altering the amount of output that is remunerated at market prices, they alter firms' incentives to raise prices.[104] For example, if a generator with a forward contract of 1,000 MWh produces 1,500 MWh, market prices only determine revenues from its net position (equal to 500 MWh) because revenues from the other 1,000 MWh are determined by the contract. This is true independently of whether the contract is physical (i.e. only the companies' net positions are traded in the wholesale market) or financial (all energy is traded in the wholesale market and forward contracts are cleared by differences). Generators' incentives to raise prices are therefore weaker with forward contracts because they reduce their net positions, or "virtual size".[105]

The economic literature also shows that contracts need to be observable for such pro-competitive effects to take place. Whilst the lack of observability may reduce (or eliminate) the effectiveness of forward contracting in anonymous exchanges, it does not apply to VPP auctions, as the volumes and identities of the firms subject to them are publicly imposed chosen by the regulator. Economic research on forward contracts also indicates that if contracts are endogenously chosen by firms, they may not have a pro-competitive effect under some conditions (e.g. if firms compete in price offers rather than quantities (Mahenc and Salanié (2004); and/or if there is an indefinite repetition of contract rounds (e.g. Ferreira (2003), and Liski and Montero (2006)). Again, these results are not directly applicable to the case of contracts that are exogenously imposed by a regulator. The interaction between endogenous forward contracts and exogenously determined VPP auctions, is, however, an area where further economic research is probably required to reach clearer policy conclusions.

Moreover, the fact that regulatory forward contracts mitigate firms' incentives to raise prices in the spot market does not imply that equilibrium prices will necessarily be lower. This depends on the volume as well as the allocation of contracts across firms. Regulatory contracts are usually more effective when allocated to large companies (as is the case in Spain and in other countries), as these firms typically face stronger incentives to raise prices.

However, contracts may be ineffective if they end up in the hands of smaller firms, as these firms typically do not exercise market power even in the absence of contracts. If one assumes that firms compete by submitting step supply functions, contracts could actually have anti-competitive effects if they are imposed on medium-sized firms.[106] Intuition runs as follows: absent contracts, such firms may compete "head-to-head" with the larger firms in the market (at least in

104. There is extensive economic literature on the effect of forward contracts. Allaz and Vila (1993) is the seminal article on this subject More recently, Bushnell *et al.* (2008) have empirically calculated the effects of forward contracts, and de Frutos and Fabra (2008) analyse the effect of contracts as a regulatory instrument.
105. The same logic implies that if the firm is a net buyer, it optimally sets prices below marginal costs (leading to allocative and productive inefficiencies).
106. See de Frutos and Fabra (2008).

some hours of the year); however, when they are subject to forward contracts, they may exercise less competitive pressure on larger firms at the margin (by offering their output at a lower price level), thus leading to higher prices. The same argument can imply that it may be beneficial to enable smaller firms to become "virtually" larger through forward purchases. However, this result does not hold if one assumes that all firms in the market compete in output levels (*à la* Cournot) or in linear supply functions (see Section 2 of this report for a review of these alternative models of electricity competition).

### Energy prices in forward markets

To the extent that spot prices have a direct effect on only a small fraction of total electricity consumption, it is necessary to understand price formation in forward markets.

The impact of forward trading (broadly understood as including VPP auctions, procurement auctions and other standard forms of forward contracting) largely depends on the opportunity costs faced by the seller (buyer) when selling (buying) part of its electricity production (needs) in the forward market. Given that the seller (buyer) still has the option of selling (buying) its energy at spot market prices, forward prices will be linked to expected spot prices. For example, after adjusting for risk *premia*, no firm should be willing to sell electricity in procurement auctions at prices below the expected spot market price. Similarly, after adjusting for risk *premia*, the maximum price that an agent should be willing to pay in order to buy electricity through VPP auctions is equal to the expected spot market price. Hence, whenever forward markets are competitive, there should not be arbitrage opportunities and forward prices should converge to expected spot market prices.

Note that the equalisation between spot and forward prices does not imply that forward contracting is irrelevant: forward contracts are relevant to the extent that they alter equilibrium pricing in the spot market. In other words, if forward contracts have pro-competitive (or anti-competitive) effects on the spot market, the level to which forward prices will converge will also be reduced (or be higher).

There is another important channel through which forward markets might have effects on the performance of spot markets. By allowing potential entrants to lock in the price at which they sell their production, forward contracts have the potential of facilitating entry, thus mitigating the potential for incumbent generators to exercise market power, an issue that will be further discussed in Section 6.2.

In sum, given that the spot market remains the underlying market for all transactions, its performance largely determines the outcomes in all other markets (including forward markets). This is not to say that the existence of liquid forward markets and/or regulatory contracts is irrelevant, as it may potentially contribute to improve (either through strategic or *real* effects) the performance of electricity spot markets.

### Forward contracts and the performance of the Spanish electricity market

One of the aims of introducing VPP auctions and (at least in part) procurement auctions in Spain was to reduce market power. Accordingly, these measures were expected to reduce the costs of procuring electricity for the regulated market, mitigate any potential productive inefficiencies in the spot market and reduce the profits made by the dominant producers. However, without a detailed empirical analysis of the effects of forward contracting in the Spanish electricity market, there are some reasons that suggest that such conclusions should be taken with a degree of caution.

### Volume

First, for the effects of forward contracting to be significant, contract volumes should be large enough relative to the value of the residual demands faced by firms. As mentioned in Section 4 of this report, the Electricity Law allows VPP auction volumes to be much larger than the ones currently implemented, in line with the suggestions contained in the White Paper. The latter were based on oligopoly simulations of the Spanish market, which indicated how large the contracts would need to be in order to render the market effectively competitive (for a more general discussion of the role of simulation modelling in electricity, see Section 2[107]). Given the gap between the volumes of forward contracting recommended in the White Paper (5-6 GW per firm, at the peak) and the size of the VPP auctions that have actually been implemented so far (a maximum of 1.25 GW per firm), it is likely that the current VPP auctions are only having a moderate impact on electricity wholesale prices in Spain.

Although procurement auctions and forward markets are an additional source of forward trading, the participation of generators in these markets is voluntary. Hence, they will not participate in procurement auctions or forward markets if it is not in their interest to do so (i.e. if these auctions reduce their market power).

### Dynamic effects

The potential pro-competitive effects of forward contracts discussed so far do not account for the possibility of a feedback effect from spot market prices to forward prices. Such effects may arise if spot market prices affect bidders' expectations about the profitability of forward sales. When auctions are frequently and indefinitely repeated (or do not have a precise deadline), the owner of the assets could have an interest in setting high spot market prices so as to increase bidders' willingness to pay for forward contracts in future auctions. This implies that spot prices will be higher than if such dynamic effects did not arise (e.g. if all virtual capacity were auctioned in a one-shot auction). Accordingly, the pro-competitive effects of contracts will be weakened (and may actually disappear).[108]

107. For an alternative simulation of the possible impact of imposing forward contract obligations in Spain using 2005 data, see de Frutos and Fabra (2008).
108. See Schultz (2005) for a theoretical illustration of this effect.

### Risk attitudes

Firms' attitudes towards risk also play a role in shaping the impact of forward contracts. Paradoxical though it may seem, generators could face more risks when selling electricity at a fixed contract price than when selling electricity through the spot market. The reason is that a significant portion of the volatility in firms' profits (at least for thermal units) comes from the volatility in fuel prices (notably gas, oil and coal). Whilst spot market prices increase with higher fuel costs, forward prices do not, given that they are fixed ex-ante. If firms are risk averse, this may imply that the price at which they are willing to sell electricity in procurement auctions is above the expected spot market price.

### Participation

The identities of the firms that participate in forward markets as well as the distribution of contracts among them are important determinants of the role played by forward contracts.

Let us first consider procurement auctions or organised future exchanges, in which generating companies have the right, but not the obligation, to participate. Bigger companies, whose market power could be mitigated through contracts, may prefer that smaller rivals or traders without physical assets enter into these contracts. If the larger companies sold their output forward, they would have stronger incentives to reduce prices in the spot market ex-post, potentially leading to lower prices for their uncovered sales.[109] However, if energy contracts procured in the auctions end up in the hands of smaller firms or parties with no physical assets, the effects of the contracts could be very small or even null, given that they would not change their bidding incentives in the spot market, as discussed above.

In relation to participation in VPP auctions, note that in these auctions, the largest producers are obliged to auction the right to use their assets to third parties. Hence, the shortcoming due to voluntary participation of the dominant firms is avoided. A related question, however, is who should then be the buyer of VPPs. First, it would be desirable that VPPs end up in the hands of firms with an interest in physically entering the market. The acquisition of VPPs could allow such potential investors to learn about market performance, thus reducing barriers to entry. However, the small lot size (VPPs in Spain were sold in lots of 2 MW each, though this has recently been increased to 10 MW) and their short life (not exceeding a year) limit the extent to which VPP auctions can constitute an effective way of entering the market. Consequently, it is more likely that VPP buyers will be pure *arbitrageurs*, as in most financial markets. Second, to the extent that symmetry among competitors may make the market more competitive, it would be desirable for small firms to become "virtually" larger through forward purchases.

In sum, the firms that are most likely to voluntarily participate in the current CESUR and VPP auctions are probably not the ones that would make such contracts more effective.

109. This could actually be a reason why forward markets have not developed in a spontaneous way and their trading volume has not been greater than that required by law.

### Regulatory suggestions

In order to avoid some of the possible adverse effects reviewed above, some changes in the current design of the CESUR and VPP auctions could be considered. For instance, it would be desirable for VPP volumes to be significantly larger, as argued above. Moreover, their delivery period (at least for some of the products) should be longer to mitigate some of the adverse dynamic effects discussed above and promote entry. This would also be in line with the White Paper's conclusions, which recommended contracts of a minimum duration of 3 years. The strike price could also be indexed to fuel prices (to reduce risk for contract holders) and lot sizes increased (to promote entry) (see Box 5).

Recent changes in the design of VPP auctions (e.g. elimination of the quarterly product, reduction in the number of auctions per year and increase in lot sizes) can be expected to improve the effectiveness of VPP auctions. However, although such changes are a step in the right direction, they are unlikely to be enough to make VPP auctions an effective pro-competitive tool in the Spanish market.

Regarding procurement auctions, these could evolve over time to a mechanism that would enable "competition *for* the market"[110], as a complement to "competition *in* the market". To achieve this goal, it would be desirable to hold procurement auctions well before the delivery period and to auction long-term energy contracts (e.g. for ten years). This would allow potential entrants to participate in these auctions (before investing in new capacity) by increasing their prospects of recovering investment costs and hence reducing risk *premia*.

Competition among potential entrants could also lead to a situation where procurement prices do not simply reflect expected spot market prices (as is largely the case under the current procurement auctions), but are actually driven down to the average cost of the new capacity (which is the cost that market prices should reflect in the medium term in a competitive market).[111] These types of long-term contracts could therefore be used to discipline incumbent generators, make the market contestable and encourage entry up to its efficient level.

The overall market design for the spot market would not change under the arrangement for procurement auctions described above. All electricity could still be traded in the spot market and be paid at the system marginal price. The contract signed between the firm and the party procuring the power (e.g. the regulator, for simplicity) would be financially settled by differences, e.g. if the procurement auction price is 50€/MWh whilst the spot market price in a given hour is 70€/MWh, the firm pays the regulator 20€/MWh, whereas it is the regulator who pays 20€/MWh to the firm if the spot market price is 30€/MWh.[112] Settling the contract by differences with respect to the

110. Harold Demsetz was the first to use this term (see Demsetz (1968)).
111. Large consumers, who are currently no longer able to purchase on regulated tariff and have to pay (indirectly) spot market prices, have started to raise this issue. For example, as published in *Cinco Días* and *El País* on 3 and 4 August 2008, the president of steel group Arcelor-Mittal stated that "the industry doesn't want subsidies or regulated tariffs…the aim is to achieve competitive prices with long-term forward contracts, based on actual generation costs, but not the marginal price system as is the case in the Pool". Similar concerns have been expressed in electricity markets in other countries.
112. Since these are long-term contracts, it might be advisable to use contract prices indexed to fuel prices (including $CO_2$ prices).

spot market price would help achieve productive efficiency and promote efficient consumption decisions. However, whilst this preserves efficiency, it does not imply that consumers pay (or firms receive) the amounts which result from applying the spot market price to all energy consumed and produced. Indeed, given that contracts are settled by differences, consumers effectively pay the contract price times the contract quantity. This implies that for those units subject to these contracts, future increases in spot prices would not generate significant variations in infra-marginal rents because the higher prices would imply increased payments for differences to the regulator (similarly, large reductions in infra-marginal profits would be avoided if spot prices were to fall). Last, these contracts could also improve the performance of the electricity spot market, given that an increasing fraction of all trades would be subject to these contracts for differences, and market power would be mitigated.

Another aspect that would need to be decided under this arrangement relates to the allocation of money that the regulator receives (or pays) when these contracts are settled by differences. One possibility is that such surplus (or deficit) is given back (or charged) to consumers as a lump-sum rebate (or lump-sum tax). It may also be used to reduce (increase) access charges or finance the costs of regulated activities or regulated subsidies (such as those received by renewable sources).

The issues discussed above are inevitably related to the issue of investment incentives, which is dealt with in more detail in Section 6.2.

**Box 5: Regulatory suggestions on VPP auctions**

**Volumes**

- Increase the volume subject to VPP auctions in order to mitigate firms' incentives to exercise market power.
- Increase lot sizes to favour entry by new agents in both the retail and wholesale markets (some models of competition in electricity markets also indicate that it may be advisable to concentrate virtual capacity amongst a smaller number of firms so that they can exercise greater competitive pressure).

**Delivery period and auction frequency**

- Introduce longer-term contracts. This reduces uncertainty for the buyers of the VPP products and can favour entry of potential investors. Longer contracts are also likely to enhance the market power mitigation effect of VPP auctions.
- Reduce the number of auctions by concentrating more volume in each one; increase the time lag between the date of the auction and the delivery period; and ideally establish a pre-defined timetable for VPP auctions, subject to review based on established competition indicators. These measures can reduce the incentive faced by generators to influence spot market prices in order to affect VPP auction revenues.

**Products and strike prices**

- Establish strike prices indexed to fuel prices, $CO_2$ prices, exchange rates, etc. (this can reduce the uncertainty faced by the bidders and ensure participation in auctions for long-term contracts).

## 6.2. The reform of capacity payments

As described in Section 4 of this report, the capacity payment mechanism was reformed in Spain in 2007. The new mechanism distinguishes between a payment for availability and an incentive for investment (determined as a decreasing function of the reserve index). In this section we will analyse some of the features of the new capacity payment mechanism.

### The regulator does not rely on energy-only markets

The reform of the capacity payment mechanism does not alter, but consolidates, one of the principles that have governed regulation in the Spanish electricity market: namely, that generation plants should be paid for being available, regardless of their production level. In other words, the Spanish regulator does not rely on an "energy-only market".

This is in line with the elecricity market design implemented in some countries, but in contrast with others. Whereas the British regulator eliminated capacity payments in 2001, several markets in the United States (including those in New England and Pennsylvania, New Jersey and Maryland (PJM)) have adopted types of capacity payments. The varied international experience reflects a lack of consensus on the need for having capacity payments in electricity markets.

Proponents of energy-only markets argue that capacity payments are not required to achieve an optimal level of total capacity in the market. They maintain that adequate investment incentives can be achieved through a combination of energy prices in the spot or forward contract markets, market-based payments for balancing services and long-term reserve contracts with the system operator. Arrangements to encourage demand-side responses (at least by some customers) can also be used to achieve optimal system reliability and lessen the need for additional generation capacity.

The energy-only market paradigm can be described as one with free entry and exit, and price-elastic demand. In such a market, the market would always clear: in times of excess demand, prices would increase until they exceeded the valuation of some consumers, who would then voluntarily exit the market until demand equated supply. If the price that consumers were willing to pay was greater than the average costs of the plants needed to meet their consumption, then investment would increase until total demand is satisfied. Thus, there would be no demand-rationing and hence no capacity problem. Moreover, if changes in relative input prices or technological progress gave rise to new and more efficient technologies, the technology mix would constantly be optimal through free entry and exit decisions. Competitive prices would make the break-even constraint binding for all technologies under the optimal investment program (for a numerical illustration, see Joskow (2007)).

Proponents of the energy-only market model also argue that, even if such an idealised energy market is not attainable, sufficient generation capacity and reserve can be procured directly by a

centralised transmission system operator through the use of market-based balancing and reserve contracts (including demand-side management contracts). These arrangements can provide adequate price signals for new investments without the need for an additional – and market-wide – capacity payment mechanism.

Supporters of the need for capacity payments argue instead that the necessary conditions for energy-only markets to generate social optimal solutions are not always met in real markets, and that some form of additional capacity payment mechanism is therefore required. This may be the case for several reasons.[113]

First, market power concerns at peak times often lead regulators to impose (explicit or implicit) price caps in energy markets. These can lead to a so-called "missing-money problem", i.e. market revenues are insufficient to cover the average cost of investments. For instance, Joskow (2007) argues that "regulators impose administrative price caps placed on prices for energy and ancillary services to deal with potential market power problems that are far below the Value of Lost Load (VOLL) that would clear the market when capacity is fully utilized" (page 4). When markets are subject to price caps, competitive peaking plants may find it difficult to cover their fixed costs.[114] The elimination of such caps would generate more earnings and lead to stronger investment incentives (see Box 6 for a stylised illustration of this issue). However, it might also create another distortion (i.e. greater market power and wealth transfers from consumers to producers) and might therefore not represent the appropriate second-best solution (if policy-makers care about distributional effects, rather than simply efficiency). Contracts for new capacity (described below) can be a way of mitigating market power whilst providing additional incentives for new capacity.

Second, price demand elasticity for most consumers tends to be very low[115], which increases the need for spare generation capacity (which the energy-only market may not be able to fully provide). This is for two main reasons: first, electricity is an essential input; and second, for most consumers retail tariffs do not vary on an hourly basis and hence demand does not respond to movements in spot prices.[116] The presence of subsidised retail tariffs (as is currently the case in Spain for many customers) can exacerbate this problem and actually lead to a need for excessive capacity.

113. For more details, see Cramton and Stoft (2006), Fabra (2007) and Joskow (2007).
114. There is empirical evidence that energy-only markets suffer from the "missing-money problem" since market revenues do not cover the fixed costs of peaking plants (see Joskow (2003) and Joskow (2007)). Based on evidence from New England, and assuming a marginal cost of between $50 and $100/MWh, Joskow (2003) estimates that annual profits of a modern gas turbine would be approximately $10,000/MW/year, much lower than an estimated investment cost of $60,000-$80,000/MW/year. However, as he also notes, the missing money problem cannot be attributed to price caps alone. In many generation markets in the United States, price caps are rarely binding, despite being far below estimates of the VOLL.
115. Some empirical studies estimate the elasticity of the demand for electricity of households to be between -0.2 and -0.4 (see, for example, Reiss and White (2005)). That means that households would reduce their consumption by 0.2%-0.4% over a year in response to an increase of 1% in the marginal price of electricity (given the existent electricity equipment). There are, however, variations in elasticity depending on the electricity equipment, levels of income and household electricity consumption.
116. In order to allow consumers to express their true price elasticity, it would be necessary to have more sophisticated meters, which could measure energy in real time. In Spain, the substitution of old equipment with new hourly meters has been encouraged since June 2006 (through RD 809/2006 of June 30).

Advocates of capacity payments also contend that, even if consumers could change their consumption in response to price changes, the need to maintain a socially optimal reserve margin over peak demand would not be avoided. There are technical reasons that justify this (e.g. real-time tariffs do not guarantee real-time demand adjustment), but also economic reasons (e.g. individual decisions only take into account the value of the energy that is consumed, but do not internalise the positive externalities generated by investments, as these improve system reliability from which all consumers benefit). These externalities arise from the virtual impossibility of storing electricity in a profitable way. This implies that all parts of the system must be perfectly synchronised, thus achieving an instantaneous matching of supply and demand at all times and at every point in the network. Failing to equalise demand and supply in any one point of the grid can have a contagion effect on the entire system and lead to power cuts to several consumers connected to the network. To avoid this, it is necessary to maintain a certain reserve margin between expected peak demand and installed capacity in order to be able to face possible variations in demand (e.g. due to seasonality and random shocks), as well as variations in supply (e.g. due to unplanned plant outages, grid congestions and lower levels of hydroelectric and wind power than expected).

Under these circumstances, investment in a new plant adds value to the system: even if the plant remains idle, it increases reliability for all users connected to the grid. System reliability therefore shares some of the features of public goods (e.g. "non-exclusion", meaning that once the good is produced, you cannot exclude others from consuming it), which can justify public intervention to guarantee a certain reserve margin. Transmission system operators can address this issue through markets for ancillary services (which contribute to balancing demand and supply in real time) and by signing out-of-market bilateral arrangements for reserve with certain generators. However, these mechanisms may not be sufficient to achieve the socially optimum level of the reserve margin, thus making an additional capacity incentive necessary.[117]

### "Availability" is distinguished from "investment"

Unlike the previous capacity payment system, the new mechanism introduced in Spain in 2007 distinguishes two concepts: a payment for availability and an investment incentive. Whereas the former is paid to all available units, the latter is only paid to new conventional units that enter the system.

117. The following quote by Joskow (2007) provides a good summary of the case made by proponents of capacity payments:
"Policymakers in many countries are concerned that competitive wholesale markets for electricity do not provide adequate incentives for investment in sufficient quantities of generating capacity or an efficient mix of generating capacity…There is now extensive empirical evidence that these concerns are valid…Electricity sector liberalization may not survive a period of underinvestment, increased hours of rolling blackouts, and higher probabilities of network collapses. A set of forward capacity obligation, capacity market, and capacity payment mechanisms can be implemented…to mitigate the missing money problem. These mechanisms can be designed to be compatible with improvements in the efficiency of spot wholesale markets, the continued evolution of competitive retail markets, as well as to restore incentives for efficient investment in generating capacity and demand response... Capacity obligation and payment mechanisms can also be designed to respond to investment disincentives that have been associated with volatility in wholesale energy prices by hedging energy prices during peak periods as well as responding to concerns about regulatory opportunism by establishing forward prices for capacity for a period of up to five years. These hedging arrangements also reduce the incentives of suppliers to exercise market power." (pages 34-35).

**Box 6: Investment in energy-only markets versus the social optimum**

Energy-only markets subject to price caps may generate under-investment with respect to the first-best social optimum.* The socially optimal capacity is such that the per-unit fixed cost of the new investment (here denoted $c$) equals consumers' maximum willingness to pay, i.e. the so-called value of lost load (VOLL, here denoted $v$). Whenever an investor expands its capacity, it incurs a unit cost equal to $c$ and receives the price cap P (in the stylised model considered in the example in this Box). If $P<v$ holds, the private gain is lower than the social gain, so under-investment results.

Consider the following duopoly model. In the first stage of the game, firms decide upon the scale of their investments whilst facing demand uncertainty (which, for simplicity, is assumed to be uniformly distributed between 0 and 1). Once capacity choices have been made (and observed), firms compete in a market organised as a uniform-price auction, i.e. all dispatched output receives the price-offer of the last accepted unit. In equilibrium, firms choose asymmetric capacities which sum up to $1-c/P$. Thus, aggregate investment is below the social optimum, $1-v/P$, and so is total welfare. Also, demand rationing occurs with positive probability, as aggregate capacity is below peak demand (normalised to $1$).

The table below reports the probability of demand rationing (the so-called loss of load probability, or LOLP), the share of consumer surplus over total surplus and the extent to which the market approaches the first best.

| Price cap | Loss of Load Probability (LOLP) | Consumer Surplus/Total Surplus | Total Surplus/Socially Optimal Surplus |
|---|---|---|---|
| $P = c$ | 100% | - | - |
| $P = v/4$ | 40% | 89.0% | 88.9% |
| $P = v/2$ | 20% | 64.8% | 98.8% |
| $P = 3v/4$ | 13.3% | 38.7% | 99.9% |
| $P = v$ | 10% | 12.0% | 100% |

Note: This assumes $v=1$ and $c=0.1$.

The results show that the LOLP is lower the higher the price cap relative to the value of lost load (VOLL). However, the LOLP is positive even when $P=v$, given that the social cost of demand-rationing is lower than the costs of additional capacity investments. The higher the price cap, the closer total welfare is to the social optimum. However, higher price caps also imply that generators obtain a larger share of total surplus. If the regulator is concerned about the distribution of total surplus (i.e. it does not weigh consumer and producer surplus equally), it will set an effective price cap at $P<v$. Hence, the social optimum will not be achieved. Introducing capacity payments under some circumstances can be a way of encouraging further investment and attaining a superior second-best outcome compared to the one obtained in an energy-only market.

* See Fabra *et al.* (2007).

It seems quite reasonable to introduce such an asymmetry between new and existing units, given that the latter are not making any new investment. However, what justifies the fact that generating units receive an extra incentive for availability? The greatest incentive to be available is provided by the margin between price and marginal cost, which is normally larger in peak demand hours when reserve margins are tighter. In other words, electricity prices should give companies the correct incentives to be available, aligning their incentives with the objectives of the tranmission system operator.[118] Why, then, should additional availability payments be introduced? Is it because market prices do not cover a sufficient proportion of the plants' variable costs? That possibility seems unlikely, given that plants, through their bids, are indicating the price at which they are willing to produce. Plants can simply bid at marginal costs to avoid producing when prices do not cover their variable costs (additional payments can also be obtained by providing ancillary services). Or is it because other kinds of strategic incentives may appear, for example, through the scheduling of maintenance? If so, the problem should be solved at its roots and not through this type of payments. For example, the transmission system operator could establish when firms should *not* schedule the maintenance of their units and introduce penalties if these indications are breached. The penalties could take the form (as contained in some regulatory proposals[119]) of a financial contract under which the generator pays the difference between market price and the price established in the contract if it is not available. Other options could be considered as well.

### The investment incentive is a decreasing function of the reserve index

The new investment incentive is a decreasing function of the reserve index, at least until the index is below 1.1 (at which point the payment is constant) and not above 1.29 (where the payment drops to zero). See illustration in Section 4.[120] This mechanism raises a number of issues.

First, the regulator seems to consider that the adequate reserve index is 1.1 (i.e. the adequate reserved margin is 10%), given that from 1.1 onwards, the payment decreases. But if the regulator knows what it wants, why look for indirect ways to achieve this capacity through the choice of a price-quantity scheme and not establish directly the desired reserve margin and let the market set the price at which the market is willing to deliver it (e.g. through an auction mechanism, as discussed below)?

Second, the design replicates a decreasing capacity demand curve, i.e. the price signal varies as a function of prevailing market conditions: the value of the new capacity is lower the larger the reserve index, so the capacity payment decreases. The same idea was implicit in the system for remunerating capacity that was in place in the United Kingdom before 2001. In the United

118. In other contexts a justification for the fact that plants should receive market prices (including low-cost generation such as wind, hydroelectric and nuclear power) is that this gives adequate incentives for plant availability. The same argument could be applied to this discussion.
119. For example, see Batlle *et al.* (2006).
120. As a positive indirect effect of this measure, the reserve index will be public, given that it is necessary for calculating the investment incentive.

Kingdom, the capacity element of the price received by generators was also higher the greater the LOLP, which was in turn a function of both demand and firms' declarations of available capacity. This formula implied that if generators predicted that some units would not be dispatched in the market, they had incentives to declare them unavailable in order to increase LOLP and thus capacity payments.[121]

The fact that payments are a decreasing function of the reserve index may induce companies to invest until the desired level of capacity is achieved. Nevertheless, reaching the maximum of the capacity payment schedule may be difficult because it requires a degree of coordination in firms' investment decisions (which are discrete, occur over time and are undertaken by heterogeneous firms). Given this complexity, it is possible that investments would fall short of achieving the 10% reserve margin target in order to avoid reaching the downwards sloping part of the capacity payment schedule. Note that reaching this segment of the schedule would reduce capacity payment in the current period as well as in future years, given the long life of these assets. On the other hand, one could also argue that competition among investors could lead to over-investment, as firms would "race" to be the first to build new plants and receive the higher capacity payments associated with a lower reserve margin. This incentive could, however, be mitigated: by over-investing today, a firm may also hurt its own future investment projects. Moreover, when firms have market power, the intensity of competition depends on available capacity. This implies that investment may not be profitable even when current prices cover investments costs. This further reduces the risk of over-investment.[122]

Third, there is typically a long lag from the moment in which an investment decision is undertaken and the time when the new plant is actually operational. The fact that the capacity payment is a function of the reserve index when the plant is on line introduces some uncertainty in decision-making[123], and thus higher risk *premia*. Moreover, such uncertainty may harm smaller investors more than larger ones for two reasons: small firms tend to be more risk averse and they have less precise information on the future value of the reserve index than larger firms, as the latter control a much larger fraction of the projects under construction. Similarly, investment in capital-intensive projects may be discouraged, as they require longer construction periods and thus involve greater uncertainty concerning the reserve index that will prevail by the time such projects are finished.

These issues illustrate some of the difficulties that the new capacity payments could raise. Such complexities give support to the following open question: if the regulator knows its target reserve index, why does it not induce it directly by setting quantities rather than using a complex

121. This possibility for strategic behaviour, as discussed by Wolak and Patrick (1996) was one of the triggers for the suppression of capacity payments in the United Kingdom.
122. For a discussion of this effect, see Fabra *et al.* (2007).
123. There are numerous examples that illustrate the difference that can arise between the level of installed capacity when an investment decision is made and when it is completed. For instance, the data in Section 5 of this report show that in some years overall generation investment increased by a very significant amount. Despite being a special case, investment in solar energy in Spain in 2007-2008 also provides an example of this: from September 2007 to September 2008, solar power grew by more than 500% and may exceed 1,500 MW by the end of 2008.

mechanism that fixes quantities and prices with no guarantee that firms' decisions will indeed deliver the desired reserve index?

### The possibility of capacity auctions is introduced

One of the regulatory changes introduced together with the new capacity payments is the possibility of holding auctions for new capacity. Under this method, the regulator would directly assume the responsibility for achieving the target reserve margin and would use auctions as an instrument to ensure that the market delivers it. These auctions could adopt different formats. One option is that investors compete over the capacity payment that they require in order to carry out the new investment. On top of such payments, the new capacity would also receive market prices in the wholesale market for their electricity production. An alternative option (which has already been briefly discussed in Section 6.1) is that investors compete over the price of a longer-term contract with the regulator for delivering a fixed volume of energy produced with the new capacity. All energy would still be traded in the wholesale market and the contract would only affect the financial settlements between the firm and the regulator.

Note that, in contrast to the newly introduced capacity payments, the use of capacity auctions implies that the regulator chooses the quantity and lets the market determine the price. Under idealised conditions, there is a one-to-one correspondence between price and quantity instruments: using a quantity instrument always imposes a corresponding implicit price, and vice versa. However, such equivalence breaks down under not-so-ideal conditions, notably, under uncertainty. Given that uncertainty is intrinsic to investments in electricity generation capacity, it is important to understand the pros and cons of using capacity auctions rather than capacity payments.

We will not compare these two instruments in all their dimensions in our discussion. However, there are some features that indicate that capacity auctions could prove more effective than capacity payments. First, capacity auctions would avoid administratively determined payments, as these would be competitively determined through the bidding process. Moreover, unless very few firms participate in the auction (something that can in principle be avoided through an adequate auction design), the regulator would ensure that its desired reserve margin is achieved. Finally, if the new plants are subject to long-term contracts that take the form of forward contracts, the performance of the spot market will improve, as market power will be mitigated.[124]

Capacity auctions could also give the regulator more flexibility in achieving other goals. For instance, the regulator could take into account changes in the technology mix which affect the

124. In other markets, auctions are already being used in order to procure new generating capacity (although the details of the mechanism may differ in some ways from the one proposed here). For example, in New England and Colombia, forward long-term contracts are being awarded through auctions to generators, thus allowing potential investors to participate in these auctions, given that delivery is not required until four years after the award of the contracts (in the Colombian case, for large investments in hydroelectric power, a period of seven years until the delivery of the energy is allowed). Companies that are awarded these contracts are subject to forward contracts whose aim is to mitigate their (potential) incentives to exercise market power in the spot market.

**Box 7: Designing capacity auctions to address participation and collusion concerns**

Auctions are a common mechanism to assign goods and determine prices. Their correct performance depends on an adequate design that is suited to the type of good or service being auctioned, and the number and characteristics of potential bidders, etc.* There are two critical questions for auctions to be competitive: there must be a large number of active bidders, and collusion to raise prices or divide the market must be avoided. Auction design, eligibility requirements and the characteristics of potential bidders affect both issues.

**Participation**

To boost participation, it is necessary to have simple auction rules. In principle, there is no need for capacity auctions to be complex. A design based on simultaneous ascending auctions, which may require several bidding rounds (as in case of procurement auctions and VPP auctions, as described in Section 4 of this report), would not be necessary, given that there are no significant synergies and/or complementarities between the goods that are auctioned. A simple design, such as a sealed-bid auction, could generate good results.

The existence of asymmetries between potential bidders may discourage the participation of weaker bidders (e.g. smaller investors facing vertically integrated incumbents). To avoid this, it is possible to reserve a percentage of the auctioned capacity for new entrants (e.g. this was done in the allocation of spectrum licenses in some countries such as the United Kingdom), limit the maximum amount of capacity that may be awarded to a single bidder, reduce participation costs through minimum requirements for bidder eligibility and, again, choose a sealed-bid format which tends to generate higher participation rates.

**Collusion**

Collusion concerns should not be an obstacle to the use of capacity auctions. This is so for a number of reasons related to the features of these auctions as well as the possibility of mitigating the risk of collusion through an adequate design. For example, the fact that capacity auctions determine a fixed-price formula for the new plant's lifetime and the fact that these auctions are not frequently repeated (e.g. once a year) should make collusion difficult. If an investor decided to deviate unilaterally from the collusive agreement, its behaviour could only be punished, say, one year later, assuming that the investor participated in the auction again.

Given that the firms that participate in these auctions are also simultaneously present in other markets (e.g. they sell electricity in the spot market and probably also in the retail market), more immediate penalties in case of deviations from the collusive agreement are available. In principle, this could facilitate collusion in capacity auctions (i.e. it could be seen as a source of "multimarket contact"). Nevertheless, this suggests that new entrants who are not yet present in the spot market or in the retail market are not likely to suffer from these penalties. Hence, they would have a relatively advantageous position in the capacity auctions, thus increasing the possibility that the collusive arrangement would be broken.

* For a discussion of some of these issues, see Klemperer (2004).

desired reserve margin by adjusting the levels of capacity procured in each auction. The regulator would also have the flexibility to impose (or not impose) additional conditions on the auctions: e.g. on bidder eligibility, if it only wants small firms to participate in order to dilute market concentration; or on the technology to be procured if it wants to favour the development of renewables or achieve a specific level of technological diversity to improve energy security. This degree of flexibility should not generate regulatory uncertainty (as could be the case with other types of interventions), since it would not affect payments for existing generation nor those for the capacity that would be procured in future auctions.

However, for these auctions to perform well, there are some important issues related to auction design that would need to be addressed. They are discussed in Box 7.

### Summary

In short, replacing the previous capacity payments (the so-called *garantía de potencia*) with the new ones constitutes a nominal change insofar as the new payments are still administratively determined (in spite of the greater sophistication that has been introduced). However, the new design also has some implicit characteristics that are conceptually new, such as the fact that generators no longer receive uniform payments (i.e. if two plants enter the market in different years, their payments differ). In order to increase the effectiveness of the new capacity payments, it would be advisable to also rely on the possibility (already considered by the regulator) of using auctions as a mechanism for assigning new capacity and determining (through market-based mechanisms) the level of capacity payments implicit in long-term procurement contracts. The existing procurement auctions could evolve and provide a model for these capacity auctions or similar auctions for long-term contracts.

# 7. Conclusions on Key Themes in the Spanish Gas and Electricity Markets

This report has provided a broad overview of the recent performance of the Spanish gas and electricity markets from a competition and regulatory perspective, and has set it in the broader context of the European energy industry. A number of key analytical themes have emerged from this review which we will comment on in this last section of the report.

## 7.1. Trends in wholesale gas competition

Gas-demand growth in Spain remains high, fuelled by the expansion of gas-fired electricity generation. This has opened the market for the entry of new players that rely on LNG imports. However, Gas Natural still accounts for roughly 60% of overall gas procurement, due to its position in the regulated gas market and the fact that it supplies gas to some of its rivals in the retail market. Though its incumbency position is being eroded over time, it still remains significant.

The growth in LNG imports makes Spain one of the most diversified gas importers in Europe, with no single gas source accounting for more than 40% of flows in 2007, and with a number of alternative gas suppliers available. The prevalence of LNG over pipeline gas is also unique in Europe and makes Spain particularly well positioned to benefit from greater gas-to-gas competition (mainly in the form of competition between LNG-exporting countries) if this were to develop to a significant extent in the future. However, current wholesale gas prices (both for LNG and pipeline gas) remain largely linked to oil prices rather than to short-term competitive dynamics within the international gas market. This, coupled with Spain's practically complete reliance on imported gas and oil, makes the Spanish energy market very exposed to fluctuations in international oil prices. This was brought into stark evidence in the first half of 2008, when crude oil prices reached unprecedented levels (increasing by 50% relative to 2007) and significantly affected the Spanish gas and electricity markets.

The most dynamic segment in the Spanish gas market remains the CCGT sector, driven by the significant entry of new CCGT generation capacity. Demand from CCGTs has more than doubled in the past four years. This has allowed electricity firms that self-supply their own CCGTs (most notably Iberdrola and Unión Fenosa) to acquire a significant position in the overall liberalised gas market. In turn, this has stimulated competition in the industrial gas market by giving entrants the required scale and flexibility to compete for customers. Gas Natural's share of both the CCGT and industrial gas markets has dropped as a result, bringing its overall share of the liberalised gas market to below 50%. This makes Spain one of the best performers in Europe in terms of gas competition for industrial customers and power producers.

### 7.2. Competition and trends in the wholesale electricity industry

The issue of market power (and related mitigation measures) in the Spanish generation market has dominated the policy debate since the liberalisation of the sector in the late 1990s. Electricity generation markets are known to be prone to the exercise of market power, especially in the presence of a concentrated market structure such as the one present in Spain at liberalisation.

Over time, the structure of the generation market in Spain has become significantly less concentrated and market power is less of a concern now than it was when the sector was first liberalised. This has been primarily driven by the entry of new CCGT capacity, most notably by the gas incumbent, Gas Natural, but also by independent firms and the smaller electricity firms (predominantly Unión Fenosa to date). As a result, the combined share of conventional output and capacity held by the top two generators dropped from 80% in the late 1990s to approximately 60% in 2007. The CCGT segment of the generation merit order (which is the most important price-setting and marginal technology in the market) is also significantly less concentrated than the overall market. This has been a helpful development, as it can be expected to have constrained the prices set by the main generators.

Our analysis also shows that, as a result of the growth of independent generation, Endesa and Iberdrola are practically no longer pivotal (i.e. required to produce in order to meet total system demand) in the Spanish generation market. On the other hand, large generators can influence prices even when they are not pivotal, since they may still face a relatively inelastic demand. Moreover, the two incumbent generators remain jointly pivotal in a significant number of hours. This, even in the absence of any form of tacit coordination, may result in prices that lie above competitive levels. The HHI for the Spanish generation market, under a narrow definition of the market that excludes special regime generation and producers located in Portugal, also remains at levels which are typically associated with concentrated markets. This is not so when considering broader definitions of the market (including special regime and/or all generation in the Iberian Peninsula). A continuing focus by the government and the regulator on market-power miti-

gation measures (reviewed below) is therefore still warranted, but this does not mean that this is necessarily the area where the greatest regulatory effort should be addressed at this stage.

Another notable feature of the Spanish wholesale electricity market has been the growth of renewable generation in the overall fuel mix. Wind power alone accounted for 16% of total installed capacity in 2006 and is set to exceed 20% by 2011. Incentives towards renewable generation have been very considerable, but may not necessarily reflect the true value of the positive externalities associated with this type of electricity. A better empirical assessment of these externalities and resorting to market-based mechanisms to procure the correct amount of renewable generation are both needed in the future to preserve an appropriate energy mix, and contain energy costs.

Special regime (which also includes some renewable sources) and CCGT generation currently represent over 50% of total installed capacity in Spain. This share is set to reach two thirds of the market by 2011, potentially creating an unbalanced energy mix. The issue of how to deal with the projected growth of these technologies in the overall energy mix poses a difficult regulatory challenge for the near future.

### 7.3. Electricity market reforms

The electricity market has been subject to several different regulatory reforms since it was liberalised. This has contributed to a significant degree of regulatory instability over the years. This report has reviewed several of the policy reforms recently introduced in the electricity market. These include the following:

**VPP auctions.** The imposition of VPP auctions on Endesa and Iberdrola starting in mid-2007 represents the main recent attempt by the government to mitigate market power in generation markets. This can be seen as a way, on a much reduced scale, to fill part of the vacuum left by the abolition of the CTCs (which had indirectly constrained wholesale prices in the early years of the market, but lost effectiveness over time and were formally abolished in 2006). These auctions still cover a relatively limited amount of energy (i.e. reaching a maximum of 1.25 GW per company in mid-2008) and are far below the levels recommended in the White Paper of 2005 on the Spanish generation market, which computed VPP requirements of 5-6 GW of peak capacity per firm in 2008. Moreover, there are several auction design considerations which are likely to reduce the effectiveness of these capacity releases (at least compared to outright plant sales). These most notably include the short duration and frequent repetition of auctions. It is therefore unlikely that VPP auctions alone (at least in their current format) can significantly improve competition in the Spanish generation market.

**Bilateral trading.** A number of recent measures have also been introduced to expand further bilateral trading in the Spanish wholesale market and shift volumes away from the day-ahead spot market. This drive started in 2006, when a large share of the volumes traded in the wholesale market were effectively treated as bilateral trades within vertically integrated firms and priced at a level below the spot price. This was a highly inefficient measure, whose main aim was to reduce procurement costs and reduce the growing tariff deficit. It created a significant market distortion, which eventually manifested itself in a rise in volumes sold in the balancing and congestion management market (by Iberdrola) and a very steep increase in the cost of these services. The measure was effectively removed at the beginning of 2007, at the same time as a formal market design for bilateral contracts was introduced in the form of procurement auctions for regulated electricity demand (CESUR). As discussed in the main body of this report, these procurement auctions may have some positive aspects (e.g. they can stabilise the energy component of the electricity tariff if they are sufficiently long, and can therefore improve the tariff-setting process), but it is unlikely that they will mitigate market power and constrain spot prices unless they are held well before the delivery period. However, procurement auctions could be used in the future to procure longer-term contracts, thereby facilitating entry.

**Deduction of windfall gains from the Emission Trading System**. The measure applied by the government to remove the windfall gains that can accrue to generators from the operation of the ETS for the 2006-2012 period has reduced wholesale electricity procurement costs (relative to a counterfactual without such a clawback). Whilst this measure is playing a significant role in reducing the size of the electricity tariff deficit, it is not a structural measure that can be expected to improve the workings of the wholesale market over time and its scope is limited only to the impact of carbon pricing.

**Electricity capacity payments**. The capacity payment mechanism was also reformed by the government in 2007. The new system is similar to the old one in that it still relies on administratively determined payments for capacity. To make the system more effective, it would be advisable to rely more extensively on auctions as a mechanism to allocate and determine capacity payments. These auctions could be combined with the existing procurement auctions and be used to allocate longer-term energy contracts to potential investors, thereby making the market more contestable. We develop a number of proposals to this effect in the main body of the report.

**The electricity tariff deficit**. As a result of an explicit policy decision by the government, retail tariffs have not been increased in line with wholesale electricity prices in recent years. This has resulted in the emergence of a significant tariff deficit (especially in 2005-2006 and again in 2008). Setting retail tariffs below market-based prices sends the wrong pricing signals in the short run to consumers (by under-pricing electricity). This is particularly the case given that the primary determinants of recent increases in electricity prices appear to have been increases in international fuel prices, which should be reflected in retail prices. Keeping prices artificially low – and not allowing for real-time pricing, at least for some customers – can lead to excessive (and inefficient) levels of electricity demand and installed generation capacity. The growing tariff

deficit also prevented the emergence of effective competition in the residential electricity (and dual-fuel) market at least until the end of 2006 (when the tariff design was reformed). This is an added (but probably smaller) source of inefficiency due to the tariff deficit.

The measures described above have effectively taken place within the same fundamental market design for electricity and deal directly or indirectly with aspects of the design of the market, but not with its structure. The experience of other liberalised generation markets (most notably the British one) shows that structural interventions remain the most effective way to achieve a more competitive market. In Spain the entry of CCGTs by smaller firms has improved the competitive structure of the market, even though this can only gradually reduce concentration levels. Another effective way to improve the structure of the market would be to increase interconnection with neighbouring systems, including Portugal (in the context of MIBEL) and France. Merger control and associated remedies can also be used to encourage a more competitive generation structure (as has been done recently by the European Commission and earlier by the British authorities). The recent divestments by Endesa to E.On/Viesgo will improve the generation market structure (even though they are not the result of regulatory intervention). However, this lever also has limitations (most notably the fact that merging parties need to agree to the proposed remedies).

### 7.4. Liberalisation of the residential energy markets

The evidence reviewed in this report shows that the progress of entrants in the Spanish residential energy sector is limited, despite the fact that the market has been fully open to competition for more than four years.

Residential markets continue to be dominated by the incumbent suppliers, who own the distribution network. For most Spanish customers (more than 80%), the incumbent providers are either Endesa or Iberdrola in electricity supply, and Gas Natural in gas supply. On average (across all regions), fewer than 5% of all electricity customers have switched away from their incumbent suppliers in electricity, and only roughly 10% in gas. This is partially because switching away from the regulated tariffs remains limited (especially in electricity, where on average fewer than 10% of customers were on market prices in 2007). Moreover, of those customers who did switch contracts, the clear majority remained with their incumbent suppliers (roughly 75% of switchers in both gas and electricity during 2007). However, residential switching behaviour is not dissimilar to several other countries in Europe, some of which have even lower levels of effective switching. It is also worth emphasising that what matters for consumers is the price they pay and the quality of the service obtained. Credible potential competition (e.g. in the form of competitive dual-offers from the owner of the electricity network for gas customers, and vice versa for electricity) may deliver this without the consumer needing to switch from the incumbent.

The reasons for the slow progress of entry in electricity retail are well known. The presence of a severe tariff deficit in 2005 and 2006 (coupled with an inefficient design of the regulated tariff) implied that margins for retailers trying to compete with the regulated tariff were negative, inducing them to reduce their presence in the market (this has particularly been the case for Iberdrola and, more recently, Gas Natural). This situation was to some extent corrected in 2007 with the move to ex-ante recognition of the deficit. It is possible that over time the fact that the tariff deficit is reflected ex-ante in the tariff (and that access charges are lowered to offset it) will allow electricity retail competition to develop (as the greater levels of switching seen in the second half of 2007 appear to indicate). However, the elimination of the deficit from the current tariff level would be a more effective and efficient way of guaranteeing a level playing field in the retail market, as it would also send more efficient signals for electricity consumption. It is therefore disappointing that the government adjusted retail tariffs in July 2008 much less than what the CNE had recommended (an 11% rise) to prevent a further increase in the tariff deficit in 2008 relative to the levels recognised ex-ante when the initial tariffs for 2008 were set.

The slow progress in residential gas entry is arguably due to a combination of general customer inertia in residential markets (which is also evident in other European countries), the vertical integration of distribution and supply, and the indirect impact of the electricity tariff deficit. The latter is impeding entry in gas, since an effective way to enter the residential market is through dual-fuel offers that combine gas and electricity. This means that the most effective actual and potential entrant in each electricity distribution area tends to be the gas incumbent and vice versa. The evidence from switching patterns in Spain over the past four years indicates that this is likely to be the case also in Spain. However, dual-fuel competition has been impeded by the presence of an electricity tariff deficit, since this has made the margin on the electricity component of the dual-fuel offer negative. This appears to have discouraged the entry of electricity firms in residential gas markets, just as it discouraged the entry of gas firms into electricity markets. Over time, the lifting of inefficient regulatory constraints should enable more effective retail competition to develop. In the transition to a fully liberalised residential electricity market, tariffs of last resort reflecting market prices should however be maintained.[125]

## 7.5. Regulatory instability

The recent application of regulation and competition policy in the Spanish gas and electricity markets has been unstable, which is contributing to a high degree of regulatory uncertainty. Whilst some degree of regulatory risk is unavoidable in a complex and highly regulated market like the energy market, the extent of regulatory instability exhibited in the Spanish energy industry since liberalisation has been excessive. There are several examples of this:

125. Different structures could be considered for such tariffs. See, for example, the proposals contained in Joskow (2000) and the current structures of retail tariffs currently in place in the Norwegian retail electricity market (see von der Fehr and Hansen (2008)).

- Merger control has not been applied on a consistent basis over the past few years, with one relatively small transaction (Unión Fenosa/Hidrocantábrico) blocked outright without remedies and another (Gas Natural/Iberdrola) blocked on ill-defined regulatory grounds and not subject to a proper competition assessment. The inconsistent recommendations of the sector regulator and the competition authorities on the Gas Natural/Endesa merger further increased the uncertainty over the application of merger control in the industry.

- As reviewed above, the overall design of wholesale electricity markets has been subject to some significant interventions over the past few years (some of which have been distortionary). These measures included the temporary imposition of a effective price cap on significant amounts of wholesale volumes in 2006 and continuous changes in the mechanism for remunerating capacity. This increased regulatory risk, especially for smaller players and potential new entrants with less knowledge of the sector and less ability to manage risks.

- The policy towards incentives for renewable energy has not been stable over time and is not grounded in robust economic analysis. The uncertainty in 2008 over the remuneration for solar energy starting in 2009 is a case in point.

- Regulation of the electricity retail markets has also been highly unstable. The fact that retail tariffs are increased on a discretionary basis by the government, coupled with the fact that they have not been adjusted in line with market prices, has clearly made it difficult for independent retailers to enter successfully. Regulatory reforms implemented in 2007 have changed this position, but it will likely take time before significant independent entry emerges in the Spanish retail energy markets.

### 7.6. Policy recommendations

The policy recommendations that can be derived from our analysis of the recent performance of competition and regulation in the Spanish gas and electricity markets are the following:

- **Encourage a balanced energy generation mix and demand control using market-based tools**

The Spanish energy market is currently heavily reliant on imported gas, and is directly exposed to variations in international gas (and oil) prices. In order to increase energy security and contain future energy costs, there is a need to further diversify energy sources. In practice, this means continuing to encourage renewable energy, but balancing its costs by taking into account well-defined and measured positive externalities that can be associated with this type of generation. Mechanisms should also be explored to preserve the current role played by nuclear and coal power in the overall energy mix over the medium-term (as long as this can be shown to be cost-efficient and consistent with environmental objectives).

Market-based measures to procure additional generation capacity should be considered to determine an adequate remuneration level for new capacity, promote an appropriate energy mix and make the market more contestable.

More decisive efforts to encourage energy savings and greater demand-side responsiveness to market prices are also required. Price signals for end consumers should be improved both in the short term (by allowing for more effective time-of-day pricing), and also in the longer term (by gradually eliminating the electricity tariff deficit).

- **Adjust electricity retail tariffs to prevent a further accumulation of the tariff deficit, and provide the correct price signals to consumers**

Regulated tariffs for electricity in Spain are still set below wholesale market prices. This is an unsustainable situation and it does not send the correct market signals to end users for electricity consumption (at least over the medium/long term). The absence of time-of-use tariffs, coupled with the fact that retail prices have been kept artificially low for a significant period of time in Spain, is likely to lead to excessive demand levels and therefore require inefficient levels of installed capacity. The fact that regulated tariffs are below market-based prices has also distorted competition both in the retail electricity market (at least up until the end of 2006) and in the related dual-fuel market (thus affecting competition for residential gas customers). There is a critical need for retail tariffs to be adjusted according to a well-defined and credible timetable to bring them in line with market prices and prevent a further accumulation of the tariff deficit. This should be implemented at the same time as measures aimed at enhancing competition in the wholesale electricity market are strengthened. Over time, ending the policy of subsidising retail tariffs could, as a secondary objective, also allow for more effective and faster liberalisation of both the gas and electricity markets. Before lifting retail price controls, the regulator would, however, need to ensure that sufficiently intense competition is present between firms in the relevant downstream markets.

- **Render market power mitigation measures in the generation sector more effective**

The market power mitigation measures introduced by the government in the generation market can be made them more effective. This applies in particular to VPP auctions implemented since mid-2007. In order to be more effective, VPP contracts of a greater size and duration are required. On the other hand, procurement auctions like CESUR should not be seen as a market power mitigation measure (since participation by generators in this type of auctions is not compulsory). The mitigation of market power in the generation market is, however, probably less critical now than it was when the market was first liberalised, thanks in part to the growth of independent competitors.

- **Induce an efficient firm and market structure**

Artificial legal or regulatory impediments to efficient corporate restructurings in the energy sector responding to technological and market trends or arising from the market for corporate control should be removed. Where possible, structural market reforms (including measures to favour greater interconnection with neighbouring countries, such as France and Portugal, and more significant domestic gas storage capacity) should be used to improve the functioning of the Spanish energy markets. Following the examples of regulators in other countries, and more recently the European Commission, both merger control and antitrust enforcement could be used more effectively in the future to obtain remedies that can improve the structure of the market, thus making competition more effective.

- **Improve regulatory stability**

There have been a myriad of regulatory initiatives taken by the government over the past two years. These have increased regulatory instability and created a complex regulatory framework. There is a need to promote regulatory stability over time (to the benefit of both firms and consumers), at the same time as improving regulation where possible with selected and targeted policy measures. Competition policy towards the sector also needs to be applied consistently within the E.U. framework, and be based on sound effects-based economic principles - both in terms of merger control and antitrust enforcement. Merger policy should enable corporate restructurings that are consistent with effective domestic competition, and that can also allow energy companies to become more efficient and acquire critical scale on international energy markets (e.g. with enough size to secure input supply at reasonable prices). Similarly, regulatory compensation mechanisms for renewable energy (e.g. wind and solar power) need to be set up on the basis of robust economic methodologies. This would also promote regulatory stability for new investments. Finally, the policy towards regulated electricity tariffs should be used to achieve and maintain an efficient and competitive energy market, but not to pursue other objectives (such as inflation control).

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# Annex 1: Regional Data on the Spanish Gas and Electricity Markets in 2007

This annex contains a series of regional statistics on the Spanish gas and electricity markets in 2007. This provides a more detailed breakdown of the data contained in the main report (primarily in Section 5). The data contained in this annex refer to peninsular Spain only (i.e. they do not include the islands and Spanish territories outside the main peninsula).

## Gas

Table A.1 shows the levels of gas imports and gas demand by region in 2007. Gas imports are allocated by region on the basis of the location of the entry points, either for pipeline gas (which enters the Spanish territory in Andalusia and Navarra) or LNG (with terminals located in Andalusia, Valencia, Catalonia, Galicia, Murcia and the Basque Country). The location of these gas import connections imply that Andalusia is the region with the largest gas export position relative to the rest of the country (+89 TWh), followed by Navarra (+14 TWh) and Valencia (+12 TWh). Other regions with a positive gas balance include Murcia, the Basque Country and Galicia. Regions with large gas deficits (due to their geographical location) include most notably Madrid (-28 TWh), Castilla La Mancha (-22 TWh) and Castilla y León (-21 TWh).

Table A.2 provides further details on gas demand by region, distinguishing between ordinary demand (for non-electricity use) and demand from the electricity sector (primarily for production by CCGT plants). Overall, the regions with the highest levels of gas demand are (in this order) Catalonia, Andalusia, Valencia and the Basque Country (which jointly account for 60% of total national gas demand). If one considers only ordinary gas demand (for residential and industrial use, excluding the electricity sector), the relative regional position changes: the regions with the largest ordinary gas consumption are (in this order), Catalonia, Valencia, Andalusia, Madrid and the Basque Country. These five regions jointly account for two thirds of total national demand for gas. The highest levels of gas demand for the electricity sector were realised in Andalusia and Catalonia (which jointly represented 46% of total gas demand for electricity), due to the presence of a significant amount of CCGT capacity in these two regions. Murcia and the Basque Country also had significant amounts of gas demand for electricity generation in 2007.

Table A.3 shows the evolution of gas liberalisation by region, both in terms of volumes and customer numbers. Overall, close to 90% of gas volumes are consumed at market prices. Regions with a particularly high share of liberalised gas demand include Murcia, La Rioja, Andalusia, Cantabria, Valencia, the Basque Country and Navarra (all above 90%). These regions (with the exception of Cantabria) tend to be those with relatively high gas demand per customer, due to the presence of significant CCGT and industrial gas consumption. In terms of customer numbers, the regions with the highest share of liberalised customers are the Basque Country (over 80%) and Asturias (over 50%). This appears to be driven by the commercial policy of the incumbent gas supplier (Naturgas, part of the EDP/HC group). Most other regions have liberalisation rates in the 30%-40% range,

with the notable exception of Extremadura, where only 2% of customers have switched away from the regulated tariff.

Table A.4 shows the shares of liberalised gas customers by firm and region at the end of 2007. As discussed in the main report, there is significant regional variation in market shares, primarily driven by the identity of the owner of the regional gas network, which also tends to be the largest supplier of liberalised gas customers. EDP/HC is the largest gas supplier by some margin in Asturias and the Basque Country (where it owns the distribution network), whilst Endesa is the largest firm in Aragón. In all other regions (with the exception of Extremadura), Gas Natural is the biggest supplier of liberalised gas customers (with a market share of 60% or more in all regions). Regional concentration indicators (as measured by the HHI) tend to be significantly higher than the equivalent national measure. The regions with the highest concentration indices are Asturias and the Basque Country (both at or above 8,000). However, this mainly reflects the fact that a very high share of customers have switched away from the regulated tariffs in these two regions and have remained with the local gas supplier. A high concentration indicator in this case does not mean that competition is weaker in these regions than in other areas (where a greater share of customers still consume on regulated tariffs and are therefore still effectively served by the incumbent supplier).

## Electricity

The tables included below also present regional information on the electricity markets. Regional data at the retail level are not publicly available in the case of electricity and we therefore mainly present data on the wholesale market.

Table A.5 shows the distribution of installed capacity by region at the end of 2007. The regions with the highest levels of capacity (all in excess of 10 GW) were Andalusia, Castilla y León, Catalonia and Galicia. Regions with relatively limited generation capacity (less than 4 GW) included Asturias, Cantabria, La Rioja, Madrid, Navarra and the Basque Country. Castilla y León had the highest levels of hydroelectric and coal capacity in Spain, and close to the highest level of wind power. Andalusia and Murcia had the highest levels of installed CCGT, followed by Valencia, Catalonia, the Basque Country and Aragón. Almost 50% of nuclear power (3.1 GW out of a total of 7.7 GW) was located in Catalonia.

Table A.6 sets out the levels of generation and net demand by region in 2007. The regions with the highest generation levels were Catalonia and Andalusia (both in excess of 40 TWh). Demand in these two regions was also the highest in Spain, at 47 TWh and 40 TWh, respectively (implying that Catalonia is a net importer of electricity). The other regions with relatively high levels of electricity demand (in excess of 20 TWh) included Madrid, Valencia and the Basque Country. All three regions had relatively large electricity deficits (equal to -30 TWh, -13 TWh and -10 TWh, respectively). Regions with significant electricity surpluses included Castilla y León (19 TWh), Extremadura (13 TWh) and Galicia (9 TWh).

## Annex Tables

*Table A.1 Gas imports and demand by region, GWh, 2007*

| Region (Autonomous Community) | Gas Imports (by entry point) | Gas Demand | Net Position |
|---|---|---|---|
| **Andalusia** | 160,711 | 71,530 | 89,181 |
| **Aragón** | | 19,988 | -19,988 |
| **Asturias** | | 5,405 | -5,405 |
| **Valencia** | 59,035 | 46,567 | 12,468 |
| **Cantabria** | | 7,398 | -7,398 |
| **C. La Mancha** | | 22,312 | -22,312 |
| **Castilla y León** | | 21,218 | -21,218 |
| **Catalonia** | 70,013 | 84,328 | -14,315 |
| **Extremadura** | | 768 | -768 |
| **Galicia** | 8,909 | 7,763 | 1,146 |
| **La Rioja** | | 10,774 | -10,774 |
| **Madrid** | | 27,565 | -27,565 |
| **Murcia** | 38,122 | 29,636 | 8,486 |
| **Navarra** | 26,306 | 11,673 | 14,633 |
| **Basque Country** | 45,532 | 41,509 | 4,023 |
| **Total** | **408,628** | **408,434** | **194** |

Source: Enagás, own calculations.
Note: The balance between demand and imports is accounted for by domestic gas production, storage and exports.

*Table A.2 Gas demand by region and type, GWh, 2007*

| **Region (Autonomous Community)** | Ordinary Demand | Demand for Electricity Use | Total | % of Ordinary Demand | % of Demand for Electricity Use | % of Total Demand |
|---|---|---|---|---|---|---|
| **Andalusia** | 31,059 | 40,471 | 71,530 | 11.7% | 28.5% | 17.5% |
| **Aragón** | 14,226 | 5,762 | 19,988 | 5.3% | 4.1% | 4.9% |
| **Asturias** | 5,405 | | 5,405 | 2.0% | 0.0% | 1.3% |
| **Valencia** | 35,956 | 10,611 | 46,567 | 13.5% | 7.5% | 11.4% |
| **Cantabria** | 7,398 | | 7,398 | 2.8% | 0.0% | 1.8% |
| **C. La Mancha** | 12,548 | 9,764 | 22,312 | 4.7% | 6.9% | 5.5% |
| **Castilla y León** | 21,218 | | 21,218 | 8.0% | 0.0% | 5.2% |
| **Catalonia** | 59,276 | 25,052 | 84,328 | 22.3% | 17.6% | 20.6% |
| **Extremadura** | 768 | | 768 | 0.3% | 0.0% | 0.2% |
| **Galicia** | 6,909 | 854 | 7,763 | 2.6% | 0.6% | 1.9% |
| **La Rioja** | 2,809 | 7,965 | 10,774 | 1.1% | 5.6% | 2.6% |
| **Madrid** | 27,565 | | 27,565 | 10.3% | 0.0% | 6.7% |
| **Murcia** | 9,974 | 19,662 | 29,636 | 3.7% | 13.8% | 7.3% |
| **Navarra** | 5,324 | 6,349 | 11,673 | 2.0% | 4.5% | 2.9% |
| **Basque Country** | 25,938 | 15,571 | 41,509 | 9.7% | 11.0% | 10.2% |
| **Total** | **266,373** | **142,061** | **408,434** | **100%** | **100%** | **100%** |

Source: Enagás.

*Table A.3 Gas volumes and customers in the liberalised market, 2007*

| **Region (Autonomous Community)** | Total Gas Demand (GWh) | % of Gas Demand that is Liberalised | Total Gas Customers ('000) | % of Gas Customers who are Liberalised | Average Gas Consumption per Customer (MWh) |
|---|---|---|---|---|---|
| **Andalusia** | 74,269 | 92.6% | 345 | 30.2% | 215 |
| **Aragón** | 19,813 | 89.9% | 178 | 28.4% | 111 |
| **Asturias** | 5,398 | 73.2% | 204 | 51.6% | 27 |
| **Valencia** | 44,036 | 92.5% | 571 | 39.7% | 77 |
| **Cantabria** | 7,566 | 90.5% | 150 | 37.6% | 51 |
| **C. La Mancha** | 19,361 | 80.2% | 176 | 37.0% | 110 |
| **Castilla y León** | 21,179 | 84.7% | 375 | 42.0% | 56 |
| **Catalonia** | 81,186 | 88.5% | 2,054 | 41.0% | 40 |
| **Extremadura** | 1,165 | 60.0% | 52 | 2.3% | 22 |
| **Galicia** | 7,634 | 87.4% | 188 | 37.6% | 41 |
| **La Rioja** | 9,742 | 94.4% | 66 | 40.8% | 148 |
| **Madrid** | 26,131 | 61.4% | 1,628 | 33.7% | 16 |
| **Murcia** | 27,537 | 98.6% | 86 | 32.0% | 321 |
| **Navarra** | 12,997 | 90.3% | 109 | 42.2% | 119 |
| **Basque Country** | 39,348 | 91.3% | 467 | 80.4% | 84 |
| **Total** | **397,364** | **88.3%** | **6,647** | **40.6%** | **60** |

Source: CNE.
Note: Gas demand data exclude customers with their own LNG tanks (*plantas satélites*), equivalent to 9.4 TWh in 2007.

*Table A.4 Shares of liberalised gas customers by region and firm, end of 2007 (% unless stated)*

| Region (Autonomous Community) | Gas Natural | EDP/HC | Endesa | Iberdrola | Unión Fenosa | HHI |
|---|---|---|---|---|---|---|
| **Andalusia** | 82.8 | | 14.7 | 2.1 | 0.4 | 7,077 |
| **Aragón** | 7.5 | | 82.5 | 3.7 | 6.3 | 6,916 |
| **Asturias** | 0.1 | 94.0 | 2.5 | 1.7 | 1.8 | 8,848 |
| **Valencia** | 74.2 | | 10.3 | 14.0 | 1.6 | 5,810 |
| **Cantabria** | 74.3 | 0.1 | 23.6 | 1.4 | 0.5 | 6,080 |
| **C. La Mancha** | 80.9 | | 1.8 | 11.3 | 6.0 | 6,712 |
| **Castilla y León** | 72.8 | | 7.0 | 16.2 | 4.1 | 5,628 |
| **Catalonia** | 73.7 | 0.3 | 23.9 | 0.9 | 1.2 | 6,005 |
| **Extremadura** | 8.1 | 0.1 | 7.9 | 82.1 | 1.8 | 6,872 |
| **Galicia** | 59.9 | | 27.4 | 0.1 | 12.7 | 4,500 |
| **La Rioja** | 70.8 | | 19.7 | 9.2 | 0.3 | 5,485 |
| **Madrid** | 69.6 | | 13.4 | 7.6 | 9.4 | 5,170 |
| **Murcia** | 80.9 | 0.1 | 8.2 | 10.3 | 0.1 | 6,718 |
| **Navarra** | 73.2 | | 13.6 | 11.9 | 1.3 | 5,687 |
| **Basque Country** | 0.1 | 87.9 | 5.3 | 6.7 | 0.0 | 7,799 |
| **Total Number of Liberalised Customers** | **1,586,296** | **431,015** | **435,791** | **157,502** | **90,676** | |
| **All Regions** | **58.7** | **16.0** | **16.1** | **5.8** | **3.4** | **4,009** |

Source: CNE.

*Table A.5 Installed generation capacity by region, MW, 2007*

| **Region (Autonomous Community)** | Hydro | Nuclear | Coal | Oil/ gas | CCGT | Wind | Special regime - other | **Total** | % of Total |
|---|---|---|---|---|---|---|---|---|---|
| **Andalusia** | 1,046 | | 2,051 | 308 | 4,789 | 1,059 | 1,299 | **10,552** | 12% |
| **Aragón** | 1,284 | | 1,342 | | 1,798 | 1,709 | 944 | **7,077** | 8% |
| **Asturias** | 661 | | 2,628 | | | 276 | 263 | **3,828** | 4% |
| **Valencia** | 1,326 | 1,085 | | | 2,791 | 413 | 831 | **6,446** | 8% |
| **Cantabria** | 389 | | | | | | 397 | **786** | 1% |
| **C. La Mancha** | 725 | 1,066 | 221 | 948 | 774 | 2,825 | 681 | **7,240** | 8% |
| **Castilla y León** | 3,979 | 466 | 2,707 | | | 2,815 | 866 | **10,833** | 13% |
| **Catalonia** | 2,206 | 3,142 | 160 | 1,570 | 2,441 | 370 | 1,783 | **11,672** | 14% |
| **Extremadura** | 2,148 | 1,957 | | | | | 68 | **4,173** | 5% |
| **Galicia** | 2,681 | | 2,031 | 470 | 1,180 | 2,806 | 1,184 | **10,352** | 12% |
| **La Rioja** | 8 | | | | 790 | 486 | 76 | **1,360** | 2% |
| **Madrid** | 59 | | | | | | 457 | **516** | 1% |
| **Murcia** | 28 | | | 578 | 3,260 | 90 | 431 | **4,387** | 5% |
| **Navarra** | 11 | | | | 1,186 | 913 | 373 | **2,483** | 3% |
| **Basque Country** | 105 | | 217 | 936 | 1,949 | 145 | 641 | **3,993** | 5% |
| **Total** | **16,656** | **7,716** | **11,357** | **4,810** | **20,958** | **13,907** | **10,294** | **85,698** | 100% |

Source: REE.

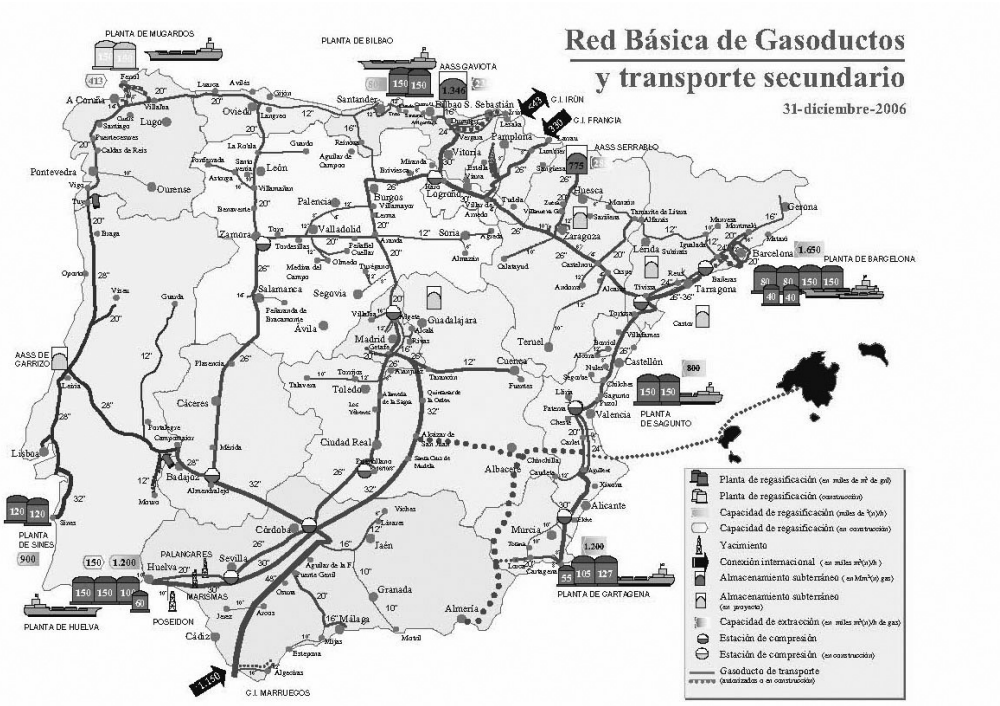
*Table A.6 Generation output and demand by region, GWh, 2007*

| Region (Autonomous Community) | Generation | Demand | Net Flows | % of Total Generation | % of Total Demand |
|---|---|---|---|---|---|
| **Andalusia** | 40,594 | 39,721 | 873 | 15% | 15% |
| **Aragón** | 18,756 | 11,071 | 7,685 | 7% | 4% |
| **Asturias** | 19,012 | 12,036 | 6,976 | 7% | 5% |
| **Valencia** | 14,299 | 27,703 | -13,404 | 5% | 11% |
| **Cantabria** | 2,485 | 4,817 | -2,332 | 1% | 2% |
| **C. La Mancha** | 21,627 | 11,949 | 9,678 | 8% | 5% |
| **Castilla y León** | 33,318 | 13,878 | 19,440 | 12% | 5% |
| **Catalonia** | 40,102 | 47,226 | -7,124 | 15% | 18% |
| **Extremadura** | 17,677 | 4,819 | 12,858 | 7% | 2% |
| **Galicia** | 28,735 | 19,687 | 9,048 | 11% | 8% |
| **La Rioja** | 5,192 | 1,907 | 3,285 | 2% | 1% |
| **Madrid** | 1,379 | 31,537 | -30,158 | 1% | 12% |
| **Murcia** | 10,643 | 8,573 | 2,070 | 4% | 3% |
| **Navarra** | 6,516 | 5,431 | 1,085 | 2% | 2% |
| **Basque Country** | 11,039 | 20,916 | -9,877 | 4% | 8% |
| **Total** | **271,374** | **261,271** | **10,103** | **100%** | **100%** |

Source: REE.
Note: The generation values are net of generators' own consumption (equivalent to 8,753 GWh in 2007). Demand excludes pumped storage demand and net exports.

## Annex 2: Maps of the Spanish Gas and Electricity Markets

*Figure 56: Map of the Spanish wholesale gas market (including pipeline connections, LNG terminals and storage facilities), end of 2006*

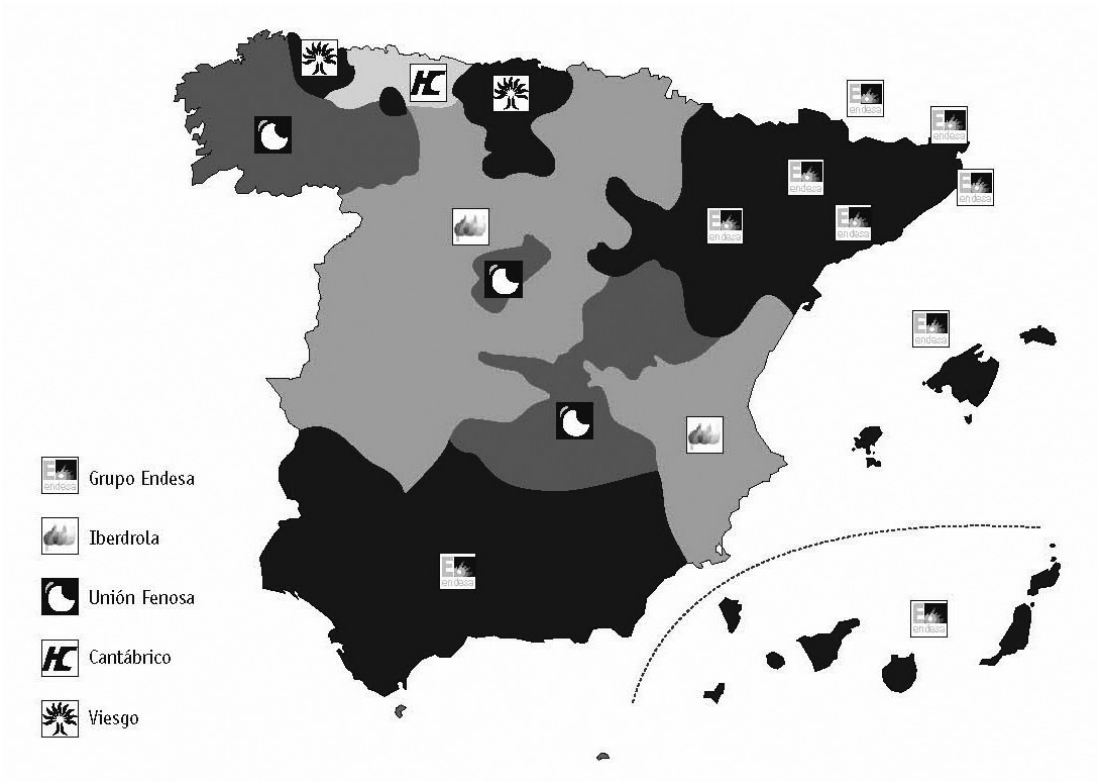



Source: CNE.

*Figure 57: Map of the Spanish regional gas distribution networks*


Source: CNE.

*Figure 58: Map of the Spanish regional electricity distribution networks*




Source: CNE.

## Annex 3: List of Acronyms

| | |
|---|---|
| bcm | billion cubic metres |
| CCGT | combined-cycle gas turbine |
| CESUR | contratos de energía para el suministro de último recurso |
| CNC | Comisión Nacional de Competencia |
| CNE | Comisión Nacional de Energía |
| $CO_2$ | carbon dioxide |
| CTC | coste de transición a la competencia |
| E.C. | European Community |
| ECJ | European Court of Justice |
| EDP/HC | Energias de Portugal/Hidrocantábrico |
| EPE | emisión primaria de energía |
| ETS | Emission Trading Scheme |
| E.U. | European Union |
| FGD | flue gas desulphurisation |
| GW | gigawatt |
| GWh | gigawatt-hour |
| HHI | Herfindahl-Hirschman Index |
| IEA | International Energy Agency |
| ISO | independent system operator |
| ITC | Industria, Turismo y Comercio |
| ITO | independent transmission operator |
| kWh | kilowatt-hour |
| LNG | liquefied natural gas |
| LOLP | loss of load probability |

| | |
|---|---|
| MIBEL | Mercado Ibérico de electricidad |
| MMBtu | millions British thermal units |
| MW | megawatt |
| MWh | megawatt-hour |
| NETA | New electricity trading arrangements |
| OECD | Organisation for Economic Co-operation and Development |
| OMEL | operador del mercado eléctrico |
| OMIE | operador del mercado Ibérico – Polo Español |
| OMIP | operador del mercado Ibérico – Polo Portugués |
| OPEC | Organization of Petroleum Exporting Countries |
| PSI | pivotal supply index |
| RD | Royal Decree |
| RDL | Royal Decree Law |
| REE | Red eléctrica de España |
| REN | Rede eléctrica nacional (Portugal) |
| RSI | residual supply index |
| tcm | trillion of cubic metres |
| TDC | Tribunal de Defensa de la Competencia |
| TLR | tariff of last resort |
| TPA | third party access |
| TSO | transportation (or transmission) system operator |
| TWh | terawatt-hour |
| UCTE | Union for the Co-ordination of Transmission of Electricity |
| U.K. | United Kingdom |
| U.S. | United States |
| VOLL | value of lost load |
| VPP | virtual power plant |



November 2008

**Giulio Federico**
Public-Private Sector Research Center, IESE Business School

Giulio Federico is a Policy Research Fellow at the Public-Private Sector Research Center of IESE Business School, and a Senior Consultant of CRA International, an economic consultancy. He holds a Ph.D. in Economics from the University of Oxford. His work focuses on the application of economic techniques to competition policy and regulation, with a specific focus on energy markets. He has been involved on behalf of firms and regulators in the competition analysis of several recent competition cases in the energy sector, both at the European level and in Spain. His research interests include the study of competition issues in energy markets, and the economics of abuse of dominance.

**Xavier Vives**
Public-Private Sector Research Center, IESE Business School

Xavier Vives is professor of Economics and Finance and the academic director of the Public-Private Sector Research Center at IESE Business School. He holds a Ph.D. in Economics from the University of California at Berkeley. He is a member of the Economic Advisory Group on Competition Policy of the European Commission; the European Economic Advisory Group of CESifo; editor of the *Journal of the European Economic Association;* a Fellow of the Econometric Society and a member of its Council; and the President of the Spanish Economic Association for 2008. His fields of specialization are industrial organization, the economics of information, banking and financial economics.

**Natalia Fabra**
Universidad Carlos III de Madrid

Natalia Fabra is an associate professor at Universidad Carlos III de Madrid and a CEPR Research Affiliate. She holds a Ph.D. in Economics from the European University Institute in Florence. Her work focuses on the analysis of strategic behaviour in electricity markets within three areas: the design of market rules; the analysis of dynamic issues such as capacity investment and forward trading; and the empirical analysis and market power. Her research papers are published in leading journals such as *Rand Journal of Economics, Journal of Industrial Economics,* and I*nternational Journal of Industrial Organization.*