The Spanish Gas and Electricity Sector: Regulation, Markets and Environmental Policies

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Whith the support of:

Generalitat de Catalunya
Departament d’Economia i Finances
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Gas and electricity markets in Europe and in Spain continue to attract the close attention of policy makers, practitioners and academics. The issues raised by these markets are complex and often controversial. These include established regulatory and competition issues, but also novel challenges related in particular to the ambitious environmental targets pursued within the European Union.

The public policy issues raised by the Spanish gas and electricity markets tend to have a particularly high profile, given some of the specific features of the evolution of these markets in Spain in the recent past. The Spanish gas and electricity markets have evolved positively in some respects since their liberalisation (most notably in terms of a growing level of competition at the wholesale level), but also raise some serious regulatory concerns, including a significant and growing shortfall between regulated revenues and costs (the ‘tariff deficit’), the increasing cost associated with support to renewable sources, and the desire to protect local but costly energy sources (such as domestic coal). At the same time there is a need for greater interconnection of both the gas and electricity markets with the rest of Europe, and greater system flexibility in general.

This report, written by Giulio Federico of the Public-Private Sector Research Center of IESE, seeks to provide an economic analysis of some of the issues that have characterised the recent evolution of the gas and electricity markets in Europe and in Spain. Special emphasis is given to environmental issues, to which a specific part of the report is devoted. The report updates and extends the previous report on *Competition and Regulation in the Spanish Gas and Electricity Markets*, published by the Public-Private Sector Research Center in 2008, and it represents the 5th in a series of reports produced by the Center on regulatory and public policy issues.

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Acknowledgements

I have been helped by several people in the preparation of this report.

I am grateful for the insightful suggestions provided by the three external advisers of this project, Natalia Fabra, Ignacio Pérez Arriaga and Nils-Henrik von der Fehr. I would also like to thank Xavier Vives for several helpful discussions on the issues treated in the report.

I received numerous helpful comments on a draft of the report from Daniele Agostini, Juan José Alba Rios, Sebastián Feimblatt Wechsler, Monica Gandolfi Caligari, José Luis Moraga, José Eduardo Moreda Díaz, Ángel López and Daniel Vargas Rozo.

I am also very grateful to Ventura Rodríguez García (of Red Eléctrica de España) and Jorge Fernández Gómez (of Intermoney Energía) for facilitating access to some of the data used in this report.

Luisa Fernanda Gutiérrez provided excellent research assistance throughout the preparation of the report, for which I am grateful. I would also like to thank Salvador Estapé for his role in putting together the report, and the Departament d’Economia i Finances of the Government of Catalonia for sponsoring this work.

The views expressed in this report are mine alone and do not necessarily represent those of the institutions to which I am affiliated.

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Summary and Conclusions

The European and Spanish gas and electricity markets are characterised by major policy challenges due to the complex and strategic nature of these markets. Public policy issues that are at stake in these markets include the challenge of introducing effective competition and regulation to ensure that market outcomes are competitive and the European market is successfully integrated; the need to manage the high levels of dependency of European energy markets on external sources of input (especially gas); and the difficulties posed by the transition to a more sustainable model in line with current European and global environmental objectives.

This report seeks to contribute to the analysis of some of these issues, with specific attention paid to the competitive segments of the Spanish gas and electricity markets (i.e. gas procurement, electricity generation and the respective retail markets), and special emphasis placed on environmental issues.

Part I of the report updates and extends the analysis contained in the first edition of the Public-Private Sector Research Center Report *Competition and Regulation in the Spanish Gas and Electricity Markets* (published in 2008) by including an analysis of key regulatory and market developments that characterised the Spanish energy markets during the 2008-2009 period.

Part II of the report is devoted to the specific analysis of environmental policy in the European and Spanish energy sector. Environmental issues have taken centre stage in the design of European electricity markets due to the stringent climate-change mitigation objectives implied by mainstream climate science and partially reflected in current E.U. policies. According to international projections, Europe will need to significantly reduce its greenhouse gas emissions over the next two decades (with required reductions of more than 40% by 2030, compared to 1990 levels) if global environmental objectives are to be met. These objectives in turn imply the need to decarbonise the power sector even more rapidly by achieving a 70% reduction in emissions by 2030 (relative to 1990) and the virtual de-carbonisation of the sector by 2050. These are clearly very challenging objectives that will require radical changes in the way electricity markets are organised. Part II of the report reviews some of the policy issues associated with climate change and the performance of E.U. and Spanish environmental policy to date.
The main elements and conclusions of both parts of the report are summarised in the remainder of this introductory section.


The European Energy Context

The overall European context in which the Spanish gas and electricity markets are situated remains one of significant external dependency, active competition policy and evolving regulation (with respect to both market structure and environmental issues).

External energy dependency remained at over 50% at E.U.-27 level (and around 80% for Spain) in 2009. The economic crisis of 2009 has moderated the recent increase in energy dependence, given the reduction in energy demand and imports resulting from the overall decrease in economic activity. At the same time domestic renewable energy sources have continued to increase, which has also contributed to mitigating external dependence. Nonetheless, medium-term projections are that European gas dependence is set to increase over time (e.g. to 80% by 2030) as domestic resources become depleted. The implementation of stringent environmental policies could, however, moderate the absolute increase in gas imports over this period by reducing the demand for gas.

The European gas market still primarily relies on pipeline imports from its main suppliers (Russia, Norway, and Algeria), even though the weight of Liquefied Natural Gas (LNG) in overall imports has increased (reaching almost one quarter of all imports in 2009). Significant increases in both pipeline and LNG import capacity are planned over the medium term, but uncertainty remains as to which of the competing import projects will go ahead (partially due to uncertainty on the future level of gas demand). Under some scenarios on new infrastructure developments, European dependence on Russian gas could increase significantly above current levels.

In terms of sector regulation and competition policy at European level, 2009 has been a particularly active year, with the publication of the revised gas and electricity directives (as part of the so-called Third Legislative Package), two additional directives on renewable energy and emissions trading, and the completion of several antitrust cases.

Under the Third Legislative Package, the European Union has refined its approach to unbundling in the energy industry by allowing Member States to opt between a full structural option (ownership unbundling) and lighter forms of functional separation.

At the same time, the European Commission has pursued several abuse of dominance cases against energy incumbents (in France, Germany, Italy and Belgium). These cases have centred
on the potential foreclosure strategies followed by vertically integrated incumbents in liberalised retail markets. As a result of these investigations, in most cases the incumbents have offered commitments which have either reduced or eliminated their vertical integration (e.g. in cases involving RWE, ENI and E.On (electricity)), or weakened their control of the market (e.g. as in matters relating to EDF, GDF/Suez and E.On (gas)). Moreover, the European Commission reviewed and cleared four large mergers between energy companies during the 2008-2009 period. These mergers have all resulted in fairly extensive structural divestments relative to the expected competition issues associated with the transactions. These trends show that competition policy remains a fundamental part of the broader deregulation and internal market agenda pursued by the European Commission in the energy sector.

**Regulation and Competition Policy in Spain**

The key regulatory developments in the Spanish gas and electricity markets since late 2007 have been the introduction of tariffs of last resort (TLR) in both gas and electricity (in mid-2008 and mid-2009, respectively); a reform of the mechanism for the determination and recovery of the tariff deficit; a continuation of the program of procurement auctions (CESUR) used to establish the cost of energy for residential electricity customers, but the discontinuation of the Virtual Power Plant (VPP) program applied to the largest generators; and measures on solar subsidies and domestic coal-fired generation.

The introduction of TLR in the residential gas and electricity markets does not increase the liberalisation of the respective retail markets *per se*, since the TLR remains a regulated tariff which is set by the government, with respect to the non-energy component. On the other hand, the trends towards greater retail liberalisation in both gas and electricity have continued after the introduction of TLR. Moreover, regulated electricity tariffs for high-voltage, SME and large residential customers were abolished between mid-2008 and mid-2009, thus further supporting the drive to deregulation of the retail market.

Another positive feature of electricity TLR, relative to the previous system, is that the energy component is now directly related to a market-based mechanism (the CESUR procurement auctions), which helps ensure that tariffs move in line with the market. Access charges, however, remain regulated at a level that is below cost, which has led to large tariffs deficits in both 2008 and 2009.

The reform of the tariff deficit introduced in April 2009 (through Royal Decree Law 6/2009) should in principle improve the arrangements for the recovery and future determination of the deficit by securitising a significant amount of the pre-2009 deficit (€10 billion), and limiting the annual deficits to be incurred during the 2009-2012 period. However, the deficit incurred in 2009 exceeded the limits introduced by RDL 6/2009, thereby suggesting that this measure lacks full political commitment. Moreover, the abolition of the measure to remove the estimated...
additional profits from free carbon allowances for the period between mid-2009 and the end of 2012 (a measure which had been applicable in Spain since 2006) places further upwards pressure on the deficit.

The Spanish electricity VPP program came to an end during the first quarter of 2010, after having been first implemented in mid-2007. A maximum of close to 2.6 GW of baseload and peak output has been affected by the program, equivalent to 5%-7% of Endesa and Iberdrola’s respective capacity. A review of the program carried out by the sector regulator (the Comisión Nacional de Energía, CNE) in 2009 indicates that the scheme may have been effective in promoting retail competition and market liquidity, but not necessarily in making wholesale market outcomes more competitive. The latter finding can be partially explained by the relatively small size of the VPP during the lifetime of the intervention.

The government’s decision not to continue the VPP program beyond the last auction (held in March 2009) seems to have been vindicated by the recent reduction of concentration in the Spanish electricity market, and by market outcomes during 2009 and early 2010, which have resulted in effectively competitive electricity prices (primarily due to a combination of lower concentration, additional renewable output and lower demand). It would have been preferable, however, to determine if the VPP scheme should be continued on the basis of a transparent review of the structure of the Spanish generation market (carried out, for example, by relying on the periodic assessments of competition prepared by the CNE). This would have provided an objective basis for future decisions on similar schemes and would have given more time to market operators to adjust to the change in regulation.

Energy markets also continue to be a key area of application of competition policy in Spain. In terms of merger control, the main concentration assessed by the competition authority (the Comisión Nacional de la Competencia, CNC) was the merger between Gas Natural and Unión Fenosa (approved in early 2009). This transaction brought together the gas incumbent with the third largest electricity firm, which also had a significant presence in the gas market (through its 50% stake in Unión Fenosa Gas). The CNC approved the merger subject to a behavioural remedy on Unión Fenosa Gas’s behaviour in the retail market, and on structural divestments in the generation and residential gas markets (namely, the sale of 2 GW of gas-fired generation capacity, and of gas distribution networks with associated residential customers). The absence of a structural remedy directly aimed at the wholesale and industrial gas markets (where Unión Fenosa Gas had become a major competitor of Gas Natural) was a notable feature of the CNC decision. It effectively signalled the CNC’s confidence that competition in the wholesale and industrial gas markets in Spain is sufficiently intense, and that the increase in market concentration brought about by the transaction would not have adverse effects on gas consumers.

The CNC also took an abuse of dominance decision against incumbent electricity distributors for withholding commercial information from a downstream competitor (Centrica Energía). This decision reflects a continuing concern for vertical integration between distribution and
retail supply, and is consistent with the general preference for ownership unbundling expressed by the European Commission.

No new abuse of dominance decisions were taken by the CNC in relation to the issue of the pricing of transmission congestion relief (restricciones técnicas), following the four decisions in this area taken over the 2006-2008 period. However, this area remains under the close scrutiny of the competition authority, which opened new investigations on this issue in late 2009 involving practically all the generators in the market. The question of how to appropriately reward the output of generators located in congested areas is not only a competition law issue, but also affects the overall remuneration regime for thermal power plants in a context with growing amounts of renewable generation.


The Wholesale Gas Market
During the 2008-2009 period the Spanish wholesale gas market was primarily characterised by significant demand volatility, a growing reliance on LNG imports, a continuing lack of flexibility in the form of sufficient domestic storage and interconnection capacity, and significant structural changes due to the Gas Natural/Unión Fenosa merger. These and other principal developments in the wholesale gas market are briefly set out below:

• **Spanish gas demand grew by 10% between 2007 and 2008** (mainly due to growth from the electricity sector), but then fell drastically between 2008 and 2009 (by almost 11%), due to the contraction in economic activity, as well as a reduction in gas-fired electricity output partially due to the continuing increase in renewable generation. Convergence between the gas and electricity markets remains strong, with the electricity component accounting for 40% of total gas demand.

• **The weight of LNG imports in total gas volumes has continued to increase**, reaching almost three quarters of all imports in 2009 (well above the E.U.-15 average of less than one quarter). The Spanish gas market remains well diversified relative to other European markets (most notably Germany, but also France and Italy) and has access to significant regasification capacity, at least six major gas sources, and no reliance on Russian gas (unlike most of Europe). These features of the Spanish gas market make it less vulnerable to potential disruptions in supply.

• **In terms of gas infrastructure, investments continue to be made in the Spanish system** with expansions by Enagás at the Barcelona and Cartagena LNG terminals and further expansion at the Sagunto facility. The new pipeline with Algeria (Medgaz) is also due to come on line by the end of 2010. This may lead to a significant increase in dependence on Algerian gas (which
may be considered excessive in light of the price dispute that took place between Gas Natural and Sonatrach in 2010).

• However, major infrastructure deficiencies remain in terms of domestic gas storage and interconnection capacity with France (especially in export mode). The domestic gas storage capacity in Spain (including LNG plants) accounted for only roughly 10% of annual demand in mid-2010, well short of levels in other major European markets like Germany, Italy and France. Access to domestic gas storage will become increasingly critical in the Spanish gas market, as gas-fired power generation is expected to operate in a more flexible mode in the future (e.g. to deal with greater levels of intermittent renewable generation). The new facility being developed by Enagas at Yela (expected to be operational in 2011) will increase Spanish underground storage capacity by roughly 50% and represents a critical project to increase the flexibility of the Spanish gas system.

• The secondary OTC market continues to grow, providing an important source of gas flexibility for LNG imports. However, it does not represent an adequate substitute for a liquid and transparent wholesale gas hub, which has not yet developed in Spain.

• The structure of the Spanish wholesale gas market is still characterised by the pre-eminent position of the incumbent firm, Gas Natural. However, Gas Natural’s share of wholesale gas imports has declined steadily with the liberalisation of the sector and the entry of independent LNG, falling from close to 80% in 2004 to 50% in 2009. This decline in market share was partially reversed in 2009 through the acquisition by Gas Natural of joint control of Unión Fenosa Gas (which accounted for an additional 13% of the Spanish wholesale market in 2009). Notwithstanding the effective increase in market concentration observed in 2009, the Spanish wholesale gas market remains less concentrated than those of most other European countries, which tend to have highly concentrated gas markets (with the exception of the United Kingdom and Germany).

The Retail Gas Market
The Spanish retail gas market remains characterised by a continuing yet gradual liberalisation, a concentrated market structure, and limited customer switching away from the incumbent providers at regional level:

• The Spanish retail gas market is effectively liberalised in terms of gas volumes, with over 90% of demand being transacted at market-determined prices. In terms of customer numbers, however, liberalisation remains incomplete, with more than 45% of customers purchasing gas at regulated TLR in the first quarter of 2010. The share of customers on regulated tariffs has, however, fallen steadily since 2004 (when it stood at close to 80%).

• The retail gas market however remains highly concentrated, with a Herfindahl-Hirschman Index (HHI) in 2009 well in excess of 2,000 (i.e. the standard threshold used for a highly
concentrated market). As in the wholesale market, effective market concentration increased during 2009 following the acquisition by Gas Natural of a 50% stake in Unión Fenosa Gas. The retail divestments which followed the CNC merger clearance decision reduced concentration in the residential market, but not in the overall retail market (due to the relatively low gas volumes associated with residential consumption).

• At regional level, market concentration in the residential market remains very high, since a significant share of customers remains on regulated tariffs and those who switch to market-determined prices tend to remain with their incumbent operator. By the end of 2009, only roughly 15% of all customers on average had actually switched gas providers in each region. In spite of the relative slow progress in residential gas competition, the performance of the Spanish market does not compare unfavourably with those of the other main gas markets in Europe, with annual consumer switching rates above the levels seen in Germany, Italy and France (but below those of the United Kingdom and the Netherlands).


The Wholesale Electricity Market
The Spanish wholesale electricity market has experienced very significant changes since early 2008, as a consequence of shifts in relative fuel prices (including CO₂), significant demand fluctuations and the continuing growth of subsidised special regime generation (mostly renewable). The main market developments are summarised below:

• Wholesale electricity demand fell for the first time since market liberalisation, dropping by close to 5% between 2008 and 2009. Over the course of the present decade, however, cumulative demand growth in the Spanish electricity market has been very high (close to 35%), well in excess of the E.U.-15 average level of just over 7%.

• The generation mix in the Spanish market has undergone drastic changes in 2008 and 2009. The major trend has been the significant growth in subsidised baseload generation (under the special regime) which, coupled with stagnant or falling demand, squeezed the output of flexible thermal output (most notably coal-fired production). The structural changes experienced in the Spanish electricity market highlight a trend towards a ‘greener’ electricity system with significantly lower carbon intensity than in the past, considerably more renewable generation and more flexible operation by thermal generators (in particular combined-cycle gas turbines (CCGTs)).

• During the 2007-2009 period, special regime output grew by 40%, whilst coal generation fell by over 50%. By mid-2010, coal generation had fallen even further, to less than a third of the 2007 level. Part of this reduction in coal generation can be attributed to the increase in CO₂
prices after the very low levels seen during 2007 (as Phase I of the Emissions Trading System came to an end). Output by CCGTs grew by 15% over the 2007-2009 period, but the 2009 output level was 14% below the peak achieved in 2008 (with a further reduction experienced by mid-2010).

- **Overall renewable generation (including conventional hydroelectric generation) accounted for roughly 27% of total electricity consumption in 2009**, up from 21% in 2008. This increase in the relative share of renewable output was achieved primarily due to continued growth in wind generation (which grew by more than a third between 2007 and 2009), and solar PV output (which increased almost 15-fold over the two-year period).

- **The most flexible generation technology in the Spanish market remains CCGT generation**, which accounted for close to 50% of total market flexibility in 2009 (defined as the upturn between average generation in the lowest and highest demand decile), above its share of output of less than 30%. By contrast, special regime output only accounted for 14% of flexibility, well below its total output share of 30%.

- **Integration between the Spanish and Portuguese markets intensified over the 2008-2009 period** with hours of full congestion on the interconnection capacity reduced to 25% in 2009 (down from roughly 80% in the second half of 2007) and the resulting price differential between the two systems falling from to roughly 2% in 2009. This can be partially explained by greater convergence in the generation mix of the two markets and an effective cross-border trading mechanism. However, some of the increased price convergence seen since 2008 may also be due to non-structural factors and could be reversed in the future.

- **Integration between the Iberian market and the rest of Europe however remained limited.** Total interconnection capacity with France remains at less than 1.5 GW (less than 3% of Iberian peak demand). Moreover, the absence of an effective cross-border mechanism between France and Spain (e.g. market coupling) limits integration between the two markets. For example, in 2008 price convergence between France and Spain was achieved for only 6% of hours. Significantly more interconnection capacity with France (in both imports and exports made) and the introduction of an effective market design are both needed to better integrate the Iberian market with the rest of Europe, and also to manage optimally the growing weight of intermittent renewable generation in Spain.

- **Prices in the Spanish wholesale market have been characterised by high levels of volatility in recent periods.** Annual day-ahead spot prices reached a historical peak of €66/MWh in 2008, but then fell to €38/MWh in 2009, and €30/MWh in the first half of 2010, as demand and fuel prices decreased, and baseload generation grew. Estimated baseload price-cost margins for thermal power plants narrowed considerably in 2009 relative to earlier periods, thus inducing these generators to operate at lower load factors in order to capture higher spot prices.
• The wholesale electricity market has become significantly less concentrated in the recent past, as the result of the continued entry of independent renewable and CCGT generation, corporate restructurings (most notably asset sales by Endesa), and the shift from coal to gas-fired generation (which reduces concentration, since the ownership structure of CCGT plants is more diluted than that of coal capacity). Under a wide definition of the market (including all generation output in Iberia), the market is almost unconcentrated on the basis of conventional thresholds, with an HHI of roughly 1,100 (almost 25% lower than in 2007). Under a narrower and more conservative market definition (i.e. considering only price-setting generation in Spain), the market remains moderately concentrated, with an estimated HHI of approximately 1,450 (over 20% less than in 2007). As a result of these trends, the Spanish market has become less concentrated than several other markets in Europe with the main exceptions of the United Kingdom, the Netherlands and the Nordic countries.

The Retail Electricity Market
At retail level, the electricity market continues to be characterised by limited but growing price liberalisation (in terms of customer numbers), slow customer switching away from the incumbent suppliers, and a significant annual shortfall between regulated revenues and costs (the so-called “tariff deficit”), which reached its highest historical levels during 2008 and 2009.

• The Spanish retail electricity market remains partially liberalised, with a significant share of total volumes (more than a third) and customers (more than 80%) purchasing electricity at regulated prices. However, the degree of liberalisation has increased rapidly since 2006-2007, thanks to reforms in the tariff deficit mechanism (i.e. the allocation of the deficit to access charges implemented from 2007 onwards), the abolition of high-voltage tariffs and the introduction of TLR.

• In terms of market concentration, the Spanish retail market is significantly more concentrated than at wholesale level, due to the strong position of the incumbent distributors (most notably Endesa and Iberdrola). However, market concentration in the national market has reduced rapidly with the liberalisation of the sector in the past two years, with the market HHI falling from over 3,000 in 2007 to roughly 2,200 in 2009. The presence of extensive price regulation also means that high levels of concentration do not necessarily result in high prices.

• Consumer switching behaviour remains very regional, as in the retail gas market, with loyalty rates for the main electricity distributors standing at 75%-90% in mid-2009, depending on the network area. This means that very few residential consumers have actually changed electricity providers since market liberalisation (even less than in the gas market). Switching rates in the Spanish electricity market are below those achieved in several other European markets (most notably the U.K., Swedish, and Dutch markets, but also in Germany and Denmark).
• The defining feature of the Spanish retail electricity market (and indeed of the electricity system as a whole) remains the presence of a large and growing tariff deficit, due to the persistent annual shortfall between regulated revenues and corresponding costs. The annual tariff deficit hit a peak of over €4.3 billion in 2008, and stood at an estimated net level of €3.8 billion in 2009 (above the annual cap set in Royal Decree Law 6/2009). On a cumulative basis, the debt stood at around €17 billion at the end of 2009, with almost 90% of it yet to be recovered.

• The main contributing factor behind the recent increase in the tariff deficit has been the growing level of the remuneration of generation under the special regime (which includes most of the renewable energy sources). The increase in the total level of special regime subsidies and/or payments between 2007 and 2009 equals or exceeds the level of the net tariff deficit in 2009. More than 60% of the increase in special regime support over this period is in turn due to the payments made to solar photovoltaic (PV) technology (in spite of this technology only providing 8% of total regime output in 2009).

Part II: Environmental Policies in the European and Spanish Energy Sector

The Economics of Climate Change in the Energy Sector

The need to mitigate the risks associated with climate change is arguably the greatest policy challenge faced by the European and Spanish energy sector at present. Conventional climate change science indicates that there is a strong case for rapidly reducing global greenhouse gas (GHG) emissions over the next four decades so as to avoid the potentially very costly consequences of excessive global warming.

In order to reduce the risk of global temperatures increasing by more than 2 degrees Celsius above pre-industrial levels (which corresponds to the threshold set in the Copenhagen Accord of late 2009), global GHG emissions need to peak within the next decade and start falling rapidly afterwards (e.g. achieving a 50% reduction in 2050 relative to the 2020 peak and a 33% cut relative to 1990).

The implied targets for the European Union are even more stringent, with the need to achieve emission reductions (relative to 1990) of over 20% by 2020, over 40% by 2030, and at least 80% by 2050. The electricity sector in particular is projected to have to shoulder a significant share of the overall abatement effort, due to the possibility for large scale deployment of renewable sources in this sector and the potential to decarbonise other sectors (such as transport and residential heating). As a result, the European power sector will need to achieve a 70% reduction in emissions by 2030 (relative to 1990) and virtual de-carbonisation by 2050 if current environmental targets are to be met.
Economic theory indicates that the most efficient way to reduce carbon emission is to put a price on CO₂, either through a cap-and-trade system (like the European Emission Trading System (ETS)), or through a carbon tax. This can ensure that emissions are appropriately priced, discourage the utilisation of carbon-intensive technology and favour production by low or zero-carbon sources (e.g. renewable, nuclear and carbon capture and storage (CCS)). Pricing CO₂ can in principle resolve the main market failure associated with climate change, namely the fact that emitters do not internalise the full social cost of their carbon emissions.

Supplementary environmental policies may be warranted if there are additional market failures that need to be addressed. However, these policies should not be justified simply by the need to reduce emissions, since this is best addressed through carbon pricing alone. For example, in the case of renewable energy there may be technology spillovers which investors in renewable projects cannot fully appropriate. If these spillovers are significant, they may warrant an R&D and/or deployment subsidy. There may be other social benefits of renewable support (such as reducing external energy dependence or contributing to an effective industrial policy), even though these are likely to be limited if compared to other forms of low-carbon generation (e.g. nuclear and CCS), or other possible competing uses of public funds.

It is important to properly understand and quantify the technological benefits of renewable support, since promoting renewable energy may come at a social cost, both in terms of the overall affordability of energy and the potential distortion of carbon pricing. The latter is due to the fact that promoting renewable energy through specific support schemes rather than through carbon pricing alone may depress the carbon price (relative to a counterfactual without renewable support or with less support), at the expense of competing forms of low-carbon energy (such as nuclear and CCS in particular, and to some extent also CCGTs). It therefore can prevent the adoption of a technology-neutral approach to carbon abatement, and raise the social costs of achieving a given emission reduction target. Distributional considerations may, however, be used to justify a policy which does not solely rely on carbon prices to deliver the required levels of GHG emission abatement.

Projections by the International Energy Agency (IEA) indicate that a mixture of abatement mechanisms will be required in the electricity sector to efficiently reduce GHG emissions in the future. These include renewable energy, nuclear power, CCS and efficiency measures. In particular, it is projected that the share of renewable electricity in total generation in Europe needs to increase to slightly over 30% by 2020 and to 43% by 2030. This prospective increase in renewable generation poses significant challenges for the power sector, due to the need to cope with the intermittency of some renewable technologies (most notably wind). Significant back-up thermal capacity will be required to guarantee security of supply under these circumstances. Thermal plants (in particular CCGTs) will need to increasingly operate in a flexible model at low average utilisation factors (e.g. 30% or less). For this to be compatible with a market equilibrium, peak prices in the electricity sector will likely need to increase significantly relative to current levels, and the gas and electricity markets will have to operate with greater overall flexibility.
Global action involving all major emitters is required to meet the ambitious abatement targets implied by climate change science. Action by only a limited sub-set of countries will be largely ineffective, given the international externality associated with global warming. Europe in particular only accounts for a small share of total GHG emissions (less than 15% in 2009), thus implying that decisive environmental measures in Europe, but not by other major emitters, would not yield the desired outcomes.

Environmental Policies in the European Energy Sector

Environmental policies in the E.U. energy sector to date have centred on three main pillars: (a) the commitment under the Kyoto protocol to reduce E.U.-15 GHG emissions over the 2008-2012 period by 8% relative to 1990; (b) the adoption of a 12% renewable primary energy target (corresponding to a 21% renewable electricity level) by 2010; and (c) the establishment of the ETS, a cap-and-trade mechanism in place since 2005.

The Kyoto target for Europe is on track to be met comfortably, with E.U.-15 emissions in 2009 estimated to be roughly 13% lower than 1990 levels (in part due to the economic downturn, which contributed to a 7% reduction between 2008 and 2009). On the other hand, renewable electricity in the E.U.-27 is set to fall short of the average 21% target (standing at approximately 18% in 2009, up 6 percentage points since 1990). The introduction of the ETS has been effective in creating a transparent price for CO2 in Europe, but has also suffered from several deficiencies in its initial design. These have included most notably an over-allocation of permits in Phase I (between 2005 and 2007), which, together with a lack of “banking” across phases, led to a collapse in the CO2 price during 2007; and the handing out of significant amounts of free permits to emitters in both Phase I and Phase II (which runs until 2012), which led directly to significant windfall gains for thermal generators.

A number of important measures were adopted in 2008-2009 to define E.U. energy policy towards the environment for the period up to 2020. These include primarily the 20-20-20 climate and energy package, which commits the European Union to achieve the following targets by 2020: a 20% reduction in GHG emissions (relative to 1990); a 20% share of renewable sources in final energy consumption (up from 10% in 2008); and a 20% improvement in efficiency. The GHG emission target was translated into the design of the ETS through a 21% reduction in emission allowances by 2020 (relative to 2005) starting in 2013, together with a move to full auctioning for the power sector (applicable to most Member States). The 20% renewable energy consumption target has been translated into binding country targets, which imply that on average the share of renewable sources in electricity consumption will need to reach a share of between 33% and 40% by 2020 across Member States.

E.U. environmental energy policy until 2020 will therefore keep relying primarily on a mixture of carbon pricing and renewable targets. The effectiveness of carbon pricing may, however, be
undermined by the sharp reduction in E.U.-27 emissions experienced in 2009 (which implies that 85% of the required reduction by 2020 was already achieved in 2009), coupled with the possibility of banking emission reductions across phases of the ETS, and the continued significant direct support for renewable energy (which places downward pressure on carbon pricing). Existing estimates for the expected level of carbon pricing in 2020 are in the range of €20–€40/tonne CO₂, which is likely to be insufficient to make investments in additional low-carbon generation (nuclear and CCS) commercially viable.

Thus, there is an economic case for increasing the emission reduction target for 2020 (e.g. to 30% below 1990 levels) in order to strengthen the price signal given by the ETS and also achieve a more sustainable abatement profile for the 2020-2030 period (when further reductions will be required).

At the same time, it is quite possible that European renewable energy targets for 2020 have been set too high, and, therefore, actual market failures that should be addressed through policies of renewable support (i.e. most notably technology market failures) are not being properly accounted for. This is likely to increase the total costs of achieving a given reduction in GHG emissions in Europe. In order to reduce the risk that the costs of renewable support will become even higher, more extensive reliance should be placed on market-based measures (e.g. capacity tenders and flexible feed-in systems) to determine the level of renewable remuneration.

Environmental Policies in the Spanish Energy Sector

Spanish energy policy on the environment in the last decade or so has largely centred on the promotion of domestic renewable resources. To date, Spain has not actively encouraged other forms of low-carbon generation, such as nuclear power, even though its electricity system still relies on nuclear plants to a significant extent. Moreover, whilst this has not been an explicit consequence of environmental policy, the shift in the generation mix from oil and coal to gas-fired plants in Spain has significantly improved the overall environmental performance of the system (by lowering its carbon intensity). However, total GHG emissions in Spain in 2009 were close to 30% in excess of their 1990 level, well above the 15% burden-sharing target agreed upon as part of the implementation of the Kyoto protocol. This can be largely attributed to the significant increase in overall energy consumption in Spain over the period.

Detailed renewable electricity targets have been set by the Spanish government through a series of national planning documents (in 1999, 2005 and 2010). The renewable target for 2010 was set at just short of 30% of electricity consumption (in order to comply with the European renewable energy targets for the same year). For 2020 this target has been increased to just short of 40% of demand.

The 2010 target is close to being achieved, since renewable electricity accounted for just over 27% of consumption in 2009, thanks to continued growth of renewable output (most notably
wind and solar) and the reduction in consumption experienced in 2009. Since the market was liberalised in 1998, renewable generation has doubled in Spain (from 38 TWh to 75 TWh), with three quarters of this increase due to wind generation, followed by solar (which accounts for 14% of the overall increase, due to the growth that it experienced in 2008 and 2009). The levels of wind and solar PV capacity in Spain significantly outperform those of other European countries, with the only exception of Germany (which is, however, a much larger market).

The considerable growth of renewable electricity in Spain has been achieved through a system of feed-in tariffs, which has significantly evolved since its inception in 1994. Up to 2007 the feed-in mechanism in place in Spain worked reasonably well and achieved considerable growth in wind generation in particular at a cost that does not appear excessive (in comparative terms, relative to the rest of Europe).

However, the cost of subsidies to special regime generation (which includes most renewable sources) almost trebled between 2007 and 2009 (going from roughly €2.2 billion to over €6 billion), with total payments (i.e. the subsidies plus remuneration from the market) almost doubling. Most of this increase in subsidies and payments is accounted for by the remuneration of solar PV technology, which increased by approximately €2.4 to €2.6 billion, following much faster than expected entry of solar plants to take advantage of the subsidy established by the government in mid-2007. Solar PV capacity increased from 0.3 GW in May 2007 to 3.5 GW at the end of 2009 (almost than 10 times than the original planning target for solar PV capacity in 2010).

By the end of 2009, the cost of solar PV subsidies accounted for over 40% of the total subsidy to special regime generation (which also includes non-renewable co-generation plants), but solar PV output only constituted 8% of special regime generation. Subsidies to solar PV were cut by almost 40% between late 2008 and mid-2010, whilst still attracting investment in new capacity. This illustrates the fact the subsidies paid out in 2007-2008 were probably set at excessive levels, since the tariff reduction implemented since then is likely to exceed the drop in costs experienced over the same period.

The Spanish experience with solar PV subsidies represents a vivid illustration of the economic dangers of relying on an imperfectly designed system of feed-in support for renewable generation (with no quantity limit on the total amount of subsidies promised to investors). Whilst a feed-in system can be effective in providing certainty to investors, it also places strong informational demands on policy makers when they set the subsidy level. Costly mistakes can be made (especially if the costs of technology fall more rapidly than expected), thus resulting in prices being set above costs and investments at those prices being much greater than anticipated (thus increasing the total costs of renewable support).

Primarily as a result of payments to solar PV plants (but also because of the decline in market prices), the total special regime subsidy reached record levels in 2009 (over €6 billion), equivalent to almost 60% of total wholesale market expenditure (defined as total wholesale market volumes
times the final wholesale market price). The subsidy per unit of avoided CO₂ emissions achieved by renewable generation in Spain in 2009 can be estimated at €200-€250/tonne CO₂, 14 to 17 times above the current market price for CO₂ (which in principle measures the social benefit of carbon abatement). This suggests that the overall subsidy levels paid in 2009 are likely to be in excess of the social benefits of promoting renewables (over and above their direct environmental impact, which, as discussed above, should be reflected in carbon pricing alone).

The increase in the level of the special regime subsidies and overall payments since 2007 has exacerbated the problem of the electricity tariff deficit, as noted above. The recent increase in the cost of renewable support has led to the emergence of a largely structural wedge between regulated costs and revenues, since special regime feed-in tariffs are fixed for long periods of time (i.e. typically 20 to 25 years). Moreover, the adoption of any retroactive measures to reduce the cost of renewable support would undermine the regulatory credibility of the system and have been largely avoided by the Spanish government as of November 2010.

The evolution of the overall generation mix in Spain will determine the ability of the market to comply with environmental targets efficiently. At present, nuclear generation is a key technology in terms of the containment of carbon emissions, since it accounts for over 40% of total carbon-free electricity in the market. Most Spanish nuclear plants will come to an end of their useful lives in the 2020s. A key decision to be taken for the post-2020 period will therefore be whether to extend the useful life of this capacity (e.g. by an additional 20 years). There is an economic and environmental case for doing so in order to reduce the total costs of carbon abatement in Spain and rely on a portfolio of technologies to reduce emissions. The extension of the useful lives of nuclear plants is likely to generate additional economic rents for the current owners of these plants. In due course (i.e. as the end of the current 40-year-life approaches), these could be evaluated and clawed back in order to partially finance the cost of renewable support (along the lines currently being proposed in Germany). These issues ought to be assessed in the context of a broader review of the case for extending the useful life of nuclear capacity beyond the 2020s.

CCGT and coal generation remain central and competing technologies in the transition to a low-carbon power system, especially as sources of flexibility. The increase in CO₂ prices since 2007, coupled with the reduction in demand, has severely hit the production of coal plants (especially less efficient plants burning domestic coal). This is largely a market response to the signal provided by carbon pricing. The Spanish government is, however, seeking to artificially support the production of power plants using domestic coal through specific legislation (enacted in October 2010 after receiving E.U. state aid approval). This measure risks significantly distorting the market (at the expense of more efficient imported coal and CCGT plants) and increasing system costs at a time when overall revenues are already insufficient to cover total costs.

CCGT generation in Spain is an increasingly important source of system flexibility, especially as a back-up for intermittent renewable generation. As renewable capacity increases further in the future, the load factors of CCGT plants are expected to decline. For this to be compatible with market equilibrium, spot market prices at peak times are likely to need to increase significantly.
to allow existing plants to cover their annual fixed costs (including gas access charges). For this to be possible, the current price cap in the spot market (set at €180/MWh) should probably be revised and the mechanism for the pricing of congestion relief services should also be improved. Moreover, the current level of capacity payments in Spain approximately covers fixed operating and maintenance costs for a period of 10 years, but not other types of fixed costs (including gas TPA charges and capital costs). It may therefore not be sufficient to promote security of supply and it might also need to be reviewed.

Conclusions: Main Policy Challenges in the Spanish Gas and Electricity Markets

The Spanish gas and electricity markets remain in a state of flux. They have been subject to a number of interrelated market and regulatory ‘shocks’ in recent years that have affected their performance and are also likely to shape future developments.

In some ways, the public policy issues faced by the Spanish gas market are less complex than those present in the electricity market. The main challenge at the wholesale level is posed by the continuing convergence between the gas and electricity markets. This means that the gas market will have to become increasingly flexible in the future as the demand of gas-fired electricity generators becomes more volatile. Greater flexibility of the Spanish gas system will be key to the efficient integration of growing levels of renewable electricity in the Spanish energy system.

These considerations imply that greater levels of domestic gas storage and interconnection with the rest of Europe will be required. Underground gas storage in Spain is limited and well below the levels present in other major European markets. Investments in this type of facility are therefore crucial and should be a key focus of future infrastructure plans. Similarly, greater export capacity towards France would allow the Spanish gas system to use gas more efficiently and cope better with domestic demand volatility. The creation of an effective single domestic gas hub would also help achieve greater flexibility in the domestic gas market and should be an important aim of future reforms of the design of the Spanish gas market.

At retail level, the main challenge is still the imperfect degree of liberalisation of the residential gas market in 2009. A significant number of customers remain on regulated TLR and at regional level only 15% of customers have actually switched supplier since the market was opened to competition. More effective dual-fuel competition is required to render the gas market more dynamic and encourage further liberalisation.

The Spanish electricity market continues to be characterised by complex and increasingly controversial public policy challenges. These are the result of past policy failures (most notably the emergence of a large tariff deficit since 2002) and new pressures on the system coming from
the need to comply with increasingly stringent environmental objectives. The two issues have become closely related in recent times, since the increase in the cost of support to renewable electricity is one of the main determinants of the current level of the annual tariff deficit.

The central policy issue in the electricity market over the short to medium term is therefore how to contain and gradually eliminate the current shortfall between regulated costs and revenues. Given the large size of the accumulated debt and current deficit, action is likely to be needed on both the revenue and cost sides.

In terms of regulated revenues, a credible, gradual program of increases in access charges is necessary to move tariffs towards a more sustainable level (contrary to the strategy pursued in 2010, which did not increase electricity access charges).

In terms of regulated costs, an effective and economically coherent way to reduce the level of costs borne by the electricity system would be to shift part of the costs of renewable support to a broader base of contributors (e.g. all taxpayers or all energy consumers). This measure would be justified by the fact that promotion of renewable electricity has a social value in the context of action against climate change that benefits the entire population, not just electricity consumers. In the future (i.e. after 2013), part of the costs of renewable support could also be financed by proceeds from auctions of emission permits.

The case for acting on market-determined energy costs (e.g. clawing back potential super-normal profits accruing to baseload generation) rests on an inherently complex legal and economic evaluation which would need a specific assessment that is beyond the scope of this report. However, implementing a measure of this kind entails significant risks, since it has the potential to undermine the principles behind market liberalisation.

Nonetheless, as discussed, future rents arising from the potential extension of the useful life of nuclear plants could be transferred to the government in due course. Moreover, a final settlement of the stranded cost payments (costes de transición a la competencia, CTC) made to generators between 1998 and 2006 may lead to a one-off reduction in energy costs if it turns out that there was over-compensation.

There are several other challenges faced by the Spanish wholesale electricity system that require specific policy responses. These include:

• The need for a better and more market-based design of the feed-in system for renewable producers as a way of preventing the risks of excessive compensation being paid to new investors.

• The review of nuclear policy, especially with respect to the desirability of extending the current 40-year lifetime of nuclear plants beyond the 2020s.
• The need for an economically coherent policy towards the domestic coal industry to avoid distorting the rest of the electricity market and increasing the costs of the system, which seems to be the likely result of current legislation.

• The prospect for more effective integration with the rest of Europe, which requires greater interconnection capacity and a better market design (e.g. a market coupling arrangement with France).

• Possible changes in the design of the wholesale electricity market (e.g. with respect to peak prices, capacity payments and congestion pricing) to allow thermal plants to efficiently cover their operating costs and face continuing incentives to provide the required levels of system flexibility.

At residential electricity level, the main policy issue remains the progress of market liberalisation, which has been even slower than in the residential gas market. This can be largely attributed to the distortion historically caused by the tariff deficit. The move to the ex-ante deficit (which shifted the deficit to the access component of the tariff, levelling the playing field in retail competition) and the introduction of TLR has rendered the residential market more dynamic, as indicated by recent data on switching rates. However, the experience of the gas market suggests that residential switching costs can be considerable and that even the elimination of some of the regulatory distortions may not be sufficient to reduce residential concentration levels. Over time, the greater scope for dual-fuel competition rendered possible by removing some of the distortions in retail electricity will hopefully enable the residential gas and electricity markets to become more dynamic, thus allowing for full price liberalisation.
Los mercados europeos del gas y la electricidad, especialmente el español, se caracterizan por los importantes retos de política sectorial a los que se enfrentan, debido a la complejidad y el carácter estratégico de estos mercados. Entre estos desafíos se incluyen: fomentar la competencia e introducir una regulación eficaz, con el fin de garantizar que los resultados del mercado sean competitivos y que se cree un mercado interior europeo; gestionar los elevados niveles de dependencia de fuentes externas de suministro (en especial del gas); y transformar los mercados del gas y la electricidad hacia un modelo más sostenible, en consonancia con los objetivos medioambientales actuales tanto a nivel europeo como global.

Este informe tiene por objetivo contribuir al análisis de algunos de estos temas, prestando especial atención a los segmentos competitivos de los mercados españoles de gas y electricidad (que en concreto son: el aprovisionamiento de gas, la generación de electricidad y los respectivos mercados minoristas) y poniendo un particular énfasis en las cuestiones medioambientales.

La primera parte del informe actualiza y amplia la primera edición del Informe del Centro Sector Público - Sector Privado sobre Competencia y Regulación en los Mercados Españoles del Gas y la Electricidad (publicado en 2008), mediante un análisis de los principales desarrollos regulatorios y de mercado que han caracterizado el sector energético español durante el período 2008-2009.

La segunda parte del informe está dedicada al examen exhaustivo de la política medioambiental en el sector energético europeo y español. Las cuestiones medioambientales ocupan un lugar central en el diseño de los mercados eléctricos europeos debido a los estrictos objetivos de mitigación del cambio climático, basados en las previsiones de las ciencias medioambientales. En este sentido, y de acuerdo con estudios internacionales elaborados al respecto, Europa tendrá que reducir significativamente las emisiones de gases de efecto invernadero en las próximas dos décadas (con reducciones, en relación a los niveles de 1990, superiores al 40% para 2030) si se quieren cumplir los objetivos medioambientales. Estos objetivos, a su vez, implican la necesidad de descarbonizar el sector eléctrico aún más rápidamente, logrando una reducción del 70% de las emisiones para 2030 (en relación a 1990), y una descarbonización casi completa del sector para el año 2050. Estos objetivos son claramente ambiciosos y
requerirán un cambio radical en cuanto a la forma en que están organizados los mercados eléctricos. Por ello, esta parte del informe analiza algunos de los temas de política relacionados con el cambio climático, la actuación de la Unión Europea (UE) y la política medioambiental española hasta la fecha.

Este capítulo introductorio resume los principales resultados y conclusiones de ambas partes del informe.

Parte I: La evolución de los mercados españoles del gas y la electricidad, 2008-2009

El contexto energético europeo

El contexto general europeo en el que se encuentra el mercado español del gas y la electricidad, a día de hoy, se sigue caracterizando por una dependencia externa significativa, unas políticas de competencia activas y una regulación sectorial en evolución, tanto en lo que respecta a la estructura del mercado como en lo relativo a los asuntos medioambientales.

En 2009, la dependencia energética externa se mantuvo por encima del 50% en la UE-27 (y cerca del 80% en España). La crisis económica de ese año ha moderado el aumento de esta dependencia constatado durante años anteriores, dada la reducción de la demanda energética y las importaciones fruto de la disminución global de la actividad económica. Al mismo tiempo, las fuentes de energía renovable nacionales han seguido creciendo, lo que también ha contribuido a mitigar la dependencia del exterior. Sin embargo, las proyecciones a medio plazo indican que la dependencia europea del gas va a aumentar con el tiempo, alcanzando hasta un 80% en 2030, a medida que se agoten los recursos nacionales. No obstante, la adopción de unas políticas medioambientales estrictas podría moderar el incremento de las importaciones de gas en términos absolutos durante este período, mediante la reducción de la demanda.

El mercado europeo del gas todavía depende principalmente de las importaciones por gasoducto de sus mayores proveedores (Rusia, Noruega y Argelia), aunque el peso de las importaciones de gas natural licuado (GNL) haya crecido en general, alcanzando casi una cuarta parte del total de importaciones del año 2009. A medio plazo se prevé un aumento significativo de la capacidad de importación de gas, tanto a través de gasoductos como de GNL, pero persiste incertidumbre sobre cuál de los proyectos de importación rivales se llevará a cabo, debido en parte a la incertidumbre sobre el futuro nivel de la demanda de gas. En todo caso, es posible que, bajo algunos escenarios relacionados con la evolución de nuevas infraestructuras, la dependencia europea del gas ruso aumente significativamente por encima de los niveles actuales.
En cuanto a la regulación sectorial y a la política de competencia, el año 2009 fue especialmente activo: se publicaron nuevas directivas de gas y electricidad, como parte del llamado Tercer Paquete Legislativo, y dos directivas adicionales en materia de energía renovable y comercio de derechos de emisiones, además de resolver varios casos de defensa de la competencia.

En el marco del Tercer Paquete Legislativo, la UE ha afinado su enfoque sobre la separación vertical de la industria energética, permitiendo a los Estados miembros optar por la segregación estructural total de las redes o por otros niveles de separación funcional menos estrictos.

Al mismo tiempo, la Comisión Europea ha investigado varios casos de abuso de posición dominante contra operadores incumbentes integrados (en Francia, Alemania, Italia y Bélgica). Estos casos se han centrado en las potenciales estrategias de exclusión llevadas a cabo por los incumbentes en los mercados minoristas liberalizados. Como resultado de estas investigaciones, en la mayoría de los casos las empresas bajo investigación han presentado compromisos que han reducido o eliminado su integración vertical (como, por ejemplo, en los casos de RWE, ENI y E.On (electricidad)), o bien han reducido su control sobre el mercado (como, por ejemplo, en los asuntos relativos a EDF, GDF/Suez y E.On (gas)).

Además, la Comisión Europea examinó y aprobó cuatro grandes fusiones entre empresas energéticas durante el periodo 2008/2009. Estas concentraciones dieron lugar a desinversiones estructurales importantes, especialmente si se valoran en relación a los posibles problemas de competencia asociados a las mismas. Estas intervenciones muestran que la política de competencia sigue siendo un elemento fundamental para la creación de un mercado interno que persigue la Comisión Europea en el sector energético.

**Regulación y política de competencia en España**

Las principales novedades en la regulación de los mercados españoles del gas y la electricidad desde finales de 2007 han sido la introducción de las Tarifas de Último Recurso (TUR), en el mercado del gas, a mediados de 2008, y en el de la electricidad a mediados de 2009; la reforma del mecanismo para la determinación y la recuperación del déficit tarifario; la continuación del programa de subastas CESUR para establecer el costo de la energía eléctrica para los consumidores residenciales, junto con la interrupción del programa de Emisiones Primarias de Energía (EPE) aplicado a los mayores generadores; así como importantes medidas sobre las subvenciones a la energía solar y sobre la generación que utiliza carbón nacional.

La introducción de la TUR en los mercados residenciales del gas y la electricidad no aumenta la liberalización de los respectivos mercados minoristas por sí misma, ya que la TUR sigue siendo una tarifa regulada que fija el Gobierno, con respecto al componente no energético. Por otra parte, las tendencias hacia una mayor liberalización en el mercado minorista, tanto en gas como en electricidad, han continuado después de la introducción de la TUR. Además, las tarifas
eléctricas reguladas de alta tensión, y las tarifas para las pymes y para los grandes clientes residenciales fueron suprimidas entre mediados de 2008 y de 2009, dando así mayor apoyo al avance de la desregulación del mercado minorista eléctrico.

Otra característica positiva de la TUR eléctrica, en relación con el sistema anterior, es que el componente energético está directamente relacionado con un mecanismo de mercado (las subastas CESUR), lo que ayuda a garantizar que, por lo menos, una parte de las tarifas se mueva con los precios de mercado. Sin embargo, las tarifas de acceso a la red continúan siendo reguladas a un nivel que se sitúa por debajo del coste, lo que ha implicado elevados déficits tarifarios durante los años 2008 y 2009.

En principio, la reforma del déficit tarifario introducida en abril de 2009 (a través del Real Decreto-ley 6/2009) debería mejorar los mecanismos para la recuperación y la determinación futura del déficit mediante la titularización de una cantidad significativa del déficit incurrido antes del 2009 (10.000 millones de euros) y la limitación del déficit anual que se genere durante el periodo 2009-2012. Sin embargo, el déficit acumulado durante el año 2009 superó los límites introducidos por el RDL 6/2009, lo que sugiere que esta medida carece de pleno compromiso político. Por otra parte, la supresión, a mediados de 2009, de la medida que elimina los beneficios obtenidos por la asignación gratuita de derechos de emisión de CO$_2$ (una medida que ha sido aplicable en España desde 2006) ejerce una presión al alza sobre el déficit.

El programa español de EPE, que fue introducido a mediados de 2007, llegó a su fin en el primer trimestre de 2010. Un máximo de cerca de 2,6 GW de carga base y punta, equivalente al 5 o 7% de las respectivas capacidades de Endesa e Iberdrola, se vio afectado por el programa. Una revisión del mismo llevado a cabo por el regulador del sector (la Comisión Nacional de Energía, CNE) en 2009 indica que el régimen pudo haber sido eficaz en la promoción de la competencia minorista y la liquidez del mercado, pero no necesariamente en la mejora de la competencia mayorista. El último resultado puede explicarse, en parte, por el tamaño relativamente pequeño de EPE, durante la vida útil de su intervención.

La decisión del Gobierno de no continuar con el programa EPE más allá de la última subasta (celebrada en marzo de 2009) parece haber sido justificada por la reciente reducción de la concentración en el mercado eléctrico español y por los resultados del mercado durante 2009 y principios de 2010, que han dado lugar a precios de la electricidad competitivos (debido, principalmente, a la combinación de una menor concentración, la producción adicional de fuentes renovables y una menor demanda). Sin embargo, hubiera sido preferible determinar si se debía continuar o no con el régimen de EPE en base a un examen transparente de la estructura del mercado de generación español (por ejemplo, llevado a cabo sobre la base de las evaluaciones periódicas de la competencia realizadas por la CNE). Esto habría proporcionado una base objetiva para las futuras decisiones sobre planes similares, y habría dado más tiempo a los operadores del mercado para adaptarse a los cambios en la regulación.
Los mercados de energía siguen siendo un área clave en la aplicación de la política de competencia también en España. En términos de control de fusiones, la mayor concentración evaluada por la autoridad de competencia (la Comisión Nacional de la Competencia, CNC) ha sido la fusión entre Gas Natural y Unión Fenosa (aprobada a principios de 2009). Esta operación unió al incumbente de gas español con la tercera empresa más grande de electricidad, que también tenía una importante presencia en el mercado del gas (a través de su participación del 50% de Unión Fenosa Gas). La CNC aprobó la fusión, pero sujeta a un compromiso en relación a la gestión de Unión Fenosa Gas en el mercado minorista y a unas desinversiones estructurales en los mercados de generación eléctrica y de suministro minorista de gas (concretamente, la venta de 2 GW de centrales de ciclo combinado y de puntos de distribución con sus correspondientes consumidores residenciales). La ausencia de medidas estructurales dirigida directamente a los mercados mayoristas e industriales del gas (donde Unión Fenosa Gas se había convertido en un importante competidor de Gas Natural) fue una característica notable de la decisión de la CNC. Este aspecto de la decisión sugiere que la CNC confía en que la competencia en los mercados mayoristas e industriales de gas en España es suficientemente intensa y en que el aumento en la concentración del mercado provocado por la operación no tendrá efectos negativos sobre los consumidores de gas.

La CNC también emitió una decisión de abuso de posición dominante contra los distribuidores de electricidad por limitar el acceso a la información disponible sobre los consumidores a un competidor minorista (Centrica Energía). Esta decisión refleja la preocupación por la integración vertical entre distribuidores y minoristas, que es consistente con la preferencia general por la separación de la propiedad expresada por la Comisión Europea.

Por último, la CNC no emitió nuevas decisiones de abuso de posición dominante sobre las restricciones técnicas en la red de trasmisión eléctrica, tras las cuatro decisiones adoptadas sobre este asunto a lo largo del periodo 2006-2008. No obstante, esta área permanece bajo un estricto control de la autoridad de competencia que, a finales de 2009, abrió nuevas investigaciones en este tema involucrando prácticamente a todos los generadores del mercado. El problema de cómo compensar apropiadamente la producción de los generadores ubicados en zonas congestionadas de la red eléctrica no es solo una cuestión de derecho de la competencia, sino que también afecta al régimen económico de las plantas de energía térmica en un contexto de creciente generación de energía renovable.

La evolución del mercado español del gas: 2008-2009

El mercado mayorista del gas
Durante el periodo 2008-2009, el mercado español del gas se caracterizó por una importante volatilidad de la demanda, una creciente dependencia de las importaciones de GNL, una falta de flexibilidad del sistema (provocada por una inadecuada capacidad de almacenamiento doméstico y de interconexión), y unos cambios estructurales considerables debido a la fusión entre Gas.
Natural y Unión Fenosa. A continuación se describen estos y otros aspectos principales de la evolución del mercado mayorista español:

- **La demanda de gas en el mercado español creció un 10% entre 2007 y 2008** (debido, principalmente, al crecimiento del sector eléctrico). Sin embargo, **cayó drásticamente entre 2008 y 2009** (casi un 11%) debido a la contracción de la actividad económica y a la reducción en la producción de las centrales de gas, que se vieron desplazadas, en parte, por el aumento constante de la generación eléctrica a través de fuentes renovables. La convergencia entre los mercados del gas y la electricidad sigue siendo significativa, con el sector eléctrico representando el 40% de la demanda total de gas.

- **El peso de las importaciones de GNL en el volumen total de gas ha seguido aumentando**, alcanzando casi tres cuartas partes del total de las importaciones en 2009 (muy por encima de la media de UE-15, que es inferior a una cuarta parte). El mercado español del gas se mantiene altamente diversificado en relación con otros mercados europeos (sobre todo con Alemania, pero también con Francia e Italia), dispone de acceso a una capacidad de regasificación significativa y, por lo menos, de seis fuentes principales de gas que, a diferencia de la mayoría de Europa, no incluyen a Rusia. Estas características del mercado español de gas lo hacen menos vulnerable a posibles interrupciones del suministro, a diferencia del resto de Europa.

- **Con respecto a las infraestructuras del sector del gas, se siguen realizando inversiones en el sistema español**, con expansiones por parte de Enagás en las terminales de GNL de Barcelona y de Cartagena, y también de las instalaciones de Sagunto. El nuevo gasoducto con Argelia (Medgaz) también debería entrar en funcionamiento en el 2010. Medgaz podría conducir a una mayor dependencia del gas argelino (que, a su vez, podría ser considerada excesiva a la luz del arbitraje sobre los precios de suministro entre Gas Natural y Sonatrach en 2010).

- **Hay deficiencias importantes en la infraestructura gasista en España**, tanto en términos del almacenamiento doméstico del gas como de la capacidad de interconexión con Francia (especialmente para la exportación). La capacidad de almacenamiento doméstico de gas en España (incluyendo las plantas de GNL) representaba, aproximadamente, sólo un 10% de la demanda anual a mediados de 2010, muy por debajo de los niveles alcanzados en otros grandes mercados Europeos como Alemania, Italia y Francia. El acceso al almacenamiento doméstico de gas será cada vez más crítico en el mercado español, ya que se espera que la generación de electricidad a partir de gas opere de un modo más flexible en el futuro (por ejemplo, para hacer frente a mayores niveles de generación de renovables intermitentes). La nueva instalación que Enagás está desarrollando en Yela (que se espera esté operativa en 2011) aumentará la capacidad española de almacenamiento de gas subterráneo aproximadamente en un 50%, lo cual puede representar un proyecto clave en el proceso de aumento de la flexibilidad del sistema de gas español.

- **El mercado secundario del gas OTC sigue creciendo**, proporcionando una fuente importante de flexibilidad para las importaciones de GNL. Sin embargo, no representa un sustituto
adecuado para un mercado primario mayorista de gas que sea líquido y transparente, el cual no se ha desarrollado todavía en España.

- La estructura del mercado mayorista del gas en España se sigue caracterizando por la posición preponderante de la empresa incumbente, Gas Natural. No obstante, la cuota de importaciones de gas mayorista de esta compañía ha disminuido progresivamente con la liberalización del sector y la entrada de GNL independiente, pasando de cerca del 80% en 2004 al 50% en 2009. Esta disminución de la cuota de mercado se revirtió parcialmente en 2009, a través de la adquisición, por parte de Gas Natural, del control conjunto de Unión Fenosa Gas (que representaba un 13% adicional del mercado mayorista español en 2009). A pesar del aumento efectivo en la concentración del mercado observada en 2009, el mercado mayorista del gas en España sigue estando menos concentrado que en la mayoría de los países europeos, los cuales tienden a tener mercados altamente concentrados (con la excepción del Reino Unido y Alemania).

El mercado minorista del gas

El mercado minorista del gas español sigue estando caracterizado por una liberalización gradual, una alta concentración y bajas tasas de cambio de proveedor por parte de los clientes residenciales a nivel regional:

- A nivel minorista, más de un 90% de la demanda se comercializa en el mercado liberalizado, lo cual demuestra que el mercado español del gas está efectivamente liberalizado en términos de volúmenes. Sin embargo, en términos de número de consumidores, la liberalización sigue siendo incompleta, como indica el hecho de que más del 45% de los consumidores de gas acudieran a la TUR durante el primer trimestre de 2010. No obstante, la participación de los clientes en el mercado regulado ha disminuido progresivamente desde 2004 (cuando esta se situaba cerca del 80%).

- El mercado minorista continúa altamente concentrado, con un Índice Herfindahl-Hirschman (IHH) en 2009 muy por encima de los 2.000 puntos (que es el umbral estándar utilizado para un mercado altamente concentrado). Al igual que en el mercado mayorista, la concentración efectiva del mercado aumentó durante el año 2009 tras la adquisición, por parte de Gas Natural, de una participación del 50% en Unión Fenosa Gas. Las desinversiones minoristas que resultaron de la decisión de la CNC redujeron la concentración en el mercado residencial, pero no lo consiguieron en el conjunto del mercado minorista (debido a los volúmenes de gas relativamente bajos asociados con el consumo residencial).

- A nivel regional, la concentración en el mercado residencial sigue siendo muy elevada, debido a que una parte importante de los clientes permanecen con las tarifas reguladas y los que cambian al mercado liberalizado tienden a permanecer con el operador incumbente de cada comunidad autónoma. A finales de 2009, en promedio, aproximadamente solo el 15% del total de consumidores había cambiado su proveedor de gas en cada C. A.. A pesar del progreso
relativamente lento de la introducción de la competencia en mercado del gas residencial, el funcionamiento del mercado español no es peor que el de otros mercados de gas en Europa. De hecho, el porcentaje de clientes que se han cambiado de proveedor en España está por encima de los niveles registrados en Alemania, Italia y Francia (pero por debajo de los del Reino Unido y los Países Bajos).

La evolución del mercado eléctrico español: 2008-2009

El mercado eléctrico mayorista
El mercado eléctrico mayorista español ha experimentado cambios muy significativos desde principios de 2008, como consecuencia de las variaciones en los precios relativos de los combustibles (incluyendo el del CO₂), las fluctuaciones significativas de la demanda y el continuo crecimiento de la generación de régimen especial subvencionado (en su mayoría renovables). Los principales acontecimientos que han tenido lugar en el mercado eléctrico mayorista son los siguientes:

• A nivel mayorista, la demanda disminuyó por primera vez desde la liberalización del mercado, bajando cerca de un 5% entre 2008 y 2009. Sin embargo, a partir del año 2000, el crecimiento acumulado de la demanda en el mercado eléctrico español ha sido muy alto (cerca de 35%), muy por encima del nivel promedio de la UE-15, de poco más del 7%.

• El mix de generación en el mercado español ha experimentado cambios radicales en 2008 y 2009. La tendencia principal ha sido un importante crecimiento en la generación del régimen especial que, junto con una demanda estancada o en declive, ha desplazado la producción térmica, sobre todo la generación de carbón. Los cambios estructurales experimentados en el mercado eléctrico español destacan una tendencia hacia un sistema eléctrico “más verde”, con una intensidad de carbono significativamente menor que en el pasado, una generación considerablemente mayor de fuentes renovables y un funcionamiento más flexible por parte de los generadores térmicos (las centrales de gas de ciclo combinado (CCGT) en particular).

• Durante el período 2007-2009, la generación en régimen especial creció un 40%, mientras que la generación que utiliza carbón disminuyó más de un 50%. A mediados de 2010, la generación de carbón disminuyó aún más, llegando a menos de un tercio del nivel de 2007. Parte de esta reducción en la producción de electricidad con carbón puede ser atribuida al aumento de los precios de CO₂ después de los bajos niveles observados durante el año 2007 (cuando la Fase I del Emissions Trading System (ETS) llegó a su fin). La producción de CCGT aumentó un 15% durante el período 2007-2009, pero el nivel de producción de 2009 estuvo un 14% por debajo del nivel alcanzado en 2008 (con una reducción aun más marcada a mediados de 2010).
La generación total de renovables, incluyendo la generación hidroeléctrica convencional, alcanzó cerca del 27% del consumo total de electricidad en 2009, frente al 21% en 2008. Este aumento en la participación relativa de la producción de renovables se ha conseguido gracias, principalmente, al constante crecimiento de la generación eólica, que creció más de un tercio entre 2007 y 2009, y a la mayor producción de electricidad solar fotovoltaica, que aumentó casi quince veces su magnitud en dos años.

En el mercado español, la tecnología de generación más flexible sigue siendo la CCGT, que representó cerca del 50% de la flexibilidad del mercado total en 2009 (definida como la diferencia entre la generación media del decil mínimo y máximo de la demanda), por encima de su participación en la producción, que fue inferior al 30%. Por el contrario, la generación en régimen especial solo representó el 14% de la flexibilidad, muy por debajo de su cuota de producción total del 30%.

La integración del mercado español y portugués se ha intensificado durante el periodo 2008-2009, con una reducción de hasta el 25% de las horas de congestión en la capacidad de interconexión en 2009 (frente a, aproximadamente, el 80% en el segundo semestre de 2007) y la resultante caída del diferencial de precios entre los dos sistemas a, aproximadamente, el 2% en 2009. Esto puede explicarse, en parte, por una mayor convergencia en el mix de generación de los dos mercados y la existencia de un mecanismo de comercio transfronterizo efectivo. Sin embargo, parte de la mayor convergencia de precios vista desde el año 2008 también puede deberse a factores no estructurales y podría revertirse en el futuro.

Por el contrario, la integración entre el mercado ibérico y el resto de Europa sigue siendo limitada. La capacidad de interconexión total con Francia continúa siendo inferior a 1,5 GW (menos del 3% de la demanda punta ibérica). Por otra parte, la ausencia de un mecanismo de comercio de electricidad efectivo entre Francia y España, como un sistema de market coupling, limita la integración entre los dos mercados. Por ejemplo, durante el año 2008 la convergencia de precios entre Francia y España se logró solo el 6% de las horas. Se necesitan una mayor capacidad de interconexión con Francia (tanto en las importaciones como en las exportaciones) y la introducción de un diseño del mercado efectivo para integrar mejor el mercado ibérico con el resto de Europa, así como para gestionar de forma óptima el peso creciente de la generación intermitente de energías renovables en España.

Los precios en el mercado mayorista español se han caracterizado por altos niveles de volatilidad desde el 2008. Los precios máximos anuales del mercado diario alcanzaron un histórico de 66 €/MWh en 2008, para luego caer a 38 €/MWh en 2009 y a 30 €/MWh en el primer semestre de 2010, como consecuencia de la caída de la demanda y de los precios del combustible, así como del crecimiento de la generación renovable. Los márgenes entre los precios de carga base y los costes de las plantas térmicas se redujeron considerablemente durante 2009 en relación con períodos anteriores, induciendo a estos generadores a operar a factores de carga más bajos con el fin de obtener precios medios mayores.
En los últimos años la concentración ha disminuido en los mercados eléctricos mayoristas, como resultado de la entrada de plantas de energía renovable y de CCGT independientes, de las reestructuraciones de las empresas incumbentes (especialmente las ventas de activos por parte de Endesa) y del cambio de la generación con carbón a la generación con gas (lo que reduce la concentración, ya que la estructura de la propiedad de las plantas de CCGT está menos concentrada que la de las plantas que utilizan carbón). Bajo una definición amplia del mercado (incluyendo toda la generación en la península ibérica) se puede considerar que el mercado está escasamente concentrado, sobre la base de los índices convencionales, con un IHH alrededor de los 1.100 puntos (casi un 25% menos que en 2007). Bajo una definición de mercado más estricta y conservadora (es decir, considerando solo la generación que fija los precios en España), el mercado sigue estando moderadamente concentrado, con un IHH estimado de aproximadamente 1.450 (más de un 20% menor que en 2007). Como resultado de estas tendencias, el mercado español se ha vuelto menos concentrado que otros mercados en Europa con la excepción del Reino Unido, los Países Bajos y los Países Nórdicos.

El mercado eléctrico minorista
A nivel minorista, el mercado eléctrico español sigue caracterizándose por una liberalización de las tarifas limitada (pero en aumento), unas reducidas tasas de cambio por parte de los consumidores residenciales, y un importante déficit anual entre los ingresos regulados y los costos (el llamado déficit tarifario), que alcanzó su máximo nivel histórico durante 2008 y 2009.

El mercado minorista eléctrico español sigue estando parcialmente liberalizado, con una cuota importante del volumen total (más de un tercio) y especialmente de los clientes (más del 80%) que adquieren electricidad a precios regulados. Sin embargo, el grado de liberalización ha crecido con rapidez desde 2006/2007, gracias a las reformas del mecanismo de déficit tarifario (es decir, a la asignación “ex-ante” del déficit a las tarifas de acceso, aplicada a partir de 2007), la abolición de las tarifas de alta tensión y la introducción de las TUR.

En cuanto a la concentración del mercado, el mercado español a nivel minorista está mucho más concentrado que a nivel mayorista, debido a la fuerte posición de los distribuidores incumbentes (en particular, Endesa e Iberdrola). Sin embargo, la concentración en el mercado nacional se ha reducido rápidamente con la liberalización del sector en los últimos dos años, con un IHH de mercado que ha pasado de ser superior a 3.000 en 2007 a ser aproximadamente 2.200 en 2009. La presencia de una regulación directa de precios también supone que los altos niveles de concentración no resultan necesariamente en precios excesivos.

El patrón de cambio de suministrador eléctrico sigue siendo muy regional, como en el mercado minorista de gas, con tasas de fidelidad para los principales distribuidores de energía eléctrica entre el 75% y el 90% a mediados de 2009, dependiendo de la zona de la red. Esto significa que muy pocos consumidores residenciales han cambiado su proveedor de electricidad desde la liberalización del mercado (incluso menos que en el mercado del gas). De hecho, el porcentaje de clientes que ha cambiado de proveedor en el mercado eléctrico español está por debajo de
los porcentajes alcanzados en otros mercados europeos (especialmente en el Reino Unido, Suecia y los Países Bajos, pero también en Alemania y Dinamarca).

- La característica que define el mercado minorista español de electricidad (y el sistema eléctrico en su conjunto) sigue siendo la presencia de un déficit tarifario elevado y creciente, debido a la persistente diferencia anual entre los ingresos regulados y los costes correspondientes. El déficit tarifario anual alcanzó un máximo superior a 4.300 millones de euros durante el año 2008, y se situó en un nivel neto estimado de 3.800 millones de euros en 2009 (por encima del límite anual establecido en el RDL 6/2009). Por su parte, la deuda acumulada se situó en torno a los 17.000 millones de euros a finales de 2009, con casi un 90% del mismo pendiente aún de ser recuperado.

- El principal factor detrás del reciente aumento del déficit tarifario ha sido el creciente nivel de remuneración a la generación en régimen especial (que incluye la mayoría de las fuentes de energía renovables). El aumento de las primas y/o los pagos totales al régimen especial entre 2007 y 2009 iguala o supera el nivel del déficit tarifario neto durante el año 2009. Más del 60% del incremento de las primas al régimen especial durante este período se debieron a los pagos efectuados a la tecnología solar fotovoltaica (a pesar de que esta tecnología solo representó un 8% de la producción total del régimen especial en 2009).

Parte II: Las políticas medioambientales en el sector energético europeo y español

La economía del cambio climático en el sector energético

La necesidad de mitigar los riesgos asociados con el cambio climático es posiblemente el mayor reto al que el sector energético europeo y español se enfrentan en la actualidad. La ciencia del cambio climático indica que hay un argumento sólido a favor de reducir rápidamente las emisiones mundiales de gases de efecto invernadero (GEI) en las próximos cuatro décadas, con el fin de evitar las consecuencias potencialmente muy costosas derivadas de un calentamiento global excesivo.

Con el fin de reducir el riesgo de que la temperatura global aumente más de 2 grados centígrados por encima de los niveles preindustriales (que se corresponde con el umbral establecido en el Acuerdo de Copenhague de finales de 2009), las emisiones globales de gases de efecto invernadero deben alcanzar su máximo en la próxima década, para después empezar a descender rápidamente (por ejemplo, logrando una reducción del 50% en 2050 respecto al máximo de 2020 y del 33% con respecto a 1990).

Los objetivos para la UE son aún más estrictos, estableciendo la necesidad de lograr reducciones de emisiones (en relación con 1990) superiores al 20% para el año 2020, al 40% para 2030, y por lo menos del 80% para 2050. Se prevé que el mercado eléctrico en particular tenga que
asumir una parte importante del esfuerzo global de reducción de emisiones, debido a la posibilidad del desarrollo a gran escala de las fuentes renovables en este sector y el potencial para descarbonizar otros sectores (como el transporte y la calefacción residencial). Como resultado, el sector energético europeo necesitaría lograr una reducción del 70% de las emisiones para 2030 (en relación a 1990), y una descarbonización casi completa para 2050 si se quieren cumplir los objetivos medioambientales.

La teoría económica señala que la forma más eficiente de reducir las emisiones de carbono es poner un precio al CO₂, ya sea a través de un mecanismo cap-and-trade (como el sistema de comercio de emisiones europeo, ETS), o a través de un impuesto sobre el dióxido de carbono. Estos mecanismos pueden garantizar que las emisiones sean valoradas correctamente, desalentando la utilización de tecnologías intensivas en carbono y favoreciendo la producción de fuentes eléctricas con emisiones de carbono bajas o nulas (por ejemplo, renovables, nuclear e instalaciones con captura y almacenamiento de carbono, Carbon Capture and Storage, CCS). Establecer un precio para el CO₂ puede, en principio, resolver los principales fallos de mercado asociados con el cambio climático, es decir, el hecho de que los emisores no internalizan el costo social de sus emisiones de carbono.

Otras políticas medioambientales complementarias pueden estar justificadas si se deben abordar fallos de mercado adicionales. Sin embargo, estas políticas no deben justificarse simplemente por la necesidad de reducir las emisiones, ya que la mejor manera de solucionarlo es a través de un mecanismo de precios de carbono. Por ejemplo, en el caso de las energías renovables, pueden existir externalidades tecnológicas que no puedan ser capturadas en su totalidad por los inversores de los proyectos. Estas externalidades (si son significativas) pueden justificar un subsidio de I+D y/o de despliegue. A su vez, pueden existir otros beneficios sociales derivados del fomento de las energías renovables (como la reducción de la dependencia energética exterior o la contribución a una política industrial efectiva), aunque estos tienden a ser limitados si se comparan con otras formas de generación eléctrica bajas en emisiones de carbono (como por ejemplo, nucleares y CCS), u otros posibles usos competitivos de los fondos públicos.

Es importante comprender y cuantificar los beneficios derivados de apoyar a las tecnologías renovables, ya que fomentar las mismas puede tener un coste social, tanto en términos de los costes totales de la energía, como de la posible distorsión de los precios del dióxido de carbono. Esto último se debe al hecho de que la promoción de las energías renovables mediante subsidios directos, y no exclusivamente a través de los precios del carbono, puede por sí misma bajar los precios del carbono (en comparación con una situación hipotética con menor ayuda a las renovables), a expensas de otras fuentes de energía bajas en emisiones (como la nuclear y la CCS, en particular y, en cierta medida, también la CCGT). Estas consideraciones implican que la promoción directa de fuentes renovables puede impedir la adopción de una política de reducción de las emisiones que sea neutral desde el punto de vista tecnológico, y por lo tanto podría aumentar los costes de dicha política. Consideraciones distributivas podrían, sin embargo, justificar políticas que no se basen únicamente en los precios del carbono para alcanzar los niveles necesarios de reducción de las emisiones de GEI.
Las proyecciones de la Agencia Internacional de la Energía (AIE) indican que será necesaria una combinación de tecnologías y mecanismos para reducir eficientemente las emisiones de GEI en el sector eléctrico en el futuro. Estos incluyen la energía renovable, la energía nuclear, la CCS y medidas de eficiencia. En particular, se prevé la necesidad de aumentar la cuota de electricidad renovable en la generación total en Europa a un poco más del 30% para el año 2020, y del 43% para el 2030. Este aumento potencial en la generación de renovables plantea retos importantes para el sector eléctrico, debido a la necesidad de hacer frente a la intermitencia de algunas energías renovables (principalmente la eólica). Será necesario tener una capacidad de generación térmica de respaldo importante para garantizar la seguridad del suministro en estas circunstancias. Se necesitará que las centrales térmicas (en particular CCGT) operen en un modelo cada vez más flexible, con un reducido factor de utilización medio (por ejemplo, del 30% o menos). Para que esto sea compatible con un equilibrio de mercado, es probable que sea necesario que aumenten de forma significativa los precios del sector eléctrico en las horas punta respecto a los niveles actuales, y que los mercados del gas y la electricidad tengan que operar con mayor flexibilidad en general.

Es necesaria una acción global que involucre a todos los grandes países emisores para cumplir con los ambiciosos objetivos de reducción que establece la ciencia del cambio climático. La acción de solo un subconjunto limitado de países será en gran medida inefectiva, dada la dimensión internacional del calentamiento global. Europa, en particular, solo representa una pequeña parte de las emisiones totales de GEI (menos del 15% en 2009), lo que implica que tomar medidas medioambientales decisivas en Europa, pero no en otros grandes países emisores, no daría los resultados deseados.

Las políticas medioambientales en el sector energético europeo

Hasta la fecha, las políticas medioambientales en el sector energético de la UE se han centrado en tres pilares principales: (a) el compromiso del Protocolo de Kyoto de reducir las emisiones de GEI de la UE-15 durante el período 2008-2012 en un 8% respecto a 1990; (b) la adopción de un objetivo de 12% de energías primarias renovables (que corresponde a un nivel del 21% de electricidad renovable) para el año 2010; y (c) el establecimiento del ETS, un mecanismo de cap-and-trade que está en vigor desde 2005.

Es probable que el objetivo de Kyoto para Europa se cumpla. Se estima que las emisiones de la UE-15 en el año 2009 fueron aproximadamente un 13% más bajas que en 1990 (debido, en parte, a la recesión económica, lo que contribuyó a una reducción del 7% entre 2008 y 2009). Por otra parte, la electricidad renovable en la UE-27 se va a situar por debajo del objetivo promedio del 21% (siendo aproximadamente un 18% en 2009, aumentando 6 puntos porcentuales desde 1990). La introducción del ETS ha sido efectiva en la creación de un precio transparente para el CO2 en Europa, pero también ha presentado varias deficiencias en su diseño inicial. Estas han incluido, sobre todo, un exceso de asignación de permisos en la Fase I (entre
2005 y 2007), lo que junto con la falta de *banking* (es decir, el traspaso de derechos de emisión entre las fases) llevó a un colapso en el precio del CO₂ durante el año 2007; y la asignación gratuita de derechos de emisión, tanto en la Fase I como en la Fase II (hasta 2012), lo que ha dado lugar a sobreingresos directos para los generadores térmicos.

Entre 2008 y 2009 se adoptaron una serie de importantes medidas para definir la política energética de la UE con respecto al medio ambiente, para el período que corresponde hasta el 2020. Estas incluyen, principalmente, el paquete de medidas climáticas y energéticas “20-20-20”, que compromete a la UE a alcanzar los siguientes objetivos para el año 2020: una reducción de las emisiones de GEI de un 20% (en relación a 1990); una participación del 20% de las fuentes renovables en el consumo final de energía (partiendo de un nivel del 10% en 2008); y una mejora del 20% en la eficiencia energética. El objetivo de emisiones de GEI se concretó en el diseño del ETS a través de una reducción del 21% en los derechos de emisión para el año 2020 (en relación con el 2005), comenzando en el 2013, junto con el establecimiento del mecanismo de subasta en el sector eléctrico (aplicable a la mayoría de los Estados miembros). El objetivo de que el 20% del consumo sea procedente de fuentes renovables ha derivado en objetivos nacionales vinculantes, lo que implica que, en promedio, la proporción de fuentes renovables en el consumo de electricidad tendrá que llegar a una cuota de entre el 33% y el 40% para el año 2020 en todos los Estados miembros.

Por lo tanto, las políticas medioambientales en el sector energético de la UE seguirán basándose, principalmente, en las señales económicas derivadas de los precios del carbono y en los objetivos relacionados con el desarrollo de las fuentes renovables. Sin embargo, la efectividad del precio del carbono puede verse afectada por la fuerte reducción de las emisiones que la UE-27 experimentó en 2009 (el 85% de la reducción necesaria para el año 2020 ya se ha alcanzado en el 2009), junto con la posibilidad de transferir los derechos de emisiones entre las fases del ETS y el continuo apoyo directo para las energías renovables. Las estimaciones existentes para el nivel esperado de precios del carbono en 2020 están en un rango entre 20 y 40 €/tonelada de CO₂, lo que probablemente sea insuficiente para que las inversiones adicionales en la generación de baja emisión de carbono (nucleares y CCS) sean viables comercialmente.

Por lo tanto, hay un argumento económico para fijar un objetivo de reducción de emisiones más estricto para el año 2020 (por ejemplo, a un 30% por debajo de los niveles de 1990), con el fin de reforzar la señal de precios dada por el ETS y lograr un patrón de reducciones más sostenible también para los años sucesivos al 2020, cuando se requerirán nuevas e importantes reducciones.

Al mismo tiempo, es posible que los objetivos europeos concernientes a las energías renovables para el año 2020 se hayan fijado en un nivel demasiado alto y por lo tanto no reflejen los fallos de mercado reales (principalmente los de carácter tecnológico) que deben ser abordados a través de políticas de apoyo a dichas energías. Es probable que esto aumente los costes totales de lograr una determinada reducción de las emisiones de GEI en Europa. Con el fin de reducir el riesgo de que los costes de apoyo a las renovables lleguen a ser aún más altos, se debería poner mayor
Énfasis en los mecanismos de mercado para determinar el nivel de remuneración de las renovables (por ejemplo, mercados de capacidad o sistemas más flexibles para la fijación de las *feed-in tariffs*).

**Las políticas medioambientales en el sector energético español**

En la última década, la política energética española en relación al medio ambiente se ha centrado principalmente en la promoción de energías renovables. Hasta la fecha, España no ha incentivado activamente otras formas de generación de bajas emisiones de carbono, como la energía nuclear, a pesar de que su sistema eléctrico sigue dependiendo de las centrales nucleares de manera significativa. Por otra parte, si bien esto no ha sido una consecuencia explícita de la política medioambiental, el cambio en el mix de generación del petróleo y el carbón hacia las plantas de gas ha mejorado de manera importante el impacto medioambiental general del sistema (reduciendo la intensidad media de carbono de la generación eléctrica). Sin embargo, las emisiones totales de GEI en España en 2009 estuvieron cerca de un 30% por encima de su nivel de 1990, y muy por encima del objetivo del 15% acordado en el marco de la aplicación del Protocolo de Kyoto. Esto puede atribuirse, en gran medida, al importante aumento del consumo total de energía en España durante este período.

El Gobierno ha marcado una serie de objetivos detallados para las fuentes renovables domésticas a través de una serie de documentos nacionales de planificación (en 1999, 2005 y 2010). En los planes del 1999 y del 2005, el objetivo de energías renovables para 2010 se fijó en casi el 30% del consumo total de electricidad (con el fin de cumplir con los objetivos europeos de energía renovable para el mismo año). Para 2020, este objetivo se ha incrementado hasta casi el 40% de la demanda.

El objetivo del 2010 está cerca de ser alcanzado, ya que la electricidad renovable representaba algo más del 27% del consumo en 2009, gracias al continuo crecimiento de la producción de renovables (principalmente eólica y solar) y a la reducción del consumo experimentado en 2009. Desde que el mercado se liberalizó en 1998, la generación de renovables se ha duplicado en España (de 38 TWh a 75 TWh), con tres cuartas partes de este incremento procedente de la generación eólica, seguida de la solar, que representa el 14% del incremento total, debido al crecimiento que experimentó en 2008 y 2009. Los niveles de capacidad eólica y solar fotovoltaica en España superan significativamente a los de otros países europeos, con la única excepción de Alemania que, sin embargo, es un mercado mucho más grande.

El considerable crecimiento de la electricidad renovable en España se ha logrado a través de un sistema de tarifas y primas que ha evolucionado mucho desde su creación en 1994. Hasta 2007, este mecanismo de primas en España ha funcionado razonablemente bien, logrando un crecimiento considerable en la generación eólica en particular, a un coste que no parece excesivo, en términos comparativos con el resto de Europa.
No obstante, el coste de las primas a la generación de régimen especial (que incluye la mayoría de las fuentes renovables) casi se triplicó entre 2007 y 2009 (pasando aproximadamente de 2.200 millones a más de 6.000 millones de euros), y los pagos totales (es decir, la sumas de la remuneración del mercado y de las primas) casi se duplicaron. La mayor parte de este aumento en las primas y en los pagos totales corresponde a la remuneración de la tecnología solar fotovoltaica, que ha aumentado entre 2.400 y 2.600 millones de euros del 2007 al 2009, como consecuencia de una entrada de plantas solares mucho mayor de lo previsto (aprovechando el mecanismo de remuneración establecido por el Gobierno a mediados de 2007). La capacidad solar fotovoltaica aumentó de 0,3 GW en mayo de 2007 a 3,5 GW a finales de 2009 (casi diez veces por encima del objetivo de la planificación original establecido para la capacidad solar fotovoltaica en 2010).

A finales de 2009, el coste de los subsidios a la energía solar fotovoltaica representó más del 40% del total de las subvenciones a la generación de régimen especial (que incluye también las plantas de cogeneración no renovables), pero su producción constituyó solo el 8% de la generación en régimen especial. El nivel de las tarifas ofrecidas a nuevos inversores en plantas fotovoltaicas se redujo en casi un 40% entre finales de 2008 y mediados de 2010, aunque sigue atrayendo inversión en nueva capacidad. Esto significa que las primas pagadas en el periodo 2007-2008 seguramente se fijaron a niveles excesivamente altos, ya que es probable que la reducción de tarifas aplicadas desde entonces exceda la caída en los costes experimentada en el mismo periodo.

La experiencia española con la remuneración de la energía solar fotovoltaica representa un ejemplo de los peligros económicos de depender de un sistema de primas administrativas para apoyar la generación de renovables si este sistema está diseñado de manera imperfecta (por ejemplo, sin un límite sobre el importe total de los subsidios prometidos a los inversores). Así, al igual que un sistema de primas puede ser efectivo para ofrecer seguridad a los inversores, también demanda una gran cantidad de información cuando se establece el nivel de las subvenciones. Se pueden cometer errores costosos (en particular si los costes de la tecnología disminuyen más rápidamente de lo previsto), dando lugar a que los precios establecidos estén por encima de los costes y que las inversiones a esos precios sean mucho mayores de lo inicialmente previsto (aumentando así los costes totales de la ayuda a las renovables).

Principalmente como resultado de los pagos a las plantas solares fotovoltaicas (pero también por el declive de los precios de mercado), los subsidios totales al régimen especial alcanzaron niveles récord en 2009 (más de 6.000 millones de euros), equivalente a casi el 60% del gasto en el mercado mayorista (que resulta de multiplicar el volumen total del mercado mayorista por su precio). El subsidio por unidad de CO₂ no emitida lograda a través de la generación de renovables en España en 2009 puede estimarse entre 200 y 250 €/tonelada de CO₂, más de catorce o diecisiete veces superior, respectivamente, al precio actual de mercado del CO₂ (que en principio mide el beneficio social de la reducción del carbono). Esto sugiere que las primas pagadas en 2009 probablemente superen los beneficios sociales adicionales de promoción de las energías renovables, más allá de su impacto directo de reducción de las emisiones que, como se mencionó anteriormente, debería reflejarse exclusivamente en el precio del carbono.
El incremento en el nivel de las subvenciones y pagos totales al régimen especial desde 2007 ha exacerbado también el problema del déficit tarifario eléctrico, como se señaló anteriormente. El aumento reciente en el coste de la ayuda a las renovables ha dado lugar a la aparición de una brecha, en gran medida estructural, entre los costes regulados y los ingresos, ya que las primas tarifarias del régimen especial se fijan para períodos de tiempo largos (es decir, normalmente de 20 o 25 años). Además, la adopción de cualquier medida con carácter retroactivo para reducir el costo de la ayuda a las renovables debilitaría la credibilidad regulatoria del sistema y se han evitado en gran parte por el Gobierno español hasta Noviembre de 2010.

La evolución del mix de generación futuro determinará la capacidad del mercado español para cumplir con los objetivos medioambientales de manera eficiente. En la actualidad, la generación nuclear es una tecnología clave en cuanto a la contención de las emisiones de carbono, ya que representa más del 40% del total de electricidad que no emite carbono del mercado. La vida útil de la mayoría de las centrales nucleares españolas finalizará durante la década de 2020. Por lo tanto, una decisión clave que debe adoptarse para el periodo posterior a 2020 será la posibilidad de ampliar la vida útil de esta capacidad (por ejemplo, 20 años más). Hay un motivo económico y medioambiental para ello, con el fin de disminuir los costes totales de la reducción de carbono en España y contar con un conjunto variado de tecnologías para reducir las emisiones. Es probable que la extensión de la vida útil de las centrales nucleares genere ingresos económicos adicionales para los propietarios actuales de estas plantas. En su debido momento (es decir, llegando al final de los de 40 años de vida actuales), estos sobreingresos podrían ser evaluados y recuperados por el Gobierno, con el fin de financiar parcialmente el costo de la ayuda a las renovables (según las líneas que se proponen en Alemania). Este mecanismo debe ser evaluado en el contexto de una revisión más amplia sobre si, y cómo, prolongar la vida útil de la capacidad nuclear más allá de la década de 2020.

La generación de CCGT y de carbón siguen siendo tecnologías centrales y competidoras en la transición a un sistema de energía de baja emisión de carbono, especialmente como fuentes de flexibilidad. El aumento de los precios de CO₂ desde el año 2007 (junto con la reducción de la demanda) ha afectado considerablemente a la producción de las plantas que utilizan carbón (especialmente a las plantas menos eficientes que queman carbón nacional). Esto es, en gran medida, una respuesta del mercado a las señales proporcionadas por los precios del carbono. Sin embargo, el Gobierno español está tratando de apoyar artificialmente la producción de las centrales que utilizan carbón nacional, a través de una legislación específica (promulgada en octubre de 2010, después de recibir la aprobación de la UE como ayuda de Estado, pero aún sin implementar). Se corre el riesgo de que esta medida distorsione el mercado de manera significativa, a expensas del carbón importado más eficiente y las plantas de CCGT, y aumente los costes del sistema en un momento en el que los ingresos totales son ya insuficientes para cubrir los costos totales.

La generación de CCGT en España es una fuente cada vez más importante de flexibilidad del sistema, especialmente como un respaldo para la generación de renovables intermitentes. A medida que aumente la capacidad de las fuentes renovables en el futuro, se prevé que los factores de carga de las plantas de CCGT disminuyan. Para que esto sea compatible con un equilibrio de
mercado, es probable que se necesite un aumento significativo de los precios del mercado en las horas punta, para permitir que las instalaciones existentes cubran sus costes fijos anuales, incluyendo las tarifas de transporte de gas. Para que esto sea posible, probablemente se debería revisar el precio máximo actual en el mercado (fijado en 180 €/MWh), junto con el mecanismo para la formación de precios para restricciones técnicas. En este sentido, cabe mencionar que el nivel actual de pagos por capacidad en España cubre aproximadamente los costos fijos de mantenimiento y operación por un período de 10 años, pero no otros tipos de costes fijos, incluyéndose las tarifas de acceso a la red de gas, y los costes de inversión. Por lo tanto, el sistema actual puede no ser suficiente para promover la seguridad del suministro, y es posible que también tenga que ser revisado.

Conclusiones: Los principales retos de política en los mercados españoles del gas y la electricidad

Los mercados españoles del gas y la electricidad permanecen en un estado continuo de reformas. En los últimos años, han estado afectados por una serie de shocks de mercado y regulatorios interrelacionados que han afectado a su funcionamiento y que probablemente también influirán en su evolución futura.

En cierto modo, los asuntos sobre políticas públicas a los que se enfrenta el mercado español de gas son menos complejos que los presentes en el mercado eléctrico. El principal reto a nivel mayorista se plantea por la convergencia continua entre el gas y la electricidad. Esto significa que, en el futuro, el mercado del gas tendrá que ser cada vez más flexible, en la medida en que la demanda de los generadores de electricidad que utilizan gas sea más volátil. Una mayor flexibilidad del sistema del gas español será clave para la integración eficiente de los crecientes niveles de electricidad renovable en el sistema energético español.

Estas consideraciones implican que se requerirán mayores niveles de almacenamiento de gas doméstico y de interconexión con el resto de Europa. El almacenamiento subterráneo de gas en España es limitado y está muy por debajo de los niveles presentes en otros mercados europeos. En consecuencia, las inversiones en este tipo de instalaciones son cruciales y deben ser un elemento clave de los planes de infraestructura futuros. Del mismo modo, una mayor capacidad de exportación hacia Francia le permitiría al sistema de gas español utilizar el gas de manera más eficiente y hacer frente a la volatilidad de la demanda interna en mejores condiciones. La creación de un mercado mayorista de gas que sea líquido y transparente también ayudaría a lograr una mayor flexibilidad en el mercado nacional de gas, y debe ser un objetivo importante de las futuras reformas del diseño del mercado español de gas.

A nivel minorista, el principal reto sigue siendo la liberalización del mercado del gas residencial, que todavía seguía incompleta en 2009. Un número importante de clientes permanecen en la TUR regulada y en el ámbito regional, en la actualidad, solo el 15% de los clientes ha cambiado.
de proveedor desde que el mercado fue abierto a la competencia. Resulta necesaria una mayor competencia efectiva en las ofertas conjuntas de gas y electricidad para hacer que el mercado del gas sea más dinámico, y fomentar una mayor liberalización.

El mercado eléctrico español se sigue caracterizando por retos de política pública complejos y cada vez más controvertidos. Estos son el resultado de políticas inadecuadas del pasado (en especial, de la aparición de un elevado déficit tarifario desde 2002), y de nuevas presiones sobre el sistema que vienen de la necesidad de cumplir con objetivos medioambientales cada vez más estrictos. Estos dos asuntos se han relacionado estrechamente en los últimos tiempos, ya que el aumento en el coste de las primas a la electricidad renovable es uno de los principales determinantes del nivel actual de déficit tarifario anual.

El reto central de la política del mercado eléctrico a corto y medio plazo es, por lo tanto, cómo contener y eliminar gradualmente el déficit actual entre los costes y los ingresos regulados. Dado el gran tamaño de la deuda acumulada y del déficit corriente, es probable que se necesiten tomar medidas tanto por el lado de los ingresos como por el de los costes.

En relación a los ingresos regulados, es necesario introducir un programa creíble y gradual de aumentos en las tarifas de acceso para situarlas a un nivel más sostenible, en contraste con la estrategia seguida durante el año 2010, que no ha incrementado las tarifas de acceso eléctrico.

En cuanto a los costes regulados, una forma efectiva y económicamente coherente de reducir el nivel de los costes soportados por el sistema eléctrico podría ser trasladar parte de los costes de las ayudas a las renovables a una base más amplia de contribuyentes (por ejemplo, todos los contribuyentes o todos los usuarios de energía). Esta medida estaría justificada por el hecho de que la promoción de la electricidad renovable tiene un valor social en el contexto de la acción contra el cambio climático que beneficia a toda la población en general y no solo a los consumidores de electricidad. En el futuro (es decir, después de 2013) una parte del coste de las ayudas a las renovables también podría ser financiada por los ingresos de la subasta de los derechos de emisión.

La justificación para una intervención sobre los costes energéticos determinados por el mercado, a través, por ejemplo, de la recuperación de los potenciales sobreingresos que correspondan a la generación ordinaria de carga base, se debería basar en una evaluación jurídica y económica inherentemente compleja que necesitaría una evaluación específica que está más allá del alcance de este informe. Sin embargo, la aplicación de una medida de este tipo conllevaría riesgos importantes, ya que tiene el potencial de debilitar los principios que hay detrás de la liberalización del mercado.

No obstante, como se ha discutido anteriormente, las rentas económicas futuras derivadas de la posible ampliación de la vida útil de las plantas nucleares, en su momento, podrían ser transferidas al Gobierno. Por otra parte, una liquidación definitiva de los Costes de Transición a la Competencia recibidos por los generadores entre 1998 y 2006 podría dar lugar a una reducción en los costes de la electricidad si resultase que hubo un exceso de compensación.
Existen otros retos a los que el sistema eléctrico mayorista español se enfrenta y que requieren respuestas políticas específicas. Estos incluyen:

- La necesidad de un mejor diseño del sistema de primas para los productores de renovables que se base más en el mercado, para evitar así el riesgo de compensaciones excesivas a nuevos inversores;

- La revisión de la política nuclear, especialmente con respecto a la conveniencia de prolongar el tiempo de vida actual de 40 años de las centrales nucleares más allá de la década de 2020;

- La necesidad de una política económica coherente con respecto a la generación eléctrica que utiliza carbón nacional, para evitar así la distorsión del resto del mercado y el aumento de los costes del sistema, lo que probablemente ocurrirá si la legislación actual se implementa;

- Una integración más efectiva con el resto de Europa, que requiere una mayor capacidad de interconexión y un mejor diseño del mercado (por ejemplo, a través de la introducción de un sistema de *market coupling* entre España y Francia); y

- Posibles cambios en el diseño del mercado mayorista de electricidad (por ejemplo, con respecto a los precios de punta, los pagos de la capacidad y la remuneración para restricciones técnicas), de manera que permita a las plantas térmicas cubrir sus costes operativos de manera eficiente y cuente con incentivos suficientes para seguir prestando los niveles necesarios de flexibilidad del sistema.

Por último, en el ámbito del mercado eléctrico residencial, la principal cuestión política sigue siendo el progreso de la liberalización del mercado, que ha sido incluso más lento que en el mercado del gas. Esto puede atribuirse, en gran medida, a la distorsión histórica causada por el déficit tarifario. El paso a la asignación ex-ante del déficit tarifario (que ha trasladado el déficit a las tarifas de acceso, para todos los comercializadores) y la introducción de la TUR han dinamizado el mercado residencial. Sin embargo, la experiencia del mercado del gas residencial sugiere que los costes en los que incurren los consumidores cuando cambian de proveedor pueden ser considerables y que incluso la eliminación de algunas de las distorsiones regulatorias puede no ser suficiente para reducir los niveles de concentración en el mercado residencial. Se espera que, con el tiempo, el mayor alcance de la competencia en las ofertas conjuntas de gas y electricidad, que podría lograrse eliminando algunas distorsiones en el mercado minorista eléctrico, permita tanto al mercado residencial del gas como al de la electricidad volverse más dinámicos, permitiendo así la completa liberalización de todas las tarifas minoristas.
1. Introduction

This report updates and extends the first edition of the Report of the Public-Private Sector Research Center on the Spanish gas and electricity markets published in 2008 (‘the 2008 report’).\(^1\)

The material contained in Part I of this report updates the review of the Spanish gas and electricity markets contained in the 2008 report, including primarily regulatory and market developments that took place during the 2008-2009 period. As in the 2008 report, the focus of the analysis is on the potentially competitive segments of the gas and electricity industries, i.e. the wholesale gas and electricity markets, and the respective retail segments.

This part of the report contains an update on European developments on energy security, regulation and competition policy (Section 2); a review of the main developments in relation to regulation and competition policy in the Spanish energy market (Section 3); and a description of the evolution of the Spanish wholesale and retail gas and electricity markets (Section 4 and Section 5, respectively).

Part II of the report is devoted to an analysis of the design and implementation of environmental policies in the European Union and Spain, which constitutes a special topic covered in this edition of the report.

After a brief introduction to the subject of climate change in the energy sector (Section 7), this part of the report reviews the fundamental economics of climate change (Section 8). It then analyses the design and implementation of environmental policies in the European Union and in Spain (Section 9 and Section 10, respectively), and concludes with an assessment of future policy challenges (Section 11).

The main findings of the report, together with its conclusions, are contained in the Summary and Conclusions section that precedes the main body of the document.

\(^1\) G. Federico and X. Vives (with the collaboration of N. Fabra), *Regulation and Competition in the Spanish Gas and Electricity Markets*, Reports of the Public-Private Sector Research Center, 1, 2008.
PART I:
Evolution of the Spanish Gas and Electricity Markets: 2008-2009
The European energy market continues to be characterised by three main policy challenges: growing external energy dependence with associated security of supply considerations; the drive towards more effective regulation and competition in the internal market; and the need to adopt effective policies to tackle climate change. This first substantive chapter of the report provides a brief survey of recent trends in relation to the first two elements of E.U. energy policy, with a specific focus on the Spanish market where relevant. The third pillar (climate change and associated policies) forms the subject matter of Part II of the report.2

2.1. Recent Trends in External Energy Dependence and Energy Security

The E.U. energy market depends on external suppliers for its fossil fuels to a significant extent. During 2009 external energy dependence at E.U.-27 level stood at 55% (57% for E.U.-15), roughly in line with the levels seen in 2006-2008. Energy dependence in Spain is significantly higher than the European average (at roughly 80% in 2008), even though it too has not increased compared to the peak reached in 2006.3

European energy dependence stabilised during the course of 2009, partially as a consequence of the reduction in energy demand associated with the economic crisis and the continued growth of domestic energy sources (mainly renewable energy). Preliminary Eurostat data for 2009 indicate that, compared to 2008, net energy imports fell by 6%, gross inland consumption dropped by 5.5%, and renewable energy increased by more than 8% (Eurostat (2010)). These trends were also evident in 2009 in Spain, where a reduction in primary energy demand (-9% relative to 2008) took place at the same time as the 16% annual increase in renewable primary energy production (see MITYC (2010)).

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2 For a survey of E.U. energy policy see also Federico and Vives (2010).
3 The definition of energy dependence used here is based on the one of Eurostat (which considers imports of oil, gas and solid fuels as a percentage of gross inland energy consumption).

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Current levels of energy dependence in Europe are largely the combination of external dependence on oil and gas, which stood, respectively, at 84% and 62% at E.U.-27 level in 2008. Gas dependence in particular has increased rapidly since 2000 (by roughly 15 percentage points) as a consequence of the shift to gas-fired technology in power generation (with reduced reliance on traditional nuclear and coal-fired capacity) and the decline of domestic gas production. The trend towards greater use of gas plants in the power sector continued during the 2006-2008 period, with the share of gas-fired electricity output (including co-generation plants) growing from 21% to 24% at E.U.-27 level, and from 31% to 39% in Spain. The only other generation technology to experience growth in its share of total output over the period was renewable electricity, as shown in Figure 2.

Total E.U.-15 gas imports over the 2000-2009 period grew by close to 50%. The equivalent growth level in Spain has been much greater, with gas imports growing more than two-fold over the same period. Russia remains the largest source of imports, accounting for close to a third of all E.U.-27 imports in 2008 (including intra-E.U. imports), followed by Norway and Algeria, as it is shown in Figure 3. The role played by the two main E.U. gas producers (the Netherlands and the United Kingdom) has declined over time and currently stands at 14% of all E.U. imports.
Figure 2: Evolution of Electricity Generation Mix, 1997 and 2006-2008


Figure 3: Shares of E.U.-27 Gas Imports by Source (including intra-E.U. imports)

Compared to the E.U.-15 as a whole, the Spanish gas market is significantly more dependent on imports (100% dependence versus 60% for the E.U.-15) and relies much more heavily on LNG supplies, which accounted for three quarters of all imports in 2009 (with the equivalent share for the E.U.-15 standing at less than one quarter), as summarised in Figure 4. During 2009, Spain accounted for 43% of all LNG imports into the E.U.-15, followed by France and the United Kingdom. The Spanish market does not import any Russian gas (in contrast to the E.U.-15), but relies more heavily on Algeria (both through pipeline imports and LNG). The availability of significant LNG capacity in Spain makes it less vulnerable to gas supply disruptions than several other European gas markets.

European gas dependence is set to increase significantly over time as domestic resources continue to decline. In its latest World Energy Outlook (published in late 2009), the International Energy Agency (IEA) projects an increase in gas dependence from current levels of 60% to more than 80% by 2030. In the two gas scenarios developed by the IEA, gas imports increase by 125 to 200 billion cubic meters (bcm) over the 2007-2030 period, and domestic production drops by 110-130 bcm. Implementation of strict environmental policies (which are incorporated in one of the two IEA scenarios) would not be sufficient to prevent the increase in relative gas dependence, even though it would significantly moderate the projected increase in total gas demand and absolute import levels (thus reducing the overall vulnerability of the European energy market to external gas sources).
Russia is expected to play a central role in the future evolution of the European energy market, given its significant level of gas reserves. Russian reserves at the end of 2009 stood at over 44 trillion cubic meters (tcm), well in excess of total OECD reserves of 16 tcm. Europe’s other main gas suppliers (Algeria, Norway, the Netherlands and the United Kingdom) jointly held only 8 tcm of gas reserves at the end of 2009. Potential competition with Russia in terms of supplying gas to Europe may, however, come from current LNG-exporting countries (especially Qatar, with over 25 tcm of reserves), Turkmenistan (8 tcm of reserves), and Iran (30 tcm of gas reserves).

The main current pipeline projects in Europe could increase total pipeline import capacity by 100 to 180 bcm in coming years (see Table 1). A considerable part of this incremental capacity (over 60%) could be sourced from Russia, due to the development of the North Stream and South Stream pipelines. Other projects, like Nabucco, would source gas from other countries (e.g. in Central Asia) and are in competition with Russian gas.

### Table 1: Key European Gas Pipeline Infrastructure Projects

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Size (bcm)</th>
<th>Source</th>
<th>Destination</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Stream</td>
<td>28 - 55</td>
<td>Russia</td>
<td>Northern Europe</td>
<td>Consortium (51% Gazprom) started construction work in April 2010, with pipeline expected to be operational by 2012. Pipeline will connect Russia to Germany directly, under the Baltic Sea.</td>
</tr>
<tr>
<td>South Stream</td>
<td>30 - 63</td>
<td>Russia</td>
<td>Italy/ Central Europe</td>
<td>Seen as “replacement” for gas transiting Ukraine, but potentially in competition with Nabucco. Project led by ENI and Gazprom, with EDF projected to acquire a stake. Current plants are for the pipeline to be commissioned by end-2015.</td>
</tr>
<tr>
<td>Transmed/ Galsi</td>
<td>7 - 15</td>
<td>Algeria</td>
<td>Italy</td>
<td>3.5 bcm expansion of Transmed due to be completed in 2009/10, with further 3.5 bcm planned. Further link through Sardinia (GALSI) scheduled for 2013 (8 bcm).</td>
</tr>
<tr>
<td>Nabucco</td>
<td>14 - 31</td>
<td>Iran/Turkmenistan/ Azerbajan</td>
<td>S.E. and Central Europe</td>
<td>Aimed at reducing dependence on Russia. Main shareholders are OMV and MOL. Supported by the E.U. Intergovernmental agreement between Turkey and E.U. member states signed in July 2009. First construction phase scheduled to start by end-2011, with first gas flowing during 2014.</td>
</tr>
<tr>
<td>Turkey-Greece-Italy (ITGI)</td>
<td>11 - 12</td>
<td>Greece/Italy</td>
<td>Azerbajan</td>
<td>Potentially in competition with Nabucco, but significantly smaller. Greece-Italy connection to be built by 2010, and pipeline to be operative in 2013.</td>
</tr>
<tr>
<td>Medgaz</td>
<td>8</td>
<td>Algeria</td>
<td>Spain/France</td>
<td>Construction of pipeline completed in 2008/09. Gas to be delivered during course of 2010. Partners include Sonatrach, Iberdrola, Endesa, CEPSA, GDE.</td>
</tr>
</tbody>
</table>

Source: Press articles.

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4 The British energy regulator Ofgem forecasts an increase in European dependence on Russian gas of as much as 55% of total imports by 2020 (see Ofgem (2009)).
Significant increases in total LNG capacity are also forecasts over the next decade or so. Total LNG capacity in Europe stood at over 150 bcm in mid-2010 (40% of which is in Spain). Planned expansion at the existing terminals plus new terminals currently under construction would add a further 70 to 80 bcm by approximately 2016-2017 (see GIE (2010)).

Overall, the planned new gas import capacity (pipeline plus LNG) may well exceed the projected increase in gas imports over the medium term in terms of annual gas requirements, especially in scenarios where strict environmental policies are implemented. However, the need for peak import capacity may still imply that a significant share of the projected expansion in import infrastructure will be required to maintain security of supply during high-demand periods (unless sufficient domestic gas storage capacity is available).

2.2. Recent European Trends in Energy Regulation and Competition Policy

The drive towards more effective regulation and competition in the European energy market has continued over the past two years. Four important European energy directives were approved during the course of 2009. The first two, the Renewable Directive and the Emission Trading System Directive, both of April 2009, relate to European climate change policy and are discussed in Part II of this report.

The other two main energy directives approved during 2009 are the Third Electricity and Gas Directives (2009/72/EC and 2009/73/EC, respectively). These directives were passed by the European Parliament in April 2009 and adopted by the European Council in June 2009. They further develop the European framework for ownership unbundling in the energy sector. However, they adopt a compromise position relative to the initial proposals for structural separation advocated by the European Commission in the face of opposition from some Member States (notably France and Germany). In particular, whilst the directives allow for full ownership unbundling, they also envisage the alternative option of functional separation in the form of an independent system operator (ISO) or an independent transmission operator (ITO). Member States are scheduled to adopt the provisions of the new directives by March 2012. The directives also include a “third country clause”, which can restrict investments from vertically integrated energy companies from outside the European Union.

As part of the third legislative package, the Commission has also enacted three new regulations essentially aimed at promoting trade, investment and collaboration across the European Union (Regulations 713/2009, 714/2009 and 715/2009). These regulations established an Agency for the Cooperation of Energy Regulators (ACER), which will complement national regulators and seek to facilitate cross-border trading within the European Union. They also created a new European Network for Transmission System Operators (ENTSO) for both gas and electricity. This network formalises cooperation between transmission network operators. ENTSO is tasked with developing standards and codes to facilitate the harmonisation of operational procedures.
and access regimes, coordinating the operation of the national networks, and coordinating the planning and monitoring of network investment.

The European Commission has also continued to be particularly active in the enforcement of competition law in the energy sector, primarily through the provisions on abuse of dominance (currently Article 102 of the European Treaty, previously Article 82). Nine abuse cases have been initiated in the energy sector since 2007, in addition to one case of collusion (under Article 101); see summary in Table 2. All but one of the Article 102 cases concern vertically integrated incumbents and relate to potential foreclosure concerns.

All of the abuse cases except one have been settled by the companies involved with commitments. The commitments have in some cases (i.e. in the matters concerning RWE, E.On and ENI) included structural remedies aimed at reducing the incumbents’ degree of vertical integration, thus partially meeting the European Commission’s overall objective in terms of further ownership unbundling in the energy industry. In other cases, the remedies have reduced the incumbents’ share of import capacity or forced them to reduce their control of the retail market.

### Table 2: Key European Antitrust Cases in the Energy Sector, 2007-2010

<table>
<thead>
<tr>
<th>Firm</th>
<th>Alleged conduct</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distrigaz (Suez)</td>
<td>Foreclosure of Belgian gas market through long-term contracts.</td>
<td>Commitment to 30% cap on long-term contracts in October 2007.</td>
</tr>
<tr>
<td>E. On (electricity)</td>
<td>Output withholding and vertical foreclosure in the German electricity balancing market.</td>
<td>Divestment of 5GW of generation capacity; and sale of electricity transmission network in November 2008.</td>
</tr>
<tr>
<td>RWE</td>
<td>Foreclosure of the German gas market through refusals to supply and margin squeeze.</td>
<td>Divestment of RWE’s gas transmission network, accepted by the Commission in March 2009.</td>
</tr>
<tr>
<td>ENI</td>
<td>Foreclosure of the Italian gas market through quality degradation, hoarding and under-investment.</td>
<td>ENI has committed to divest its stakes in the relevant gas pipelines. The Commission accepted this commitment and closed the investigation in September 2010.</td>
</tr>
<tr>
<td>EDF</td>
<td>Foreclosure of the French electricity market for industrial users through long-term contracts.</td>
<td>EDF has committed to release to the market 65% of the electricity it contracts with large industrial users in France each year. Commitment accepted by the Commission in March 2010.</td>
</tr>
<tr>
<td>SvK (Swedish TSO)</td>
<td>Limits on interconnection capacity in order to reduce domestic congestion.</td>
<td>Commitments offered to increase effective interconnection capacity. Accepted by the Commission in March 2010.</td>
</tr>
</tbody>
</table>
The Spanish Gas and Electricity Sector: Regulation, Markets and Environmental Policies

Table 2 (continued)

<table>
<thead>
<tr>
<th>Firm</th>
<th>Alleged conduct</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>GDF/Suez</td>
<td>Foreclosure of the French gas market through long-term reservations of import</td>
<td>Commitment to release a significant share of long-term bookings, and</td>
</tr>
<tr>
<td></td>
<td>capacity and underinvestment.</td>
<td>reduced share of GDF to below 50%. Accepted by the Commission in December 2009.</td>
</tr>
<tr>
<td>E. On (gas)</td>
<td>Concern that competitors foreclosed by long-term capacity bookings.</td>
<td>Commitment to ‘significant, structural’ reduction of long-term</td>
</tr>
<tr>
<td></td>
<td></td>
<td>reservations offered by E.On in December 2009, and accepted by the</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Commission in May 2010.</td>
</tr>
</tbody>
</table>

Source: European Commission.

In terms of merger control, the European Commission approved four relatively significant mergers in the energy sector during the 2008-2009 period: EDF/British Energy in the United Kingdom (in December 2008); RWE/Essent and Vattenfall/Nuon, both affecting Germany and the Netherlands (in June 2009); and EDF/Segebel in the Belgian and French markets (in November 2009). The main features of these four merger cases are summarised in Table 3.

Table 3: Merger Control in the European Energy Market, 2008-2009

<table>
<thead>
<tr>
<th>Case</th>
<th>Date</th>
<th>Description</th>
<th>Remedies</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDF/British</td>
<td>December 2008</td>
<td>Acquisition by EDF of the majority of the nuclear assets in the UK (including sites for new development), and of BE’s industrial customers. Raised horizontal concerns in the generation market, potential vertical effects (due to loss of liquidity), and loss of access to nuclear new build sites.</td>
<td>Divestment of two price-setting generation plants (equivalent more than 50% of EDF’s capacity), release of energy to the market for a four year period (2012-2013), and sale of one nuclear new build site.</td>
</tr>
<tr>
<td>Energy</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RWE/Essent</td>
<td>June 2009</td>
<td>Acquisition by the German incumbent of one of the three main firms in the Dutch market, with activities also in Germany. Main concern was horizontal overlap in German electricity and gas markets (whilst cross-border issues considered not a concern).</td>
<td>Divestment of Essent’s stake in German energy company in order to remove horizontal overlap.</td>
</tr>
<tr>
<td>Vattenfall/Nuon</td>
<td>June 2009</td>
<td>Acquisition by the German incumbent of one of the three main firms in the Dutch market, with activities also in local retail markets in Germany. Main concern was horizontal overlap in Germany.</td>
<td>Divestment of Nuon’s activities in Germany in order to remove horizontal overlap in local retail markets.</td>
</tr>
<tr>
<td>EDF/Segebel</td>
<td>November 2009</td>
<td>Acquisition by EDF of 51% stake in second energy firm in Belgium (SPE). Raised issues due to loss of potential competition since EDF was entering the Belgian market independently.</td>
<td>Sale of one of EDF’s two generation projects, and undertaking to invest in the second by 2012 (or divest it).</td>
</tr>
</tbody>
</table>

Source: European Commission.
Whilst these transactions were less problematic in terms of possible competition effects than some of the deals previously assessed by the Commission and reviewed in the 2008 report (most notably EDP/ENI/GDP and GDF/SUEZ), the Commission has continued to apply a strict approach to potential competition effects and remedy design in the energy markets. For example, in the merger between EDF and British Energy, EDF had to divest the equivalent of more than 50% of its generation capacity in the United Kingdom in order to acquire British Energy, in spite of the fact that the parties’ combined share of the British generation market was approximately 25% (before the divestments). Similarly, the horizontal overlaps created by the RWE/Essent and EDF/Segebel transactions in the German and Belgian electricity markets, respectively, were limited. Nonetheless, the remedies required to clear these two mergers either removed or significantly reduced the overlaps between the parties.

Three of the transactions assessed by the Commission involved potential cross-border issues, given the increasing integration of electricity markets in North-West Europe (France, Belgium, the Netherlands and Germany). In its assessment, the Commission did not consider the integration between the affected markets to be strong enough to create competition effects across borders. However, as market integration continues to intensify in Europe (through the harmonisation of market rules and greater interconnection capacity), this type of cross-border competition effects are likely to feature in future merger assessments.
### 3. Developments in Regulation and Competition Policy in Spain

#### 3.1. Regulatory Developments

There were several regulatory developments in the Spanish gas and electricity sector during the 2008-2009 period. The key regulatory measures affecting the Spanish wholesale and retail energy markets\(^5\) are summarised in Table 4 and are further described below (with the exception of the measures on solar energy and domestic coal, which are reviewed in Part II of this report).

**Table 4: Summary of Key Regulatory Reforms in the Spanish Gas and Electricity Markets, July 2008-October 2010**

<table>
<thead>
<tr>
<th>Item</th>
<th>Date</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tariff of Last Resort in Gas Sector</td>
<td>July 2008</td>
<td>Tariff of last resort introduced in the residential gas sector for all consumers with annual requirements below 3 GWh. Consumption threshold lowered to 50 MWh from July 2009.</td>
</tr>
<tr>
<td>Subsidies to PV solar energy (RD 1578/2008)</td>
<td>Sept. 2008</td>
<td>Subsidy regime for photovoltaic installations reformed, reducing the level of subsidies and introducing a quota-based system to determine the future remuneration of solar PV plants.</td>
</tr>
<tr>
<td>Completion of VPP program</td>
<td>March 2009</td>
<td>The 7th and last Virtual Power Plant auction was held in March 2009, for the period April 2009-March 2010. Overall seven VPP auctions were held since June 2007, reaching a maximum total affected capacity of 2.4-2.5 GW during the second half of 2009.</td>
</tr>
<tr>
<td>Reform of Tariff Deficit (RDL 6/2009)</td>
<td>April 2009</td>
<td>Binding limits introduced on annual deficits for the period 2009-2012. Deficit to be eliminated by January 2013. Past deficits (up to €10 billion) and future deficits to be backed by sovereign guarantee. Electricity system costs associated with supply to islands gradually transferred to the general budget. Abolishes recovery of windfall gains associated with carbon pricing and free emission allowances from July 2009. Introduces social tariff obligation on electricity suppliers.</td>
</tr>
</tbody>
</table>

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5 This report does not survey developments with respect to network regulation in the energy sector.
Table 4 (Continued)

<table>
<thead>
<tr>
<th>Item</th>
<th>Date</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>OCSUM (RD 1011/2009)</td>
<td>June 2009</td>
<td>Establishes Office of Retail Switching (Oficina de Cambios de Suministrador, OCSUM), tasked with supervising residential switching in the gas and electricity markets. Also provides for unconditional access to information on consumer details to competing suppliers.</td>
</tr>
<tr>
<td>Tariffs of Last Resort in Electricity Sector</td>
<td>July 2009</td>
<td>Tariffs of last resort introduced in the residential electricity sector, for consumers with capacity below 10 kW. Penalties introduced for large residential and SME consumers that do not switch to the liberalised market.</td>
</tr>
</tbody>
</table>

3.1.1. Tariffs of Last Resort
Tariffs of last resort (TLR) were introduced in the gas and electricity residential segments starting in mid-2008 and mid-2009, respectively. These tariffs replaced the previous regulated tariffs and established the maximum prices that can be charged by the appointed supplier of last resort in each distribution network area.

The eligibility threshold for TLR in the gas sector was initially set at 3 GWh per annum and subsequently lowered to annual consumption of 50 MWh (which is still well above average residential consumption of 10 MWh). Roughly 45% of all gas customers in Spain remain on the TLR as of the end of March 2010, down from over 55% of consumers on regulated tariffs in July 2008, when TLR were introduced in the gas market (see CNE (2010a)).

In the electricity market, TLR were applicable to residential consumers with capacity below 10 kW starting in July 2009. This threshold excludes residential consumers with capacity between 10 and 15 kW, as well as SMEs. These two customer groups had a right to a regulated tariff until June 2009. Starting in July 2009, they faced a surcharge on the TLR in order to induce them to shift to the liberalised market. The CNE reports that, by the end of March 2010, 83% of Spanish electricity consumers were on TLR, relative to 90% of consumers on regulated tariffs at the end of June 2009 (see CNE (2010a)).

An important feature of the electricity TLR is that the level of its wholesale energy component is directly set via periodic procurement auctions known as CESUR (i.e. there is an automatic pass-through of wholesale market prices). Eleven CESUR auctions were held during the June 2007-June 2010 period, with quarterly frequency until June 2009 and semi-annual frequency thereafter. These auctions included a quarterly product throughout the period and a six-monthly product for the three auctions held between March and September 2008. All auctions included a baseload product, whilst a peak product (for demand between 8 a.m. and 8 p.m. on
weekdays) was traded starting with the seventh auction (held in December 2008). CESUR volumes were cleared for differences with respect to the hourly spot price from the ninth auction (held in June 2009). In 2009, an estimated 38 TWh of electricity was auctioned through CESUR, equivalent to 15% of total final demand and 35% of demand of consumers on regulated tariffs/TLR.

3.1.2. Reform of the Tariff Deficit
The mechanism governing the tariff deficit was reformed in mid-2009 through Royal Decree Law (RDL) 6/2009. This piece of legislation introduces legal caps on the levels of the annual deficit for the 2009-2012 period. The cap was set at €3.5 billion\(^6\) in 2009 (a level that is lower than the deficit incurred during 2008) and then declines to €3 billion in 2010, €2 billion in 2011, and €1 billion in 2012. The decree also provides for a securitisation fund that will include collection rights on deficits incurred during the 2009-2012 period and for previous outstanding deficits up to €10 billion. This fund is backed by a sovereign guarantee.

In order to contain the size of the deficit, RDL 6/2009 gradually shifts the additional costs of electricity supply to the Spanish islands to the general budget.\(^7\) These additional costs amounted to more than €1.3 billion in 2009 (i.e. close to 40% of the tariff deficit limit for 2009).

RDL 6/2009 also abolishes the recovery of the estimated profit gain accruing to Spanish generators from the establishment of carbon pricing and the existence of free allowances, which had been applicable in Spain since 2006.\(^8\) The abolition of this measure came into force in July 2009. It implies an effective increase in the level of the deficit relative to an alternative scenario where windfall gains due to carbon pricing would have been returned by generators. On the other hand, RDL 6/2009 also provides for the establishment of social tariffs (set below the TLR) to be funded by electricity generators.

Access charges and regulated end-tariffs were increased between January 2008 and January 2010 in order to bridge the gap between regulated revenues and total costs, and to contain the tariff deficit. However, these increases were insufficient to reduce the tariff deficits accrued in 2008 and 2009, as reviewed in Section 5 of this report. Electricity tariffs were frozen in July 2010 in the context of the announcement of cross-party talks on the future design of the energy sector, but were increased again in October 2010 (to reflect the evolution of wholesale electricity prices).

\(^6\) Throughout this report the term \textit{billion} refers to the Anglo-Saxon version, i.e. a billion is equivalent to 1,000 million (or $10^9$).
\(^7\) The share of these additional costs allocated to the budget increases from 17% in 2009, to 34% in 2010, 51% in 2011, 75% in 2012 and 100% thereafter.
\(^8\) The nature and details of Spanish legislation on windfall gains from carbon pricing is explained in detail in Section 4.2 of the 2008 report.
3.1.3. Virtual Power Plant Auctions

The Spanish Virtual Power Plant (VPP) program continued until March 2009, when the last VPP auction was held. This VPP scheme obliged the two largest generators in Spain (Endesa and Iberdrola) to auction part of their generation output to the market through quarterly or semi-annual forward contracts.

Figure 5 plots the total electricity capacity affected by the program in each quarter between the third quarter of 2007 and the first quarter of 2010, a period during which seven auctions were held. Total capacity under the VPPs reached a maximum of roughly 2,550 MW (i.e. 1,275 MW each for Endesa and Iberdrola) at the end of 2008. This level of forward contracting was equivalent to 7% of Endesa’s installed capacity in 2008 and 5% of Iberdrola’s capacity. In 2009, significantly lower levels of contract cover were achieved through the VPPs, mainly due to the low level of baseload capacity actually sold through the seventh auction (less than 50% of the capacity made available in that auction).

Figure 5: Evolution of VPP Volumes (baseload and peak combined), Q3 2007-Q1 2010

VPPs were discontinued after the auction held in March 2009. The Spanish energy regulator (the Comisión Nacional de Energía, CNE) launched a public consultation in July 2009 on the impact of the VPP program. Following this consultation, the CNE concluded that before considering a new VPP program in Spain there was a need for a better understanding of the structure and impact on the market of the voluntary OTC forward market and of the consequences of vertical integration between generation and supply on retail market competition (see CNE (2009a)).
3.2. Competition Policy in the Spanish Energy Sector

Competition policy continues to be active in the Spanish energy sector. During the 2008-2009 period, a major merger (Gas Natural/Unión Fenosa) was assessed and approved by the Comisión Nacional de la Competencia (CNC). Moreover, an abuse of dominance case (Centrica Energía) came to conclusion, and further antitrust proceedings were initiated in the electricity market.

3.2.1. The Gas Natural/Unión Fenosa Merger

Gas Natural bid for control of Unión Fenosa in 2008, having failed in its earlier attempt to purchase Endesa in 2006-2007. The merger was approved by the CNC in February 2009 under the new Spanish competition law (15/2007), which gives the CNC a final say on merger control decisions (see CNC (2009)).

The transaction brought together Gas Natural (the gas incumbent and fourth largest electricity generator) with Unión Fenosa, which at the time of the operation was (under some measures) the second largest supplier of gas to liberalised customers in Spain and the third largest electricity generator and supplier. Unión Fenosa was vertically integrated in the LNG supply chain through its 50% stake in Unión Fenosa Gas (UFG), which in turn owned gas infrastructure and LNG production assets. The main competition effects identified by the CNC in its decision, and related remedies are summarised in Table 5 below.

Table 5: Competition Effects and Remedies in the Gas Natural/Unión Fenosa Merger

<table>
<thead>
<tr>
<th>Type of Competition Issue</th>
<th>CNC Assessment</th>
<th>Remedy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizontal effects in wholesale gas</td>
<td>Loss of Unión Fenosa Gas as effective vertically integrated competitor (in particular for the provision of gas flexibility).</td>
<td>No specific remedy. Contestable gas demand created by downstream remedies to facilitate upstream entry.</td>
</tr>
<tr>
<td>Horizontal effects in wholesale electricity</td>
<td>Risk of coordinated effects in generation market (due to creation of more symmetric competitor to Endesa and Iberdrola), Unilateral effects not seen as problematic.</td>
<td>Divestment of 2 GW of CCGT assets.</td>
</tr>
<tr>
<td>Horizontal effects in retail gas and electricity</td>
<td>Loss of Unión Fenosa Gas and Unión Fenosa as effective vertically integrated competitor for industrial and residential gas clients; creation of double incumbency positions in areas of network overlap risks reducing competition for residential gas and electricity.</td>
<td>Functional separation of retail arm of Unión Fenosa Gas from the rest of the group. Divestment of 600,000 gas distribution points, with associated residential clients (9% of national total), preferably in network overlap regions.</td>
</tr>
<tr>
<td>Vertical foreclosure effects</td>
<td>None, due to possibility of self-supply by rival CCGTs and contractual constraints on input foreclosure strategy.</td>
<td>None</td>
</tr>
</tbody>
</table>
The CNC was mainly concerned about horizontal effects in the gas and electricity markets in its review of the merger. In the wholesale and industrial gas markets, the obvious concern was due to the disappearance of UFG as a credible independent competitor to Gas Natural, which had grown rapidly in recent years, partially due to its effective vertical integration policy. The CNC also expressed a concern in relation to residential gas clients, due to the higher barriers to entry and perceived switching costs in this market.

In the generation market, the CNC deemed that the unilateral effects due to the direct loss of competition between Unión Fenosa and Gas Natural were not significant. This was so in spite of the fairly large combined share of price-setting generation accounted for by the parties (roughly 25% of capacity in 2008 according to the calculations performed by the CNC, and closer to 30% in output terms), which could be expected to put upwards pressure on prices. The CNC was, however, concerned about the risk of coordination between the three main firms in the generation market (Endesa, Iberdrola and the merged entity), due to increased symmetry in the market.

The remedies accepted by the competition authority to address its competition concerns included two structural divestments (the sale of 2 GW of CCGT capacity; and of at least 600,000 gas distribution points and associated residential customer portfolios) and a behavioural one with respect to UFG’s retail arm. The behavioural remedy consisted of the functional separation of UFG’s retail activities from the rest of the merged group, allowing it in principle to pursue an autonomous commercial policy and continue competing against Gas Natural.

The CNC decision did not contain a specific remedy directly addressed at the wholesale gas market on the basis that the contestable demand created by the structural remedies (i.e. the sale of CCGT capacity and gas networks) would also facilitate entry upstream. The absence of a structural remedy explicitly directed at the gas markets where UFG was most active (i.e. wholesale gas procurement and supply to industrial customers) is a notable feature of the CNC decision. It can be seen as a departure from general European Commission practice on merger control (including in the energy sector). In particular, the European Commission has required several structural divestments in the energy mergers it assessed in the recent past (including the four summarised in Section 2, and the additional four mergers reviewed in the 2008 report) to address concerns of both a horizontal and vertical nature. Overall, the approach taken by the CNC in this case signalled its confidence that competition in the wholesale and industrial gas markets in Spain is sufficiently intense, so that the increase in effective concentration brought about by the transaction would not have adverse effects on consumers.

The estimated impact of the Gas Natural/Unión Fenosa transaction on concentration in the gas and electricity markets is reviewed in Sections 4 and 5 of this report.
3. Developments in Regulation and Competition Policy in Spain

3.2.2. Abuse of Dominance Cases in the Spanish Energy Sector
The CNC adopted a series of abuse of dominance decisions in the retail electricity market in April 2009 against the five electricity distributors in Spain. The distributors were fined a total of €35 million for allegedly withholding information on their retail consumers from an independent retail competitor (Centrica Energía) during the 2005-2008 period.

The fundamental issue tackled by the Spanish competition authority in these cases was the lack of ownership unbundling between distribution and retail activities in the Spanish electricity market (which is common in most European electricity markets). This vertical integration may give rise to incentives to discriminate against rival downstream providers. This concern for potential foreclosure effects is in line with the European Article 102 cases reviewed in Section 2 of this report. On the other hand, the presence of a tariff deficit in Spain during the period of the alleged abuse means that it is not clear whether the alleged practice would have had an adverse effect on consumers (since competition was in any event impeded by the presence of the deficit for at least part of the abuse period).

Another active area of antitrust enforcement in the Spanish energy market relates to the issue of the pricing of congestion relief services (restricciones técnicas) in the wholesale electricity market. As reviewed in the 2008 report, four abuse decisions were taken by the CNC (previously the Tribunal de Defensa de la Competencia (TDC)) during the 2006-2008 period. These decisions concerned Viesgo, Iberdrola (twice) and Gas Natural. In all cases the generators were found to be abusing their market power by charging allegedly excessive prices when called to produce in areas with transmission congestions.

No new decisions have been taken by the CNC on this issue since April 2008. However, new proceedings were opened by the CNC against practically all generators in the market in October 2009 for allegedly abusive conduct in the pricing of electricity congestion relief during the 2004-2008 period.

The fact that these proceedings apply to the entire generation market suggests that the fundamental issue should be addressed by reforming the design of the market rather than intervening through ex-post competition law. In this context, in April 2010, the CNE put forward a proposal for regulating the prices of congestion services (see CNE (2010b)). Under the CNE proposal, generators would be compensated for congestion services either at their variable production cost or at the price of the intra-day market (if they offer their energy in the intra-day output in order to produce at capacity after being called to relieve congestions). Part II of this report briefly considers the implications of the current competition policy towards congestion pricing and the possible regulatory solution in connection with the broader issue of fixed cost recovery by thermal generators.

This section of the report provides an update on the evolution of the Spanish gas market during the 2008-2009 period. It first reviews the wholesale segment of the gas market and then turns to the corresponding retail market.

4.1. Wholesale Gas

4.1.1. 2009 Overview
The basic structure of the Spanish wholesale gas market during 2009 is summarised in Figure 6. LNG imports were sourced in 2009 from seven main importing countries of which the Gulf (Oman and Qatar) was the largest. LNG is regasified at six terminals, the largest in output terms being Enagás’s terminal in Barcelona, followed by Sagunto (independently owned) and Huelva (also owned by Enagás). Pipeline imports were sourced from Algeria and Norway. Overall, Algeria remained the largest single source of gas imports, followed by LNG from the Gulf, LNG from Nigeria, and imports from Norway. In 2009, the largest component of demand was industrial demand, followed by demand from the electricity sector and residential demand (with the latter accounting for only 15% of the total).
Figure 6: Structure of the Spanish Wholesale Gas Market in 2009

Note: The figures in brackets are the relevant gas volumes in TWh. Source: Enagás, CNE.

4.1.2. Evolution of Wholesale Gas Demand
During 2008 gas demand grew by 10% relative to the previous year, due to growth in the electricity element in excess of 30% (which was in turn caused by increasing levels of CCGT generation in the electricity sector, which displaced coal-fired output). During 2009, however, gas demand fell by close to 11%, due to the combination of a 14% reduction in the electricity component (mainly caused by the reduction in electricity demand and the growth of baseload special regime generation) and a 8% fall in conventional gas demand (due to the economic downturn). During the first half of 2010, demand again grew at a moderate rate (1.5%), as growth in conventional demand during this period (+10.5%) was offset by a continued reduction in electricity demand (-14.2%).

The Spanish wholesale gas market continues to be characterised by increasing convergence with the wholesale electricity sector. An important element of gas demand (40% in 2009) is due to the production of gas-fired electricity. Moreover, the electricity-based element of gas demand is the most dynamic component of total demand, accounting for 90% of the growth experienced by the overall gas sector since 2004 and significantly affecting annual variations in total demand (as illustrated above).

Figure 7 plots the evolution of demand in the Spanish wholesale gas market during the 1998-2009 period. As the figure shows, demand has grown very significantly over the 12-year period...

since liberalisation (from 150 TWh in 1998 to just over 400 TWh in 2009), notwithstanding the reduction in demand experienced in 2009. The weight of LNG imports relative to pipeline imports grew steadily over this period, reaching close to 75% in 2009 (from less than 50% in 1998), a situation that is unique in Europe.

Figure 7: Evolution of Volumes in the Spanish Gas Wholesale Market, 1998-2009

Source: CNE, Enagás.

4.1.3. Composition of Gas Imports

The evolution of the composition of gas imports into Spain is shown in Figure 8 for the past four years. The chart shows the share of imports from each country and a ‘concentration indicator’ for overall imports. Import concentration has declined since 2007, due to a reduction in the relative weight of Algerian and Nigerian imports. Overall, the Spanish wholesale gas market is well diversified, with six countries accounting for most imports. Whilst import concentration remains high according to standard measures (i.e. the Herfindahl-Hirschman Index (HHI) remains in excess of 2,000), import concentration is lower than in other European markets, most notably Germany (which depends on Russia for 35% of its imports and on Norway for a similar amount) and Italy. Spain also benefits from greater reliance on LNG import capacity, which is significantly more flexible than pipeline imports.
### Figure 8: Composition of Spanish Gas Imports, by Country

<table>
<thead>
<tr>
<th>Year</th>
<th>Others</th>
<th>Qatar/Oman (LNG)</th>
<th>Norway (pipeline + LNG)</th>
<th>Trinidad &amp; Tobago (LNG)</th>
<th>Egypt (LNG)</th>
<th>Algeria (pipeline + LNG)</th>
<th>HHI</th>
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<td>2,321</td>
<td>2</td>
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<td>1</td>
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<tr>
<td>2008</td>
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<td>2,321</td>
<td>2</td>
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<td>2</td>
<td>2,321</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>0</td>
</tr>
</tbody>
</table>

Source: Enagás.

#### 4.1.4. Evolution of Domestic Gas Infrastructure

Spanish gas import capacity continued to expand at the LNG terminals during the 2007-2009 period. According to data published by Enagás, total regasification capacity increased by 10% relative to 2007, thanks to expansion at the Barcelona, Cartagena and Sagunto terminals. LNG storage capacity also increased by 14% due to investment in Cartagena and Sagunto.

However, overall storage capacity in Spain remains relatively limited, in particular with respect to underground storage facilities. The two existing underground facilities (Gaviota and Serrablo) accounted for just over 10 TWh of gas inflows into the system in 2009, which is equivalent to less than 3% of overall demand. Total storage capacity (also including LNG storage) stood at roughly 4 bcm in mid-2010 according to data published by Gas Infrastructure Europe, equivalent to roughly 10% of annual demand (see GIE (2010b)). This level is well short of the corresponding levels in major European markets (i.e. Germany, France and Italy all have in excess of 13 bcm of gas storage, corresponding approximately to a 20%-30% share of demand). The main exception is the U.K. gas market, which, however, is less dependent than Spain on imported gas and has relatively more access to flexible underground storage.

According to the update on energy infrastructure projects published by the CNE in March 2010 (CNE (2010c)), all current gas storage projects except for one (the Enagás facility at Yela) are suffering delays relative to their initial plans. The new storage site at Yela being constructed by Enagás is, however, expected to be operational in 2011. This facility will increase domestic
underground storage by close to 50%. Given the more flexible role played by gas in the electricity sector (reviewed below), adequate access to domestic gas flexibility remains critical for the Spanish energy system as a whole.

Another major new infrastructure expected to come on line in Spain is the Medgaz pipeline connection with Algeria. This new pipeline was initially expected to come on line in mid-2009, and is scheduled to start importing gas into Spain during the course of 2010. Medgaz will diversify the number of operators in Spain with access to pipeline gas, and significantly increase overall pipeline import capacity. It will also enable Spain to start exporting gas to the rest of Europe, once export infrastructure from Spain is strengthened. However, it might also increase overall gas dependence on Algeria to levels that could be seen as excessive (as potentially witnessed by the price dispute between Gas Natural and Sonatrach in the course of 2010). The CNE (2010d) forecasts an increase in overall supply dependence on Algerian gas from roughly 32% in 2009 to 40% in 2012.

4.1.5. Pricing and Trading
Wholesale gas prices in Spain follow international trends closely. As illustrated in Figure 9, Spanish wholesale gas prices peaked in 2008 (increasing by 20%-30% relative to 2007) due to the increase in oil prices experienced until mid-2008, but declined significantly after that and returned to 2007 levels in 2009. LNG prices in Spain have tended to lie below Spanish pipeline prices in recent years, but slightly above European LNG prices.

Figure 9: Evolution of Wholesale Gas Prices in Spain, 1996-2009
There is no primary wholesale gas market in Spain, contrary to the situation in countries with significant production of domestic gas (e.g. the United Kingdom and the Netherlands). Secondary trading in Spain is, however, well developed and an important source of gas flexibility (especially for LNG imports). OTC swap trading reached 714 TWh in 2009, growing by 60% relative to the 2007 level, and reached a level equivalent to almost 180% of gas demand (up from roughly 110% of demand in 2007). The prices traded in the OTC market are, however, not public, which means that this market does not contribute to wholesale price transparency in Spain. Moreover, gas OTC trades take place at several balancing points in the Spanish system, thus implying that the secondary gas market does not act as an effective gas hub (for a discussion of these issues, see CNE (2010e)).

4.1.6. Domestic Market Structure
The structure of the Spanish wholesale gas market remains characterised by the pre-eminent position of the incumbent firm, Gas Natural. However, Gas Natural’s share of wholesale gas imports has declined steadily with the liberalisation of the sector and the entry of independent LNG, falling from close to 80% in 2004 to 50% in 2009.

This decline in market share was partially reversed in 2009 through the acquisition by Gas Natural of joint control (together with the Italian gas incumbent ENI) of Unión Fenosa Gas (UFG). UFG accounted for 13% of the Spanish wholesale gas market in 2009. Following the Unión Fenosa deal, Gas Natural’s effective share of the wholesale gas market is of up to 63% (depending on the nature and degree of control exercised by Gas Natural in UFG), which was similar to 2006 levels.

Notwithstanding the high level of concentration and the increase observed in 2009, the Spanish wholesale gas market remains less concentrated than those of most other European countries. According to E.U.-wide data published by the European Commission in 2010 (European Commission (2010a)), only in the United Kingdom and Germany did the largest 3 firms account for a lower national share of wholesale gas than in Spain (based on 2008 data). The effects of the Gas Natural/Unión Fenosa merger are unlikely to significantly affect this comparison, given the high degree of concentration reported for other European countries.

Figure 10: Evolution of Gas Natural’s Share of the Wholesale Gas Market, 2004-2009

Note: Gas Natural’s share of wholesale gas is computed as the sum of its retail sales, sales to third parties and sales to the regulated market.
Source: Gas Natural, CNE.

4.2. Retail Gas

4.2.1. Progress Towards Market Liberalisation
The Spanish retail gas market remains only partially liberalised due to the presence of regulated tariffs until June 2008 and tariffs of last resort (TLR) thereafter. TLR were introduced for all low-pressure consumers with consumption below 3 GWh per annum in June 2008 (as discussed in Section 3).

In energy consumption terms, the market is largely liberalised, given the significant weight of industrial and electricity demand in total consumption (more than 80% of volumes in 2009), and the fact that these segments of the market do not face price regulation. As of March 2010, roughly 93% of all gas volumes were transacted at commercially determined prices (see Figure 11).
In terms of the number of customers, the proportion of the market on liberalised prices is significantly lower (54% in March 2010) due to the weight of the residential market and the fact that a significant share of residential consumers remain on TLR. Nonetheless, since TLR were introduced in the gas market in mid-2008, the share of liberalised gas consumers has increased quite significantly (by roughly 10 percentage points), continuing the gradual trend towards greater retail liberalisation at the residential level in evidence since 2004-2005.

4.2.2. Domestic Market Structure
The Spanish retail gas market is characterised by a high degree of concentration and the presence of a relatively strong retail incumbent (Gas Natural). Gas Natural has, however, steadily lost market share until 2008, with its share falling by almost 10 percentage point since 2004, from 53% to 44% (see Figure 12).

This trend was effectively halted in 2009 with the acquisition by Gas Natural of Unión Fenosa, including its 50% stake in Unión Fenosa Gas (UFG). Gas Natural’s notional share of the retail market in 2009 including Unión Fenosa can be estimated at 48% if one assumes that Gas Natural controls UFG, and the two firms behave as a single entity in the retail gas market. The

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9 The behavioural remedies on UFG’s retail arm imposed by the CNC may affect this assumption for the duration of the commitments. The estimated combined share in 2009 reported here accounts for the structural divestment agreed upon with the CNC (i.e. the sale of roughly 630,000 residential customers implemented by Gas Natural during the course of 2009, which have been estimated at 1%-1.5% of the overall retail market in volume terms).
corresponding level of the retail HHI increased to above 3,000 in 2009, up from roughly 2,600 in 2008.\(^\text{10}\)

Gas Natural’s largest competitors in the retail gas market remain the other main electricity firms, Iberdrola and Endesa. Endesa in particular has been growing rapidly in the retail gas market, more than doubling its market share since 2004 and achieving a share of 15\% in the industrial segment by 2008 (making it Gas Natural’s largest competitor in this segment).

**Figure 12: Retail Shares in the Spanish Gas Market, 2004-2009**

Note: Market shares refer to liberalised energy until June 2008 and all energy consumed thereafter. The effect of the Gas Natural/Unión Fenosa merger (including the divestment of residential consumers) is reflected starting in January 2009.

Source: CNE.

### 4.2.3. Switching Behaviour

Concentration in the residential gas market remains significantly higher than in the retail gas market as a whole. The CNE reports that Gas Natural held a 73\% share of the residential market in 2008, followed by Endesa with 13\% and EDP/HC (through Naturgas) with 9\% (see CNE (2010f)). Gas Natural held a similar share of total gas customers by the end of 2009. Gas

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\(^{10}\) HHI levels can be adjusted depending on the actual degree of control exercised by Gas Natural in UFG. The adjusted HHI in the case of a silent stake by Gas Natural in UFG stands at approximately 2,500 in 2009. In the case of ‘one-way’ control (which assumes that UFG maximises its profits and those of Gas Natural, whilst the latter maximises its profits and those associated with its stake in UFG), the HHI stands at roughly 2,900.
Natural’s share of the residential market can be estimated to drop to roughly 64% as a result of the network and residential customers sales agreed upon with the CNC in the context of the merger with Unión Fenosa.

The reasons for the higher degree of concentration in the residential market segment are the fact that a significant share of gas customers (e.g. close to 50% in 2009) remains on TLR with the incumbent gas distributors, and that those consumers who switch to the liberalised market tend to remain loyal to the incumbent supplier. In 2008, loyalty rates for residential gas stood at roughly 80% for the three main gas distributors (Gas Natural, Endesa and EDP/HC), and actually had increased relative to 2007 (see CNE (2010f)).

The presence of high loyalty rates means that concentration at regional level remains significantly higher than at national level in terms of the number of customers. The average share of the regional gas incumbents stood at over 86% in 2008 and around 85% in 2009 (Figure 13 plots the 2009 data). This means that, by the end of 2009, only 15 out of 100 gas customers had actually switched providers after liberalisation of the market. Whilst this outcome is not necessarily inconsistent with an effectively competitive market, it does suggest that the market is characterised by a significant degree of customer inertia and that it continues to be influenced by the presence of regulated tariffs.

Figure 13: Regional Shares in the Retail Gas Market, by Number of Customers in 2009

* Weighted average by number of customers in each region.
Source: CNE.
In spite of the relative slow progress in residential gas competition revealed by the figures reviewed above, the performance of the Spanish market in terms of consumer switching behaviour does not compare unfavourably with those of the other main gas markets in Europe. Data published by the Council of European Energy Regulators (CEER) in 2009 indicate the annual switching rates observed in the Spanish residential and SME gas market during 2007 (roughly 5%) were lower than those of the United Kingdom (close to 20%) and the Netherlands (approximately 8%), but well above those seen in Germany, Italy, France, Denmark and Austria (see CEER (2009)).

5.1. Wholesale Electricity

5.1.1. Evolution of Wholesale Electricity Demand
Demand in the Spanish wholesale electricity sector grew moderately in 2008 (by less than 1% relative to 2007), but was adversely affected by the economic downturn in 2009. Domestic demand in 2009 fell almost 5% relative to 2008, bringing the level of demand below that observed in 2006. However, demand started to recover in the first half of 2010, growing by over 4% relative to the same period of 2009.

In spite of the reduction in demand experienced in 2009, the overall growth of Spanish electricity consumption in the past decade significantly exceeded the levels of other European countries, as shown in Figure 14. Over the decade, Spanish consumption grew by more than one third on a cumulative basis, whilst across all E.U.-15 countries demand increased by approximately 7%.
5.1.2. Evolution of the Generation Mix
The mix of the Spanish generation market has continued to evolve significantly in recent years. As shown in Figure 15, since the market was liberalised in 1998, the main changes in the generation mix have been the entry of combined cycle gas turbines (CCGTs) and wind plants, and the corresponding reductions in oil and, more recently, coal-fired production.

CCGT capacity almost trebled in 6 years (from just over 8 GW in 2004 to more than 22 GW in 2009) and its output peaked in 2008 at over 90 TWh. Wind capacity more than doubled (from 8.5 GW to just over 18 GW) between 2004 and 2009, and its output reached a maximum during the period of 37 TWh in 2009.

Non-wind special regime generation also grew significantly in the past five years with a 50% increase in capacity (from 9 to over 13 GW) between 2004 and 2009. During this period, the renewable element of special regime (excluding the wind component) experienced an almost four-fold increase in output, whilst the non-renewable element (mainly co-generation) doubled over the period. Overall, total generation under the special regime grew by a factor of four between 1998 and 2009 (from 20 to 81 TWh).

Nuclear and hydro generation remained roughly stable in absolute generation terms over the period since 1998. The main reduction in output was experienced by less efficient oil/gas peaking turbines (whose output fell to 2 TWh in 2009) and, more recently, by coal-fired generation (which dropped to 34 TWh in 2009 from the levels of 70 TWh or more reached as recently as in the 2005-2007 period).
Overall entry of conventional capacity (net of plant retirements) slowed down significantly in 2008 and 2009 relative to previous years, with installed conventional capacity growing by less than 0.5 GW over the two years. Total installed capacity in 2009 was, however, more than double the level of peak demand, with the effective reserve margin (accounting for plant availability) standing at roughly 30% according to system operator REE.

In terms of shares of output, the single largest output contributor in both 2008 and 2009 was CCGT generation, in contrast with the 2004-2007 period, when the largest source was coal-fired production. In 2008, CCGT generation accounted for roughly a third of total production, but this share dropped to less than 30% in 2009. Wind generation in 2009 was the third largest individual generation technology (ahead of coal, but behind nuclear and CCGTs).\textsuperscript{11} However, special regime generation as a whole (including all subsidised generation) was the largest contributor (accounting for 30% of total output).

During the course of 2009, the reduction in demand coupled with the increase in special regime generation (which grew by 20% relative to 2008) squeezed primarily flexible thermal generation sources, with coal production dropping by 27% relative to 2008, and CCGT output falling by 14%. This overall trend continued during the first half of 2010 (partially also due to high levels of hydroelectric energy). By mid-2010, annual coal-fired generation stood at 23 TWh (less than a third of the 2007 level), whilst CCGT output was at 73 TWh, 20% lower than its annual peak of 2008 (in spite of an increase in capacity of 6% over the period).

\textsuperscript{11} The shares of gross generation in 2009 for the main technologies in the market were as follows: CCGTs (29%), nuclear (19%), wind (14%), coal (13%), non-renewable special regime (10%), and hydro (9%).
The hourly profiles of the different generation technologies in the Spanish market differ greatly, in line with the basic economics of power markets (see Figure 16). In particular, technologies with low variable costs (and higher fixed costs) tend to operate in baseload mode with a fairly constant output profile. This is the case in particular for nuclear generation. Special regime capacity also operates as a baseload source, even though its generation levels are volatile on an hourly basis due to its intermittent nature.

Special regime generation accounted for 14% of the system’s flexibility requirements in 2009 (defining flexibility as the difference between generation in the highest and lowest generation deciles), well below its output share of 30%. By contrast, thermal and hydroelectric generation provided the largest shares of flexibility, well in excess of their respective shares of output. This is particularly the case for CCGT generation (which supplied 47% of total flexibility needs), followed by hydroelectric generation (19%) and coal (17%).

5.1.3. Interconnection With Other Markets

Spain remained an exporting country during the 2008-2009 period. Net exports increased to 11 TWh in 2008 (mainly due to larger exports to Portugal and lower imports from France), but fell to 8.4 TWh in 2009 (due to lower exports to Portugal).

Integration with the Portuguese market through MIBEL became significantly more extensive over the period, as is illustrated in Figure 17. Congestion levels on the interconnection with Portugal fell from about 80% during the second half of 2007 (when MIBEL was implemented) to about 60% in 2008 and 25% in 2009. During the same period, the price differential between Spain and Portugal narrowed from over 20% to roughly 2%. Part of this price convergence may not be structural and might be reversed in the future. It is, however, clear that the market design

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**Figure 16: Average Hourly Generation Levels by Technology in Each Demand Decile (from highest to lowest) in 2009, GWh**

<table>
<thead>
<tr>
<th>Load decile</th>
<th>Fuel/Gas</th>
<th>Hydroelectric</th>
<th>CCGT</th>
<th>Coal</th>
<th>Special Regime</th>
<th>Imports</th>
<th>Nuclear</th>
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<tbody>
<tr>
<td>1</td>
<td>4.6</td>
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</table>

Source: REE; own analysis.

The difference in the operational regimes and characteristics of competing technologies in the Spanish power market is also reflected in the percentages of time when each technology sets the market price. In 2009, the technology that set the price most often was CCGTs (41% of the time), followed by hydroelectric power (38% of the time) and other thermal plants (15%). All other technologies set the price only for a combined 5% of the time, in spite of the fact that they accounted for close to 50% of output. CCGT technology was also the source of output that was most often at the margin in the market in 2009, accounting for more than 70% of all energy bids at a price between 95% and 100% of the spot price (well in excess of its share of total output).
of MIBEL is favouring greater integration between the Spanish and Portuguese systems (as discussed below).

**Figure 17: Integration Between the Spanish and Portuguese Wholesale Electricity Markets, 2007-2009**

On the other hand, effective integration with the rest of Europe through France remains limited. Net import capacity from France to Spain stood at 1.4 GW during winter 2009-2010, whilst export capacity was only 0.5 GW (according to data published by ENTSO-E). Moreover, the absence of an effective market design to coordinate electricity dispatch in the two systems (for example, via market coupling) reduces the effectiveness of integration between Spain and France.

For example, in 2008 (see Figure 18), effective price convergence between France and Spain was achieved for only 6% of hours. During the hours when prices diverged significantly, the interconnector was fully utilised (signalling the presence of effective trading between the countries) only 27% of the time. During the residual 73% of hours, the interconnector either had spare capacity which could have been profitably utilised or its flows actually went in the opposite direction to the price difference (due to imperfections in contracting arrangements, including the restrictions on imports imposed on the main Spanish generators). This stands in contrast with the operation of the Spanish-Portuguese interconnection where, thanks to the market splitting mechanism, hours when flows were inconsistent with the price differential were very limited in 2008 (2% of the time overall) and significantly more extensive price convergence was achieved (more than 40% of the time).

Source: REE, OMEL.

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There are also plans to introduce market coupling between Spain and France as part of European plans on further market integration (e.g. the Price Coupling of Regions project announced by European power exchanges in 2010). However, no specific timetable exists for the introduction of market coupling on the French-Spanish border and this is not expected before 2012.

Figure 18: Market Integration Between the Spanish, Portuguese and French Markets, 2008

Total import capacity into Spain stood at 2.8 GW in winter 2009\textsuperscript{12}, equivalent to 6\% of typical weekday peak demand, and 3\% of installed capacity. The corresponding levels for the Iberian market as a whole were even lower, given the existence of interconnection capacity between Spain and Portugal. Total import capacity into Iberia in 2009 equalled 2.6\% of peak demand and 1.3\% of total capacity. These interconnection levels are significantly lower than the levels of import capacity present in other European countries such as Germany (13\%-22\% of peak load), France (13\%), Italy (13\%), Belgium (23\%) and the Netherlands (27\%).

By 2020, Spanish import capacity is projected to increase to 5.7 GW due to significant interconnection capacity with France and Portugal expected over the coming years. This is projected to be equivalent to roughly 9\% of demand or 4\% of installed capacity, which is still well below the current levels of other European countries and the European target for import

\textsuperscript{12} Based on data published by the European Network of Transmission System Operators for Electricity (ENTSO-E), in January 2009.
capacity of 10% of domestic capacity (and even more so if one considers the interconnection levels of the Iberian Peninsula as a whole).

5.1.4. Prices and Trading
In 2008, wholesale electricity prices reached their highest level since the liberalisation of the market (close to €70/MWh), but subsequently fell significantly in 2009 (to €43/MWh, a reduction of 39%), the lowest level since 2004 (see Figure 19). In terms of the composition of final wholesale prices, the reform of capacity payments introduced in 2007 reduced the cost of capacity payments significantly (from close to €5/MWh in 2006 to between €1 and €2/MWh in 2008-2009). Prices for ancillary services (including congestion management) increased by roughly 10% in 2008 and 2009 relative to previous years (with the exception of 2006), but still accounted for a limited proportion of total wholesale expenditure.

Baseload day-ahead spot prices in 2009 stood at just above €38/MWh (with peak prices at €41/MWh). The downward trend experienced since 2008 continued into the first half of 2010, when spot prices averaged €30/MWh. The first four months of 2010 were characterised by several instances of very low prices due to the surplus of low-cost generation during off-peak hours. For example, 18% of hours during January-April 2010 had spot prices below €1/MWh, compared to only 1% of hours in the whole of 2009.

Figure 19: Evolution of Wholesale Electricity Prices, 2004-2009

Source: REE.
Whilst the price reduction of 2009 was associated with lower fuel costs, the evidence also suggests that the margins between average spot prices and estimated fuel costs for thermal plants also shrank considerably in 2009 relative to earlier years for both coal and CCGT plants (see Figure 20). Baseload price-cost margins for coal and CCGT plants fell from an average of roughly 40%-45% during the 2004-2008 period to close to 0 in 2009, thus inducing thermal plants to operate only in fewer high-price hours (achieving average load factors of roughly 40%). The reduction in margins for thermal plants in 2009 can be primarily attributed to a combination of the fall in demand and of the increase in low-cost generation (mainly special regime).

Figure 20: Evolution of Prices and Thermal Fuel Costs in the Spanish Wholesale Electricity Market, 2004-2009

In terms of trading behaviour, the day-ahead spot market remained the central marketplace in the Spanish system, with total volumes in 2009 of 201 TWh, equivalent to 74% of gross generation. Net sales in the intra-day market remained limited, at 4-6 TWh in the 2008-2009 period (e.g. 2% of total demand in 2009), but gross transactions were much greater (i.e. 30 TWh in 2009). Electricity volumes accepted for congestion relief services increased between 2008 and 2009 (from less than 7 TWh in 2008 to 9.5 TWh in 2009), reflecting the lower day-ahead prices seen in 2009 which excluded some thermal plants from the merit order determined in the spot market.
There was also a very significant rise in electricity OTC trading between 2006 and 2009. Brokers’ and traders’ data indicate an increase in OTC volumes from 16 TWh in 2006 to over 150 TWh in 2009 (with a further large increase experienced in the first half of 2010). These trades are largely financial, as shown by the fact that volumes transacted in the day-ahead market remained very significant.

5.1.5. Domestic Market Structure
The Spanish (or Iberian) wholesale electricity market was moderately concentrated in 2009 under most conventional measures. The market has become notably less concentrated over the past two years primarily as a result of the continued entry of independent special regime generation and the significant reduction in the market share of the historically largest operator in output terms (Endesa). This is in line with the general trend observed in the market since its deregulation in 1998.

Assessing market structure and the potential for market power in electricity generation markets is complex due to some of the specific features of the market (including most notably the presence of significant cost asymmetries across plants and firms). Conventional measures like the HHI can therefore only provide an imperfect proxy for the competitiveness of a given market structure. However, provided that the relevant market is adequately defined, HHI s are still a useful high-level indicator, which can be complemented with other tools such as pivotality measures (which are discussed below).

Five possible definitions of the relevant wholesale electricity market are considered below which differ in terms of their geographic scope (i.e. whether Portugal is included or not) and in terms of the plants included in the putative market (i.e. all generators, only conventional plants or only price-setting assets). Under all five alternative definitions of the wholesale electricity market, the HHI has fallen consistently since 2004 (as shown in Figure 21).13 If one considers the widest possible market (including all generation sources, and both Spanish and Portuguese plants), the HHI stood at roughly 1,100 in 2009, slightly above the standard threshold employed by the European Commission for an un-concentrated market (which is 1,000). Concentration under this definition of the market has declined significantly since 2007 (by roughly 24%), mainly due to the sustained entry of special regime generation not owned by the incumbent firms.

Under more conservative definitions of the Spanish market (e.g. excluding Portugal, and/or excluding special regime generation and other non price-setting assets), the 2009 HHI is considerably higher than 1,000 in some cases, but still at or below the threshold for a highly concentrated market (which equals 2,000) under all definitions.

13 In all cases, the HHIs were computed by taking into account the market shares of the six largest generators in the market: Endesa, Iberdrola, Gas Natural/Unión Fenosa (both pre- and post-merger), EDP/HC and E.On. The market share of all other generators was not taken into account (effectively assuming that all other firms act as a price-taking fringe). Market shares were computed using individual plant data published by REE and REN (for conventional generation) and the special regime generation levels reported by each company.

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Defining the market as including only price-setting generation in Spain (which is a plausible, yet fairly conservative definition of the market for the purposes of assessing the potential for market power\textsuperscript{14}), the HHI in 2009 stood at an estimated 1,450 points, over 40% lower than in 2004. The main reasons for the reduction in concentration of price-setting generation since 2004 has been the entry of independent CCGTs, the asset sales from Endesa to E.On in 2008 and the recent shift from coal generation (which is more concentrated) to CCGT generation (which is less concentrated). The Gas Natural/Unión Fenosa merger increased concentration in price-setting generation in 2009 (relative to a counterfactual without the transaction) but this effect was mitigated by the 2 GW of CCGT divestments agreed upon with the competition authorities. This remedy implied that price-setting concentration continued to decline between 2008 and 2009 in spite of the transaction\textsuperscript{15}.

\textbf{Figure 21: Concentration in the Wholesale Electricity Market, 2004-2009}

Note: Price-setting generation is defined as all generation except nuclear, special regime and run-of-river hydro (estimated at an average hourly output level of 1.3 GW). The HHI estimates incorporate the impact of the Gas Natural/Unión Fenosa merger (and associated remedies) starting in January 2009, and the sales of assets from Endesa to Acciona starting in July 2009 (as reflected in Endesa’s 2009 Annual Report). The HHI is computed on the basis of the market shares of the six largest firms in terms of conventional output.

Source: REE; REN; company annual reports; own analysis.

\textsuperscript{14} For a formal discussion of the role of price-setting assets in electricity markets, see Federico and López (2009).

\textsuperscript{15} This divestment was not implemented during the course of 2009. However, the analysis shown here incorporates an estimate of the impact of the divestment on market structure in 2009 in order to provide a realistic picture of market concentration going forward.
The distribution of market share by firm during 2009 is illustrated in Figure 22.\textsuperscript{16} Endesa and Iberdrola remained the largest firms in the Spanish market in terms of conventional output (accounting for close to 60\% of conventional generation). However, their combined position in Spain was significantly smaller in terms of overall generation (45\%) and price-setting generation (42\%). With respect to price-setting generation, the newly merged entity Gas Natural/Unión Fenosa was as large as Endesa and Iberdrola (even after accounting for the estimated impact of the divestment of 2 GW of CCGTs), thus implying that the Spanish market no longer has a duopolistic structure under this definition of the market.

Under the widest definition of the wholesale market (i.e. all generation in Iberia), in 2009 the two historical incumbents accounted for only 40\% of output and independent players held a third of the overall market. The highest individual market share obtained under this definition of the market (21\% for Iberdrola) was in the range of the 19\%-22\% share of capacity computed in the 2005 White Paper as compatible with effective competition (see Pérez Arriaga et al. (2005)).

\textbf{Figure 22: Generation Market Shares by Firm, 2009}

![Figure 22: Generation Market Shares by Firm, 2009](image)

Note: price-setting generation defined as all generation except nuclear, special regime and run-of-river hydro (estimated at an average hourly output level of 1.3 GW). Shares incorporate the impact of the Gas Natural/Unión Fenosa merger (and associated remedies) from January 2009, and the sales of assets from Endesa to Acciona from July 2009 (as reflected in Endesa’s 2009 Annual Report).

Source: REE; REN; company annual reports; own analysis.

\textsuperscript{16} The underlying levels of generation capacity and output by firm and technology in 2009 are summarised in the tables included in Appendix A.
As a result of the entry of additional capacity and changes in market structure (coupled with the relatively low levels of demand experienced in 2009), Endesa and Iberdrola were no longer ‘pivotal’ for practical purposes in 2009 (see the analysis shown in Figure 23). A firm can be defined as pivotal if some of its capacity is required to meet load during any given hour. The estimates shown here indicate that Endesa was only pivotal during the three highest demand hours in 2009 (i.e. less than 0.1% of the time) and that Iberdrola was pivotal for only 13 hours (i.e. 0.14% of the time). These levels of pivotality are considerably lower than the equivalent values of 2007.

If one considers a more conservative residual supply index (RSI) measure°, the residual supply faced by Endesa in 2009 was not sufficient to meet 110% of load for only 1.5% of hours, with the equivalent measure standing at 2.5% in the case of Iberdrola. The corresponding RSI levels in 2007 were 9% and 11.5%, respectively. Pivotality indicators in Spain may, however, increase again in the future if peak demand were to increase significantly relative to 2009 levels.

Figure 23: Generator Pivotality in Spain, 2007 and 2009

Note: The residual capacity faced by each firm is computed as the sum of: maximum hourly imports; average levels of special regime generation during the top 20% of hours; average levels of hydroelectric generation during the top 20% of hours; and average available thermal capacity.

Source: REE; company annual reports; own analysis.

17 These estimates are broadly consistent with those reported by the CNE in its report on competition in the Spanish gas and electricity markets published in May 2010 (CNE (2010f)). In its report, the CNE estimated that Endesa was not pivotal in 2008 and that Iberdrola was pivotal for only 30 hours.

18 This measures the tightness of the supply-demand balance, assuming that all of the capacity available to one firm is not offered to the market.
Comparative European data indicate that the trend towards lower concentration in the wholesale electricity market was stronger in Spain than several other European countries. Eurostat data for 2008 show that the share of the largest firm in Spain was one of the lowest in Europe and only higher than the United Kingdom, but lower than equivalent levels in France, Germany, Italy and other European countries (with the exception of Finland). According to the same data, Spain has experienced one of the greatest reductions in the share of the largest firm since 2000 (second only to Ireland). In terms of overall capacity concentration levels in 2008, the Spanish generation market was more concentrated than the United Kingdom, Italy and the Netherlands, but less concentrated than Germany, France, Belgium, Portugal and Greece, considering only those E.U.-15 countries with available data (see European Commission (2010a)).

5.2. Retail Electricity

5.2.1. Progress Towards Retail Liberalisation
The Spanish retail electricity market continues to be largely price-regulated, as shown by the number of customers on regulated tariffs. At the end of March 2010, over 80% of all customers remained on TLR.

However, the reforms introduced in the retail electricity market since mid-2008 (most notably, the abolition of high-voltage tariffs in July 2008 and the introduction of TLR only for smaller domestic consumers in July 2009) have made a significant contribution to liberalising the market. Since the end of June 2008, the share of the liberalised electricity market has increased from 33% to 64% in energy terms, and from 7% to 17% in terms of the number of customers (see Figure 24). During the period between July 2009 (when TLR were introduced) and March 2010, the number of SME electricity users in market-determined prices more than doubled (in line with the fact that these consumers are penalised if they do not switch to the market) and the number of residential customers not on regulated tariffs increased by 80%. As a result of these changes the degree of liberalisation in the electricity market in early 2010 surpassed the levels last reached in late 2005 (before the adverse impact of the tariff deficit on retail competition).

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19 The Netherlands is not included in the Eurostat data but it is likely to have lower concentration levels than those observed in Spain, as shown by other concentration indicators.

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5.2.2. Domestic Market Structure

The liberalised retail electricity market is largely supplied by the traditional incumbent utilities. Endesa acquired a leading position in this market in 2006 (when other competitors scaled back their activities due to the existence of the tariff deficit), but its share has gradually declined since, falling from 54% in 2006 to just below 40% in the first three quarters of 2009 (see Figure 25). Over the same period, Iberdrola increased its share (from 13% to 17%), whilst the position of the combined Gas Natural/Unión Fenosa group fell to 15% in 2009 (from 22% in 2008). Energy purchases by large industrial clients through the Fortia consortium accounted for 8% of the total liberalised market (and 12% of the market for industrial clients) during the year ending in September 2009. As a result of these changes in market structure, the concentration index in the liberalised electricity market fell from a high of over 3,300 in 2006 to roughly 2,200 in 2009, which was below the corresponding level in the retail gas market.
5.2.3. Switching Behaviour
As in the retail gas market, switching behaviour in the electricity market has a distinct regional pattern, with the overwhelming majority of consumers switching to their local incumbent (i.e. the owner of the distribution network) when opting to move out of the regulated market. Loyalty rates over the 2004-2009 period are shown in Figure 26. The highest loyalty rates are those of Endesa and EDP/HC (both in excess of 90% in the third quarter of 2009), whilst loyalty levels in the Iberdrola and Unión Fenosa network areas were approximately 75% during the same period of 2009. Loyalty rates have increased since 2007 in spite of the fact that the market has become progressively more liberalised in this period.

* January-September 2009.
** Includes Unión Fenosa in 2009.
Source: CNE.
Based on data from 2007, switching rates in the Spanish residential and SME electricity markets were below the levels achieved in more liberalised markets (most notably the U.K., Swedish and Dutch markets, but also the German and Danish markets), and in line with those observed in France, Portugal and Italy (see CEER (2009)). The increase in liberalisation and switching in the Spanish market prompted by the introduction of TLR in mid-2009 may affect this comparison.

5.2.4. Evolution of the Tariff Deficit
One of the distinctive features of the Spanish retail electricity market is the presence of a significant shortfall between overall regulated revenues (collected from regulated tariffs and access charges) and corresponding costs. This shortfall, called the tariff deficit, reached its highest annual levels in the 2008-2009 period, with annual amounts of roughly €4.3-4.4 billion in each of the two years. These deficit levels were higher than the corresponding annual deficits in the 2005-2007 period, and also in excess of the limits on the tariff deficits established by RDL 6/2009 for the 2009-2012 period (see Figure 27).

The high annual deficit level experienced in 2008 was associated with exceptionally high wholesale electricity costs (which were not fully reflected in overall electricity tariff revenues, which hardly increased between 2007 and 2008). The 2009 annual deficit reached a similar level to that of 2008 in spite of much lower wholesale electricity prices. This was primarily the result of the continued
increase in remuneration of special regime generation (the reasons for this are discussed in detail in Part II of this report). Between 2008 and 2009 total payments to special regime generators increased by over €1.2 billion (in spite of the reduction in market prices) and the total effective subsidy (i.e. the difference between payments and the market price) increased by over €2.6 billion. The increase in the level of total payments to special regime generation between 2007 and 2009 alone exceeded the level of the net annual tariff deficit in 2009. Most of this increment (roughly 60%) was due to payments made to solar PV generation.

The CNE estimates that the final level of the 2009 tariff deficit may be reduced by roughly €0.5 billion by shifting part of the cost associated with electricity supply to the Spanish islands to the general budget (in line with RDL 6/2009) and accounting for an expected revenue surplus due to the way in which the capacity charge paid by consumers was initially computed (see CNE (2010g)). Even allowing for these adjustments, the final tariff deficit in 2009 would stand at around €3.8 billion, higher than in any other year except for 2008, and in excess of the €3.5 billion cap established by RDL 6/2009.

The accumulated tariff deficit at the end of 2009 stood at just below €17 billion (net of the adjustments to the 2009 deficit mentioned above), which was higher than the total level of regulated revenues in 2009. Almost 90% of this debt has yet to be collected by the electricity companies. The CNE is recommending a final settlement of the competition transition costs (CTCs) paid to generators between 1998 and 2006. Such a settlement may affect the magnitude of the accumulated tariff deficit owed to the electricity firm (see CNE (2010g)).
Figure 27: Evolution of the Annual Electricity Tariff Deficit, 2005-2009, and Deficit Caps for 2009-2012

Note: Annual deficits include the costs associated with annuity payments on past deficits. Emission Trading System (ETS) recovery refers to the expected revenues from collecting the windfall gains associated with the introduction of carbon pricing and free emission allowances, as set out by Spanish legislation applicable until June 2009. The level of the tariff deficit shown for 2009 does not reflect the adjustments discussed in the main text, which reduce the deficit to a net level of approximately €3.8 billion.

Source: CNE.
PART II: Environmental Policies in the European and Spanish Energy Sector
The need to mitigate the risks associated with climate change is arguably the greatest policy challenge faced by the European and Spanish energy sector at present. The European Union has committed to fairly ambitious environmental targets for 2020 (especially in terms of renewable deployment), which are expected to need to be even more stringent for the period beyond 2020. These targets are likely to require a profound transformation of the power sector in particular, with significant and continued growth of renewable energy and the need to consider and promote alternative sources of low-carbon generation (most notably, nuclear power and thermal plants based on carbon capture and storage (CCS)20).

Whilst over the past two decades the main imperative pursued by E.U. energy policy has been the drive towards more competition in the wholesale and retail energy markets, the next decades are likely to be dominated instead by the need to design and implement effective policies to tackle climate change.

This second part of this report is devoted to the analysis of the environmental issues that are currently facing the European and Spanish energy sector (with a particular focus on the power sector), and their policy implications. The focus on the electricity sector is justified by the fact that it accounts for a large share of total greenhouse gas (GHG) emissions at present and because it has significant decarbonisation potential due to the possibility of large-scale deployment of low-carbon technologies. The power industry is therefore set to acquire a critical role in the process of reducing GHG emissions in other sectors as well (e.g. transport and residential heating).

This part of the report starts by reviewing the basic economics of climate change, both in terms of the potential costs and benefit of action to address global warming, and of the optimal design of policies aimed at limiting the stock of carbon emissions in the atmosphere. It then reviews the design and performance of E.U. and Spanish environmental policy in the power sector to date. Finally, the report discusses the key policy challenges associated with environmental policy in the European and Spanish energy sectors over the medium term, given the current policy objective of drastically curtailing carbon emissions by 2050.

20 CCS technology allows thermal plants (both coal- and gas-fired) to capture, transport and store underground most of their CO2 emissions, thus reducing their emission rate into the atmosphere by roughly 80%.
The economics of climate change and related policies is complex. This is due to the interactions between the predictions of climate change science, the presence of multiple market failures associated with carbon emissions and low-carbon technologies, and the structural complexities of energy markets (most notably in the power sector).

The review of the fundamental economics of climate change presented in this background section focuses in turn on:

i. The scientific evidence on global warming and the implications for the cost-benefit analysis of action towards climate change.

ii. The main market failures associated with climate change and the required policies to address such failures.

iii. The implications for the power sector of a greater share of low-carbon generation (most notably renewable).

iv. The interaction between environmental policies and other key energy policies pursued in Europe (i.e. energy security, and more effective regulation and competition).

7.1. Climate Change and the Timing of Reductions in Greenhouse Gas Emissions

There is currently a fairly widespread consensus among European policymakers on the need to decisively reduce GHG emissions\(^2\) over the next couple of decades in order to prevent the risk of excessive global warming. This is reflected in current E.U. environmental policy (reviewed

\(^2\) Given that most GHG emissions are due to CO\(_2\) emissions, the terms GHG and CO\(_2\) (or carbon) emissions are used interchangeably in this report.
It is also testified more broadly by the outcome of the Copenhagen meeting on climate change of December 2009 (i.e. the Copenhagen Accord), where world leaders agreed on the need for deep cuts in global emissions so as to hold the increase in global temperature below 2 degrees Celsius (even though they failed to agree on precise commitments to reduce emissions).

The current scientific evidence, as summarised in the Intergovernmental Panel on Climate Change (IPCC) of 2007\textsuperscript{22}, is that the global stock of GHG needs to stabilise at roughly 445-490 parts per million (ppm) of CO$_2$-equivalent (CO$_2$-eq.) in order to contain the increase in global mean temperatures above pre-industrial levels to 2-2.4 degrees Celsius. The IPCC also reports that the global stock of CO$_2$-eq. stood at 375 ppm in 2005, well above pre-industrial levels as a result of human activities.

Temperature increases in excess of the 2-2.4 degrees Celsius range reported by the IPCC are likely to be associated with dangerous and costly global warming. Under a business-as-usual (BAU) scenario, the stock of emissions will reach a level of 1,000 ppm during the next century according to the IEA (2009), thus implying a global temperature rise of up to 6 degrees Celsius with potentially very damaging consequences for human activity.

7.1.1. Implications for GHG Emission Profiles
Stabilising the stock of emissions at 445-490 ppm of CO$_2$-eq. requires global emissions to peak by around 2015 and to be reduced by 50% to 85% by 2050, relative to 2000 levels, according to the estimates contained in IPCC (2007). If emissions are stabilised at 450 ppm there is approximately a 50% chance that temperatures will not increase above the threshold of 2 degrees Celsius (DECC (2009a)). Less incisive action on GHG emission would be associated with significantly higher temperature increases according to the IPCC estimates, as shown in Figure 28 below.

\textsuperscript{22} The scientific evidence on climate change summarised in the IPCC 2007 report is the factual starting point for the review of the economics of climate change presented in the report.
More recent calculations presented by McKinsey (2009) show that by 2030 global GHG emissions could fall by 35% compared to 1990 (if appropriate policies are implemented) and that this reduction could make it reasonably possible to contain the increase in temperature within the threshold of 2 degrees Celsius. McKinsey (2009) also reports that a delay in taking abatement actions (e.g. until the next decade) would make it practically impossible to prevent global warming in excess of 2 degrees Celsius.

Similarly, the IEA (2010a) argues that the decade between 2010 and 2020 is critical in order to achieve the required reduction of at least 50% of global emissions by 2050. For this to be feasible, global emissions need to peak by 2020 and decline steadily thereafter. Attempting this reduction later in time would need much sharper reductions in the flow of CO₂ emissions and significantly higher costs.

For Europe, the required reductions in energy-related CO₂ emissions are even sharper than for the world as a whole. In the scenario developed by the IEA (2009) to stabilise the concentration of GHG at 450 ppm of CO₂-eq., Europe’s energy CO₂ emissions are required to fall by over 20% by 2020 (relative to 1990), and by more than 40% by 2030. The corresponding reductions in the power sector are sharper still, with the share of the electricity industry in total energy emissions almost halving between 2007 (when it stood at 37%) and 2030 (when the corresponding share is required to be cut to 20%). This implies that emissions in the European power sector would need to fall by 70% by 2030 (relative to 1990).
IEA projections indicate that a broad range of technologies will be needed to achieve the required reduction in emissions relative to a BAU scenario (see Figure 29). Over the next decade (by 2020), global abatement efforts can be fairly moderate and mainly focused on energy-efficiency measures (accounting for two thirds of required reductions), with a significant contribution also from renewable and nuclear power (30% of abatement in total). By 2030 and 2050 the role played by CCS generation is projected to have to increase considerably (accounting for almost 20% of abatement efforts by 2050, relative to 3% only by 2020), with renewable and nuclear power combined still playing a significant role (close to ¼ of the overall carbon reduction by 2050). By 2050 efficiency and end-use fuel switching measures are forecast to account for almost 60% of abatement measures. By that year, total emission-reduction efforts would need to cut emissions by three quarters relative to a BAU scenario. These projections also imply that the cost of meeting environmental targets would increase substantially if only some technologies are relied upon to cut emissions.23

Figure 29: Global CO₂ Emissions and Distribution of Abatement Efforts by Modality

23 Macroeconomic simulations performed in the United Kingdom indicate that the total cost of achieving an 80% reduction in emissions by 2050 would almost double if only renewable generation were used to decarbonise the power sector versus an alternative policy of using nuclear and CCS technologies as well (see DECC (2009b)).
7.1.2. The Costs and Benefits of Action on Climate Change

The Stern Review commissioned by the U.K. government in 2006 was tasked with reviewing the economics of climate change (Stern (2007)). The Review focused its analysis on scenarios where GHG stabilised in the range of 450-550 ppm of CO₂-eq. (slightly above those considered by the IPPC as compatible with an excessive increase in global warming).

The Stern Review estimated that the annual costs of stabilising emissions at 500-550 ppm would be around 1% of annual GDP by 2050 (on average), and found this level to be significant but “fully consistent with continued growth and development, in contrast with unabated climate change, which will eventually pose significant threats to growth” (Executive Summary, p. 13).24

The European Commission’s impact assessment of its climate change package of 2007 (which is described in the next section of this report) shows that investment in a low-carbon economy would cost 0.5% of total global GDP during the 2013-2030 period, thereby implying a reduction in global growth of roughly 0.2% per year up to 2020.25 The IPCC 2007 report indicates a slightly lower reduction in annual growth rates by 2030 and 2050 (less than 0.12 percentage points) in order to stabilise GHG in the 445-535 ppm range. By contrast, the Stern Review computed that the cost of inaction on climate change would be on the order of 5%-20% of annual global GDP (on average in the future). These computations justified the Review’s conclusion that the “benefits of strong early action [on climate change] considerably outweigh the costs”.

Stern’s conclusions for early action on climate change are partially based on a consumption smoothing argument: it is better to suffer a constant small loss in consumption, rather than delay action and incur a much larger loss in the future. As noted by some economists (e.g. Nordhaus (2007) and Weitzman (2007)), this argument supports the conclusion in the Stern Review if one weighs future consumption almost the same as current consumption, by assuming a fairly low social discount rate. Using higher rates weakens the case for early action. On the other hand, both Stern and Weitzman note that there is a risk that the consequence of global warming will be much worse than expected, with potentially catastrophic consequences. Climate change policy arguably should also seek to reduce the likelihood of this risk by effectively representing insurance against the possibility of very significant consumption losses (see, in particular, Weitzman (2010)). The uncertainty associated with the costs of climate change can therefore actually strengthen the case for early action to curb GHG emissions and provide support to current E.U. policy on this issue (provided that other countries also reduce their emissions so as to meet global environmental objectives).

24 More recent estimates contained in DECC (2009b) indicate a cost of 3% of global GDP by 2050 for a trajectory towards stabilisation at 450 ppm CO₂-eq.
7.2. Economic Mechanisms for Reducing Carbon Emissions

The scientific evidence and economic arguments reviewed above provide support for a policy aimed at curtailing carbon emissions rapidly over the 2020-2050 period in order to prevent an excessive increase in global temperatures. A separate policy question is how to optimally achieve the required reduction in GHG emissions. This question should be guided by the overall objective of minimising the cost of reducing carbon emissions. Cost-minimisation calls for the adoption of a set of policies that directly address the market failures associated with climate change and only intervene where market failures are present. It also suggests the need to design a technology- and sector-neutral approach to carbon abatement, implying that carbon reduction should take place in those sectors that have the lowest cost of reducing emissions, and that it should rely on technologies that minimise abatement costs (over time).

7.2.1. Carbon Pricing

The fundamental market failure to be addressed by climate change policy is the externality associated with GHG emissions. This externality relates to the fact that emitters of GHG do not face the full social costs of emissions, which include their adverse impact on the environment (as measured by the risk of global warming associated with GHG emissions).

This market failure can be addressed by putting a price on GHG emissions to be borne by emitters or consumers. Standard economic theory indicates that this price should be set equal to the incremental cost of carbon abatement (so as to induce emitters to abate). The optimal amount of abatement to be targeted via carbon pricing is given by equalising the social marginal benefit of abatement (which is equivalent to the social damage from emissions) with its marginal cost.

Figure 30 summarises the concept of optimal carbon pricing by showing a hypothetical “merit order” (or abatement cost curve) for emission abatement relative to a BAU counterfactual for the power sector only. This schedule stacks in increasing order each potential source of emission reductions starting from the lowest-cost options (in terms of € per tonne of avoided emission) to the more expensive ones. Abatement options are costed on the basis of their long-run incremental costs (which include the capital costs of deployment).

In the hypothetical example shown in Figure 30 (which is loosely based on McKinsey’s review of carbon abatement economics for the power sector (McKinsey (2009))26, the cheapest forms of abatement are energy efficiency efforts (which would be privately profitable even in the absence of carbon pricing), followed by switching existing electricity output from coal plants to less

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26 McKinsey (2009) shows that by 2030 the merit order of the main carbon-abatement options relative to BAU in the power sector will include (in increasing cost order): demand reduction, nuclear power, low-penetration wind, solar CPS and PV, and CCS (applied to both gas and coal).
polluting gas-fired plants, new nuclear capacity, on-shore wind capacity, other types of renewable energy and CCS.

In the hypothetical example, in a given time period $t$, it is optimal to invest in all carbon-abatement options except CCS in order to reduce carbon emissions. The optimal carbon price would be set at the cost of the most expensive abatement option required, which in the example considered here is represented by renewable sources other than on-shore wind. The corresponding optimal carbon price will be reflected in electricity prices during hours when thermal power stations are price-setting, thus increasing the profitability of carbon-free baseload generators (e.g. nuclear and renewable), making them more competitive and stimulating entry (assuming that the latter is feasible).

Figure 30: Illustration of Hypothetical Abatement Cost Curve for the Power Sector and Optimal Carbon Price

Carbon pricing can be achieved using two basic mechanisms: a cap-and-trade (or quota) system; or a carbon tax.

- **Cap-and-trade.** Under cap-and-trade, a binding cap on emissions is set in any given period (or across multiple periods) and emission permits are allocated to emitters (either through an auction or via alternative mechanisms such as grandfathering) that allow them to subsequently trade with each other. Trading of permits between emitters will establish a price for carbon emissions that will in equilibrium equal the marginal cost of abatement at the emission quota.

Trading will also allow abatement to take place where it is most efficient, e.g. more emission-intensive producers (e.g. coal-generators) will face incentives to sell their permits to less
emitting technologies (e.g. gas-fired generators), assuming that the emission cap binds. This is because less emitting generators are able to produce more electricity output for a given number of emission permits and a given level of relative fuel prices. They will therefore place a higher value on the permits than technologies with higher emission rates. This outcome can be achieved independently of whether permits are grandfathered or auctioned.27

Trading of emission permits also allows for an optimal distribution of abatement efforts across sectors and countries, as long as the cap-and-trade scheme includes multiple sectors and countries.

- **A carbon tax.** The alternative to a cap-and-trade system is a carbon tax, which directly sets the price of carbon. Emitters will take this tax into account in their pricing and output decisions. This will in turn discourage production from high carbon-emitters (e.g. coal plants) to the benefit of less emitting technologies and carbon-free sources. The abatement levels achieved with a carbon tax will equal the point where the tax crosses the marginal cost of abatement schedule, as illustrated in Figure 30.

If the positions of the marginal cost and benefit schedule are certain, then a carbon tax is equivalent to a cap-and-trade system in that both can achieve the optimal abatement effort. If there is uncertainty on the positions of the schedules, then the two systems are no longer equivalent. Economic theory (e.g. Weitzman (1974)) suggests in this case that if the marginal benefit of abatement is steep (relative to the marginal cost schedule), then a cap-and-trade system is superior to a carbon tax. Alternatively, if the marginal benefit schedule is flat (relative to marginal cost), a carbon tax is preferable. This economic result derives from the fact that, under conditions of uncertainty, the socially optimal outcome is unlikely to be achieved. However, the efficiency loss resulting from deviating from the optimal carbon price will be reduced by using a carbon tax (rather than a cap-and-trade mechanism) if the marginal cost schedule is steeper than the marginal benefit schedule. The reverse result holds with a steep marginal benefit schedule relative to marginal costs.

Some economists (e.g. Green (2008) and Newbery (2010a)) have argued that in any given time period the marginal benefit of abatement is fairly flat, since the flow of emissions in a time period has a limited effect on the stock of emissions (which in turn determines global warming). This would support the use of a carbon tax over a quota-based system.

On the other hand, a cap-and-trade system can target emission reductions directly with lower informational requirements (Tirole (2010)). It also has several political economy advantages over carbon taxes (e.g. the ability to compensate emitters if necessary and to publicly commit to

27 In an auction-based system, emission-intensive producers will not be able to afford to purchase emission permits at the price established in the auction, given their higher emission rates relative to cleaner producers. This will generate the same outcome of a situation where permits are grandfathered and trading subsequently takes place.
a given medium-term emission target). Over a long period of time, the design of both a carbon tax or a cap-and-trade system can be adjusted as more information on the costs and benefits of abatement become available, meaning that in practice the difference between the two systems in terms of their final outcomes may not be that substantial.

The other potential disadvantage of a cap-and-trade system over a carbon tax is that it can lead to fluctuations in the carbon price, making investments in long-lived low-carbon assets riskier (Baldursson and von der Fehr (2004)). Because of this feature, some policy makers, e.g. in the United Kingdom, both the Treasury in its Energy Market Assessment of March 2010 (U.K. Treasury (2010)); and the Committee on Climate Change in its June 2010 report (CCC (2010)), have advocated for a floor to be established on carbon prices for some technologies. The aim of this measure would be to reduce the risk associated with long-lived investments in low-carbon generation (e.g. nuclear and CCS), whilst preserving some of the benefits of a cap-and-trade system.

Current prices under the European carbon trading scheme are well below €20/tonne CO₂, as reviewed below. The U.K.’s Committee for Climate Change estimated that the carbon price in 2020 will be between €25 and €40/tonne, given the current European emission targets (CCC (2010)). Whilst there is uncertainty on the levels of carbon prices necessary to stimulate low-carbon investment, both current carbon prices and the forecast for 2020 are likely to be below the required levels.

For example, the IEA projects that carbon prices in OECD countries would need to reach levels of USD 50/tonne CO₂ by 2020 and USD 110/tonne CO₂ by 2030 to allow for the required abatement efforts (including investment in new nuclear, renewables, and CCS) – see IEA (2009). Carbon pricing at these levels would make onshore wind and nuclear more competitive than fossil-fuel generation (CCGTs and coal) by 2020, and would also make CCS more competitive by 2030. At lower carbon prices (e.g. USD 30/tonne CO₂), nuclear power is not commercially attractive relative to coal and gas-fired generation (using a return on capital of 10%) (IEA (2010b)).

Alternative modelling of cost-abatement options contained in McKinsey (2009) also indicates that carbon prices need to be significantly higher than current levels for new-build in coal CCS to be commercially feasible (in the range of €70 to €80/tonne CO₂ by 2015 and €30 to €45/tonne CO₂ by 2030, as a result of lower assumed capital costs for CCS plants due to assumed learning effects). To reach overall carbon-abatement targets (i.e. a worldwide reduction of 35% to 40% relative to 1990 by 2030), a global carbon price of just short of €60/tonne CO₂ would be necessary (also allowing for coal and gas CCS retrofit).

7.2.2. Technology Policy and Renewable Support

If the only market failure associated with climate change were the fact that GHG emitters do not internalise the social cost of emissions, then establishing a single carbon price would be sufficient to achieve the socially optimal outcome (with no uncertainty on the costs and benefits of abatement, as noted above). In particular, no specific support for some types of low-carbon
technologies such as renewable energy would be required. If renewable sources were needed to efficiently achieve a given abatement level, then the carbon price would increase sufficiently so as to make renewable generators competitive relative to fossil-fuel technologies (as in the cost of abatement curve shown in Figure 30).

Establishing a carbon price would represent a technology-neutral form of achieving carbon abatement without favouring some options (e.g. renewable) at the expense of others (e.g. nuclear and CCS). Indeed, a specific support policy towards renewable energy (or any other form of low-carbon generation) damages the profitability of other forms of low-carbon investment by reducing the carbon price relative to a counterfactual with no support (assuming a fixed emissions target). The reduction in carbon prices is due to the fact that renewable support increases the supply of carbon-free energy for any given level of carbon prices (see Aldy and Pizer (2009)).

However, there may be additional market failures associated with immature forms of low-carbon technologies that warrant specific and complementary support measures. In particular, innovation in low-carbon sources by a given investor may generate spillover effects on other investors which imply that the original innovator cannot fully appropriate the return from the investment.28 This spillover (or lack of full appropriability) would discourage the optimal level of R&D and/or deployment in the absence of government support (see, e.g., Hanemann (2009)). Moreover, some immature technologies (e.g. solar PV) display quite strong learning rates associated with R&D and/or deployment.29 If investors cannot fully appropriate these learning effects, again, the optimal level of investment and deployment will not be achieved.

Technology policies in favour of renewable generation can therefore be used to complement the beneficial effects of carbon prices, thus providing an additional incentive for deployment. These policies can take the form of subsidies for R&D and/or deployment. Alternatively, forms of cooperation in renewable R&D between market operators could be encouraged (as long as the risk of collusion in the product market can be mitigated).

A dual environmental policy is needed if there are two separate market failures to deal with: the direct environmental one and the innovation one. The optimal policy therefore requires a combination of both carbon pricing and technology policies. As formally shown by Acemoglu et al. (2009) and discussed in Aghion et al. (2009), using carbon prices alone will not be efficient and will raise the cost of action on climate change.

The presence of technology spillovers can, in principle, justify the adoption of both ‘push’ (i.e. R&D support) and ‘pull’ (i.e. deployment subsidies) policies in favour of some types of

28 As noted in the Stern Review, “the knowledge gained from R&D is a public good; companies may under-invest in projects with a big social payoff if they fear they will be unable to capture the full benefits. Thus there are good economic reasons to promote new technology directly” (Stern (2007), Executive Summary).

29 IEA (2008) uses learning rates of 7% for onshore wind, 9% for offshore wind, 10% for concentrated solar power (CSP) and 18% for solar PV, based on input from technology experts. McKinsey (2009) uses similar learning rates for renewable electricity.
low-carbon production, such as immature renewable generation and CCS. Ultimately, when low-carbon technologies are more mature, carbon pricing may be sufficient to encourage the entry of low-carbon sources and a more technology-neutral policy can be adopted. Figure 31, from IEA (2010a), summarises the type of policies for supporting low-carbon technologies as a function of the market deployment and maturity of each technology.

Figure 31: Policies for Supporting Renewable Technologies

Source: IEA (2010a).

In the absence of a precise quantification of the size and sources of the spillover effects, it is, however, hard to establish the optimal split between push and pull policies, and the socially desirable target for renewable deployment overall. The European Commission has committed to demanding renewable targets by 2020 (on top of a commitment to reduce carbon emissions). It is not clear, however, that technology spillover effects on their own can justify the level of these deployment targets (relative to the renewable deployment levels that would be achieved using carbon pricing alone). As Newbery (2010b) argues, the required calculations for establishing the optimal level of renewable support are hard and the country-specific targets set by the Commission may be interpreted instead as a way of “avoiding the question, encouraging solidarity and ensuring fair and equitable burden sharing” (p. 3132).

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30 Frontier Economics (2009) finds that well-designed supply-push policies (e.g. R&D support) can lead to greater marginal impact on innovation than demand-pull policies.

31 For a general discussion of this issue, see Tirole (2008).
The Design of Renewable Support Mechanisms

An additional question in the design of renewable electricity support schemes relates to the issue of which mechanism to adopt to provide effective deployment subsidies. The main dichotomy that has emerged in European practice on this issue is one between tradable quotas (or green certificates) and feed-in tariffs.

Under the first mechanism, a quota is set on renewable energy as a percentage of electricity supplied. Suppliers are obliged to meet this quota by purchasing green certificates from renewable electricity generators. Renewable producers therefore receive the price of the green certificate in addition to the wholesale electricity price, thus encouraging their deployment. “Banding” (i.e. the allocation of higher amounts of green certificates for any unit of output by a specific technology) can be used to encourage the deployment of more expensive sources of renewable generation (e.g. solar PV). A positive feature of a tradable green certificate scheme is that it is market-based, and can avoid over-compensating renewable generation. A drawback is that it may lead to volatile prices for green certificates over time (as the cost of competing renewable technologies evolves). It may not also favour the adoption of immature technologies unless appropriate banding is implemented.

Under an alternative feed-in-tariff mechanism, a fixed price is set administratively for each renewable technology for a given time period. This price lies above the expected electricity wholesale price in order to encourage entry of renewable generators. The feed-in tariff can be established irrespective of the price of electricity or be set as a premium on top of the electricity price. In the case of a feed-in premium, minimum and maximum levels for the overall compensation received can also be established, as is the case in Spain at present for some renewable technologies. The main benefit of feed-in tariffs over market-based mechanism is that they can provide greater investor certainty during the life of the investment. However, they carry the risk of over-compensating producers of renewable electricity if there is significant uncertainty on the cost of renewable generation and on learning effects over time (as the Spanish experience with solar subsidies discussed in Section 9 demonstrates).

A hybrid mechanism between green certificates and feed-in tariffs is represented by renewable capacity tenders. Under this system, periodic tenders for renewable generation (potentially differentiating between technologies) can be organised in order to set the level of the fixed tariff (or market premium above wholesale prices) that is required to meet a particular renewable generation target for that period. The fixed tariff could apply for a long time period (e.g. 25 years). If a premium over the market price is established, this could be indexed to the carbon and/or electricity price in order to reduce market risk and the possibility of under- or over-compensating renewable generators. There is, however, limited international experience of successful auctions for renewable capacity. Rules would need to be carefully designed to ensure that investors deliver on the renewable capacity commitments agreed upon as part of these auctions and that participation costs are not too burdensome for smaller investors.
Table 6 summarises the advantages and disadvantages associated with green certificates and feed-in tariffs according to a December 2008 review by the Council of European Energy Regulators (CEER (2008)). An additional high-level difference between the two systems (not included in the CEER table) is that a green certificate system can provide more certainty that a given renewable objective will be met (provided that prices are allowed to reach their equilibrium levels), whilst a feed-in mechanism gives more certainty on the cost of a renewable support scheme (as long as adequate quantity limits are in place).

**Table 6: Advantages and Disadvantages of Renewable Support Schemes According to CEER Analysis**

<table>
<thead>
<tr>
<th></th>
<th>Advantages</th>
<th>Disadvantages</th>
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<tbody>
<tr>
<td>Quota obligations</td>
<td>• Flexible and market-oriented.</td>
<td>• Greater insecurity for investors.</td>
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<tr>
<td></td>
<td>• Initiate technological developments and innovation.</td>
<td>• Volatile certificate prices.</td>
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<td></td>
<td>• Often more political acceptance.</td>
<td>• High transaction and monitoring costs.</td>
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<td></td>
<td>• Easy to expand to other countries.</td>
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<tr>
<td>Feed-in tariffs</td>
<td>• Very effective at increasing renewable energy.</td>
<td>• Not cost efficient.</td>
</tr>
<tr>
<td></td>
<td>• Few regulatory and administrative costs.</td>
<td>• Difficult to set correct fixed price or premium.</td>
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<tr>
<td></td>
<td>• Stable basic conditions.</td>
<td>• Not market oriented. However, premiums are</td>
</tr>
<tr>
<td></td>
<td>• Greater investor certainty and planning reliability.</td>
<td>more so compared to fixed tariffs.</td>
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**Additional Potential Reasons to Support Renewable Generation**

There are other potential market imperfections associated with investment in renewable generation that may justify deployment support policies. These include security of supply issues and capital market imperfections.32

The first relates partially to the fact that renewable energy is a domestic source of energy and can therefore reduce dependence on foreign (and potentially unstable) sources of supply.33 Given the public good features of security of supply, this consideration may provide further justification for a renewable support scheme (as an indirect way of limiting imports from potentially unstable suppliers).

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32 Additional considerations which do not relate to energy-related market failures include the potential benefits associated with industrial policy and employment generation. These benefits should also be assessed in comparison with other competing uses of public funds.

33 Additional security of supply considerations (relative to alternative forms of low-carbon generation, like CCS and nuclear) are that renewable sources can represent a long-term solution of energy consumption needs (unlike CCS, which requires sufficient carbon storage capacity over the medium to long term) and do not pose the type of safety and waste-management concerns associated with nuclear power.
On the other hand, the incremental security of supply benefit of renewable resources needs to be properly assessed relative to other forms of low-carbon generation which renewable energy may be crowding out over time (by lowering the carbon price). In particular, given that nuclear generation and coal-based CCS do not raise significant issues of external dependence (as both uranium and coal are easily available from a range of politically stable countries), the incremental security of supply benefits associated with renewable generation may be limited. In the short-term, however, renewable deployment may reduce dependence on foreign gas suppliers, which may improve external security of supply (especially if sufficient levels of domestic gas and electricity flexibility are available to mitigate the impact of the intermittency of renewable generation).

The second type of market imperfection relates to the riskiness of investment in low-carbon generation in the absence of a specific support scheme. Investments in low-carbon sources are particularly risky, since they are typically projects with high fixed costs and low variable costs, and whose market revenues are volatile due to fluctuations in input prices for thermal generators (i.e. oil, gas, coal and carbon). These investments lack the ‘natural hedge’ associated with thermal generators, whose marginal costs are correlated with electricity prices. Capital markets may therefore be unwilling to finance investments in low-carbon generation and prefer instead to fund more conventional generation projects. This may not represent a market failure as such, but it suggests that, in the short-term, markets may fail to deliver the levels of investments in low-carbon generation that are needed to achieve large reductions in emissions over the medium to long term. These considerations support the case for a floor on carbon prices (to apply to all investments in low-carbon technologies) or for long-term contracts (e.g. feed-in tariffs).

7.2.3. International Public Good Considerations

A third aspect of the market failures associated with climate change relates to the fact that GHG emission abatement is also an international public good. This means that if a country reduces its emissions, this benefits other countries too by reducing the risk of global warming. This can create standard free-riding incentives between countries in the absence of an international decision-making mechanism and the risk of the under-provision of global abatement efforts relative to the optimal level. Similar issues can arise in relation to technology policy, since spillovers from renewable R&D and deployment are likely to arise across borders.

A way to solve these market failures is via international coordination and agreement on both emissions and renewable targets. At European level, this process of target setting and burden sharing by country has been relatively effective in the recent past and has allowed Europe to adopt a relatively stringent set of policies on climate change (reviewed below).

At the broader international level, the process of agreeing on emission cuts has been much more difficult, as shown (for example) by the failure to agree on binding targets at the United Nations.
summit in late 2009 in Copenhagen. This is partially due to the fact that the fastest growth in carbon emissions has been observed in developing and newly industrialised countries, which face a sharper trade-off between economic growth and decarbonisation than more developed economies.

Figure 32 summarises the overall levels of energy-related CO₂ emissions across the world in 1990 and 2009 and illustrates the fact the China is currently the world largest emitter and that the fastest increase in emissions was observed in developing countries over the 1990-2009 period (with only a moderate increase in the United States and a reduction in Europe). The data also show that the European Union only accounted for a modest share of total GHG emission in 2009 (13%). In the absence of an effective and binding global agreement on GHG reductions, current European efforts in this area will only have a limited impact on climate change and will therefore prove largely ineffective.³⁴

Figure 32: International CO₂ Emissions

Note: Emission data include only coal-, oil- and gas-related emissions, and are not comparable to national emission data.

³⁴ If the global supply of fossil fuels is sufficiently inelastic, environmental policies in only some “green” countries may also not contribute significantly to reduce total GHG emissions due to price effects on fossil fuels and the resulting higher level of emissions in “non-green” countries (see CESifo (2008), chapter 5).
7.3. The Economics of Electricity Markets in the Presence of Large Amounts of Low-Carbon Generation

Electricity markets have a particularly prominent role in the implementation of environmental policy in the energy sector as a whole. This is partially because power generation is a particularly large emitter of CO₂ in that it accounts for over 40% of global energy-related CO₂ emissions, which is well in excess of any other sector (such as transport and industry). It is also because power generation has greater decarbonisation potential than other sectors, thanks to the potential large-scale deployment of renewable and CCS generation, and the presence of carbon-free sources such as nuclear. The power sector can therefore help decarbonise other industries, most notably transport (e.g. via the adoption of electric cars) and residential heating. The demand for electricity generation is therefore likely to rise as other sectors decarbonise by becoming more electricity-intensive, thereby increasing the importance of environmental policies adopted in the power sector.

Because of these considerations, it is projected that the power sector will need to decarbonise rapidly over the next few decades if climate change goals are to be met. IEA (2009) projects that, at E.U. level, the carbon intensity of generation needs to fall by more than 70% (from the current level of roughly 440 g CO₂/kWh to less than 120 g CO₂/kWh). IEA (2010) also forecasts that, by 2050, the electricity sector in OECD Europe will need to be almost decarbonised, with more than 50% of generation coming from renewable and most the remainder being sourced by nuclear and CCS. Over the next decade (i.e. by 2020), it is projected that the share of renewable in the European Union will need to increase to between 33% and 40% of total electricity consumption in order to meet the current E.U. target of overall renewable energy (which is set at 20% of final energy consumption).

The significant increase in low-carbon generation required over the short to medium term poses significant challenges for the power sector. This is so for two basic reasons. The first is that some types of low-carbon generation (in particular wind, solar PV and nuclear) have low variable costs and relatively high fixed costs.

An increase in the level of low-carbon and low variable cost capacity will therefore increase the number of hours in the year when this capacity is marginal (or price-setting). As a result, market prices will be very low (e.g. close to 0 and possibly below 0 if, for example, renewable generators actually face a positive opportunity cost from not producing due to the presence of output subsidies).

Thermal generators with positive variable costs will therefore need to recover their fixed investment and operational costs in a lower number of hours, thereby requiring higher prices in these hours. For this to be possible in a competitive market, the effective reserve margin at peak times (i.e. the difference between demand and available supply) will need to become lower over time, thus allowing peak generators to obtain higher margins when they produce. Alternatively, a separate capacity payment mechanism would be required to compensate thermal generators for at least part of their fixed costs.
In the absence of a sufficient capacity payment arrangement\textsuperscript{35} (which would stimulate entry), the price duration curves\textsuperscript{36} will therefore need to flip relative to current levels and become substantially peakier. As a result, thermal plants with positive variable costs will operate for a lower number of hours of the year. This process is illustrated in Figure 33, which plots a hypothetical price duration curve with higher levels of renewable generation in the left-hand panel (compared to a price duration curve with less renewable capacity) and the corresponding load duration curve in the right-hand panel. For simplicity, the figure assumes that flexible thermal generation is provided only by CCGT plants.

\textbf{Figure 33: Implications of Greater Amount of Renewable Generation on Electricity Prices and Load Duration Curves}

The second reason why higher levels of low-carbon generation put pressure on electricity markets is that the most important and, at present, the most cost-effective component of renewable generation is on-shore wind. Wind is by its nature an intermittent source of generation, meaning that its output is not guaranteed and fluctuates with weather conditions. High levels of wind generation therefore require corresponding amounts of flexible thermal capacity (typically, CCGT) as back-up generation in order to maintain system security.\textsuperscript{37} A system with significant levels of back-up generation may, however, not allow prices to rise sufficiently during peak times, thus reducing the ability of investors in thermal generation to recover their fixed costs and in turn limiting their incentives to enter the market.

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\textsuperscript{35} This could include direct capacity payments made to generators or long-term reserve contracts procured by the transmission system operator.

\textsuperscript{36} Price and load duration curves rank values from the highest (0\% duration) to the lowest (100\% duration) to describe the hourly profiles of prices/load over a given period (typically one year).

\textsuperscript{37} This challenge can be partially addressed by improving the forecasting of intermittent renewable generation, and by more effective interconnection of electricity markets (which can diversify the volume risk associated with renewable power).
Both of these issues are illustrated in simulations performed for the U.K. electricity market. These simulations indicate that in scenarios with significantly higher levels of wind capacity, peak prices in the United Kingdom would more than double by 2020 compared to current levels and could increase more than ten-fold by 2030 (see DECC (2009b)). Newbery (2010b) summarises the findings of a similar simulation for 2020, which indicates that, in order to meet the European renewable target, 56 GW of renewable capacity will be needed in the United Kingdom, as well as a similar amount of non-renewable capacity. The latter would largely operate in back-up mode and achieve a load factor of just over 30% (given a peak demand level of 63 GW). Ofgem, the U.K. regulator, also projects that CCGT load factors will have to fall below 30% by 2025 if renewable targets are to be met, compared to current levels in excess of 60% (Ofgem (2009)).

The overall challenge posed by integrating significantly higher amounts of low-carbon generation into electricity markets is therefore one of guaranteeing system security at the same time as providing the adequate incentives for entry by flexible generation. Investors in flexible thermal generation will need to have sufficient confidence that peak prices will be able to rise significantly during times when renewable output is low and/or demand is high. Given the likely uncertainty over whether future peak prices will be able to reach the required levels and the volatility associated with electricity prices due to the presence of intermittent generation, market forces alone might not be able to deliver the required levels of entry by thermal generation. These considerations exacerbate the ‘missing money’ problem that has been associated with electricity markets (especially in the presence of binding caps on spot prices) and provide further support for separate arrangements to remunerate capacity to supplement revenues from energy markets.38

Given the complexities involved in determining the required level of incentives for entry by thermal generation, it is, however, unlikely that an administratively set capacity payment would be able to achieve a desirable generation mix and deliver the correct level of back-up flexible generation. A system of capacity tenders or long-term reserve contracts established by the transmission system operator is likely to be a superior system to attract investment in additional thermal capacity when required. Capacity tenders could also be used to encourage entry by low-carbon capacity (including renewable, nuclear and CCS).39 Demand-side flexibility could also be procured using similar mechanisms.

The difficulty posed by an extensive use of capacity tenders is that the policy makers would be partially pre-determining the ‘right’ energy mix by specifying the levels of capacity of each technology being procured. This calls for adopting technology-neutral capacity payment

38 The 2008 report reviews the pros and cons of establishing capacity payment mechanisms in electricity markets.
39 The adoption of capacity tenders for all generation capacity (including low-carbon generation and conventional thermal capacity) is one of the policy options considered by Ofgem, the U.K. regulator, in its review of options for delivering secure and sustainable energy supplies (Ofgem (2010)).
mechanisms as far as possible. Moreover, to avoid over- or under-compensating generators (in particular those whose costs are not correlated to electricity prices, such as renewables and nuclear), indexation provisions could be introduced in the capacity payments established through the auctions. For example, these payments could be indexed to the carbon price so that, if the carbon price were to rise in the future, the additional payment from the tender would be reduced (reducing the incidence of windfall profits). Similarly, if the price were to drop, the capacity payment established would increase, thereby insulating the producer from some price volatility.

Capacity mechanisms of the type described above would not address the issue of fixed-cost recovery for existing installed capacity. In a context where there is over-capacity of thermal plants, separate arrangements may need to be put in place to allow for the recovery of fixed (but not sunk) operational costs (e.g. fixed gas access charges and O&M costs) to avoid the risk of a premature exit of plants. This could mitigate the need to introduce higher capacity payments for new plants by preserving a sufficient reserve margin.

7.4. Interactions With Other Elements of Energy Policy

The final element of the economics of climate change reviewed in this chapter is the relationship between environmental policies in the energy sector and the other two core components of E.U. energy policy: security of supply and competition and liberalisation. The three policies interact in various ways: they are complementary in some respects, and create tradeoffs that need to be resolved in others.

In the recent past, environmental policies and external security of supply have not been entirely mutually compatible due to the fact that gas was the most easily available source of relatively low-carbon generation (compared to coal), but it was largely sourced from external suppliers (e.g. Russia and Algeria). This potential conflict between the two policy objectives is set to diminish over time, given that, in order to meet increasingly ambitious emission targets, gas-fired generation will play a smaller role (at least in terms of overall output) and domestic resources (renewable, and to some extent nuclear) should become more prominent. Moreover, coal-based CCS would help mitigate external security of supply issues, since coal supply is more easily and widely available internationally than gas.

However (as discussed above), gas-fired generation will still be needed as a source of back-up generation, at least in the transition to an entirely decarbonised market. This means that gas contracts with foreign suppliers will need to become more flexible and that additional investments in domestic gas storage capacity will be needed.

Moreover, internal security of supply may be negatively affected by the higher share of renewable generation required to meet environmental objectives due to the intermittent nature of most renewable energy. This creates some tension between the two policy objectives that may need to
be mitigated by devising appropriate capacity payment mechanisms and investing more in domestic flexibility (again, gas storage infrastructure, but also electricity-pumped storage capacity) and interconnection across Europe.

Competition policy and environmental policy should broadly be seen as complementary in most circumstances. This is because competition policy (and more effective regulation in general) aims to render energy markets more efficient and reduce the overall cost of the system. It therefore plays an important role in ensuring that the transformation towards a low-carbon market is achieved at the lowest possible cost. This is particularly so given that it is likely that pursuing the current European environmental objectives will increase total electricity costs significantly by increasing reliance on more expensive sources of generation. In a context of rising overall costs, keeping prices as close to variable cost as possible (which is one of the basic aims of competition policy) becomes even more important in order to reduce the impact of environmental policies on consumers.

However, it will also be increasingly important not to necessarily conflate instances of high energy prices (e.g. during times of system stress) with the exercise of market power by energy firms. Energy prices will need to be able to respond to peak market conditions in order to provide the correct signals of economic scarcity and reward investment in infrastructure (e.g. new thermal generation capacity), which may only or primarily be required during peak periods. Competition policy and/or regulation will need to be applied carefully so as not to distort these market mechanisms.

This consideration is actually likely to make it all the more important to have competitive markets in place (both in terms of vertical and horizontal structure) to give policy makers and consumers the confidence that the internal energy market is not distorted by the presence of operators with significant market power.
This chapter of the report reviews the fundamental elements of E.U. environmental policy and its performance to date (with a specific focus on Spain where appropriate). It does so by distinguishing between two basic periods: the one from 1990 to 2010, which corresponds roughly to the reference period of the Kyoto Protocol; and the period between 2010 and 2020, which represents the main reference period for the current environmental targets set at E.U. level.

8.1. Phase I of E.U. Environmental Policy: 1990-2010

During the 1990-2010 period, E.U. environmental policy was characterised by three main elements, which are reviewed below:

i. A commitment under the Kyoto protocol to reduce GHG emissions by 8% during the 2008-2012 period relative to 1990.

ii. The establishment of Europe-wide carbon pricing through a cap-and-trade mechanism known as the Emission Trading System (ETS) to facilitate the reduction in carbon emissions and encourage the entry and production of low-carbon technologies.

iii. The adoption of a 12% target on the share of renewable energy in gross primary energy consumption by 2010, coupled with country-specific targets on the share of renewable generation in total electricity consumption by the same year.

8.1.1. The Kyoto Targets on GHG Emission Reductions

Under the Kyoto Protocol (initially adopted in 1997 and ratified by the European Union in 2002), the E.U.-15 countries committed to reduce their overall GHG emissions by 8% during the 5-year period between 2008 and 2012 relative to the 1990 base year. This commitment was met by a combination of a reduction in emissions and other mechanisms available under the Protocol.40

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40 These include the use of flexible mechanisms (e.g. acquisition of emission allowances from other parties to the Protocol, and project-based credits under the Clean Development Mechanism) and ‘carbon sink removals’ (e.g. through improved forest management).
By the end of 2009, GHG emissions in the E.U.-15 were roughly 13% below the base level established under the Kyoto protocol and therefore well on track to meet the commitment (see Figure 34, left-hand panel). This performance was partially due to the economic crisis of 2009, which lowered E.U.-15 GHG emissions by almost 7% relative to 2008 (ETC/ACC (2010)). For the E.U.-27 as a whole, GHG emissions in 2009 were 17.3% lower than in 1990, largely due to the economic transformation of Eastern Europe over the period, the switch to gas-fired generation in some markets (most notably the United Kingdom) and the recent economic downturn.

The overall reduction in E.U.-15 emissions masks the difference in performance across Member States. During the 1990-2008 period (for which complete country-specific data are available from the European Environment Agency), emission reductions in Germany and the United Kingdom alone (approximately 430 million tonnes (Gt) of CO₂-eq.) more than explained the overall reduction experienced at E.U.-15 level (-295 Gt), and compensated for the increases observed in Spain (116 Gt), Italy (25 Gt) and the rest of the E.U.-15 (24 Gt) (EEA (2010)). These figures are shown in the right-hand panel of Figure 34.

Figure 34: European Performance Under the Kyoto Targets, 1990-2009
(million tonnes of CO₂-eq.)

Source: EEA; ETC/ACC; Ministerio de Medio Ambiente.

Emissions in Spain in 2009 were close to 30% above the Kyoto base year, well above the 15% increase allowed for Spain under the European burden-sharing mechanism. The relative discrepancy between Spain’s actual change in emissions and its burden-sharing target was the largest across the E.U.-15 in 2008. Spain plans to bridge the gap between its emissions
and its target by relying on the flexibility mechanisms available under the Kyoto Protocol. The gap between Spain’s emissions and its Kyoto target narrowed during 2009 due to the continued increase of renewable generation and (most notably) the economic downturn in 2009. These factors accounted for an 8% reduction in emissions in Spain relative to the previous year.

The European Environment Agency projected during 2009 that E.U.-15 could outperform the Kyoto target by between 0.5% and 5% of base year emissions, depending on the mix of policies and the use of the Kyoto mechanisms being adopted (EEA (2009)). These projections were significantly affected by the economic crisis and the close to 7% reduction in E.U.-15 emissions experienced in 2009. This reduction will allow the E.U.-15 to meet its Kyoto Protocol targets more easily, but is likely to represent a largely one-off decrease that cannot be easily extrapolated into the future.

8.1.2. The Emission Trading System (ETS)
The ETS established in Europe in 2005 represents one of the fundamental elements of European environmental policy. The ETS is a cap-and-trade scheme which establishes a price for CO₂ emissions within the European Union. It currently includes roughly 40% of total GHG emissions in Europe and close to 50% of its CO₂ emissions.

The ETS has so far included two phases: Phase I from 2005 until 2007; and Phase II, which is scheduled to run from 2008 until 2012 (inclusive). A third phase is scheduled for the 2013-2020 period. Under the first two phases, allowances have been allocated to the CO₂ emitters included in the scheme mostly for free, thus allowing them to trade these permits among themselves with the purpose of establishing a transparent and unique price for carbon (in line with the economic theory of carbon pricing reviewed above).

The emission target contained in Phase I of the ETS was in excess of actual emissions in 2005-2007 and therefore did not represent a constraint from an economic perspective (even though it was legally binding). This excess in allocations was due to difficulties in collecting adequate data on historical emissions, resulting in an over-estimate of past emissions and, therefore, an emissions target that was too high (relative to a business-as-usual benchmark). The over-allocation of permits, coupled with the lack of banking across Phases I and II, led to a collapse in the price of E.U. CO₂ allowances at the end of Phase I (see Figure 35). For Phase II, the target has been set at roughly 6.5% below 2005 levels to facilitate compliance with the Kyoto Protocol (European Commission (2008a)).

CO₂ prices under Phase I of the ETS fluctuated between maximum monthly levels of over €25/tonne CO₂ in early 2006 and effectively 0 for most of 2007. During Phase II, prices initially recovered to €20-€25/tonne CO₂, but fell subsequently due to the impact of the economic downturn, and have stabilised at around €15/tonne CO₂ since mid-2009.
The creation of the ETS has established a transparent price for carbon across Europe and allowed for efficient carbon trading to take place. As such, it will be a key mechanism to facilitate efficient compliance with the European Union’s current environmental targets during the 2010-2020 period.

However, the initial design of the ETS was flawed in some important respects. Most notably, over-allocation of permits in Phase I undermined the validity of the scheme in that phase and the price signal that it was able to deliver. Moreover, the free allocation of allowances to electricity generators and other large emitters during the first two phases directly created large windfall profits during periods when CO2 prices were positive. These profits arose from the fact the wholesale electricity price reflected the opportunity cost of the permits (as it should in a competitive market), but thermal generators did not actually bear the cost of purchasing the permits. This over-compensated producers for the introduction of carbon pricing and effectively increased the resulting costs faced by consumers. The shift to full auctioning of permits in the power sector in most E.U. countries from 2013 onwards (reviewed below) will reverse this effect (for thermal generators) and will imply that some emitters (coal plants in particular) will become net losers from the existence of the ETS.
8.1.3. E.U. Renewable Targets for 2010

In addition to the introduction of carbon pricing in 2005, the European Union also pursued a specific policy in favour of renewable sources of energy. This was initiated in 1997 with the publication of the White Paper on Renewable Sources of Energy (European Commission (1997)). In this paper, the European Commission established a strategy aimed at achieving a share of renewable energy sources in gross inland consumption of 12% by 2010 for the European Union as a whole. Gross inland energy consumption includes the consumption of all energy sources, including oil, solid fuels (such as coal), natural gas, nuclear and renewable sources. It is therefore a broader measure than just electricity consumption (which in turn relies on the primary energy sources that form part of overall energy consumption). The 12% target implied more than doubling the contribution of renewable energy relative to 1995 (when the E.U. share stood at 5.3%, as reported in the 1997 White Paper).

In September 2001 the European Commission established further renewable targets specific only to electricity in a directive on the promotion of electricity produced from renewable energy sources in the internal electricity (Directive 2001/77/EC). This directive contained indicative targets for each Member State on the proportion of gross national electricity consumption to be sourced from renewable sources by 2010. These electricity targets were set in order to comply with the overall target of 12% of energy consumption contained in the White Paper, thereby implying the need for over 20% of renewable electricity consumption across the E.U.-27 by 2010.

The 2010 targets contained in the 2001 Directive varied across countries to take into account differences in the starting levels of renewable electricity in each Member State. The targets range from a share of 10% or less in Belgium, Hungary, the Netherlands and the United Kingdom, to 30% or more in Austria, Finland and Sweden. For Spain, the Directive indicated a target of 29.4% of final electricity consumption, which was in line with Spain’s Renewable Energy Plan of 1999.

The performance of the European Union as a whole and Spain in particular with respect to the overall renewable electricity targets is summarised in Figure 36. The share of wind generation in the European Union and in Spain is also plotted (on the secondary axis).
The European Union as a whole achieved a 16.7% share of renewable generation in 2008 (up from 12% in 1990). Preliminary estimates for 2009 (based on Eurostat data) indicate that the corresponding share for 2009 increased to over 18%, which, however, remained short of the target of 21% for 2010. Countries that performed well relative to their renewable electricity targets include Denmark, Germany and Hungary, based on the European Commission review of April 2009 (European Commission (2009)).

The percentage of renewable generation in Spain stood at around 21% in 2008 (up from an average level of 18% in the 2001-2007 period) and was estimated to have further increased to roughly 27% in 2009 (based on data published in REE (2010), described in more detail below) due to the continued growth in renewable electricity and the reduction in demand. Part of the superior performance of renewable electricity in Spain relative to the rest of Europe can be attributed to the role played by wind generation, which accounts for close to 14% of consumption in Spain (well above the average level of 4% achieved in the E.U.-27).

Different renewable support schemes have been employed across the European Union to subsidise renewable generation and encourage the achievement of E.U. targets. As reviewed by Lorenzoni (2010), the majority of E.U.-15 countries (11 out of 15) have adopted either a feed-in tariff mechanism and/or a premium tariff system (whereby the renewable subsidy is paid on top of market prices). Only four E.U.-15 countries (Belgium, Finland, Sweden and the United Kingdom)
have relied primarily on alternative systems such as green certificates and fiscal incentives to promote renewable generation. As discussed in the next chapter of this report, Spain has used a mixture of feed-in tariffs and premium tariffs to support renewable generation.

The European Commission reviewed the relative performance of different renewable support schemes in 2008 (European Commission (2008b)). It found that feed-in tariffs had been more successful than green certificates in promoting deployment of renewable generation and did so at a lower cost in the year that was analysed (2006). The Commission also highlighted the Spanish mechanism as being particularly effective in promoting wind generation, even though this came at a cost relative to comparable schemes in other countries (e.g. the Spanish remuneration for wind energy generated higher profit margins than in all other feed-in schemes with the exception of Hungary and the Czech Republic).

8.2. Phase II of E.U. Environmental Policy: 2010-2020

European climate change policy has been substantially revised and made more stringent for the period after 2010. The overarching principles for this revision were contained in the Commission’s climate and energy package approved by the European Union in 2008. This package includes three key targets:

i. Reducing total E.U.-27 GHG emissions by 20% by 2020 (relative to 1990 levels) with a further commitment to implement a 30% reduction in the context of a successful international negotiation on global emission cuts.

ii. Reaching a 20% level in the use of renewable sources in gross final energy consumption by 2020 (up from a level of just over 10% in 2008). This target implies achieving a percentage of renewable electricity of between roughly 33% and 40%, depending on the country.

iii. Reducing primary energy consumption by 20% of projected 2020 levels by improving efficiency.

The climate and energy package was followed by two specific directives in April 2009 aimed at implementing the Commission’s targets:

• **The ETS Directive (2009/29/EC).** This directive establishes that emission allowances set in the ETS will be reduced by 21% below their 2005 levels by 2020 (in excess of the required reduction in overall GHG emissions during the same period). This change will be implemented from 2013 onwards (Phase III) with full auctioning of permits for the power sector in most Member States and a gradual phasing out of free allowances for other sectors under the ETS. The ETS is also set to be expanded in 2013 to include the aviation sector.
The Renewable Energy Directive (2009/28/EC). Under this directive, the 20% target of renewable energy sources by 2010 contained in the climate and energy package was translated into specific binding targets for each Member State. The target for Spain was set at 20%, which is therefore in line with the average level to be achieved across the European Union.

The new climate package broadly follows the same architecture of previous E.U. environmental policies, but with more stringent targets and a substantial revision to the ETS. The 20% reduction in emissions by 2020 implies an acceleration of carbon-cutting efforts relative to those observed during the 1990-2008 period (when E.U.-27 emissions fell by 11% over a longer time period and in part due to the one-off economic restructuring of Central and Eastern Europe). On the other hand, the economic downturn of 2009 contributed to a situation where current GHG emission are already 17% below 1990 levels, thus implying that the 20% reduction is likely to be easier to achieve than was originally anticipated.

The 21% reduction in CO\textsubscript{2} allowances under the ETS by 2020 (relative to 2005) also represents a significantly faster reduction than the 6.5% cut implemented in the first two phases of the scheme (between 2005 and 2012). However, the mechanics of the ETS (coupled with the economic downturn of 2009) is likely to soften the impact of the reduction in emission permits. In particular, as shown by the IEA (2009), the surplus of CO\textsubscript{2} allowances that is likely to arise during Phase II of the ETS due to the recession can be ‘banked’ into Phase III, thereby allowing countries to emit more than the Phase III cap would suggest. The IEA estimates that, by the end of Phase III of the ETS in 2020, emission levels may actually be at levels similar to 2008, mainly due to reliance on the banking of credits. The absence of a reduction in emissions by 2020 would make it harder (and costlier) for the European Union to achieve the required cuts in carbon emissions for subsequent periods (e.g. by 2030). This mechanism also risks depressing carbon pricing up to 2020 and discouraging investment in low-carbon technologies.

Because of these potential concerns, in May 2010 the Commission analysed a unilateral move to increase its commitment to reduce GHG emissions to 30% by 2020, up from the current targeted reduction of 20% (European Commission (2010b)). According to the Commission’s analysis, the economic crisis of 2009 lowered the cost of achieving the original 20% target and also rendered that target less incisive in driving forward the required structural changes.

A more stringent 2020 target would also be in line with the IEA analysis for Europe in its “450 ppm scenario” (which is compatible with environmental objectives). This scenario suggests the need for an overall reduction in CO\textsubscript{2} emissions in excess of 20% by 2020 (without allowing for banking of excess allowances from the current period) and a reduction of over 30% in the power sector relative to 2007 (well in excess of the reduction in ETS allowances of 21% over roughly the same period); see IEA (2009).

In terms of the required electricity mix (see Figure 37), the IEA suggests that by 2020 over 30% of electricity should come from renewable sources, roughly in line with the target in the 2009 Renewable Energy Directive. This analysis indicates that, if the European emission targets for
2020 are to be tightened, this should not be implemented by further increasing the share of renewable energy.

The IEA projections for 2020 also indicate the need for a stable share of nuclear output by 2020 (relative to 2008) and a slight increase by 2030. Given the expected increase in electricity demand (15% in 2030 relative to 2007), this will require new nuclear plants to replace decommissioned plants and allow for some net growth in nuclear generation (roughly 20% relative to current levels).

Figure 37: Electricity Generation Mix, IEA Scenarios for 2020 and 2030 (E.U.)

Finally, in relation to the revised ETS design in Phase III, the move to full auctioning for the power sector and an increase in auctioning overall is a positive adjustment to the scheme. It will prevent windfall gains being generated for carbon emitters (but not for non-emitters) at the same time as it creates a pool of resources that can be used to finance emission-reducing activities (e.g. CCS demonstration projects, as is the case under the ETS Directive, and renewable technology policy). The introduction of banking across Phase II and Phase III will also improve the efficiency of the price signal provided by the ETS.
Spanish energy policy towards the environment has largely centred on the promotion of domestic renewable resources. To date, Spain has not actively encouraged other forms of low-carbon generation, such as nuclear power, even though its electricity system still relies on nuclear plants to a significant extent. Moreover, whilst this has not been an explicit focus or outcome of environmental policy, the shift in the generation mix from oil and (more recently) coal to gas-fired plants in Spain has significantly improved the overall environmental performance of the system. This chapter of the report focuses on Spanish energy policy towards the environment, mainly concentrating on renewable policy, but also commenting on related measures taken with respect to other generation technologies (coal, nuclear and gas).

9.1. Spanish National Renewable Plans: Targets and Performance

Spanish policy towards renewable energy sources has been set out in different national plans for the promotion of renewable energy. The first such plan (the Plan de Fomento de las Energías Renovables en España - PFER) was published in 1999. This plan set a target on the share of renewable electricity of 29.4% by 2010, which was subsequently adopted in the European Directive on renewable electricity of 2001. This target was based on the combination of a forecast for renewable electricity growth (increasing from roughly 20 TWh in 1998 to 77 TWh by 2010) and a projection of moderate growth in energy consumption. In practice, consumption growth exceeded the levels forecasted in PFER 1999, which prompted a revision of the plan in 2005 with more aggressive targets on renewable generation, which were increased to roughly 100 TWh by 2010.41

In June 2010, Spain extended its renewable energy plan to the 2011-2020 period, in compliance with the 2009 European Directive on renewable energy. Under the revised plan (Plan de Acción Nacional de Energías Renovables de España - PANER 2010), roughly 153 TWh of renewable

41 The overall gross generation forecast for 2010 was increased from 288 TWh in the original PFER to 334 TWh in the revised version of 2005.
electricity is forecasted to be required by 2020, representing approximately 38% of total gross generation.

The targets set in the three plans and the actual levels of renewable electricity deployment reached in 2009 are summarised in Figure 38 below (left-hand panel), together with the historical evolution of renewable generation in mainland Spain during the 1998-2009 period (right-hand panel).

Figure 38: Renewable Generation Levels and Targets, 2009, 2010 and 2020 (left-hand panel); and the Evolution of Renewable Generation in Mainland Spain, 1998-2009 (right-hand panel) (TWh)

Note: Conventional hydroelectric energy excludes an estimate for pumped storage generation (set at 70% of pumped storage consumption). Source: PFER 1999, PFER 2005, PANER 2010, REE.

Total renewable generation in Spain stood at roughly 76 TWh in 2009 (including the islands)\(^{42}\), with gross consumption of 280 TWh, implying that just over 27% of national consumption was sourced from renewable generation. The non-hydroelectric element of renewable generation (which represents the largest component of renewable production under the special regime) significantly outperformed the original 2010 targets contained in the PFER of 1999 (by more than 25%).

\(^{42}\) The level of 76 TWh of renewable generation in 2009 excludes an estimate for pumped storage generation.
Actual renewable generation levels in 2009 are very close to those envisaged in the original 1999 Plan (as shown in Figure 38), with the shortfalls in conventional hydroelectric generation and other forms of renewable electricity (primarily biomass) being offset by surpluses in wind and solar output (15 TWh and 6 TWh, respectively).

In terms of the historical evolution of renewable generation in mainland Spain, between 1998 (when the market was liberalised) and 2009, renewable generation effectively doubled, going from 38 TWh to 75 TWh. The explicitly subsidised element of renewable generation (which is included in special regime generation, as discussed below) accounted for all of this growth, in that it increased almost ten-fold, from 6 TWh to 53 TWh. Three quarters of the increment in subsidised renewable generation was due to wind power (which increased from 1 TWh in 1998 to 37 TWh in 2009), followed by solar power (which accounted for 14% of the increment, i.e. close to 7 TWh, almost entirely due to the growth experienced by photovoltaic solar output in 2008 and 2009).

The 2009 levels are below the 2005 revised renewable targets for 2010, partially because the wind targets were revised upwards substantially in 2005. However, gross generation in 2009 was also below the levels predicted for 2010 in the 2005 updated plan (roughly 14% lower), meaning that the original target of 29.4% of renewable electricity by 2010 could be met, depending on the outturn for demand and renewable output in 2010.

Total renewable energy as a percentage of primary energy consumption stood at 9.4% in Spain in 2009 (according to PANER 2010), up from just over 5% in 1995 but still below the 2010 European target of 12%.

In the 2020 projections developed by the Spanish government in PANER 2010, overall renewable generation is projected to double compared to the levels achieved in 2009, with the fastest growth elements being solar energy (projected to quadruple), wind (projected to double) and biomass (also forecast to double). The overall share of renewable energy in gross generation is expected to increase to 38%, almost a 50% increase compared to the current share.

Wind and solar PV generation in Spain have grown very rapidly in recent years also when compared to the performance of other E.U. countries, as summarised in Figure 39 below. In 2009 Spain accounted for over a quarter of all wind capacity in E.U.-27, well above its share of total generation, which was below 10%. It was second in Europe only to Germany in terms of the level of total installed capacity in 2009, even though during the 2004-2009 period wind capacity grew more in Spain than in any other E.U. country (in absolute terms). Wind output reached close to 14% of total mainland generation in Spain, in excess of the contribution made by coal and hydro generation individually (but still below CCGT and nuclear generation).

In terms of solar PV, Spain accounted for over 20% of total E.U.-27 capacity in 2009, again well in excess of its share of total generation. Also in this case, it was second only to Germany in terms of total installed capacity, but by a greater relative margin compared to wind.
remarkable rise of PV capacity in Spain in 2008 was confirmed by the fact that in 2008 Spain alone accounted for close to 50% of total PV installations in the E.U.-27 (due to the legislation introduced in Spain in mid-2008, as discussed below).

Figure 39: Evolution of Wind and Solar PV Capacity in Spain and Other E.U.-27 Countries, 2004-2009

9.2. Evolution of Legislation on Renewable Support

Spanish legislation on the energy sector provides for a special regime that includes all generation subsidised above the market price in Spain. This includes most renewable generation sources (with the exception of conventional hydro) and also co-generation plants (primarily based on gas). The legislation governing special regime generation has been the main mechanism through which the Spanish electricity system has promoted the growth of renewable electricity since market liberalisation.

Special regime generation was first established in December 1994, before the electricity market was opened to competition. The framework for special regime generation has evolved significantly since then through a series of legislative interventions which are summarised in Table 7.
Table 7: Evolution of Legislation on Special Regime Generation, 1994-2010

<table>
<thead>
<tr>
<th>Legislation</th>
<th>Main Provisions</th>
</tr>
</thead>
<tbody>
<tr>
<td>RD 2366/1994, December 1994</td>
<td>Defines special regime generation as all non-hydro renewable plants with capacity of less than 100 MW, small hydro (less than 10 MW), and co-generation. Special regime plants can sell their output to distribution companies at regulated price.</td>
</tr>
<tr>
<td>Law 54/1997, November 1997</td>
<td>Defines special regime generation within the context of the newly liberalised market. Sets out the general principle of encouraging special regime generation to meet environmental and security of supply objectives.</td>
</tr>
<tr>
<td>RD 2818/1998, December 1998</td>
<td>Establishes the feed-in mechanism for special regime. Feed-in tariffs are set to equal the wholesale market price plus a subsidy that is differentiated by technology. Plants have the ability but no obligation to bid their energy into the market.</td>
</tr>
<tr>
<td>RD 436/2004, March 2004</td>
<td>Establishes two remuneration mechanisms for most types of special regime generation: feed-in tariffs (set as a percentage of a benchmark electricity tariff, by technology); and premium tariffs (set as a premium on the market price for plants participating in the wholesale market). Feed-in tariffs and premia are to be revised every 4 years, on a non-retroactive basis.</td>
</tr>
<tr>
<td>RD 661/2007, May 2007</td>
<td>Sets feed-in tariffs and premium tariffs in absolute terms (c/kWh) rather than as a percentage of a benchmark electricity tariff. Introduces caps and floors on total remuneration under the market option. Increases remuneration of solar PV plants with capacity of between 0.1 and 10 MW.</td>
</tr>
<tr>
<td>RD 1578/2008, September 2008</td>
<td>Modifies remuneration mechanism for solar PV installations by reducing the feed-in tariff and establishing a system of quarterly quotas to determine the evolution of feed-in tariff levels.</td>
</tr>
<tr>
<td>RD 1003/2010, August 2010</td>
<td>Provides for inspections of solar PV plants to ensure compliance with the required conditions to qualify for the subsidy set in RD 661/2007.</td>
</tr>
</tbody>
</table>

Note: RD stands for Royal Decree.

Spain opted for a feed-in tariff mechanism for the promotion of renewable energy since inception. This mechanism was, however, significantly refined through the changes introduced in 2004 and in 2007.

The 2004 reform introduced an option that encouraged most types of special regime generation (including, most notably, wind and co-generation) to participate in the wholesale market. This option proved to be very attractive, given the level of spot market prices. Whilst in 2004, before RD 436/2004 was introduced, less than 20% of special regime generation was selling its output to the market, by 2006 this share increased to more than 70%. In 2009 it stood at 73% of total sales. Further incentives for effective market integration (such as mandatory production forecasting and penalty charges for imbalance) were also introduced.

The 2004 decree was economically more attractive than the previous regime (under RD 2818/1998). This is shown by the fact that most special regime plants that started operating under RD 2818/1998 switched to the new mechanism when it became available (total generation sold under RD 2818/1998 fell from over 24 TWh in 2004 to less than 7 TWh two years later).
The market option introduced by the 2004 decree was particularly attractive for wind generation, with the resulting subsidy above the market price increasing by between 40% and 75% during the 2004-2007 period relative to the tariffs established under RD 2818/1998 (with the exception of 2006, when the subsidy levels under the two decrees were similar).

RD 661/2007 further amended the special regime mechanism in two significant aspects. The first was that it reduced the uncertainty faced by investors in special regime generation by expressing the subsidy and premium levels in absolute terms rather than by reference to a notional tariff that was subject to change. This significantly reduced the price risk faced by investors. The introduction of a maximum and minimum level of remuneration for generators opting to bid into the market further reduced risk for investors at the same time as it reduced the likelihood of over-compensating special regime generators in the event of high market prices (relative to the efficient cost required to meet a given target).

The second important aspect of RD 661/2007 was that it maintained the high levels of feed-in tariffs for solar PV installation (more than €400/MWh) and also extended this level to plants with capacity of between 0.1 and 10 MW (the previous size limit was 0.1 MW). It also preserved the existing target for total solar PV capacity under the PFER at just over 370 MW. In addition, the decree stipulated that feed-in tariffs would be adjusted after reaching 85% of the renewable deployment target for each technology and that tariffs would be maintained for at least one year following completion of 85% of the target.

These provisions – coupled with the guaranteed absolute level of feed-in tariffs introduced by RD 661/2007 and the absence of a binding quantity limit on total capacity – prompted massive new-build of solar PV plants in order to benefit from the high level of feed-in support before the overall target in the PFER was reached. Solar PV capacity increased from 275 MW in May 2007 (when RD 661/2007 was introduced) to 3,120 MW in September 2008 (when its validity lapsed). The original target of just over 370 MW of PV solar capacity set in RD 661/2007 was met in the 2 months after the introduction of the new legislation. By the end of 2009, solar PV capacity stood at 3.5 GW, almost 10 times more than the original PFER target.

The rapid growth of solar PV capacity over this period raised concerns that some of the new capacity may have not fully complied with the requirements set out in RD 661/2007 to qualify for the subsidy payments. This led to the introduction of specific legislation in August 2010 (RD 1003/2010), which aims to detect any irregularities in the installation of solar PV facilities and may lead to the reduction or removal of the subsidy for some plants.

The reform of solar PV remuneration introduced in September 2008 led to much lower feed-in tariffs. RD 1578/2008 initially cut the tariff for ground installations by almost one quarter (from €420/MWh to €320/MWh). It also introduced a system of periodic tenders for pre-specified amounts of new capacity aimed at limiting the amount of new capacity benefiting from high subsidies and establishing a mechanism for reducing tariffs if tenders are over-subscribed. Six such tenders took place by mid-2010 for ground installations, with capacity in each tender
ranging between 50 MW and 95 MW. All of these tenders were over-subscribed, thus resulting in a feed-in tariff of €265/MWh by mid-2010, 37% below the level paid under RD 661/2007. The corresponding tariff for large roof-top installations (> 20 kW) also fell to below €300/MWh as a result of the reforms introduced by RD 1578/2008.

Overall, the rapid levels of growth of wind and, more recently, solar power experienced in Spain can be attributed to a significant extent to the legislative framework present in Spain, coupled with generally favourable market conditions (e.g. rising electricity prices for most of the period, low interest rates and falling equipment costs). The special regime mechanism offered attractive feed-in tariffs coupled with beneficial features such as the presence of a favourable market option (introduced in 2004) and limits on the degree of market-risk faced by investors (introduced in 2007). The resulting increase in renewable generation has, however, come at a social cost in terms of considerably increasing the level of the total subsidies paid to renewable facilities, as examined in the next section of this chapter.

9.3. Levels of Subsidy Paid to Special Regime Generation

The total amount of subsidy paid to special regime generation over and above the market price increased considerably in Spain from roughly €1.2 billion in 2005 to over €6 billion in 2009 (see Figure 40, left-hand panel). This five-fold increase in the overall subsidy was due to a number of factors, including the growth of total special regime generation in this period, the change in its composition (with the growing weight of solar PV) and the increase in feed-in tariffs relative to the market price (which increased the implied subsidy, most notably in 2009).

In terms of total payments (i.e. the sum of the market price and the subsidy), the remuneration of special regime generation increased from just over €4 billion in 2005 to roughly €9 billion in 2009, with the average payment rising by almost 40% (from €83/MWh in 2005 to €114/MWh in 2009).

Overall, the special regime subsidy as a percentage of total wholesale expenditure (i.e. defined as market expenditure plus the cost of special regime subsidies) shot up from 15% or less prior to 2009 to over 35% in 2009, as a result of the increase in subsidy payments and also the drop in wholesale expenditures due to low market prices (see right-hand panel of Figure 40). Even at average market prices (e.g. taking an average of spot prices in the last 5 years), the total subsidy stood at close to €5 billion in 2009, equivalent to 25% of total wholesale expenditure (evaluated at the higher notional market prices).
A notable feature of the recent evolution of the payment to special regime generation is the role played by solar PV following the introduction of RD 661/2007 (summarised above). The subsidy paid to solar PV capacity accounted for more than 40% of the total subsidy payment in 2009, even though solar output represented only 8% of special regime generation (the corresponding levels for 2007 were of 9% and 1%). Solar PV also accounted for over 60% of the increase in both total payments and total subsidies to special regime generation between 2007 and 2009.

The data summarised above suggests that the level of subsidy paid to special regime generation may have reached potentially unsustainable levels by 2009, primarily as a result of the impact of the remuneration paid to solar PV power in 2008 and 2009.

One way to assess the affordability of special regime remuneration is to compare it with the annual tariff deficit in the system (i.e. the shortfall between regulated revenues and costs, where the latter includes the special regime subsidies). It is, of course, impossible to identify a single cause for the existence of an annual tariff deficit in Spain, since it is the result of multiple factors and has characterised the Spanish electricity market for most of the last 8 years. However, the recent increase in renewable support was the primary contributor to the high annual deficit level experienced in 2009 (and in part in 2008). In particular (as shown in the left-hand panel of

43 For a general discussion of the electricity tariff deficit, see Section 5 of this report.

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Figure 41), prior to 2009 the subsidy to special regime generation only accounted for a part of the deficit (with the exception of 2007, when the annual deficit was fairly low and special regime subsidies were high due to low wholesale prices). However, in 2009, the subsidy was well in excess of the tariff deficit, even though the tariff deficit was of considerable magnitude (in excess of €4 billion before the adjustments identified by the CNE, as discussed in Section 5). The increase in solar PV subsidies and payments between 2007 and 2009 alone (roughly €2.4-€2.6 billion, depending on the measure) accounted for 55%-60% of the gross annual tariff deficit in 2009.

Another potential way to assess the sustainability and effectiveness of the payments to special regime generation is to compute the implied social cost in terms of the CO₂ emissions avoided through subsidised renewable generation and compare it to the market price for CO₂ (which, in principle, reflects the social value of carbon abatement at the prevailing emission targets). This analysis is presented in the right-hand panel of Figure 41, which estimates that renewable generation avoided roughly 18 million tonnes of CO₂ in 2009 (equivalent to roughly 25% of actual emissions by the electricity sector). Given the magnitude of the subsidy payment, this reduction in emissions came at a cost of roughly €250/tonne CO₂ (or approximately €210/tonne CO₂ if the subsidy is evaluated at a higher spot price in line with the average level in the last five years). The implied value of carbon emissions avoided through renewable generation was therefore several-fold higher than the market price (which stood at €15/tonne CO₂ in mid-2010).

For reasons discussed earlier in this report, there are reasons to suggest that the current level of carbon pricing may be too low (in part due to the presence of renewable support policies) relative to the socially optimal levels required by 2020 and beyond to support investment in low-carbon technologies. Moreover, the promotion of renewable generation should primarily seek to resolve other externalities not captured in the carbon price, such as technology spillover effects and potential security of supply considerations. Notwithstanding these issues, an implied carbon price of €210-€250/tonne CO₂, which is 14-17 times above current market prices, suggests that the renewable subsidy levels paid in Spain in 2009 were likely to be excessive relative to their social contribution.

44 This conclusion also holds if the special regime subsidy in 2009 is computing by assuming a higher spot market price (i.e. the average of the last five years).
45 The cost to consumers of renewable support will be lower than the level computed here, since additional renewable generation lowers market prices and therefore reduces the infra-marginal rents earned by conventional generators in the market to the benefit of electricity consumers (at least in the short to medium term before the generation mix adjusts to the change in spot prices).
46 This assumes that renewable generation displaces CCGT plants, which is a broadly reasonable assumption for the Spanish electricity market.
47 The incremental cost avoided by displacing thermal generation should also be factored into this calculation. This benefit is, however, unlikely to significantly exceed the value of renewable generation at market prices (unless the thermal supply curve is very steep). This means that the computation of the implied carbon price based on the level of renewable subsidies (rather than the level of total payments) described in the main text is unlikely to substantially overstate the social cost of renewable support.
In summary, Spanish policy towards renewable generation has facilitated very rapid growth of this type of generation, most notably in the form of wind and (more recently) solar power. Despite high growth in electricity demand (relative to other European countries), Spain is effectively on track to meet its original 2010 target of sourcing close to 30% of its demand via renewable generation. This result has, however, come at a significant cost to the system, most notably due to the high levels of subsidies paid to solar PV generation in 2008 and 2009. Subsidies to wind generation were more moderate, especially in comparison to the contribution made by this technology to total renewable generation. The apparent over-compensation of solar PV generation in Spain highlights the dangers of relying on imperfectly designed feed-in tariffs in situations where policy makers do not have full information on the costs of each technology and do not put ‘safety valves’ in place (e.g. a binding quantity limit) to guard against the risk of over-compensation. These considerations also highlight the benefit of greater reliance on market-based mechanisms to determine the adequate level of renewable support.

The need to manage the cost of renewable support in Spain should not, however, justify a retroactive reduction in compensation for investments that have already occurred. This would severely damage regulatory stability and credibility in the system at the cost of future investments in the sector. Costs ought to be reduced on a forward-looking basis, whilst existing commitments should be recovered via a combination of higher electricity tariffs and additional resources from...
general tax revenues. Newbery (2010), for example, makes a strong argument in favour of covering the cost of renewable support through general tax revenues, given that support for renewable electricity is justified by innovation in technology, i.e. a public good that does not benefit electricity consumers alone.

In July and August 2010 the Spanish government announced two draft measures to reduce the cost of renewable support. They include a partially retroactive reduction of the premium paid to wind capacity that entered the market after 2008 (for the period until the end of 2012) and a further decrease in the tariffs paid to future solar plants. Estimates provided by the CNE indicate that these measures are unlikely to considerably reduce the cost of support to existing renewable plants (CNE (2010h)).

9.4. Policies on the Overall Spanish Generation Mix

Whilst renewable policy forms the foundation of Spanish measures to contain carbon emissions from the energy and electricity sectors, there are other elements of energy policy that are also relevant to the efficient attainment of Spain’s environmental objectives. These include the current policies towards alternative forms of low-carbon generation (e.g. nuclear power) and those involving conventional thermal generation (coal and CCGTs). Recent developments in these policies are reviewed below, followed by an analysis of the overall direction of the generation mix in Spain, as compared to the benchmark mix identified by the IEA to comply with environmental objectives.

9.4.1. Nuclear Generation

Nuclear power remains a key source of carbon-free electricity in Spain. In 2009 it accounted for over 50 TWh of generation output, equivalent to just over 40% of total carbon-free electricity in Spain. Most nuclear reactors in Spain will come to the end of their standard 40-year life during the 2020s. The decision on whether to extend the lifetime of these plants will therefore become a critical element of energy policy over the medium term. In the absence of life extension (e.g. as is currently being envisaged in the United States and in Germany) or new nuclear-build (as is being considered in a number of European countries, including the United Kingdom48, Italy, Sweden and Finland), significant additional amounts of renewable generation will be required for Spain to meet its environmental targets. Alternatively, replacing the shortfall in

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48 The United Kingdom’s National Policy Statement for Nuclear Power (November 2009) stated that “Nuclear power is low-carbon, economic, dependable, safe, and capable of increasing diversity of energy supply and reducing our dependence on any one technology or country for our energy or fuel supplies. Excluding nuclear power as an option for generating electricity would make it harder and more expensive to meet our emission targets. It could also jeopardise the security of the UK’s energy supply”. It recommends developing new nuclear power stations significantly earlier than 2025 in order to help meet the United Kingdom’s commitment to carbon reduction (see DECC (2009c)).
nuclear output with CCGT generation would increase total emissions from the electricity market by almost 20 million tonnes of CO₂ (i.e. over 25% of the total in 2009), which is out of line with the current European targets for emission control.

A preliminary discussion on this issue took place in Spain in 2009 in relation to the oldest and smallest nuclear plant, in Garoña, whose 40-year lifetime expires in 2011. The Spanish government decided in July 2009 to extend its life by 2 years, in spite of requests for a 10-year extension. Applying a similar solution to the entire portfolio of nuclear generators whose 40-year life comes to an end during the 2020s would create a serious issue for the Spanish electricity system for the reasons outlined above.

It is likely that extending the lifetime of nuclear reactors by 20 years for environmental reasons would create significant rents for the owners of these assets, since their operating costs are below market revenues (especially in an environment with high carbon prices). Given that these additional rents are unexpected (and were not accounted for when the market was first liberalised), mechanisms could be put in place in the future (i.e. as the current 40-year lives come to an end) to avoid the emergence of future windfall gains and reduce the costs of clean electricity for consumers. For example, the right to the additional nuclear power during the 20-year extension could be auctioned (via power purchase agreements or virtual power plant schemes), with the current owners of the plants being compensated only for the operational cost of running the plants. Alternatively, specific taxation of the nuclear plant owners benefiting from the life extension could be considered in due course in Spain, as is contained in the draft energy plan announced by the German government in September 2010.

9.4.2. Coal-fired Generation

Coal-fired generation is the most polluting form of electricity generation, with emission rates in excess of 900 g CO₂/kWh (more than double those associated with CCGTs). In the absence of commercially viable CCS, production by coal plants is therefore eventually not sustainable in an electricity market in the transition to decarbonisation. Carbon pricing can signal this by making coal-fired generation less competitive relative to other forms of thermal production, such as CCGT, and by encouraging the entry of carbon-free generation (which displaces thermal generation).

The recent evolution of coal-fired generation in the Spanish market confirms this expected trend. Coal-fired generation in mainland Spain has recently declined by more than half, from an average of over 70 TWh in the 2002-2007 period to 34 TWh in 2009, and even less (23 TWh) in the 12 months ending in mid-2010.

The Spanish government has sought to manage the repercussions of the loss of competitiveness of coal-fired generation on the domestic coal industry. It introduced a decree in February 2010 (RD 134/2010) aimed at guaranteeing a minimum level of output at 10 plants that burn domestic coal (accounting for 4.6 GW of conventional coal capacity out of a total of 11.3 GW; and for 16 TWh of generation in 2009, excluding Elcogas). An amended version of this legislation was
authorised by the European Commission in September 2010 under state aid rules. The final decree on domestic coal was subsequently published in early October 2010 (RD 1221/2010), but had not entered into force as of November 2010.

The minimum electricity output level to be achieved by the plants included in the legislation is reported not to exceed roughly 23 TWh per year (during the 2011-2014 period). This is equivalent to the total electricity production of all coal-fired plants in Spain in the 12 months ending in June 2010, also including plants burning imported coal. The required increase in domestic coal-fired generation will be achieved by amending the merit order established in the day-ahead market. In particular, subsidised domestic coal plants are to be included in a revised merit order at the expense of plants initially accepted in the market. Plants will be excluded based on their emission rates (i.e. starting with generators with the highest emission rates, such as coal plants, and then moving to CCGTs).

Given the levels of total coal-fired generation observed during the year ending in mid-2010, it appears that the new legislation is likely to effectively crowd out plants using imported coal from the market and may also affect CCGTs (if some of the imported coal plants are required to produce to maintain system reliability).

The CNE and CNC both assessed the original draft decree in late 2009 and found it to be flawed in several aspects. In particular, the CNE identified several problems with the measure (see CNE (2009b)), including the risk that bidding incentives in the spot market would be distorted and that total emissions from the market would increase significantly if CCGTs were to be displaced to accommodate domestic coal plants. The CNE also highlighted the prospect that system costs would increase by up to €800 million due to the effective subsidies to be paid to domestic coal plants and the need to compensate excluded thermal plants (this last measure was subsequently suppressed, implying a cost to the system estimated at roughly €500 million, as estimated in CNE (2010i)).

It is apparent that a measure aimed at protecting coal-fired generation and increasing its production runs contrary to the aims of environmental policy in the energy sector, which is to favour more efficient and less emitting technologies at the expense of more emitting ones. Protection of domestic coal is therefore likely to increase the total cost of complying with environmental targets and to ultimately harm consumers.

Moreover, the alleged benefit of promoting a domestic source of energy in order to reduce energy dependence in the short to medium term (which is one of the arguments used by the Spanish government to justify the measure) is not particularly convincing in this case. The legislation introduced is likely to mainly reduce imports of international coal, which is easily available in the global market from politically stable countries. Therefore, dependence on imported coal does not materially increase Spain’s vulnerability to disruptions in energy supply.

Economic efficiency considerations indicate that if the Spanish government wishes to compensate the domestic coal industry for the ongoing changes in the electricity market, it would be less
costly and more effective to do so directly (in a way that is compatible with E.U. state aid rules), rather than by distorting production in the overall electricity market.

9.4.3. CCGT Generation

Together with coal, CCGT generation is the other key conventional thermal generation in the Spanish generation market. Contrary to coal, CCGT output has historically been on an increasing trend in the market due to the rapid entry of new CCGT plants since 2002. CCGT generation reached a peak of over 90 TWh in 2008 (from only 5 TWh in 2002), even though in 2009 its output declined to 78 TWh and in the 12 months before June 2010 it fell further to 73 TWh (implying average load factors of less than 40%, down from more than 50% in 2008).

For the reasons outlined earlier in this chapter, CCGT generation is an increasingly important technology in power markets, given its flexibility (which allows for the effective integration of renewable generation) and its relatively low-carbon emission rate. CCGT generation is therefore set to be a key bridge technology in the transition to a fully decarbonised power sector.

These trends are also evident in Spain, where CCGT generation is the key source of flexibility for the system (together with hydro), as shown in Section 5 of this report. CCGT plants are the main source of adjustment for the intermittency of renewable generation, as shown by the fact that daily CCGT output is strongly inversely correlated with special regime production (with a negative correlation coefficient of 0.66 on weekdays in 2009). The evidence is that on days with high wind output, CCGTs turn down their output significantly and do the opposite on days with low wind output. For example, on the peak day for hourly wind generation in 2009 (November 8), hourly CCGT output ranged from less than 1 GW to less than 4 GW. Conversely, on the day with the lowest hourly wind generation (August 27 2009), CCGT generation ranged from 11 GW to more than 15 GW.

CCGT generation (and thermal generation in general) is also a key contributor to peak output, especially when compared to special regime generation. At the peak hour in 2009 (on January 13), CCGT generation stood at 17 GW (accounting for close to 40% of peak demand) and thermal generation overall was 32 GW (more than 70% of the total). By contrast, special regime generation accounted for less than 8 GW (out of total special regime capacity of 32 GW). More generally, given the intermittency of renewable generation, the contribution of special regime generation to peak demand cannot be guaranteed, as shown by the fact that between 2005 and 2009 it varied between a low of 5.4 GW (in 2007) and a high of 12.8 GW (in 2008). Vázquez and Fernández Álvarez (2010) report that, given the volatility of wind generation, only 7.5% of total wind capacity is considered by the transmission system operator for the purposes of covering peak demand.

The continuing need for CCGT generation for system reliability and flexibility in Spain has implications for the design of the wholesale electricity market. For example, it raises the question of whether the Spanish capacity payment mechanism should be reformed to strengthen incentives to enter (or not to exit) the market in order to guarantee security of supply. This is not likely to
be an immediate concern in Spain at present, given the high levels of installed CCGT capacity, but it may become one in the future (especially as older thermal plants start retiring).

The current capacity payment mechanism, which was reformed in 2007, limits the payment to 10 years, setting it at €20/kW per year for existing plants that entered the market after 1998 and a maximum of €28/kW per year for new plants. A capacity payment of this level is approximately sufficient to cover annualised operation and maintenance costs (which are estimated at €25/kW by the European Commission (2008c)). An additional spread (or price-cost margin) on energy sales of roughly €12/MWh is required to allow for capital-cost recovery49 (excluding other fixed charges like gas transport costs). This is well above the average spreads observed in 2009 (which were below €5/MWh at peak times).

These calculations illustrate the fact that the current capacity payment mechanism in Spain would not encourage new entry at the level of peak spot prices observed in 2009 (and may not even be able to prevent some of the existing thermal plants being decommissioned prematurely). Spreads for CCGTs are likely to exceed 2009 levels when the Spanish economy eventually recovers and if carbon prices increase over time. However, it remains to be seen whether they will increase enough to permit full recovery of fixed costs for existing and new CCGTs.

A closely related policy question is whether CCGT plants should be allowed to recover some of their fixed operational and capital costs in specific situations when their output is needed by the system, as when they are required to relieve congestions on the transmission network. As mentioned in Section 3, this issue has attracted significant scrutiny by the competition authority in Spain. The CNC is concerned that generators are charging excessive prices when they offer their output for congestion management.

Locational market power is a well-established concern in power markets and it is likely that some generators may be in a position to charge excessively high prices at times by virtue of their location on the network. On the other hand, generators should not be forced to offer their energy at variable cost in a pay-as-bid environment like the one used to solve congestion issues, since this does not allow for any level of fixed-cost recovery. The standard logic of electricity spot pricing indicates that prices should at times allow for some fixed-cost recovery to generate the required incentives to enter the market (assuming that, if there is a capacity payment, it would not fully compensate for the cost of investment). Moreover, appropriate locational pricing can provide the incentives to enter at the correct location (e.g. where demand is located) and thereby alleviate congestion problems.

A regulatory solution to the problem of congestion pricing (which is probably the most adequate way to deal with the issue) should take these principles into account. The regulatory proposal

49 This calculation assumes a 40% load factor, capital costs of €635/kW (based on European Commission (2008c)), a real discount rate of 5% and a 30-year plant lifetime.
put forward by the CNE in April 2010, however, would only allow plants required to relieve congestions to recover their variable costs, with no provision made for fixed cost recovery. A solution of this type would only be sustainable if the combination of capacity payments and infra-marginal rents in the spot market were enough to allow for fixed cost recovery (which was not the case in 2009).

9.4.4. Implications for the Overall Generation Mix in 2020 and Beyond
Spain's current plans for the evolution of its generation mix up to 2020 are summarised in Figure 42, together with the actual mix achieved in 2009 and the IEA scenarios for the environmentally compatible mix in Europe in 2020 and 2030 (discussed above). According to the 2020 estimates published in PANER 2010, by 2020 the Spanish system is projected to have a lower share of coal and oil compared to the current situation, roughly the same share of gas, significantly more renewable (close to 40%) and proportionately less nuclear (down from the current share of 18% of generation to 14%).

Figure 42: Spanish Energy Mix in 2009 and 2020, and Comparison with IEA Projections

The overall share of gas-fired production (35%) will be split between CCGT and co-generation. Using the share of co-generation output published by the Spanish government in its March 2010 proposals on the 2020 energy mix, it can be estimated that CCGT generation will amount to...
roughly 80 TWh in 2020, which is in line with the output levels reached in 2009 (but probably with a higher level of installed capacity and, therefore, lower load factors).

The 2020 plan for Spain is broadly compatible with IEA projections for 2020 in terms of its effects on carbon emissions and its carbon intensity. The lower share of nuclear output envisaged in Spain (14% vs. 28%) is compensated for by a higher share of renewable and more weight on gas relative to coal. However, by relying more on renewable energy than nuclear, the Spanish system will face greater intermittency issues, which will require gas-fired capacity to act in a flexible manner and operate primarily during peak hours.

Looking further ahead to 2030, the IEA predicts the need for a growing share of renewable, a slight increase in the share of nuclear and the entry of significant amounts of coal and gas with CCS. Achieving the renewable output levels required by the IEA will not be unduly difficult for Spain if the current 2020 targets are met. However, it will be very difficult to achieve the 30% of nuclear generation contained in the IEA projections. The life of the current fleet of nuclear generators would all need to be extended beyond 2030 for this to be possible and new nuclear capacity would need to be considered. Alternatively, the system would need to rely even more on renewable power, backed up by flexible thermal technology based on CCS. There is, however, a risk that such an alternative option would increase system costs significantly relative to IEA benchmark scenarios. Once again, these projections indicate the need for an in-depth review of the option of extending the lifetime of nuclear plants in Spain beyond the 2020s.

10.1. Common Challenges for Europe and Spain

Meeting the environmental objectives set by international policy makers, as embodied in the Copenhagen Accord of late 2009, will require a paradigm shift in energy markets over the next 20 to 40 years (assuming that an effective international agreement can be reached on these issues). Over this time horizon, developed countries will need to achieve deep cuts in GHG emissions to comply with the environmental targets and reach a reduction of at least 80% by 2050 relative to 1990 (European Commission (2010b)). The power sector in particular will also have to virtually decarbonise over this period, given the greater potential for the use of low- or zero-carbon technologies in this sector (renewables, nuclear and CCS), and the ability of the electricity industry to reduce emissions in other sectors (e.g. transport and heating). Projections indicate that carbon emissions in the European power sector will be reduced by 70% by 2030 (relative to 1990) with the industry being almost completely de-carbonised by 2050; more than half of electricity will come from renewable sources and the rest will be split between nuclear and CCS (IEA (2010a)).

The required changes in the European energy industry are likely to increase costs significantly as more environmentally friendly but also more costly technologies are used. Carbon prices are likely to increase over the future (thus raising the cost of fossil-fuel technologies) and so will the cost associated with renewable subsidies as targets become more ambitious. The overarching policy challenge should be one of achieving the required transformation towards a low-carbon economy at the lowest possible cost for society. For this to be possible, government interventions in the sector should be aimed at directly addressing the main sources of market failures.

In particular, this means that carbon pricing should be the main economic instrument used to contain carbon emissions and achieve the required targets in a socially optimal way. This would ensure that a technology-neutral approach is adopted and that the most cost-efficient low-carbon technologies are utilised to reduce emissions. However, political and distributional considerations indicate that it is unlikely that carbon prices will reach the levels required to induce efficient abatement efforts, which implies that second-best solutions may have to be accepted.
The presence of additional market failures, such as technology spillovers, can justify the adoption of supplementary policies, like R&D and possibly also deployment support to renewables. However, when such policies are designed and reviewed, it needs to be clear which specific market failure is being corrected through government intervention. In particular, renewable support policies should not be justified in terms of the environmental externality associated with climate change, since this externality should be mainly addressed via carbon pricing for the reasons discussed above. Moreover, deployment support to renewable generation may actually reduce the effectiveness of carbon pricing in stimulating the entry of other forms of low-carbon generation by reducing the market price of CO₂. Careful thought should be given to these issues when revising and updating the current European renewable targets.

Once the main market failures are internalised via public policies (e.g. carbon pricing and renewable support), market tools should be relied upon to maximise the efficiency of the energy sector in the transition to de-carbonisation. This calls for such measures as the introduction of carefully designed auction-based procedures to set renewable subsidies and a gradual move away from administratively determined feed-in tariffs. Capacity tenders could also be used to attract the required levels of flexible thermal generation if price signals from the energy market are perceived to be too unreliable to guarantee security of supply.

Given the complexity of the required structural changes, it will be difficult to design policies to achieve maximum efficiency. It is very possible that the relative contribution of competing low-carbon technologies (renewables, CCS and nuclear) and their respective deployment path over time will not be optimised. In particular, in the medium term there is a risk of over-reliance on renewable generation in Europe, given the ambitious European targets set for 2020. Whilst renewable generation may eventually have to reach a high share of total consumption (e.g. 50% according to IEA projections for 2050), a 35%-40% target in 2020 may represent an excessively steep deployment trajectory (based on the IEA’s modelling of the timing and composition of efficient abatement efforts).

On the other hand, partially due to the economic crisis of 2009-2010, the European carbon emission targets for 2020 do not appear to be sufficiently ambitious (with 85% of the required reduction in GHG emissions having already been achieved in 2009). If the target is ratcheted up to a 30% reduction relative to 1990, it will be socially desirable to achieve the incremental reduction in emissions primarily by lowering the emission cap under the ETS (thus achieving a higher carbon price), rather than by further increasing the renewable target. This will encourage energy efficiency and also investment in alternative forms of low-carbon generation (nuclear and CCS). A significantly higher carbon price may, however, raise distributional issues that will need to be addressed, since it will increase the market price received by all energy sources (and not just the incremental low-carbon investments required to meet the more stringent environmental objectives).
10.2. Implications for the Spanish Power Market

The Spanish electricity market has achieved a significant transformation towards a more environmentally sustainable model in the last 5 to 6 years. This has been driven by a rapid increase in renewable generation, coupled with even faster growth in relatively low-emission gas-fired generation. Since 2004, renewable generation has grown by 50% and it reached more than a quarter of total consumption in 2009 (close to the European target for 2010). During the same period, CCGT generation almost trebled, whilst coal generation halved. As a result of these changes, overall carbon emissions from the power sector fell by almost 40% over this period (whilst demand grew by 14%).

The Spanish electricity market is therefore effectively on track to meet the 2020 targets set at European level and in 2009 it achieved a generation mix that is broadly compatible with the required mix for 2020 (partially helped by the drop in demand experienced in 2009).

However, this largely positive evolution does not mean that the environmental policy issues faced in Spain are not significant. On the contrary, the significant emphasis placed in the Spanish market on renewable generation is creating specific challenges that need to be addressed. These include the following three issues in particular:

A: Managing the Cost of Renewable Support

Spain’s relative effective performance in emission reductions in the power sector has come at the cost of high levels of financial support to renewable generation. The total subsidy to special regime generation (which includes the majority of renewable production) exceeded €6 billion in 2009. This represents more than a third of total wholesale expenditures and accounts for over 100% of the annual tariff deficit of the same year (defined as the shortfall between tariff revenues and related procurement and network costs). A high share of the special regime subsidy (more than 40%) can be explained by the feed-in tariffs offered to solar PV plants in 2007-2008, which were most probably set at excessive levels (as indicated by the fact that tariffs dropped by almost 40% by mid-2010, a fall which was likely in excess of the cost reduction experienced over the same period).

Lowering the costs of future investments in renewable energy requires revisiting the current system of feed-in tariffs and premia, and moving towards more market-based mechanisms, such as well-designed capacity tenders. The current system established to set feed-in tariffs for PV solar power may provide a satisfactory transitional template for the system as a whole, since it allows for a degree of flexibility in the determination of renewable remuneration.

In order to preserve the regulatory credibility of the system, any reductions in renewable support should, however, be applied only to future projects and not retroactively to investments that have already occurred. The high cost of renewable support to date will inevitably need to be...
reflected in higher electricity tariffs, with a part possibly being funded by taxation of overall energy consumption and/or by general tax revenues (if compatible with the overall fiscal balance of the government).

B: Integration of Renewables and the Role Played by Flexible Thermal Generation

The fast growth of renewable electricity in Spain and the prospects for continued growth to 2020 raises the separate challenge of how to optimally integrate this type of power in the overall electricity system in order to preserve security of supply. In particular, the intermittency of renewable generation requires the presence of back-up flexible generation and reduces the contribution of renewable electricity to security of supply.

The Spanish system is coping with these challenges primarily by relying on flexible CCGT generation as the main source of back-up power. However, the growth of renewables (coupled with the drop in demand and high levels of installed CCGT capacity) has significantly lowered the utilisation factors of gas-fired generation in 2009, thus bringing load factors to below 40%. Current projections for 2020 suggest that future CCGT load factors are unlikely to increase considerably above this level.

A low utilisation of conventional flexible capacity is to be expected in transition to a virtually decarbonised electricity market (where plants with CCS, hydroelectric power including pumped storage, and demand-side response would, in principle, provide most of the system’s flexibility requirements). For this to be sustainable, however, peak prices need to increase significantly above current levels to allow for the recovery of the fixed costs associated with investments in thermal generation (and also in new baseload generation, which would earn very low prices at off-peak times). There is a risk, however, that peak prices may not increase sufficiently (creating a ‘missing money’ problem) or that investors will perceive the risk of new investments in thermal generators to be excessive.

It may therefore be necessary to reform and strengthen the current system for capacity remuneration in Spain, which rewards investments in new capacity for only a 10-year period and at a level that only roughly covers annualised O&M costs (but not capital and fixed gas transport costs). Similarly, if regulatory solutions are introduced to resolve the pricing of congestion management and ancillary service provision in Spain, they should also allow for a degree of fixed-cost recovery on the part of flexible generation (assuming that capacity payments are not sufficient to cover fixed costs).

The growth of renewable generation also further highlights the need for additional investment in infrastructure to facilitate its integration into the system. In particular, greater and better integration with the European electricity system through France (e.g. with additional interconnection capacity and the introduction of a more effective method of cross-border congestion management) is needed to reduce the requirement for domestic flexibility. Similarly, additional domestic gas storage capacity and the creation of an effective wholesale gas market in Spain are both needed to allow CCGT plants to operate in a more flexible mode at lower cost.
C: Policy Towards Other Forms of Power: Coal and Nuclear

In order to efficiently meet current environmental targets, Spanish policy makers also need to adopt an internally coherent strategy towards the overall generation mix, including other key types of generation such as coal-fired plants and nuclear power.

In terms of policy towards coal, it is fairly clear that coal-fired generation is set to decline rapidly over the next decade and that coal plants will not be sustainable unless fitted with CCS technology. The evolution of the Spanish market is already signalling this trend, with load factors for coal plants standing at less than 25% in 2009-2010.

The Spanish decree on domestic coal of October 2010 (which was approved under state aid rules by the European Commission) is not consistent with this direction. Under the provisions of this measure, the merit order of the electricity market would be distorted in order to increase the output of plants burning domestic coal. This would lead to the prospect of a significant increase in system costs (at a time when tariff revenues are already insufficient to cover overall costs) and also higher carbon emissions due to the displacement of more efficient coal-fired plants and possibly also CCGTs. Moreover, there are weak security of supply justifications for the intervention, since dependence on coal imports does not raise significant security of supply concerns and because domestic coal plants are not a particularly important source of flexibility in Spain (given the presence of significant CCGT and imported coal capacity which can perform this role).

In terms of nuclear power, there is a pressing need to start a detailed review in Spain of the pros and cons of extending the lifetime of nuclear generators beyond the current 40-year useful life, and possibly commissioning new nuclear plants in the next decade. International projections on the required mix of carbon abatement technologies indicate that nuclear generation is expected to play an important role in the energy market in future in order to achieve the current environmental objectives. For example, the IEA projects that nuclear generation needs to account for close to 30% of European electricity supply by 2030 (implying a 20% increase in output relative to 2007 generation levels) for Europe to achieve a sustainable power mix.

Most of Spain’s nuclear fleet comes to the end of its 40-year lifetime between 2020 and 2030, which could potentially create a large gap in terms of carbon-free generation by 2030. One option to fill this gap would be to rely even more on renewable sources, but this is likely to materially increase system costs relative to the option of extending the lifetime of existing nuclear plants from 40 to 60 years. Moreover, additional rents generated from the nuclear lifetime extension could be extracted by the government in due course via auction-based procedures or through specific tax measures (following the example of the draft energy plan announced in Germany in September 2010). This would help contain wholesale electricity costs. Nuclear generation, however, also raises broader social issues, connected to safety and the management of nuclear waste. The issue of extending the current lives of nuclear plants is therefore complex and in need of a detailed analysis in order to reach a balanced view on the benefits and costs of further reliance on nuclear generation in 2030 and beyond.
### Table 8: Total Electricity Generation Capacity by Firm and Technology, 2009, Mainland Spain (GW)

<table>
<thead>
<tr>
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<th>Iberdrola</th>
<th>Endesa</th>
<th>GN/UF</th>
<th>EDP/HC</th>
<th>E.On</th>
<th>Others</th>
<th>TOTAL</th>
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<td>5.8</td>
<td>1.3</td>
<td>1.5</td>
<td>5.8</td>
<td>22.2</td>
</tr>
<tr>
<td>Nuclear</td>
<td>3.3</td>
<td>3.6</td>
<td>0.6</td>
<td>0.2</td>
<td>0.0</td>
<td>0.0</td>
<td>7.7</td>
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<tr>
<td>Hydro</td>
<td>8.8</td>
<td>4.7</td>
<td>1.9</td>
<td>0.4</td>
<td>0.7</td>
<td>0.7</td>
<td>17.2</td>
</tr>
<tr>
<td>Special regime</td>
<td>5.7</td>
<td>0.6</td>
<td>1.0</td>
<td>2.0</td>
<td>0.0</td>
<td>22.8</td>
<td>31.9</td>
</tr>
<tr>
<td>TOTAL</td>
<td>25.7</td>
<td>17.3</td>
<td>11.9</td>
<td>5.3</td>
<td>3.7</td>
<td>29.5</td>
<td>93.5</td>
</tr>
<tr>
<td>Market share</td>
<td>28%</td>
<td>19%</td>
<td>13%</td>
<td>6%</td>
<td>4%</td>
<td>32%</td>
<td>100%</td>
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Source: REE, Companies’ Annual Reports.
### Table 9: Total Electricity Generation Output by Firm and Technology, 2009, Mainland Spain (TWh)

<table>
<thead>
<tr>
<th></th>
<th>Iberdrola</th>
<th>Endesa</th>
<th>GN/UF</th>
<th>EDP/HC</th>
<th>E.On</th>
<th>Others</th>
<th>TOTAL</th>
</tr>
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<tbody>
<tr>
<td>Coal</td>
<td>2.2</td>
<td>17.2</td>
<td>3.4</td>
<td>6.3</td>
<td>4.7</td>
<td>0.0</td>
<td>33.9</td>
</tr>
<tr>
<td>Oil</td>
<td>0.0</td>
<td>0.2</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>1.8</td>
<td>2.1</td>
</tr>
<tr>
<td>CCGT</td>
<td>18.6</td>
<td>6.4</td>
<td>19.7</td>
<td>3.6</td>
<td>6.4</td>
<td>23.6</td>
<td>78.3</td>
</tr>
<tr>
<td>Nuclear</td>
<td>23.8</td>
<td>23.5</td>
<td>4.3</td>
<td>12.6</td>
<td>0.0</td>
<td>0.0</td>
<td>52.8</td>
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<tr>
<td>Hydro</td>
<td>9.6</td>
<td>8.5</td>
<td>3.4</td>
<td>0.9</td>
<td>0.9</td>
<td>0.6</td>
<td>24.0</td>
</tr>
<tr>
<td>Special regime</td>
<td>12.0</td>
<td>2.2</td>
<td>2.5</td>
<td>4.2</td>
<td>0.0</td>
<td>60.0</td>
<td>80.9</td>
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<tr>
<td>TOTAL</td>
<td>66.3</td>
<td>58.2</td>
<td>33.2</td>
<td>16.1</td>
<td>12.1</td>
<td>86.0</td>
<td>271.8</td>
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<tr>
<td>Market share</td>
<td>24%</td>
<td>21%</td>
<td>12%</td>
<td>6%</td>
<td>4%</td>
<td>32%</td>
<td>100%</td>
</tr>
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Source: REE, Companies' Annual Reports.


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### Appendix C: List of Acronyms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>bcm</td>
<td>Billion cubic metres</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined cycle gas turbine</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon capture and storage</td>
</tr>
<tr>
<td>CESUR</td>
<td>Contratos de energía para el suministro de último recurso</td>
</tr>
<tr>
<td>CNC</td>
<td>Comisión nacional de la competencia</td>
</tr>
<tr>
<td>CNE</td>
<td>Comisión nacional de energía</td>
</tr>
<tr>
<td>CO$_2$</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>CTCs</td>
<td>Costes de transición a la competencia (competition transition costs)</td>
</tr>
<tr>
<td>EDP/HC</td>
<td>Energías de Portugal/Hidrocantábrico</td>
</tr>
<tr>
<td>ENTSO</td>
<td>European Network for Transmission System Operators</td>
</tr>
<tr>
<td>EPE</td>
<td>Emisión primaria de energía</td>
</tr>
<tr>
<td>ETS</td>
<td>Emissions trading system</td>
</tr>
<tr>
<td>E.U.</td>
<td>European Union</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse gas</td>
</tr>
<tr>
<td>GW</td>
<td>Gigawatt</td>
</tr>
<tr>
<td>GWh</td>
<td>Gigawatt-hour</td>
</tr>
<tr>
<td>Acronym</td>
<td>Definition</td>
</tr>
<tr>
<td>---------</td>
<td>------------</td>
</tr>
<tr>
<td>TLR</td>
<td>Tariff of last resort</td>
</tr>
<tr>
<td>TPA</td>
<td>Third-party access</td>
</tr>
<tr>
<td>TSO</td>
<td>Transportation (or transmission) system operator</td>
</tr>
<tr>
<td>TWh</td>
<td>Terawatt-hour</td>
</tr>
<tr>
<td>VPP</td>
<td>Virtual power plant</td>
</tr>
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</table>
Regulation and Competition in the Spanish Gas and Electricity Markets

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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.

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