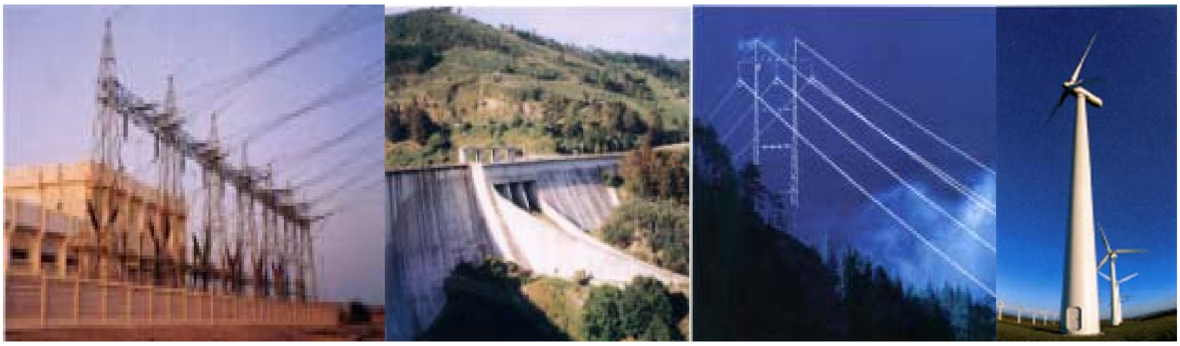
Final Report



Implications of the EU Emissions Trading Scheme for the UK Power Generation Sector

to

Department of Trade and Industry (DTI)

11 November 2005

IPA Energy Consulting

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1. EXECUTIVE SUMMARY

1.1. Introduction

IPA Energy Consulting Ltd (IPA) was commissioned by the Department of Trade and Industry (DTI) to conduct a study on the impact of the EU Emissions Trading Scheme (EU ETS) on investment and pricing within the UK power generation sector.

The study brings together results from:

- Desk research and interviews with key market participants;
- Scenario modelling using IPA's proprietary integrated energy market model, ECLIPSE;
- Sensitivity analysis of specific EU ETS implementation options; and
- Analysis of pricing impacts using a combination of bespoke analysis and IPA's EPSYM model for the major European markets.

1.2. Impact on Prices

- Our analysis shows strong evidence that the price of carbon is being passed through to wholesale electricity prices in the UK, Germany, Netherlands and France at around the marginal intensity of coal plant, implying possible over-recovery of true marginal costs by the industry. The analysis for Spain and Italy was inconclusive, possibly due in part to the lack of liquid traded markets in these countries.
- The cost of carbon is expected to add a direct uplift of £3.50-£10.50/MWh to GB wholesale power prices over the forecast period to 2020, assuming carbon prices of €15, €20 and €25/t CO_2 in Phases I, II and beyond, and full pass-through of carbon prices at the carbon intensity of the marginal plant. In addition, the incorporation of carbon into wholesale prices will drive capacity changes. The sensitivity of wholesale prices to carbon is expected to increase over Phase II as coal plant increasingly runs at the margin, but to reduce after around 2014 as lower intensity plant takes its place.
- While GB starts with the lowest carbon uplift in wholesale power prices, relative to the other major EU markets, France and Italy tend to have lower uplifts later in the forecast period, reflecting the fact that the UK remains reliant on some coal generation later in the period – despite significant CCGT build – due to the closure of nuclear plant. However, when translated into retail prices, the UK is likely to remain in the two cheapest countries for all classes of customer, despite forecast increases of around 12% (in real terms) from 2004 levels by 2010 for domestic customers and 23-28% for industrial customers, under Base Case assumptions.
- Despite the significance of these impacts, the changes in wholesale price due to the EU ETS are relatively small compared to the existing differences between countries in retail uplift and taxation. Thus, it is likely that fiscal, regulatory and market developments will have a greater impact upon the relativity of retail prices around Europe than the impact due to the EU ETS alone.

1.3. Impact on Profitability

- The combination of free allocations with full pass-through of marginal costs is estimated to result in increased profitability for the UK power generation sector of approximately £800m/year over Phase I (based on the current annual allocation of 130MtCO_2). This represents a direct transfer of value from electricity consumers. The overall impact on sector profitability would have been neutral with an annual allocation of around 45 $MtCO_2$ (assuming a constant carbon price of €15/tCO_2).

- However, sector profitability is expected to decline over Phase II, as the impact of carbon prices and new entry CCGT plant reduces the profitability of coal plant, and lower power prices reduce the profitability of nuclear plant. The profitability of the sector is expected to flatten out in Phase III and beyond, as the sector becomes increasingly dominated by a single technology (CCGT). Free allocations would continue to boost sector profitability if applied beyond Phase II.

1.4. Impact on Plant Mix and Emissions

- Under all scenarios, the GB plant mix is expected to converge on a CCGT-dominated system by the end of Phase II. This results in convergence on emissions of around 120$MtCO_2$ from 2015, rising slightly through to 2020 with nuclear closures. It should be noted that no extension to the current RO targets (which increase until 2015/2016) has been assumed.
- The relative competitiveness of coal plant reduces over the forecast horizon in all scenarios. This reflects the fact that although high gas prices (relative to coal) across Europe will result in increased coal burn, this is likely to be associated with higher carbon prices, which acts to undermine the competitiveness of coal (as shown in our High Case scenario). Low gas prices (relative to coal) will bring forward new entry and reduce the running of coal plant, leading to a similar outcome, although the trajectory of emissions over Phase II will differ (as shown in our Low Case scenario).
- In all scenarios, emissions significantly exceed allocations over Phase I (by over 30 $MtCO_2$/year). Assuming the same amount of allocations in Phase II, emissions would only reduce to match the level of allocations by the end of the phase.

1.5. Sensitivity to the Carbon Price

- The sensitivity of wholesale prices to carbon prices increases with higher carbon prices. The competitiveness of coal plant relative to CCGT is eroded with higher carbon prices and coal therefore increasingly replaces gas plant as the marginal technology, which leads to a higher marginal carbon intensity and hence a greater impact on power prices.
- The profitability of nuclear stations and existing CCGTs is broadly correlated with carbon prices, whereas the profitability of coal plant depends on the interplay between the value of free allocations and the impact of carbon pricing on the relative competitiveness of gas and coal.
- The economics of new build and closure decisions are also highly sensitive to the carbon price, with around 3GW of additional new build CCGT capacity being projected for the Phase II period under carbon prices of €40/tCO_2, compared with €10/tCO_2. The amount of plant closure also varies (by around 2GW) between the sensitivities.
- Total emissions from the sector are around 30$MtCO_2$ less in 2012 under a carbon price of €40/tCO_2 than under a carbon price of €10/tCO_2.

1.6. Sensitivity to EU ETS Implementation Decisions

- Phase II EU ETS implementation decisions can affect the emissions profile over Phase II. For example, *not* allocating free allowances to new entrants could mean that emissions remain above allocations for the entire phase. Sensitivity analysis on our Base Case scenario showed an increase in 2012 emissions of around 11MtCO_2 with 50% and 13MtCO_2 with zero free allocations for new entrants. Providing 100% free allocations is also expected to reduce power prices by around £2/MWh in 2012, relative to the position with no free allocations. Given a lead time of approximately 3 years for a CCGT plant, the current uncertainty over Phase II allocations to new entrants may be considered already to be delaying the effective commissioning date of new plant investments.

- Allowing closed installations to retain allowances for the remainder of the phase could potentially bring forward all of the closures of coal plant expected during the phase (3 GW in the Base Case). However, it is questionable whether such a level of closure could be achieved without compromising security of supply (since such plant would have maximum incentive to close at the start of 2008). This might lead to increased demands from coal plant for capacity or reserve payments to stay open.
- Allowing installations to use CERs will reduce the effective price of carbon to which generators are exposed, to the weighted average of the EUA and CER prices. In addition, allowing installations to use CERs up to a limit effectively constitutes a second allocation, at the CER price rather than zero cost. If CERs may only be used by existing installations then this may serve to increase the differential between existing and new entrant costs, thereby delaying new entry.
- The overall allocation volume primarily affects the profitability of existing plant. Increasing the level of free allocations from an assumed 130 MtCO_2 in the Base Case to 170 MtCO_2 in Phase II results in around 3GW less coal closures over the phase. However, this only marginally reduces power prices (by less than £1/MWh). There is around 0.5GW less new build (due to lower power prices) and therefore plant margins increase. Decreasing the level of free allocations to zero is estimated to result in an additional 1GW more coal capacity closing over the phase (compared with the Base Case). This only marginally increases power prices and does not result in additional new entry, resulting in significant reductions in plant margin.
- Basing allocations on the same measure of historical running as used for Phase I but with emissions calculated at the marginal intensity of a modern CCGT would mean a reduction in annual sector allocations to around 70 MtCO_2 in Phase II. This would primarily impact on profitability, reducing sector EBITDA by around £0.8 billion in 2008 and £0.5 billion in 2012, relative to the Base Case. Basing allocations on actual running requirements would increase sector EBITDA by around £0.7 billion in 2008 and £0.1 billion in 2012. Power sector emissions would remain the same as in the Base Case.

2. ABBREVIATIONS

AAU	Assigned Amount Unit
AGR	Advanced Gas-cooled Reactor
API#2	Coal price index
BAU	Business As Usual
BSUoS	Balancing Services Use of System
CCA	Climate Change Agreement
CCGT	Combined Cycle Gas Turbine
CCL	Climate Change Levy
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CH4	Methane
CHP	Combined Heat and Power
CO_2	Carbon dioxide
Defra	Department for Environment, Food and Rural Affairs
DTI	Department of Trade and Industry
EBITDA	Earnings Before Interest, Tax and Depreciation
ERU	Emission Reduction Unit
ETS	Emissions Trading Scheme
EUA	EU ETS Allowance
EU	European Union
FGD	Flue Gas Desulphurisation
GB	Great Britain
GCV	Gross Calorific Value
GW	Gigawatt (1000 MW)
GWh	Gigawatt hour (1000 MWh)
IPC	Integrated Pollution Control
IPPC	Integrated Pollution Prevention & Control
JI	Joint Implementation
LCPD	Large Combustion Plants Directive
LEC	[Climate Change] Levy Exemption Certificate
LTI	Long Term Interruptible [contracts]
MW	Megawatt
MWh	Megawatt hour
NAP	National Allocation Plan
NBP	National Balancing Point
NER	New Entrant Reserve
NETA	New Electricity Trading Arrangements
NGT	National Grid Transco
NI	Northern Ireland
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
PPA	Power Purchase Agreement
PPC	Pollution Prevention Control
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
RoI	Republic of Ireland
SEC	Securities and Exchange Commission
UEP	Updated Energy Projections

3. INTRODUCTION

3.1. Background

IPA Energy Consulting Ltd (IPA) was commissioned by the Department of Trade and Industry (DTI) to advise on the impact of the EU Emissions Trading Scheme (EU ETS) on investment and pricing within the UK power generation sector.

Directive 2003/87/EC (henceforth 'the EU ETS Directive'), establishing a European scheme for trading in greenhouse gas allowances, entered into force on 13 October 2003. The Directive establishes a requirement on operators of installations described in Annex I of the Directive to hold a permit issued by the relevant competent authority and to surrender allowances equal to actual emissions on an annual basis. The Directive also sets out rules governing the allocation of allowances for two phases, with the first running from 2005-2007 and the second from 2008-2012, and it is intended that the scheme will continue beyond then.

Phase I of the scheme commenced on 1 January 2005. Under the Phase I National Allocation Plan (NAP) the UK will initially allocate allowances equivalent to 736.3 $MtCO_2$, and is currently pursuing a legal case against the European Commission for the right to increase the allocation as part of an updated NAP to 756.1 $MtCO_2$. The Phase I NAP places most of the emission reduction burden on the power generation sector, which received allowances equivalent to 391.7 $MtCO_2$ for Phase I (130.6 $MtCO_2$/year). The other industrial sectors received allocations which were intended to be equivalent to their projected emissions.

The Government is currently considering options for Phase II of the scheme, including the overall amount of allowances and the allocation methodology. The treatment of the power generation sector is currently part of this consideration, along with the consequent impacts on other energy policy objectives and in particular security of energy supply.

This research project was commissioned to provide analysis in respect of the impact of the EU ETS on investment decisions in the generation sector and consequent impacts on energy security of supply, and on pricing impacts and associated factors.

3.2. This Report

Section 4 provides an overview of the factors affecting investment in the UK power generation sector, including an analysis of how the UK compares with other major EU markets, and an overview of the actions that may be taken by generators.

Section 5 describes the approach taken to modelling scenarios for the future development of the UK power generation market and the implementation of the EU ETS, including all relevant assumptions made.

Section 6 presents our analysis of three scenarios for the UK power generation market. The scenarios are not intended to cover all possible developments; rather, they are presented in order to illustrate the relative impacts that a number of key assumptions about future trends and decisions would be likely to have in combination. This section includes a discussion of impacts on security of supply.

Section 7 then provides more detailed sensitivity analysis of the major factors over which the UK Government has some degree of influence with respect to implementation of the EU ETS in Phase II in particular.

Section 8 presents our analysis of the historical impact of carbon on wholesale power prices, expected future impact, the relationship between wholesale and retail prices and forecast retail prices for the major EU markets.

4. FACTORS AFFECTING INVESTMENT

This section discusses the factors affecting investment in new capacity in the UK power generation sector, the importance of the EU ETS Phase II decisions relative to these other factors, and how the UK compares with other EU Member States.

4.1. Factors Affecting Investment

For this part of the research project we combined our own understanding of the UK and EU power markets with the opinions of a small number of key market participants, obtained through a series of semi-structured telephone interviews. Interviewees agreed to participate on the basis that their individual responses would be kept in confidence but published in aggregate or anonymous form. Interviewees were not told for whom the research was being undertaken, as it was felt that this could have biased the results.

The most important factors cited as affecting investment decisions in power generation assets were the economic fundamentals (e.g., spark spread for CCGT plant, feed-in tariff or ROC price for renewables) and the degree of market liberalisation (including a number of related factors such as transparency, degree of competition, regulatory barriers to entry and regulatory certainty).

Taxation was a further factor, and transportation costs – both of fuels and electricity – were mentioned as a less important factor, which was still important at the margin in terms of the location of new plant.

The EU ETS decisions were seen as important, but relatively lower down the priority list. However, the importance placed on the EU ETS decisions differed between respondents, probably reflecting the degree to which they were concerned about the impact on existing plant, rather than new investment.

The sense from market participants was that the potential benefits of the EU ETS, principally in terms of free allocations for new entrants, but also possibly in terms of increased power prices, would currently be disregarded due to the current uncertainty over Phase II NAPs. Therefore while the uncertainty is unlikely to be affecting investments which are economic in the absence of these potential benefits, it is likely to be delaying investments which might only be economic with these benefits.

Of the EU ETS decisions, the most important were considered to be the new entrant rules (including both the question of free allocations to new entrants and the definition of new entrant – for example, whether a new entrant in Phase I would continue to be treated as a new entrant in Phase II, and likewise into future phases). The second most important decision was considered to be the use of benchmarking as opposed to grandfathering, or some form of updated grandfathering. JI/CDM limits and the carbon price were considered to be relatively irrelevant factors, because any effect was assumed to be passed through to consumers. All respondents thought that carbon prices were either already being passed through in full, or would be (in all markets) in the medium to longer term.

4.1.1. Comparison of UK with other EU markets

In theory, any potential investment with a risk-adjusted Net Present Value greater than zero should be able to attract investment in a perfectly competitive global capital market. In practice, a variety of constraints exist on the availability of capital, such as intra-company investment budget limits,[1] the availability of management time or other necessary resources, or legal restrictions on the issue of shares. An investment such as a new large-scale power generation project requires considerable technical skills, for example, which are mainly to be found in existing large power companies and cannot easily be increased in the short term. Nevertheless, such limitations may be expected to ease for a market that is consistently attractive over a sufficient period of time to allow for the necessary adjustment.

The market for investment in new power generation projects in Europe is expected to be dominated by the existing large European power companies with customer bases in the country of investment, or in adjacent countries with sufficient interconnector capacity. This will effectively limit the total availability of resources for such projects, and each company will tend to direct its limited resources toward the most attractive market in which they already have a presence, or a realistic prospect of establishing a presence.

This strategy owes much to the fact that independent (or non-European) generators have typically been deterred from investing in European generation and supply markets with a low degree of market liberalisation, or a high degree of vertical integration and/or market dominance. The exception may be in countries with liquid traded markets, where investors may be prepared to take market risk, provided they have confidence in the overall market framework and regulation. Several market participants pointed out that the UK has the most attractive market for independent investment in the EU, as it has a transparent, liquid market with relatively low barriers to entry. Other countries approaching the UK's level of attractiveness on this metric included the Nordic countries and Spain.

On the other hand, the comment was made that spark spreads in the UK are not yet at a sufficiently high level to stimulate new build, although this is 'on the horizon'.

The comment was made that Italy has no workable market, and it will be some time before this is likely to be implemented. Both France and Italy have the problem of market dominance of a single market player, leading to reduced attractiveness for new independent investment.

An issue noted by one respondent in relation to Germany was that the increase in wind power generation in the north of the country has led to insufficient grid capacity for new conventional generation. Although the availability of transmission network capacity is an issue in some parts of the UK where significant *renewable* build is expected (such as the North and West of Scotland), this is unlikely to limit investment in *conventional* generation at a national level. This is because other factors, such as NGT's locational transmission charging methodology and access to the gas network, provide incentives for conventional generation to locate in parts of the country which are not grid capacity constrained (see section 6.7 below).

Countries also differ in terms of the challenge they face in terms of reducing carbon dioxide emissions. A country whose power sector faces a particularly challenging target in Phase II (such as Italy or Spain) will be more likely to allocate fewer free allowances to *existing* installations than a country whose power sector is broadly on track to meet its target (such as the UK or France). However, it is difficult to predict what effect a challenging target may have on Phase II provisions for new entrants. Scarcity of allowances might suggest that a country with a more challenging target might have difficulty setting aside a sufficient number of

[1] For example, a company's head office may only allow a division of the company to invest up to a certain limit, regardless of whether or not additional investment opportunities exist for that division.

allowances for all new entrants; but on the other hand, a country with a challenging target will have a strong incentive to encourage new entrants in order to reduce overall emissions. It may perhaps be of greater relevance whether there are other factors driving new entry, such as demand growth or forced closure of existing plant, as this will provide an economic incentive for new investment even in the absence of free allocations for new entrants.

It was also noted that the carbon intensity (i.e. the amount of carbon dioxide produced per MWh of electricity generated) of the marginal plant varies across different countries, leading to differences in the magnitude of the carbon 'uplift' caused by the pass-through of carbon costs into the wholesale price of electricity. In other words, assuming the same level of gas and coal prices, new gas plant could expect to be most economic in countries where coal plant is at the margin (leading to a higher level of uplift, and hence higher power prices, than in countries where gas plant is at the margin).

Table 1 below summarises the major factors affecting investment and the relative attractiveness of the major EU markets. The factors are necessarily generalised so that a high-level comparison can be made between countries.

Table 1: Factors Affecting Investment in the Major EU Power Markets

	Need for New Capacity to meet Demand[2]	Need for New Capacity to meet Emissions Targets	Degree of Liberalisation[3]	Major Companies[4]	Demand Growth[5]	Emissions Trajectory[6]
UK	Medium	High	1	6/6	1.4%	Downward/On track
Germany	Low	High	2	2/4	0.7%	Downward/On track
France	Medium	Low-Medium	4	1/1	2.0%	Flat/On track
Spain	High	Medium	3	2/2	3.1%	Upward/On track
Italy	High	High	4	1/1	2.7%	Upward/Not on track

[2] This is based on the combination of underlying demand growth, closure of existing capacity, and the level of the existing plant margin.
[3] 1 being the most liberalised, 4 being the least.
[4] This has been divided into the number of major companies in generation and the number of major companies in supply. A smaller number of companies in the generation sector suggests a less competitive market, perhaps with higher profit margins, whereas concentration on the buy side (smaller number of suppliers) will tend to put downward pressure on profit margins.
[5] Source data: Eurelectric, Eurprog 2004 for Germany, France, Spain and Italy; NGT Seven Year Statement for the UK.
[6] This has been divided into whether the historical trajectory (since 1990) is broadly upward, downward or flat; and whether the country's Phase I allocations appear to be in line with meeting their Kyoto targets, or not.

The table shows that Italy and Spain have an urgent requirement for new capacity, driven by physical considerations (demand growth, reducing the plant margin) as well as carbon considerations. However, Italy in particular remains unattractive due to the lack of transparency in its market, and the dominance of Enel. Spain is a more likely investment destination in the near term.

The UK and Germany are similar in terms of their requirement for new capacity, while the UK is a clear front-runner in terms of market structure, transparency and regulatory certainty. France has a smaller total requirement for new capacity, and the dominance of EDF is a significant barrier to investment by new entrants.

4.2. Actions Taken by Generators

The EU ETS provides a driver for investment in lower carbon intensity generation. To this extent it should encourage investment in existing plant to reduce carbon intensity. There are a number of ways of reducing carbon intensity:

- **Improvements in Generation Efficiency**

Although in theory it may be possible to improve generation efficiency at some stations, the high fuel component in the marginal cost of generation has meant that the power sector has always been extremely focused on maximising the efficiency of plant, although it has to be accepted that there is often a trade-off between optimising efficiency and maintaining plant flexibility (for peaking plant, the ability to respond quickly and having low fixed costs to spread over short periods of generation may be more important than efficiency of generation). Thus, it is unlikely that significant improvements in generation efficiency of existing plant will be made as a direct response to the EU ETS.

- **Fuel Switching within Station**

Some stations have dual fuel capability, and so can reduce carbon intensity by switching fuel. In GB three stations (Peterhead, Kingsnorth and Didcot A) have dual fuel capability, although only Didcot A has coal/gas dual fuel and so could switch to a significantly lower intensity fuel source.[7] Although it would be possible to retrofit dual firing with gas at coal stations, there is a relatively large cost associated with such adaptations and connection to the gas transmission grid. In addition, the reductions in carbon intensity are much lower than those that would arise from the construction of a new CCGT. Thus, it is considered unlikely that there will be significant investment in dual firing of existing stations as a result of the EU ETS.

- **Fuel Switching within a Generation Portfolio**

Most of the portfolio generators have a mix of generation technologies within their generation fleet. Portfolio generators will constantly optimise the running within their portfolio in response to changing demand, outages and commodity prices. Thus, the EU ETS simply provides an additional parameter that should be taken into account within this optimisation, and should not lead to increased administrative costs. The impact of portfolio optimisation is captured in detail within the ECLIPSE modelling presented within this report.

- **Investment in New Generation Capacity**

A key response to the EU ETS will be through investment in new generation capacity with lower carbon intensity. New CCGT plant is expected to replace up to 3GW of coal

[7] Peterhead uses gas and oil and Kingsnorth uses coal and oil. In addition, some CCGTs have the ability to run for short periods with a backup fuel. However, as the backup fuel is usually higher carbon intensity than gas, this does not offer any opportunity to reduce emissions.

plant projected to become uneconomic over Phase II through a combination of changing commodity prices, emissions constraints and the EU ETS. Further new generation capacity is expected to be required to replace over 2GW of nuclear plant expected to close over Phase II, as well as to meet underlying demand growth. While the EU ETS will not provide the primary driver for these latter investments, the existence of a price for carbon emissions will provide an incentive to minimise the carbon intensity of any new generation. Finally, the Renewables Obligation provides the primary driver for an estimated 6GW of new renewable capacity over Phase II. Again the impact of the EU ETS on investment in new generation capacity is captured in detail within the ECLIPSE modelling presented within this report.

- **Investment in JI/CDM Projects**

Investment in JI/CDM projects could give players access to cheaper emissions credits from abroad (CERs and ERUs). It is likely that this route may be pursued by some of the large pan-European utilities, but this has not been investigated in detail in this report. However, the impact of ERUs and CERs has been discussed, and the sensitivity of the impact of the EU ETS to the price and volume of CERs is investigated in detail.

4.3. Additional Costs

There are a number of additional costs that generators will face as a result of the introduction of the EU ETS. These include:

- **Trading**

The introduction of the EU ETS has created another commodity that needs to be managed and traded by generating stations. There are costs associated with trading commodities (such as the costs of additional personnel/training, IT/communications, broker's fees and market information). However, there are also opportunities for profit from being a physical player in a commodity market. It is likely that the large vertically integrated and portfolio generators are those most able to benefit from the opportunities of trading, and their additional costs will be low in relation to their total fixed costs. Independent generators will face higher costs in relation to their total fixed costs, and may be relatively risk averse in terms of actively trading the carbon markets.

- **Monitoring and Verification**

The EU ETS has created additional requirements for monitoring and verification of emissions. However, the power sector has already (since 1998) been required to monitor and report carbon dioxide emissions over 10,000 tonnes/annum under the Integrated Pollution Control (IPC) regime established under Part I of the Environmental Protection Act 1990, so the additional costs associated with the EU ETS are likely to be relatively low.

- **Regulation**

The EU ETS has created an additional level of regulation for the power sector. While the cost of additional regulation (e.g. additional personnel) for large companies is relatively low, it will be a more significant overhead for independent generators. For example, the cost of hiring an additional person, together with demands on existing personnel for time and data inputs, might add £50-100,000 to the fixed costs for a small generator.

- **Uncertainty**

The EU ETS has introduced additional uncertainty for the power sector, both in terms of the carbon price exposures, and in terms of regulatory uncertainty. Increasing the risks associated with operating in the power sector will increase the costs of operation, due primarily to increases in the costs of capital. A 1% increase in the corporate discount rate (reflecting a relatively small increase in perceived risk) for an 80% debt-financed new CCGT project would add approximately £0.15/MWh to the cost of new entry. Although these effects may be evident across the generation sector, it is likely that they will have a greater impact on independent generators, than on vertically integrated companies with a mix of generation, supply and distribution within the portfolio.

5. SCENARIO MODELLING

This section introduces the quantitative work undertaken to model the impact of various EU ETS factors on the UK power market, and describes the scenarios investigated and assumptions used.

It should be noted that all future prices quoted in this and subsequent sections are in real terms.

5.1. Modelling Tools

The key to understanding the likely impacts of the EU ETS Phase II decisions on the UK power sector is a thorough understanding of the impact of the scheme on the economics of generation. In order to understand the economics of generation in sufficient depth it has been necessary to model in some detail the whole power market for the period to 2020.

Historically, traditional models of the power sector have modelled separately or at best iteratively the various elements of the power market – starting from a forecast of demand and a 'merit order' of generation costs leading to a price and despatch schedule. More recently, this simplistic approach has become less and less effective – increasingly the operation of the market has been strongly influenced by the introduction of policy drivers such as the Renewables Obligations, the Large Combustion Plants Directive and IPPC Directive and – most recently – the EU ETS. Because all these elements of the market are inter-related, to understand effectively the impacts of the various policy measures it is important to model them in a consistent, coherent and fully integrated framework, rather than simply to combine disparate forecasts of power price, renewable build etc.

IPA's proprietary power system model ECLIPSE has been designed to address this interface between policy instruments and the power market. Further information about ECLIPSE is provided at Annex A.

5.2. Scenarios

Three scenarios have been investigated – a Base Case, a Low Case and a High Case. The scenarios are not intended to cover comprehensively all possible developments; rather, they are presented in order to illustrate the relative impacts that various assumptions about future decisions would be likely to have in combination. The Base Case represents a central view (our own, and not necessarily that of the DTI) while the Low Case represents a cluster of assumptions associated with a low carbon price and comparatively generous allocation regime, and the High Case represents assumptions associated with a high carbon price and comparatively strict allocation regime.

The assumptions used in the scenarios are summarised in tabular form and described below.

5.2.1. Base Case

Table 2: Base Case Assumptions

BASE CASE	Phase I (2005-2007)	Phase II (2008-2012)	Phase III & beyond (2013-2020)
EUA Price	€15/tCO_2-e	€20/tCO_2-e	€25/tCO_2-e
CER Price	€15/tCO_2-e	€15/tCO_2-e	€25/tCO_2-e
Installation limit on use of CERs	0%	6%	50%

Allocation to generating sector	130.6MTCO_2/year	130.6MTCO_2/year	No free Allocation
Allocation Methodology	Known Allocations	Pro-Rate to Phase I	Auctioning
New Entrants	100% Free Allocation	100% Free Allocation	No Free Allocation
Closures	Retain for year then surrender	Retain for year then surrender	N/A
Commodities			
Gas: IPA Base case			
Coal: Central UEP			

- ***Description***

The price of allowances (EUAs) increases over the period, reflecting tightening emissions targets across the EU. The increasing availability and use of CERs helps to mediate the price increases. Restrictions in the level of CERs that can be used in Phase II mean that there is a slight oversupply of CERs, allowing their price to fall below that for EUAs in Phase II. However, by Phase III, increased use of CERs ensures that demand is greater than supply, and CERs no longer trade at a discount to EUAs.

Allocations for Phase II follow the same pattern as for Phase I for existing installations, with new installations receiving 100% free allocations.[8] In Phase III the lack of free allocations for existing installations and new entrants serves to change the absolute and relative economics of plant and increase the absolute costs of new entry (for fossil fuel generation technologies).

5.2.2. Low Case

Table 3: Low Case Assumptions

LOW CASE	Phase I (2005-2007)	Phase II (2008-2012)	Phase III & beyond (2013-2020)
EUA Price	€15/tCO_2-e	€10/tCO_2-e	€15/tCO_2-e
CER Price	€15/tCO_2-e	€10/tCO_2-e	€15/tCO_2-e
Installation limit on use of CERs	0%	50%	50%
Allocation to generating sector	130.6MTCO_2/year	130.6MTCO_2/year	65.3 MTCO_2/year
Allocation Methodology	Known Allocations	Pro-Rate to Phase I	Pro-Rate to Phase I
New Entrants	100% Free Allocation	100% Free Allocation	No Free Allocation
Closures	Retain for year then surrender	Retain for Phase then surrender	Retain for year then surrender
Commodities			
Gas: IPA Low Gas			
Coal: High UEP Coal			

[8] While the actual Phase I new entrant methodology is based on benchmarking, it has been assumed for the sake of simplicity that all new plant is as efficient as the benchmark, and that this will continue into Phase II.

- ***Description***

As the carbon market develops and greater numbers of sellers come to the market, EUA prices decrease from Phase I to II. This reflects a number of parties becoming long in carbon either through reduced economic activity or investment in less carbon intense technology. This is also stimulated by an increasing shift from coal to gas fired generation in the power sector, reflecting the relativity in the pricing of these commodities compared to the Base Case.

The ability to use a higher level of CERs against emissions requirements than in the Base Case also helps put downward pressure on EUA prices. However the demand for CERs outstrips supply, forcing the price of CERs to increase to the level of EUA prices.

As the market enters Phase III, the tightening in the emissions target puts upward pressure on the price of carbon.

In the Low Case there is still a free allocation to installations in Phase III and beyond, although there is no longer any free allocation for new entrants. The rules for closure during Phase II are also different, placing slightly different economic pressures on existing plant.

5.2.3. High Case

Table 4: High Case Assumptions

HIGH CASE	Phase I (2005-2007)	Phase II (2008-2012)	Phase III & beyond (2013-2020)
EUA Price	€15/tCO_2-e	€40/tCO_2-e	€50/tCO_2-e
CER Price	€15/tCO_2-e	€40/tCO_2-e	€50/tCO_2-e
Installation limit on use of CERs	0%	0%	50%
Allocation to generating sector	130.6MTCO_2/year	70 MTCO_2/year	No Free Allocation
Allocation Methodology	Known Allocations	CCGT Emission Factor times load factor used in Phase 1 allocation	Auctioning
New Entrants	100% Free Allocation	No free Allocation	No free Allocation
Closures	Retain for year then surrender	Retain for year then surrender	Retain for year then surrender
Commodities			
Gas: IPA High Case			
Coal: Low UEP Coal			

- ***Description***

Tighter emissions targets across the traded sector put upward pressure on carbon prices, and this combined with slower emissions abatement due to less investment in technology to reduce carbon intensity, and higher economic activity, sees higher carbon prices than in the Base Case. The strong gas price relative to coal also stimulates higher emissions from the power sector, also contributing to upward pressure on carbon prices.

The absence of the ability to use CERs in Phase II also puts upward pressure on carbon prices relative to the Base Case. The high level of carbon prices in

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Phase III ensures the demand for CERs outstrips demand, so CERs do not trade at a discount to EUAs.

The difference in allocation methodology and reduced allocation to the power sector in Phase II relative to the Base Case results in changes to the relative economics of plant, with the lack of a Phase II free allocation for new entrants serving to increase the cost of new entry.

5.3. Commodity Price Scenarios

Commodity prices over the forecast horizon provide a significant driver of power prices and the evolution of the industry. The relativity of gas and coal prices particularly impacts upon the economics of different generation technologies, the emissions from the generation sector, and the economics of new entry.

The Low Case scenario has been designed to reflect a set of commodity prices that, *ceteris paribus*, will result in lower carbon emissions and so would provide a fundamental driver for lower carbon prices. The High Case scenario has been designed to reflect a set of commodity prices that will result in higher carbon emissions and so would provide a fundamental driver for higher carbon prices.

The table below shows the commodity and carbon prices used in the scenarios.

Table 5: Commodity Price Assumptions

Scenario	Carbon Scenario	UEP Coal Price Scenario	IPA Gas Price Scenario
Base Case	Base	Central	Base
Low Case	Low	High	Low
High Case	High	Low	High

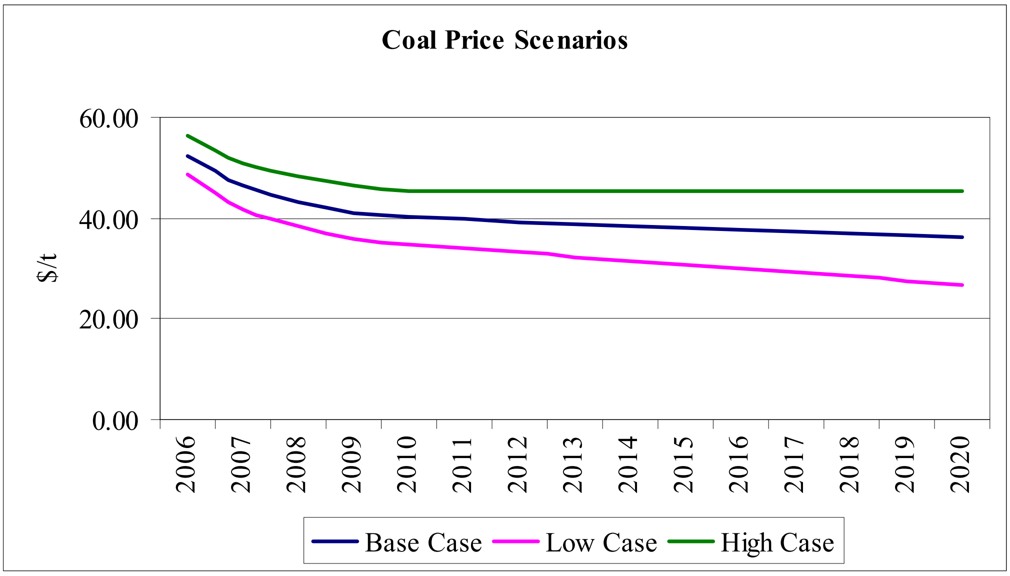
Each of the commodity and carbon price scenarios is discussed further below.

5.3.1. Coal Scenarios

The coal price scenarios are based upon the UEP forecasts used for Government modelling. All of the scenarios show coal prices softening from their current high market price, with significant price reductions over the short term (to 2008) and prices stabilising over the longer term, although remaining backwardated.[9]

[9] A commodity is said to be 'backwardated' if the prices for future delivery are below the spot market price.

Figure 1: Coal Price Scenarios



5.3.2. Gas Scenarios

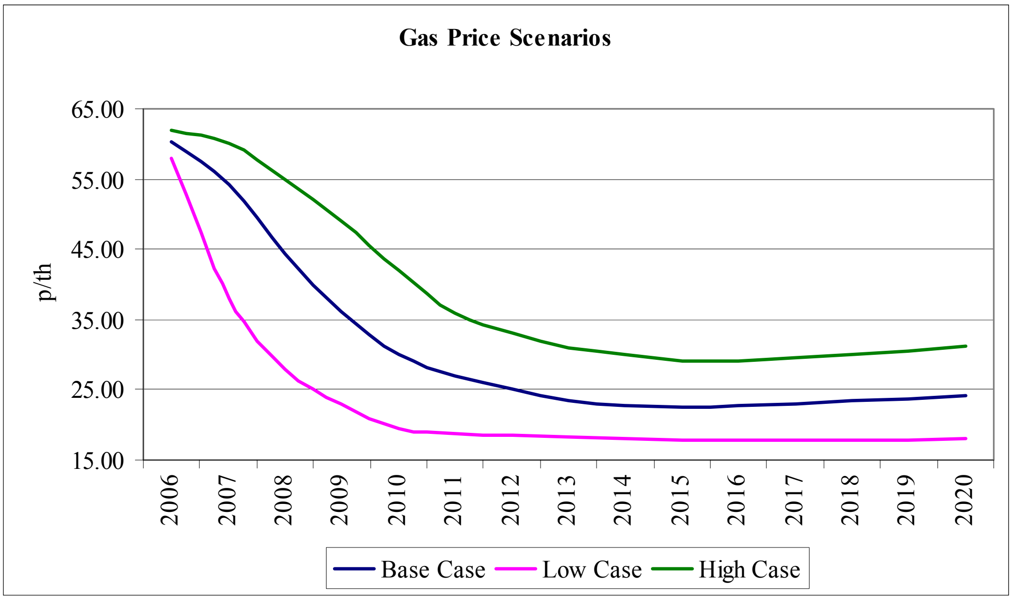
The gas price scenarios have been developed by IPA, and have been used in preference to the UEP gas price scenarios to better reflect the current strength of the gas market. The Base Case scenario reflects the current quoted market prices over the period to 2009 (calendar year). The UEP and IPA Base Case gas forecasts slowly converge and are broadly similar post 2014.

Gas supplies into the UK have not historically had the same contractual price linkages to oil as seen on the continent, but nevertheless there has been a relatively strong correlation between oil prices and gas prices at the UK National Balancing Point (NBP) over the last 10 years. The gas price forecast assumes there will be a strong linkage between oil and NBP gas prices, with the NBP-oil price correlation strengthening as the UK becomes more dependent upon gas imports.

The IPA Base Case gas forecast is based on current NBP gas market quotes to 2009, with gas prices dropping slightly faster than oil prices, reflecting increased plant margins. However, over the period 2010-2015 prices are forecast to strengthen slightly relative to oil price, reflecting the continuing requirements for investment in import and swing capacity within the UK. Beyond 2015, the forecast gas price remains correlated with oil, reflecting the fact that over 2/3rds of gas supplies will be imported, with much of this using oil based pricing.

The differences between the Base and Low and High case scenarios broadly reflect the differences in the oil pricing under the three scenarios, at least in the longer term. The gas price forecast scenarios are shown in the chart below.

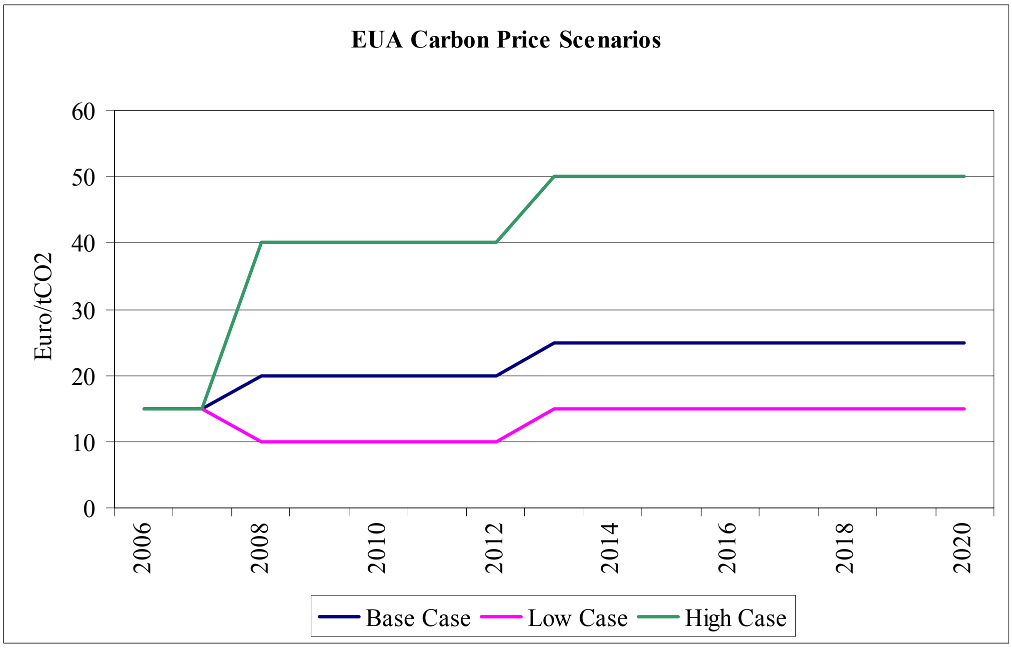
Figure 2: Gas Price Scenarios

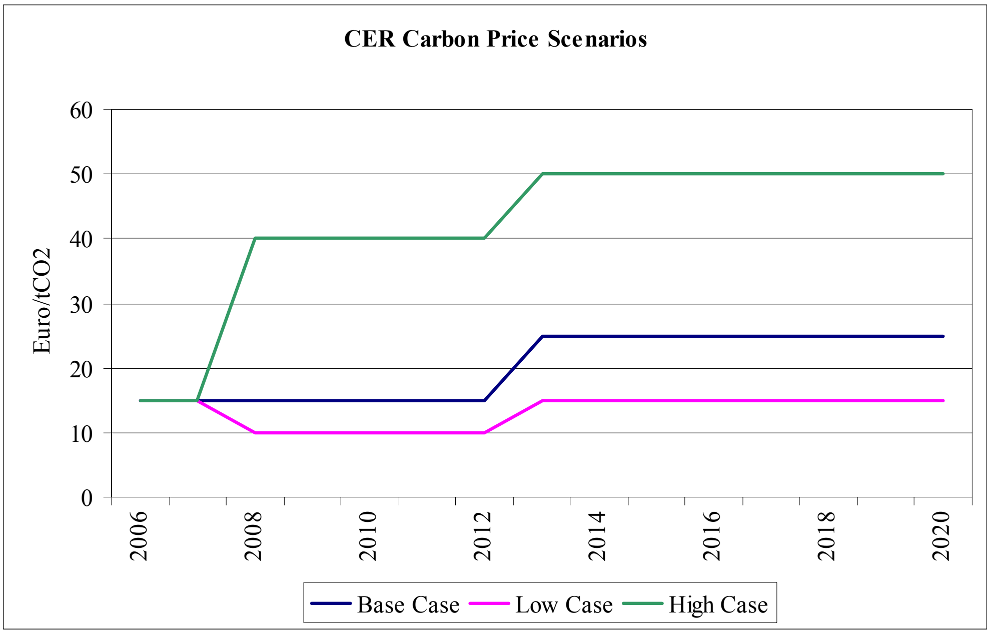


5.3.3. Carbon Scenarios

The carbon price scenarios have been determined through discussions with the DTI and are shown graphically in the chart below.

Figure 3: Carbon Price Scenarios





5.4. Additional Assumptions

5.4.1. Nuclear

The nuclear closure programme has a significant impact on the power market and the carbon emissions associated with power generation. Nuclear closure decisions are likely to be predominantly influenced by safety issues, and so are assumptions inputted into the model.

The nuclear plant closure assumptions are summarised in the table below. The key assumptions are:

- Magnox plant are assumed to close as per current closure plans, as published by NGT in the "Seven Year Statement;" and
- The Advanced Gas-cooled Reactors (AGRs) are assumed to achieve life extensions of five years beyond the life stated in British Energy's October 2004 20-F submission to the SEC. It is accepted that British Energy state that in their submission that graphite core brick cracks and reduced boiler life could mean life extensions are not possible and could even reduce expected lifetimes. However, it is British Energy's stated position that they intend to seek extension to operating lifetimes for their stations.

Table 6: Nuclear Closure Assumptions

Station	Type	Capacity (MW)	Assumed last year of operation
Dungeness B	AGR	1,056	2013
Hartlepool	AGR	1,207	2019
Heysham 1	AGR	1,248	2019
Heysham 2	AGR	1,258	2028
Hinkley Point B	AGR	1,261	2016
Hunterston	AGR	1,288	2016
Torness	AGR	1,364	2028

Dungeness A	Magnox	440	2007
Oldbury	Magnox	475	2009
Sizewell A	Magnox	458	2007
Wylfa	Magnox	1,006	2010
Sizewell B	PWR	1,190	2030

5.4.2. Renewables Obligation Assumptions

The GB Renewables Obligation (RO) on suppliers of electricity increases to 15.4% in 2015/16 (6.3% in 2011/12 in NI), then remains constant beyond that date. These current definitions of the level of the RO are used in the modelling, but it is accepted that as part of the current RO Review, increasing the Obligation beyond these dates will be considered.

Table 7: Renewables Obligation Assumptions

Year	Total Obligation (as % of GB sales)	Total Obligation (as % of NI sales)
2004/05	4.9	2.5
2005/06	5.5	2.6
2006/07	6.7	2.8
2007/08	7.9	3.0
2008/09	9.1	3.5
2009/10	9.7	4.0
2010/11	10.4	5.0
2011/12	11.4	6.3
2012/13	12.4	6.3
2013/14	13.4	6.3
2014/15	14.4	6.3
2015/16	15.4	6.3
2016/17-2020/21	15.4	6.3

5.4.3. Allocation Certainty

It has been assumed that the allocations for future phases are known several years ahead, and so investment and closure decisions are based upon 'known' allocations. Thus, investment and closures reflect correct economic behaviour, with allocations not being discounted to reflect the uncertainties that would exist where allocations are unknown. The effect of uncertainty on investment decisions has been discussed at section 7.5 below.

5.4.4. Carbon Pass-Through

The modelling assumes that carbon costs are passed through to the wholesale power price as a variable cost, and so increase the short run costs of generation. This increases the fundamental price of electricity by the price of carbon multiplied by the carbon intensity of the marginal unit. The rationale for this treatment of carbon costs is that generating electricity requires the surrender of EUAs which could otherwise be sold on the carbon market, and therefore the use of EUAs has an opportunity cost which should be priced into the marginal cost of generation.

5.4.5. IPPC and LCPD

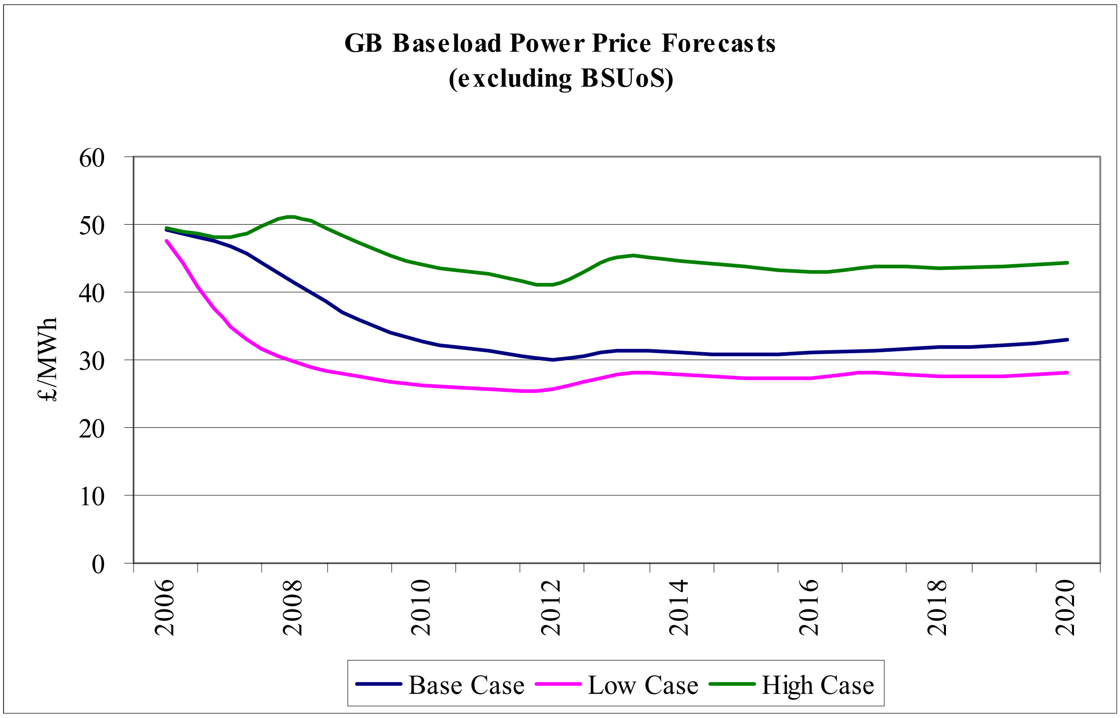
The following assumptions have been made about the IPPC and LCPD regimes:

- The LCPD is implemented within the UK using an Emission Limit Value (ELV) approach, at least for the generation sector;
- All non-FGD coal plant apply for and receive a limited hours derogation from the LCPD;
- The definition of the sulphur limits under the IPPC is consistent with the LCPD and means that non-FGD plant can run for a maximum of 2,500 hours per year over the period 2008-2015. This is assumed to be evenly spread over the period; and
- Plant that have received a limited running derogation under the LCPD are not forced to close post 2015, but are re-licensed as peaking plant with a maximum annual running of 1,500 hours. This affects some 9GW of non-FGD coal plant. If re-licensing is not possible, the plant would be required to close, potentially placing the system under considerable strain unless additional plant were constructed in the expectation of consequent higher peak power prices. This would most likely be less efficient OCGT plant (rather than CCGT plant), as this has lower fixed costs to spread over peak running hours. Nevertheless, it should be noted that peak power prices would have to spike at very high levels to support the economics of building new plant to meet the last MWh of peak demand.

6. SCENARIO ANALYSIS

This section discusses the modelling results associated with each of the scenarios, in terms of the power price, the evolution of the generation mix and the level of system security provided. The wholesale price track associated with the three scenarios is provided in the chart below.

Figure 4: GB Baseload Power Price Forecasts (excluding BSUoS)



In each of the three scenarios wholesale electricity prices respond to falling commodity prices, with reductions in price typically mitigated by increasing carbon costs and tightening plant margins due to nuclear closures. Carbon pricing provides a driver for structural change within the industry, which over the forecast horizon provides increasing economic advantage to lower carbon intensity generation. This supports power prices above the cost of new entry for CCGT over periods of the forecast, and leads to significant CCGT capacity development as well as closure of some coal plant (as its load factor falls as a result of competition from CCGT plant). The rate of structural change of the industry is driven by the relativity of commodity prices, carbon prices and the rules governing carbon allocations. Thus both power prices and the rate of evolution of the generation capacity vary between the scenarios.

The results are discussed by scenario and presented graphically in the figures below which show, for each scenario:

- Comparison between converted seasonal coal and gas prices[10] including the impact of carbon, which illustrates the relative competitiveness of coal and gas plant; and
- Wholesale power price forecast, compared with new entrant CCGT costs and short run marginal prices, which illustrates when new gas plant is likely to be built.

[10] 'Converted' prices show coal and gas prices converted into an equivalent cost of produced power (including the cost of carbon) using typical efficiency factors for existing coal and CCGT plant respectively.

6.1. Base Case

This section provides a discussion of the Base Case in terms of the drivers for evolution of the generation capacity mix, as well as analysis of power prices over the forecast horizon.

6.1.1. Period 2006-2007

- Over the period to 2007 power prices begin to soften, due primarily to the softening of commodity prices – particularly gas. Coal plant is initially extremely competitive with gas, but this edge is eroded as relative gas prices reduce.
- The competitiveness of coal means that the coal plant fleet maintains relatively high load factors, constrained by IPPC sulphur constraints, with total coal running reaching around 130TWh/year.
- The impact of ROCs, LECs and higher power prices serves to stimulate renewable build, with around 1.5GW of renewable capacity (mainly wind) added to the system by the end of 2007.

6.1.2. Period 2008-2012

- Over the period to 2008 power prices begin to soften, due primarily to the softening of commodity prices – particularly gas. However, commodity and power prices begin to level toward the end of the period.
- The competitiveness of coal relative to gas is eroded over the period, due both to falling gas prices and the increased cost of carbon. By the end of the period coal is likely to be competitive only over peak periods.
- The LCPD increasingly constrains the running of non-FGD plant, although the completion of FGD at Cottam, Aberthaw and half of Longannet allows potential coal burn to be maintained. Nevertheless, coal burn begins to decline over the period, reflecting reduced competitiveness.
- The lower running of non-FGD plant results in lower load factor plant becoming less profitable, and modelling suggests that around 3GW of coal plant could close over the period 2009-2012.
- The closure of the Magnox nuclear plant, coupled with the closure of coal plant and increasing demand, begins to put downward pressure on the plant margin. This allows upward pressure on power prices resulting in an increasing spread between system short run marginal costs and market price.
- The strength of the power price ensures that new CCGTs (receiving 100% free carbon allocations in this scenario) are economic, and around 5GW of plant is built over the period, likely to commence with the construction of plant such as Marchwood and Langage (combined over 2.5GW) that are already in project planning.
- ROC prices are reduced but are maintained above the buy-out price and so continue to stimulate renewable build, with around 6GW build over the period, primarily a mix of on- and off-shore wind.

6.1.3. Period 2013-2020

- Power prices initially increase slightly in response to carbon prices but then remain relatively stable over the remainder of the period, reflecting relatively stable commodity and carbon prices. However, this price stability masks significant evolution in the generation mix, and the requirement for new build maintains wholesale prices above new entry levels.
- The increase in carbon costs serves to further reduce the profitability of coal generation, which is no longer competitive with gas over the period. In particular, non-FGD coal plant are increasingly constrained over the period. Modelling suggests that over 2GW of plant close over the period to 2015, with the economics of remaining plant remaining challenging, but some plant may have to be maintained to offset forecast nuclear closures.
- The coal closures, coupled with the Nuclear AGR closure program (approximately 6GW closed over the period) and continued – although slowing – demand growth, result in increasing downward pressure on the plant margin (see section 6.6), which implies continued upward pressure on the wholesale price of electricity.
- Power prices are maintained above the cost of entry for new CCGT plant (the cost of which increases due to the removal of a right to free allocations), and this continues to stimulate build, with around 2GW built to 2016 and a further 4GW built to 2020, effectively replacing nuclear plant as it closes.
- The ROC price is maintained above the buy-out price to 2017, resulting in strong renewable build – with around 7GW built over the period, a mix of offshore and onshore wind and some biomass. However, the annual Renewables Obligation is fully met in 2017, and beyond this point the modelling suggests the ROC price could reduce below the buy-out price.[11] Modelling suggests that the price is initially likely to reduce to around £10/MWh, reflecting the additional value required to meet the marginal costs of biomass plant, however toward the end of the forecast the price could reduce toward zero. The reduction in ROC prices limits renewable build beyond this point, with onshore wind providing the only technology that is viable without support, with the prospect of around another 1.5GW constructed over the remainder of the forecast period.
- Over the period the generation mix becomes increasingly dominated by gas-fired generation, with increasing volumes of wind generation. The increasing level of intermittent generation tends to increase the expected level of unserved electricity, notwithstanding increasing levels of generation capacity. It is assumed that some coal plant suggested by the model to be uneconomic is maintained on the system to provide additional flexible capacity (see section 6.6 for a fuller discussion).

[11] ROC prices will only collapse if renewable developers continue to construct projects beyond those required to meet the obligation. The modelling suggests that the economics of some renewable projects may be supported by power price alone. However, developers may be more conservative in their assessment, and not build *through* the RO requirements.

Figure 5: Base Case Converted Seasonal Commodity Prices (Including fuel costs and carbon costs at typical plant efficiencies)

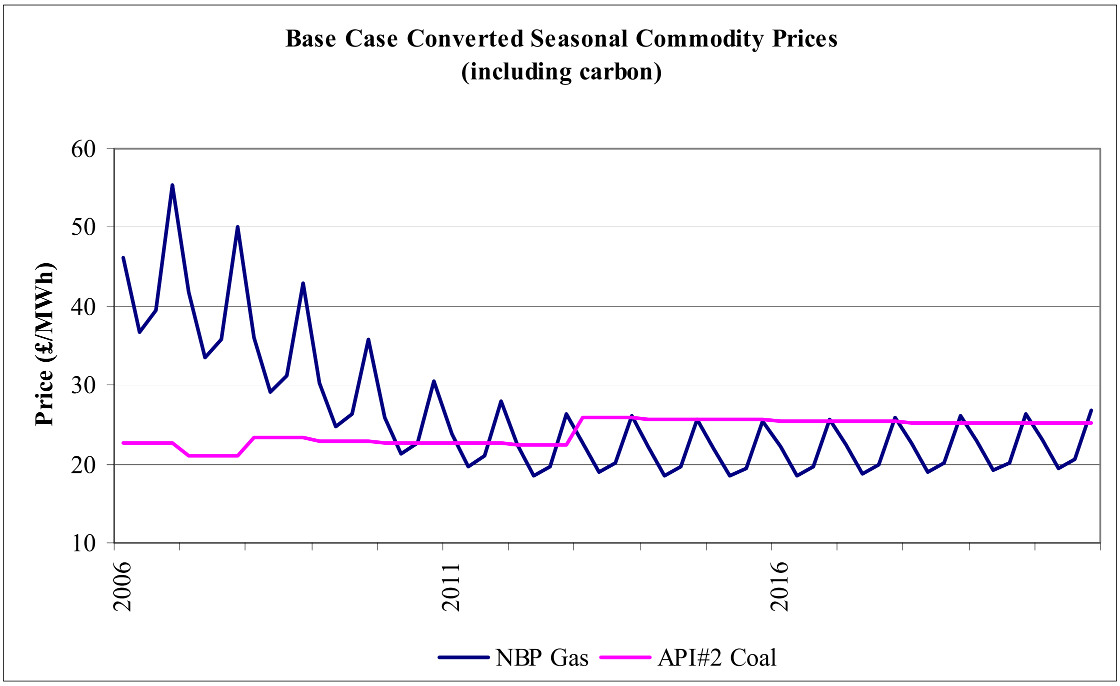
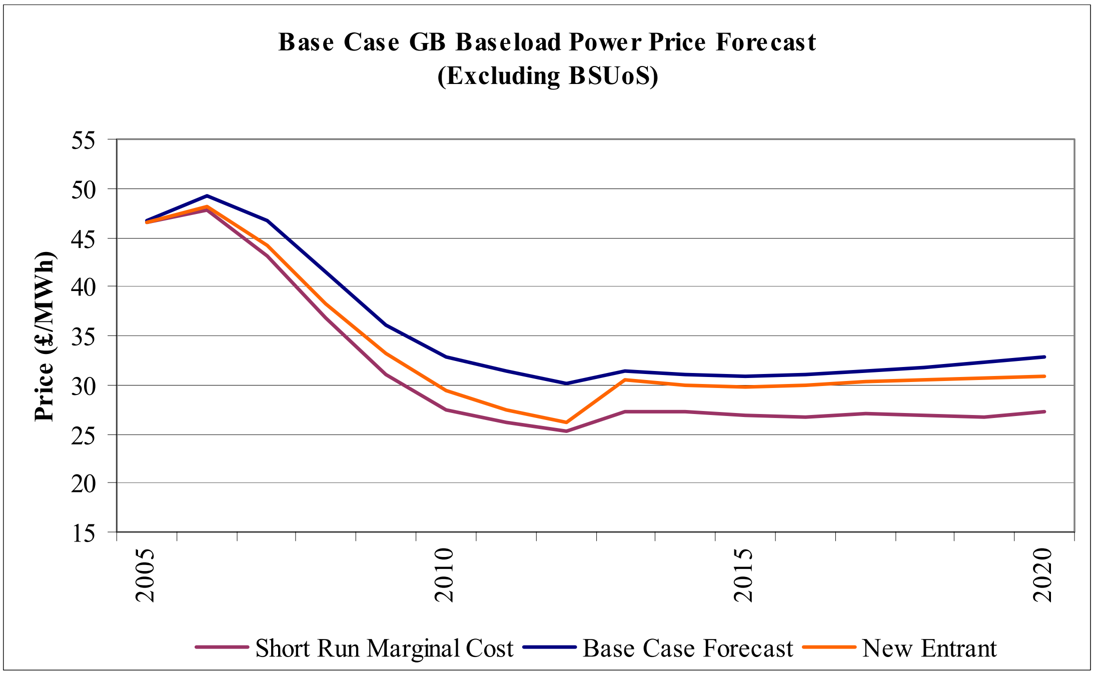


Figure 6: Base Case GB Baseload Power Forecast (Excluding BSUoS)



6.2. Low Case

This section provides a discussion of the Low Case in terms of the drivers for evolution of the generation capacity mix as well as analysis of power prices over the forecast horizon.

6.2.1. Period 2006-2007

- Power prices soften significantly over the period reflecting reductions in commodity prices – in particular, gas. Market prices are maintained relatively close to short run marginal costs, reflecting a reasonable plant margin and low drivers for capacity change. The lower gas and carbon prices ensure that power prices are lower than in the Base Case.
- Coal plant is competitive relative to gas-fired generation over the period, despite reductions in the gas price. Coal plant achieves relatively high load factors, similar to those in the Base Case, with the IPPC sulphur limits again providing a constraint on running.
- As in the Base Case, power and ROC prices ensure significant renewable capacity (mainly wind) is built over the period.

6.2.2. Period 2008-2012

- Power prices continue to soften over the initial few years, stabilising toward the end of the period, driven by reductions in commodity and carbon prices. The lower gas and carbon prices ensure power prices remain lower than in the Base Case. The spread between the system short run marginal cost and market prices begins to grow, responding to the tightening plant margin due to Magnox closures (reflected in a higher level of expected unserved energy as discussed in section 6.6).
- The lower power price provides less of a driver for the development of embedded generation such as CHP, resulting in around 1GW less plant development over the period.
- The competitiveness of coal plant is steadily eroded over the period. Coal plant starts the period competitive with gas over much of the year, and ends the period only competitive over peak hours. The running of coal plant approximately halves over the period, and this puts increasing pressure on the economics of plant, resulting in the closure of around 2.5GW, commencing earlier than in the Base Case. This is driven by lower power prices as well as the closure rules allowing plant to retain carbon allocations for the entire phase under this scenario. However, the overall level of closures over the period is only 0.5GW lower than in the Base Case, due to a lower plant margin (reflected in a slightly higher level of unserved electricity).
- As in the Base Case, the closure of coal and Magnox nuclear stations begins to put pressure on the plant margin.
- The competitiveness of gas plant makes CCGT new build economics favourable, and around 5GW of plant is built over the period, as in the Base Case.
- Despite lower power prices, the ability of renewable generation to obtain ROCs for their output ensures that most renewable technologies are still

profitable. Similar volumes of onshore and offshore wind are constructed, but a slightly lower volume of biomass plant is constructed than in the Base Case, due to lower power and ROC prices making the economics of biomass plant less attractive.

6.2.3. Period 2013-2020

- Power prices increase slightly with the carbon price increase at the beginning of Phase III, and then remain relatively stable over the period, reflecting stable commodity and carbon prices. As in the Base Case, this stability masks significant evolution in the generation mix, with the closure of nuclear and coal plant increasing wholesale electricity prices above new entry levels.
- The economics of coal plant mean that they cannot compete with gas generation, and the reduced competitiveness compared to the Base Case means that coal running is lower in this scenario. This makes the economics of coal plant challenging, with around 2.5GW closed over the period. However, the maintenance of a level of free allocation means that the economics of coal plant are better than in the Base Case.
- Power prices are maintained above the cost of a new entrant CCGT, and increased gas competitiveness relative to the Base Case ensures that a higher volume (8GW over the period) of CCGT is built. This capacity replaces the nuclear plant and ensures that plant margins are not as tight as in the Base Case (resulting in lower levels of expected unserved electricity).
- As in the Base Case, ROCs continue to stimulate renewable build, and similar volumes are built to 2017 when the Renewables Obligation is met. Beyond then the ROC price is extremely sensitive to volumes of renewable output, modelling suggests that the ROC price would reduce below the buyout price in 2019, but as in the Base Case would not collapse to zero. As in the Base Case, onshore wind is economic without ROCs at this point, and a similar volume of new capacity is built to the end of the period.

Figure 7: Low Case Converted Seasonal Commodity Prices (Including fuel costs and carbon costs at typical plant efficiencies)

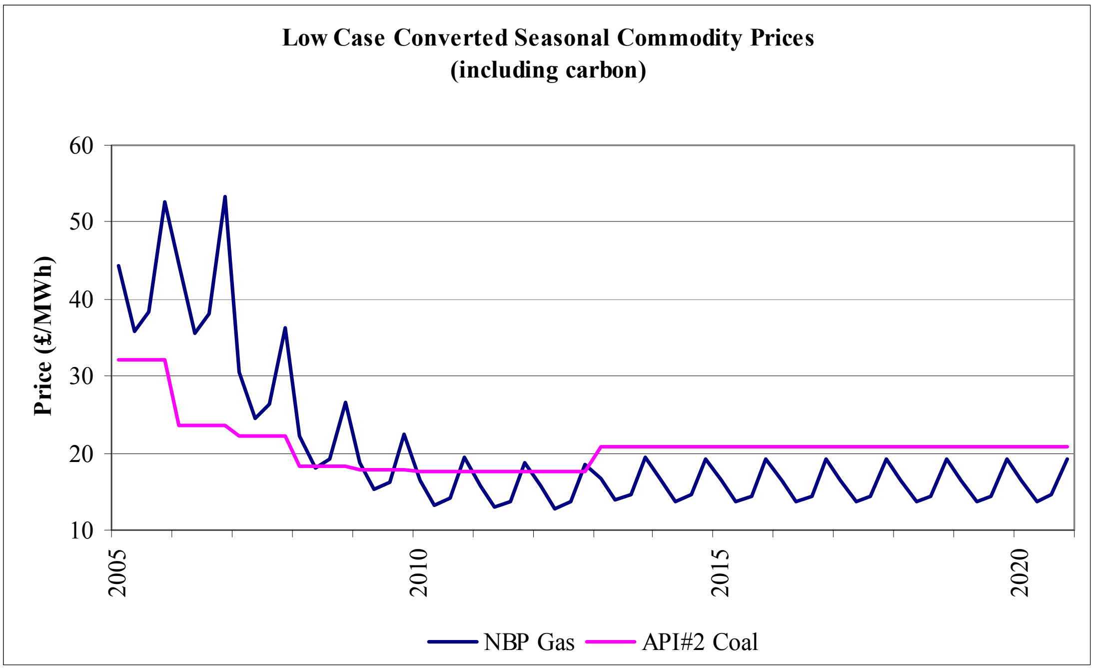
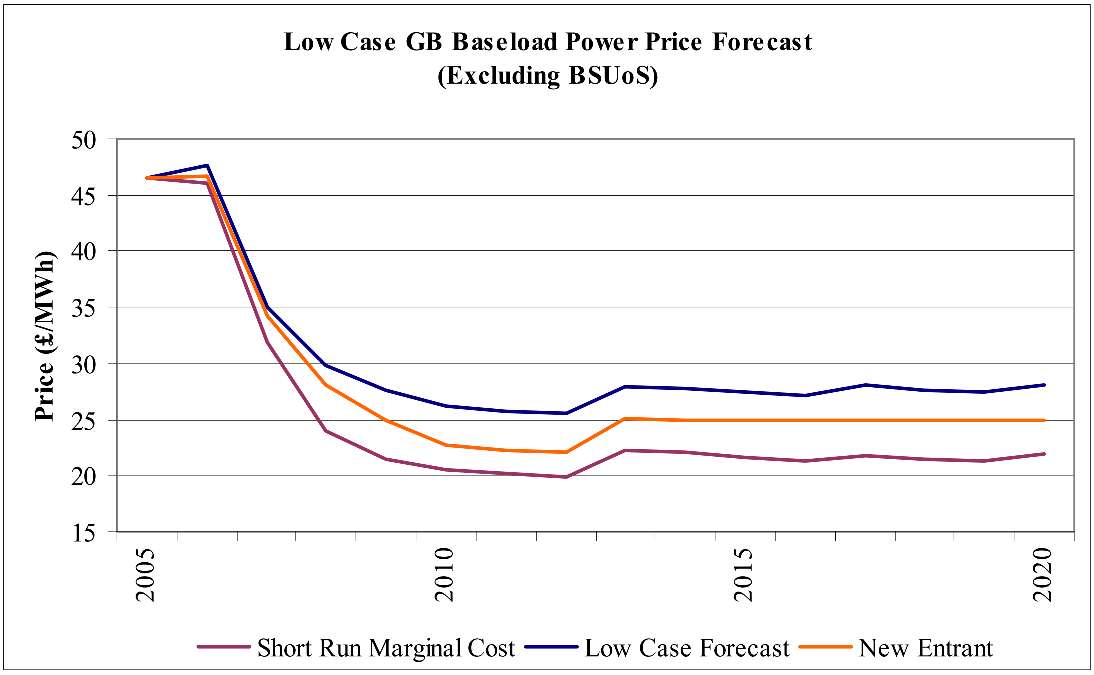


Figure 8: Low Case GB Baseload Power Forecast (Excluding BSUoS)



6.3. High Case

This section provides a discussion of the High Case in terms of the drivers for evolution of the generation capacity mix as well as analysis of power prices over the forecast horizon.

6.3.1. Period 2006-2007

- Power prices soften very slightly over the period, reflecting small reductions in commodity prices, with market prices maintained close to short run marginal costs.
- Coal plant is very competitive relative to gas fired plant, and achieves similar levels of running as in the Base Case, again subject to IPPC sulphur constraints.
- As in the Base Case, power and ROC prices ensure significant wind build over the period.

6.3.2. Period 2008-2012

- Power prices initially strengthen in response to a step in carbon price, and then soften over the remainder of the period reflecting softening commodity prices. The spread between system marginal costs and market prices begins to grow over the period, reflecting Magnox closures and a lower level of CCGT build, which tends to lower the plant margin and to increase the expected volume of unserved electricity.
- The competitiveness of coal is significantly reduced over the period as gas prices fall relative to coal. However, coal running is maintained at a much higher level than in the Base Case, as there is a lower level of CCGT build, reflecting the higher cost of new entry due to the lack of Phase II free allocations for new entrants in this scenario. This ensures that coal plant profitability is typically only slightly reduced, despite lower free allocations for existing plant in this scenario. The improved economics of coal plant relative to the Base Case mean that only 0.5GW is closed over the period.
- The effective costs of new entry CCGT are relatively higher than in the Base Case, due both to higher gas costs, and the lack of free carbon allocations for new entrants in Phase II. However, by 2011 power prices have exceeded the price of new entry, resulting in around 2GW being constructed to the end of the period, less than in the Base Case.
- As in the Base Case, with the support of ROCs onshore wind, offshore wind and biomass technologies are economic, and around 6GW is built over the period, primarily a mix of on and offshore wind, as in the Base Case.

6.3.3. Period 2013-2020

- The power price initially increases reflecting an increase in carbon price, and then softens slightly over the period, reflecting structural changes within the power sector. This structural change allows a spread between market prices and system marginal costs to be maintained.

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- Coal plant is not competitive with gas over the period, despite lower coal prices relative to gas in this scenario. This is due to the higher carbon price in this scenario that penalises coal plant for its higher carbon intensity.
- The AGR nuclear closures put pressure on plant margins, with the challenging economics of coal plant also accounting for 2.5GW of coal closures over the period.
- The modelling suggests the economics of some of the remaining coal plant will be challenging, but the plant may remain open to provide flexibility and capacity to the system, in the face of nuclear closures (see section 6.6). As a result significantly less coal plant is closed over the whole forecast horizon than in the Base Case (although there is a higher level of closures of the period 2013-2020).
- Despite the higher costs of gas, the higher carbon price and higher volumes of coal burn (over the first half of the period) ensure that market power prices exceed the new entry cost for CCGT. Indeed over the first half of the period the system marginal cost exceeds the cost of new entry. This results in around 8GW of CCGT plant is built over the period, predominantly replacing the nuclear plant that is closed. The volume of gas build is higher than in the Base Case over the period, but lower over the whole forecast horizon.
- As in the Base Case, the flattening of the Renewables Obligation post 2016 leads to the obligation being met in 2017, reducing ROC prices below the buy-out price and toward zero. The higher power prices ensure that both on- and off-shore wind are still economic without ROCs. This allows continued build of renewables to the end of the period. Around 16GW of renewable generation is constructed over the period, significantly higher than in the Base Case.

Figure 9: High Case Converted Seasonal Commodity Prices (Including fuel costs and carbon costs at typical plant efficiencies)

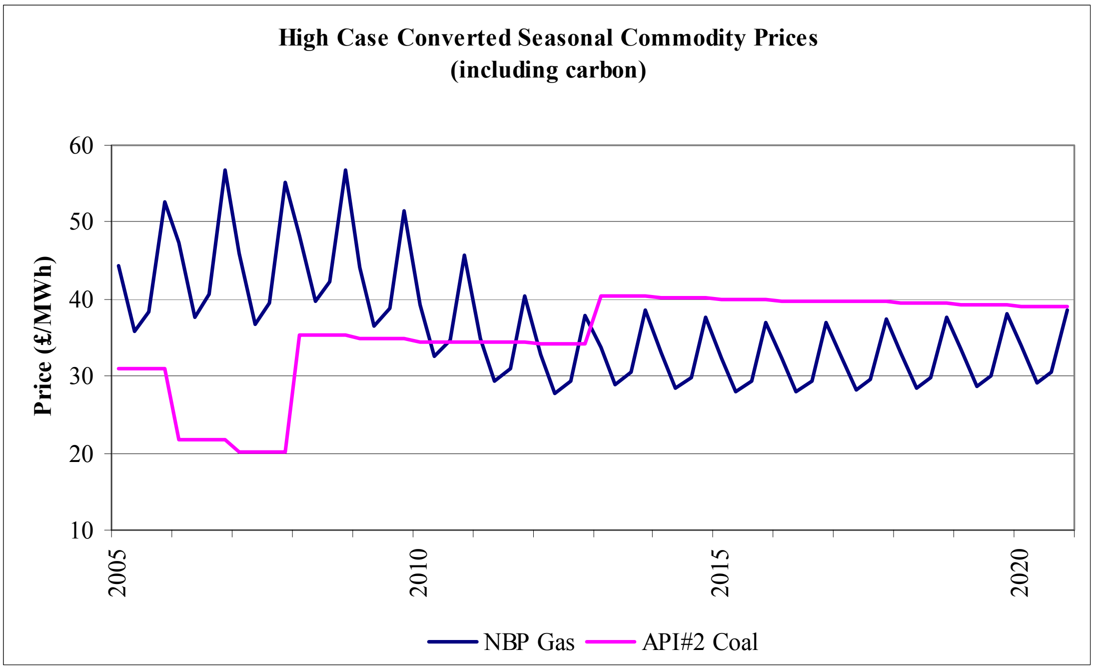
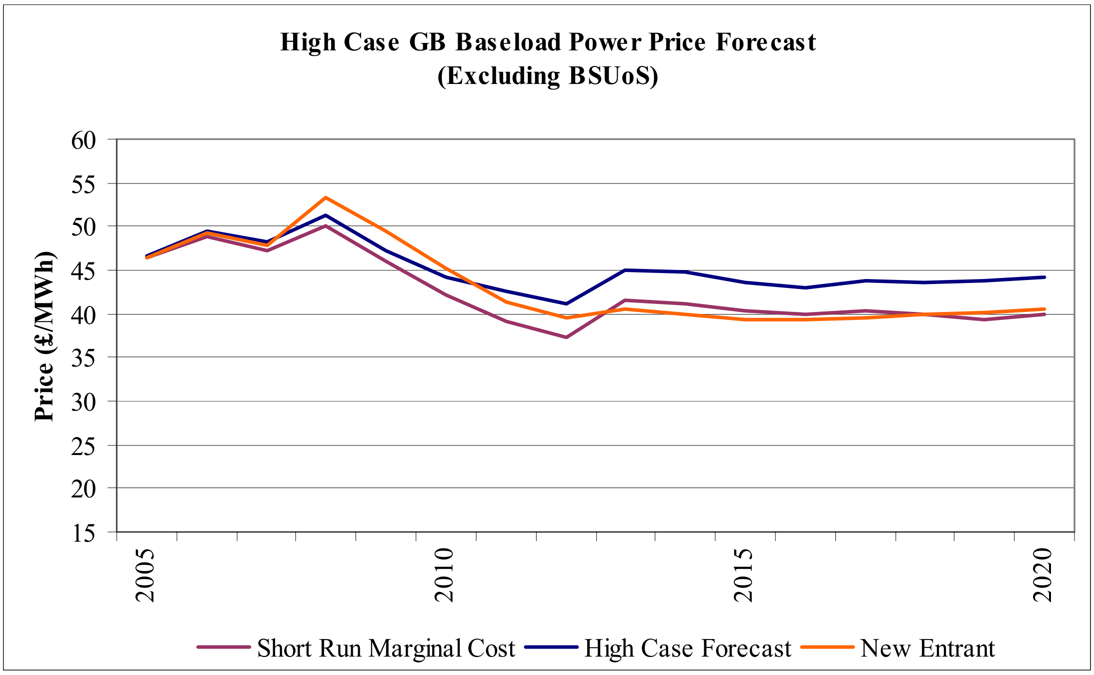


Figure 10: High Case GB Baseload Power Forecast (Excluding BSUoS)



6.4. Impacts on Profitability of Generators

This section investigates the profitability of existing electricity generation assets, by technology and for the sector as a whole. It investigates the impact on generation profitability of the different scenarios, and how the profitability of existing generation changes over time.

The most important consideration for existing generation is whether or not it is likely to be profitable to remain in operation. The most appropriate measure of profitability that is relevant to this decision is EBITDA (Earnings before Interest, Tax, Depreciation and Amortisation), as it reflects the actual revenue earning capacity of the plant. In general, a positive EBITDA means that a plant is worth keeping in operation – even if it does not cover its current financing costs.[12]

When we consider investments in new generation capacity, on the other hand, it is essential to consider the cost of financing, in addition to revenue earning capacity. Therefore in our analysis of new entrants at section 7.5.2 below, we have considered fully built-up costs (i.e. including capital and financing costs) in order to calculate the cost of new entry. Essentially, the cost of new entry has been set at the level that would achieve a rate of return equal to the new entrant's assumed cost of capital.

The EBITDA has been calculated on the basis that generators are exposed to spot power, commodity and carbon prices, and have not hedged prices using long term contracts. The only exception to this is the CCGT stations that are on LTI (Long Term Interruptible) contracts, where IPA has some knowledge of the approximate terms. The calculations of EBITDA have been made on a station basis and exclude the centralised costs associated with administrative and corporate functions.

The EBITDA has only been presented for the main conventional generation technologies (nuclear, coal, CCGT and oil) and so excludes earnings on interconnectors (dominated by foreign power prices), pump storage hydro (which is dominated by ancillary services payments) and earnings from renewables (heavily influenced by revenue from ROCs). However, the ROC income from co-firing with biomass at coal stations has been included within the analysis of the coal stations.

Where plant becomes uneconomic, but has been assumed to be maintained on the system to provide system security, it is assumed that some form of incentive would be introduced to increase earnings to a neutral position, sufficient to make maintaining the plant capacity economic. For a fuller discussion see section 6.6 below.

6.4.1. Generation Profitability

The profitability of the GB power sector is shown in Figure 11, and the average EBITDA per kilowatt of installed capacity for different generation technologies is investigated in Figure 12.

It can be seen that in all the scenarios the profitability reduces over the forecast horizon. There are a number of factors that have a significant influence on profitability, these include:

- Our modelling assumes that carbon prices are passed through to power price at the carbon intensity of marginal plant. However, free allocations provide plant with additional revenue increasing profitability. Over the

[12] Even if a plant is taken into administration because it is unable to meet its debt repayments, it will still be kept in operation by the administrators if it has a positive EBITDA.

forecast horizon the level of free allocations reduces, putting downward pressure on profits. In the low scenario a level of free allocations is maintained over the entire forecast period, and this helps boost profitability from 2013-2020 in the low case.

- The EBITDA of the nuclear stations is directly related to power price. In the Low and Base Case scenarios power prices are initially high and then soften over the forecast period, with nuclear profitability following this trend. In the High Case scenario, high power prices levels are maintained over the forecast horizon, ensuring greater nuclear profitability than under the Base Case. In all scenarios the nuclear closures (due to lifetime limits rather than economic considerations) reduce nuclear capacity over the forecast horizon, decreasing the contribution of nuclear profitability to the sector.

- Coal plant receive typically receive a larger allocation of free allowances than CCGTs due to their higher carbon intensity, and this tends to boost profitability in the short term. However, the use of an allocation methodology based upon CCGT emission factors in the High Case (for Phase II) reduces allocations to coal plant, putting downward pressure on coal profitability relative to CCGTs. In all scenarios coal plant profitability reduces over the forecast horizon, as a result of their reducing competitiveness against gas, due both to commodity price movements and the increasing cost of carbon. Tighter emission limits dictated by the IPPC and LCPD also serve to restrict running making the economics of coal generation more challenging. By 2015, the coal fleet is largely uneconomic and predominantly maintained to ensure security of supply. Uneconomic coal stations are closed but this does not impact upon sector profitability. The profitability of coal stations is higher in the Low case than in the Base Case post 2012, due to continuing free allocations in Phase III. However, the relatively low value of carbon means that this effect is not as significant as if free allocations were maintained under other scenarios.

- The EBITDA associated with existing CCGTs remains relatively constant over the forecast horizon in all scenarios. This reflects the fact that they are the marginal plant over much of the forecast horizon (initially due to high gas prices, and then as coal running reduces). However, existing CCGT manage to extract some economic rent from the market, because the EU ETS provides a stimulus for capacity to evolve from coal to new CCGT, allowing markets prices to be maintained at a sufficient level to make new build CCGT economic. The contribution to sector EBITDA is relatively constant over the forecast horizon.

- Over the forecast horizon the EU ETS provides a driver for capacity change. This typically maintains prices above the cost of new entry, and means that the industry evolves to be increasingly dominated by less carbon intensive forms of generation – in particular, gas-fired plant. The expected retirement of existing nuclear plant provides a further driver for new investment. As the plant mix becomes increasingly dominated by one technology, sector profitability is reduced since all capacity has similar marginal costs. Over the forecast horizon there remains an ongoing requirement for new build. However, it might be expected that beyond the end of the forecast horizon, new capacity will no longer be required, and competition between gas plant could greatly reduce sector profitability.

Figure 11: GB Power Sector Profitability

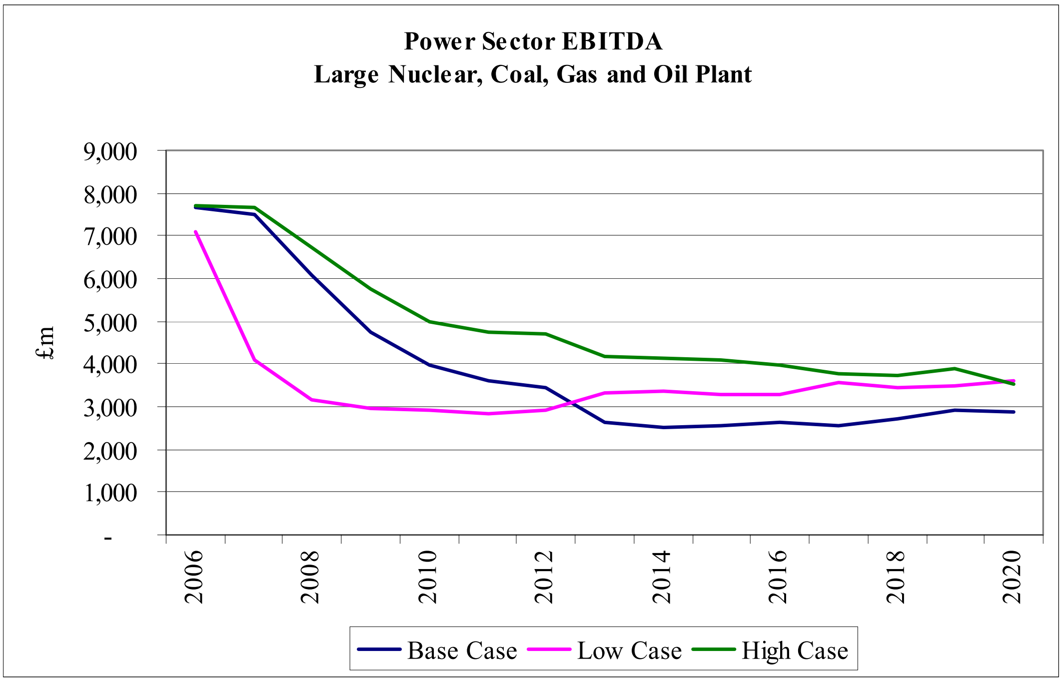
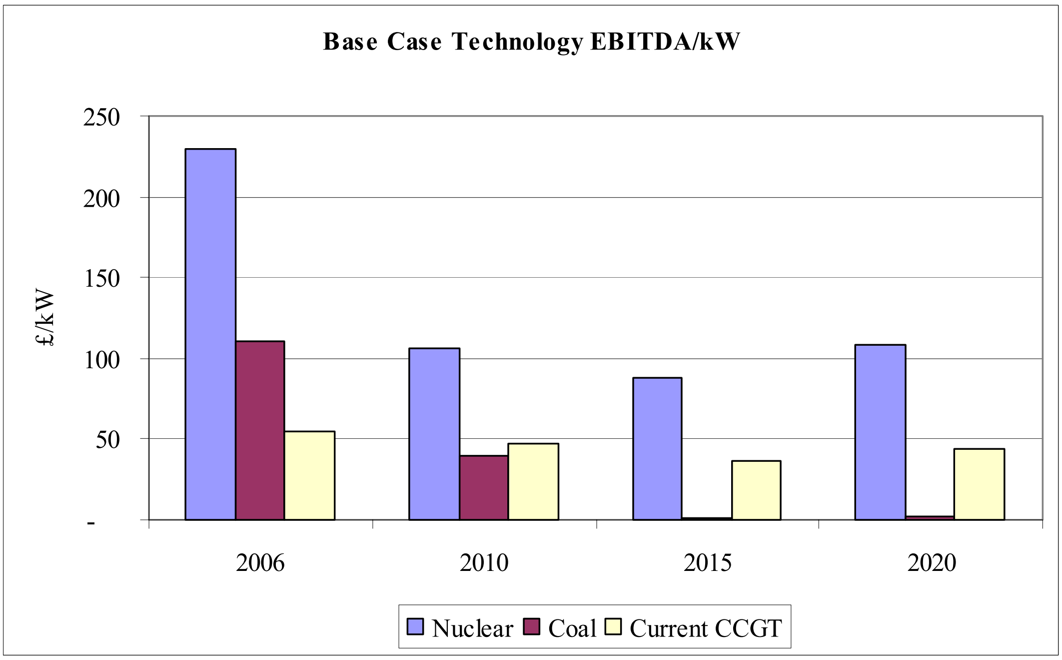
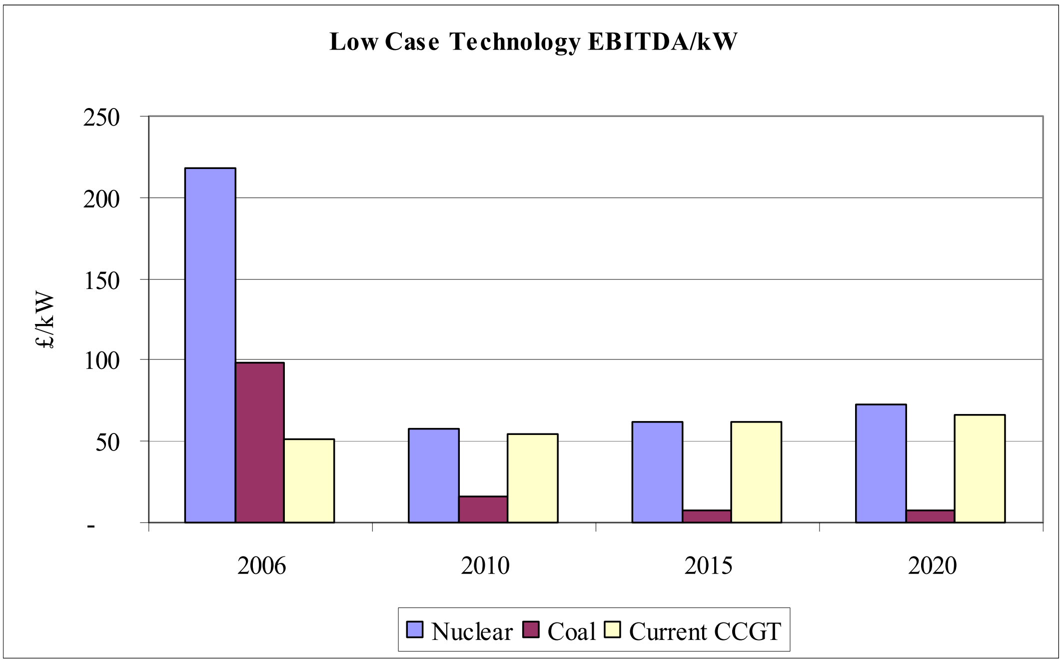
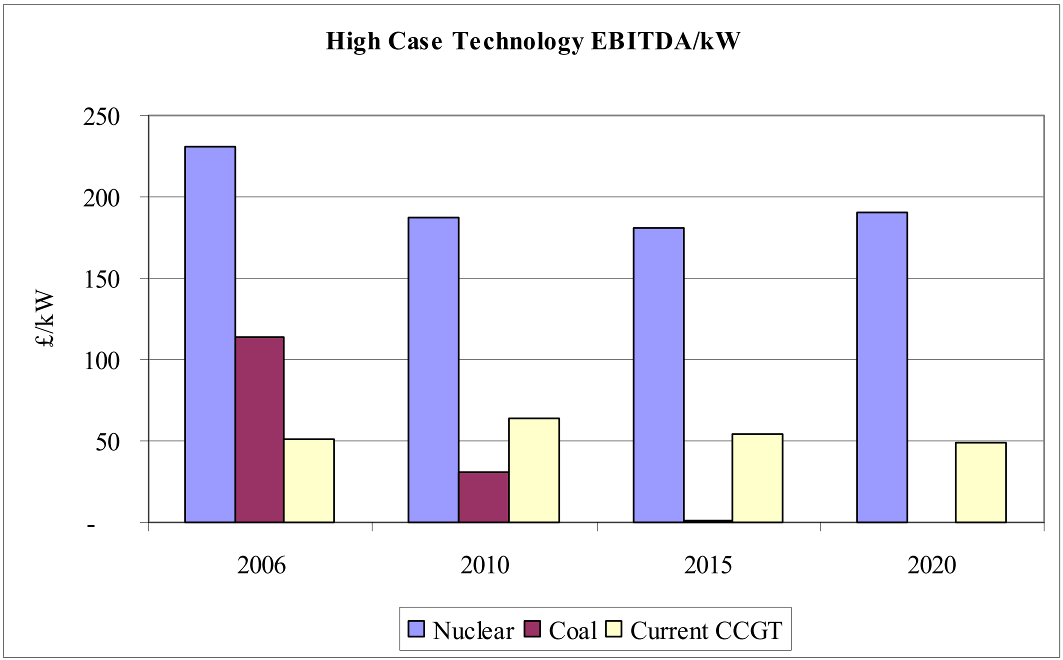


Figure 12: Profitability by Generation Technology




Low Case Technology EBITDA/kW
£/kW
250
200
150
100
50
-
2006
2010
2015
2020
Nuclear
Coal
Current CCGT


High Case Technology EBITDA/kW
£/kW
250
200
150
100
50
-
2006
2010
2015
2020
Nuclear
Coal
Current CCGT

6.4.2. Transfer of Value

This section has highlighted that the power generation sector will see significant earnings over the short to medium term. Furthermore, there has been a significant increase in earnings since 2003 when wholesale prices were at historic lows. Increases in profitability in the generation sector are likely to represent a transfer of value from consumers to generators (to the extent that wholesale prices are passed through into tariffs by retail suppliers).

The increase in sector earnings is the combined effect of changes in commodity prices, the introduction of the EU ETS and capacity changes. For instance, increases in commodity prices have increased power prices, significantly increasing the profitability of nuclear plant. In addition, where there is a significant spread between coal and gas prices, this results in profitability for the generation using the lower price commodity – currently resulting in increased earnings for coal stations.

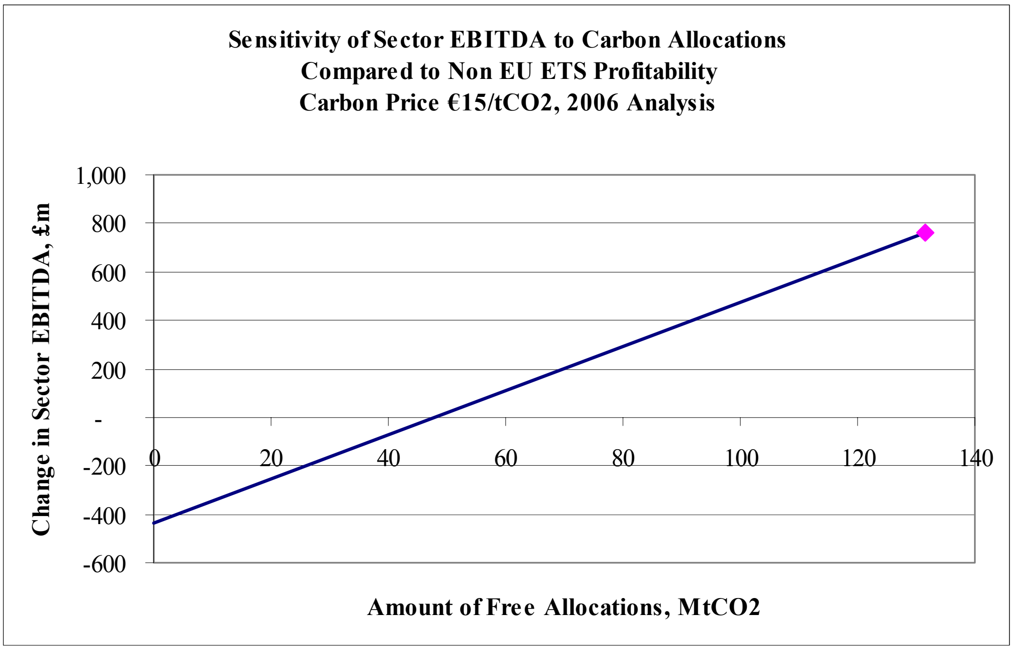
It is interesting to investigate the impact on earnings of the EU ETS alone, as this is indicative of the transfer of value from consumers to generators as a result of the EU ETS. This analysis has been undertaken in Figure 13 for 2006, where the change in earnings resulting from the EU ETS has been plotted against the number of free allocations. Unsurprisingly, since the increase in power price due to the EU ETS is driven by the market price of carbon (assumed to remain constant in this analysis), free allocations constitute a direct contribution to sector profitability. Furthermore, it can be seen that:

- If no free allocations were granted to the sector, earnings would have been reduced as a result of the EU ETS, due to the fact that the average carbon intensity of the marginal plant is closer to the carbon intensity of CCGT plant, and hence the increase in power prices is less than that required to maintain the earnings of coal plant;
- If around 45MtCO_2 free allocations had been granted to the sector then the EU ETS would have had little impact upon sector earnings; and
- The actual Phase I allocation was 130MtCO_2, and it can be seen that this results in an increase in sector earnings as a result of the EU ETS, in the order of £800m/year.[13]

This analysis could be extended to investigate the impact of the EU ETS on sector earnings over the forecast horizon. However, since there is significant development in generation capacity in response to the EU ETS, and as a result increasing capital investment in the industry, it becomes increasingly difficult to compare earnings over the forecast horizon with and without the EU ETS on a like for like basis.

[13] The impact on earnings is equal to the net impact on power prices due to the pass-through of the cost of carbon, minus the difference between free allocations and required allowances.

Figure 13: Impact of EU ETS on Sector Profitability – Base Case



6.4.3. Impact on Market Structure

The power industry has seen considerable changes in recent years. The number of large suppliers has decreased from the 14 original zonal supply companies to the 6 major companies who now compete across the country. In addition, there are a number of other supply companies that provide additional competition, particularly within the industrial sectors. The number of generators increased from privatisation with divestment and new entry, but has been reducing over the last few years, as the major vertically integrated companies have purchased plant. The only area where there is an increasing diversity of generation companies is within the renewable energy sector.

The power industry appears to have reached a level at which further mergers of generators and/or suppliers is increasingly likely to trigger competition concerns. In addition, the major vertically integrated suppliers have all pursued a strategy of maintaining a reasonable balance between generation and demand by owning a sufficient volume of generation assets. Therefore it is likely that as plant is taken out of service (whether as a result of the EU ETS, or for other reasons), the vertically integrated suppliers will seek to maintain this balance in their portfolios by investing in new generation capacity. It is therefore considered unlikely that the capacity changes driven by the EU ETS will result in a significant impact upon the present ownership structure.

However, it is possible that the increased market and political risks associated with the EU ETS may prove a barrier to entry for independent generation project developers, particularly while there is significant uncertainty associated with the level of free allocations. It is therefore considered that it is most likely that the majority of new CCGT plant will be constructed by the major vertically integrated companies over the next 5-10 years, potentially leading to a slight increase in consolidation in fossil-fuelled generation.

6.5. Generation Fuel Mix and Carbon Emissions

This section examines the evolution of the generation mix over the forecast horizon and investigates the impact on emissions. The capacity mix, generation output, total emissions and emissions allocations under the three scenarios are shown in Figure 14, Figure 15 and Figure 16 below. A comparison of the total emissions and emissions intensity under the three scenarios is given in Figure 17.

It can be seen that under all three scenarios, there is a reduction in nuclear and coal capacity, and a significant growth in CCGT and renewable capacity – trends that are to some extent independent of the introduction of the EU ETS. The rate of evolution varies between the scenarios, with coal output and capacity reducing more quickly in the Low Case and less quickly in the High Case. The reduction in coal burn that occurs primarily over the period of Phase II of the EU ETS leads to a reduction in total system emissions and the emissions intensity of the system, as coal is replaced with gas and renewable output. However, toward the end of the forecast horizon, increasing gas and renewable output primarily replaces nuclear generation capacity, and a slight increase in system emissions is observable post 2016 in all scenarios.

Analysis of the total systems emissions shows that under each of the scenarios, there is a different rate of transition to a lower carbon intensity system. However, all scenarios converge to similar carbon intensities around 2015. The rate of change of capacity broadly reflects differences between the commodity price and carbon price assumptions in the scenarios, specifically the changes associated with the relative competitiveness of coal and gas.

In all three scenarios, the competitiveness of coal is eroded over the forecast horizon, and this results the scenarios converging to similar solutions. Although it would be possible to construct scenarios which yield different capacity mixes, a reduction in the competitiveness of coal is a logical result of the introduction of the EU ETS. Further, although a lower coal price may increase coal burn, this would logically increase demand for carbon – and so increase carbon price, reducing coal competitiveness. There are therefore a number of factors that are likely to drive the evolution to a lower carbon intensity system, and this is likely to result in different commodity price scenarios converging on a CCGT dominated system.

There is significant growth in wind generation capacity over the forecast horizon under all three scenarios. Wind is an inherently intermittent resource. This means that there is a probability associated with any given proportion of the total potential capacity of a wind generator being available at any given point in time.

The ‘capacity credit’ of a generator is the amount of capacity that is likely to be available at a confidence level chosen to reflect a desired level of security of supply. The capacity credit of wind generation portfolio will be lower than that of a conventional generation portfolio, as conventional plant has a higher probability of being available at any point in time. This means (*ceteris paribus*) that a larger amount of wind capacity will be required to meet the same level of security of supply provided by conventional generation.

Geographical diversification can improve the capacity credit of wind, provided the wind resource is not geographically correlated to a significant degree. Other developments, such as taller turbine towers or moving offshore, may also improve the capacity credit of wind, either by diversification or by accessing less intermittent wind resources.

The *predictability* of wind output is a separate issue. Even if wind output were completely predictable, its intermittency would still raise the same issues for security of supply. The predictability of wind will affect the *use* of capacity (for example, the degree of ‘readiness’ in which reserve capacity is maintained), but the net system intermittency will determine the *amount* of capacity required to be maintained to provide a given level of security of supply.

The net intermittency of future wind output across the UK is a matter of some debate. It has been assumed here that the output from the wind portfolio across GB is highly correlated, as a conservative assumption. There is evidence to suggest that while wind speeds are highly correlated at distances of 100km or less, the correlation falls below 0.5 for distances over 200km.[14] It is therefore accepted that actual correlations may be lower than assumed, especially with the growth in offshore wind generation over the later half of the forecast horizon, which may be expected to diversify the wind portfolio.

It has been assumed for the purposes of this study that in response to the growth in wind generation the total volume of capacity on the system will need to increase relative to peak demand to maintain a fixed level of system security, resulting in higher total system costs. The increased volume of capacity has been achieved within the modelling by maintaining some otherwise ‘uneconomic’ coal plant on the system over the later half of the forecast horizon. System security is discussed in more detail in section 6.6. In reality, the System Operator may also make use of other options for managing security of supply, including increased use of demand management.

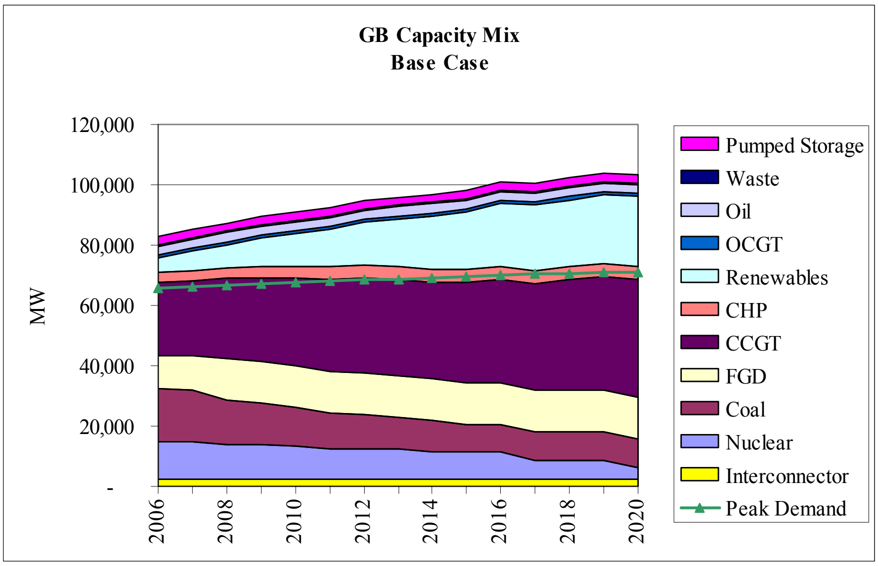
A comparison of sector emissions and free allocations shows that under all three scenarios emissions significantly exceed allocations over Phase I. Over Phase II emissions reduce, and under the Base and Low Cases, emissions fall to a level approximately equal to the allocation volume by the end of the Phase. Under the High Case scenario emissions are greater over Phase II, and the level of free allocations is lower than under the other scenarios, yielding a significant spread between the level of emissions and allocations over Phase II. The Low Case is the only scenario that allocates free emissions after the second Phase, with the assumed amount of free allocations significantly below actual emissions in Phase III.

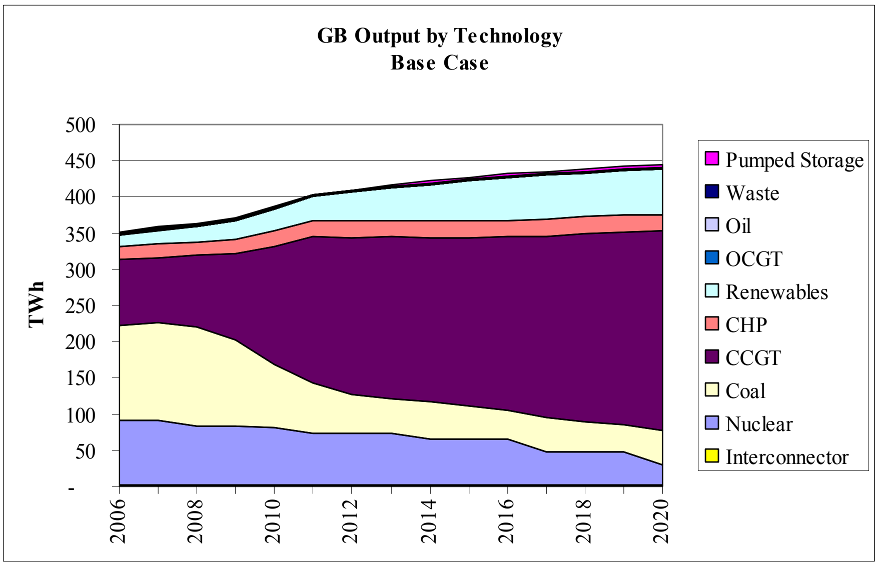
In both the Base and Low Case scenarios new entrants receive free allocations over Phase II, and the level of annual allocations to new entrants grows over the Phase - with the cumulative effect of capacity growth. Under both scenarios the annual volume of free allocations to new entrants[15] grows to around 11.5MtCO_2 per annum in 2012, around 8.5% of the annual allocations. The cumulative allocation required for new entrants over Phase II is around 34 MtCO_2, or 5% of the total Phase II generation sector allocation. This indicates that a new entrant reserve of around 5% of total Phase II generation sector allocations may be sufficient to meet the requirements of new CCGT capacity.

[14] See for example Sinden, G. Renewable Energy in the UK: Intermittency and Security. SuperGen presentation, June 2004.

[15] The figures for new entrants only include new CCGT plant and not CHP, although there is forecast growth in CHP capacity. It is assumed that CHP allocations will be from the industrial sector which the installation serves.

Figure 14: Base Case GB Capacity, Output and Emissions





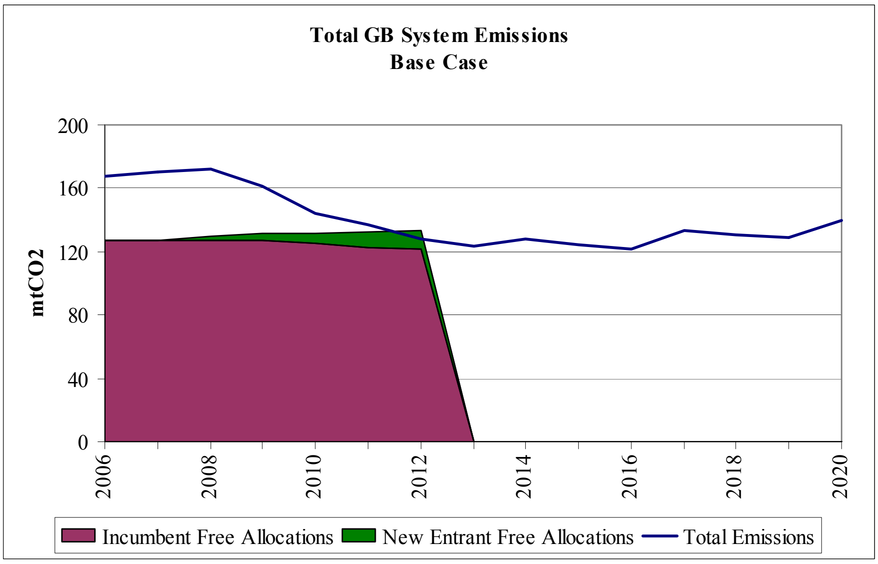
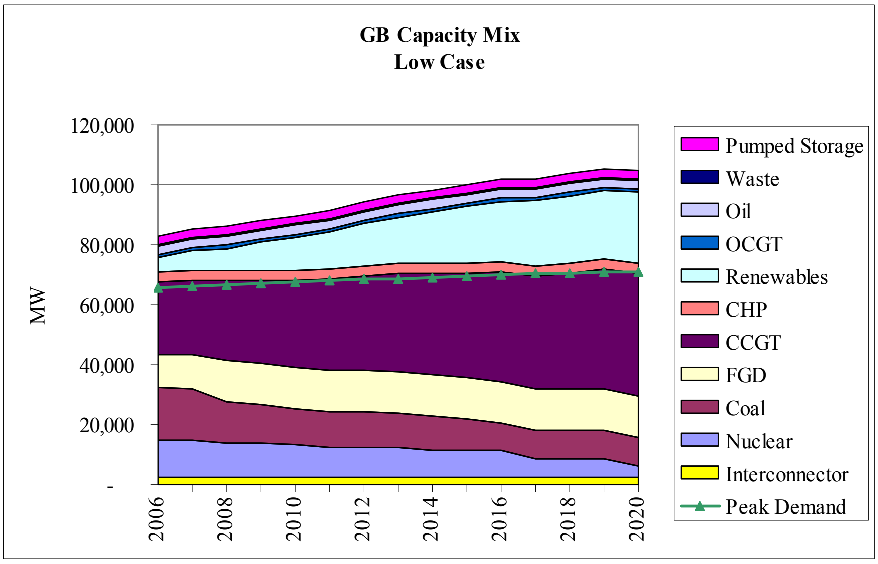
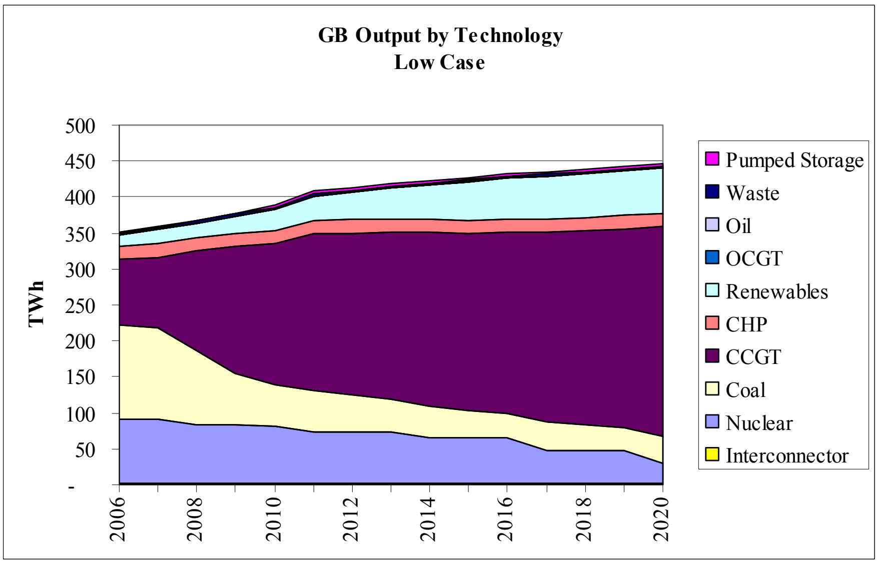


Figure 15: Low Case GB Capacity, Output and Emissions





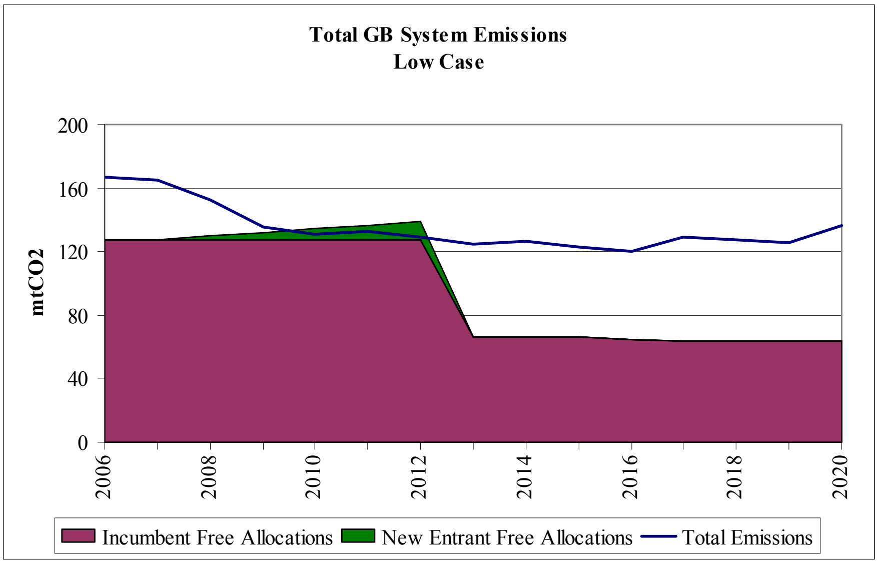
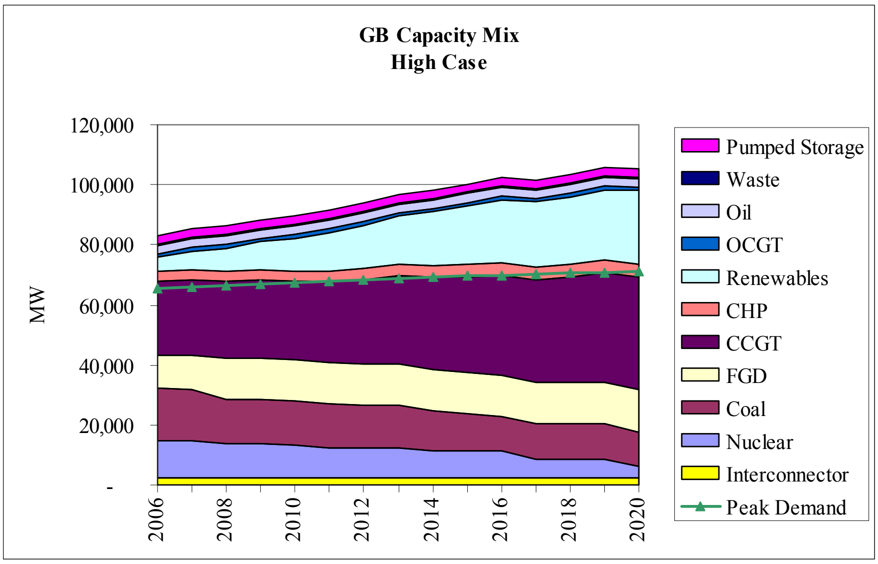
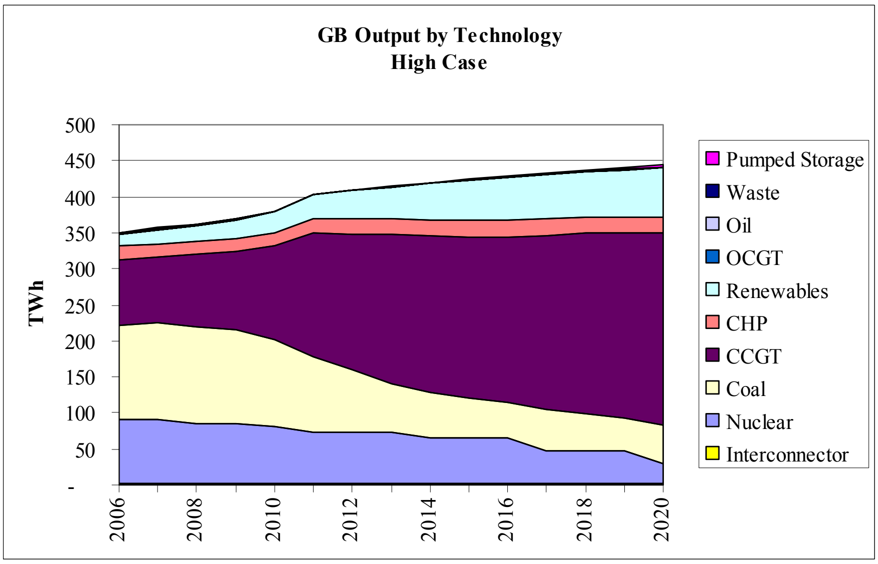


Figure 16: High Case GB Capacity, Output and Emissions





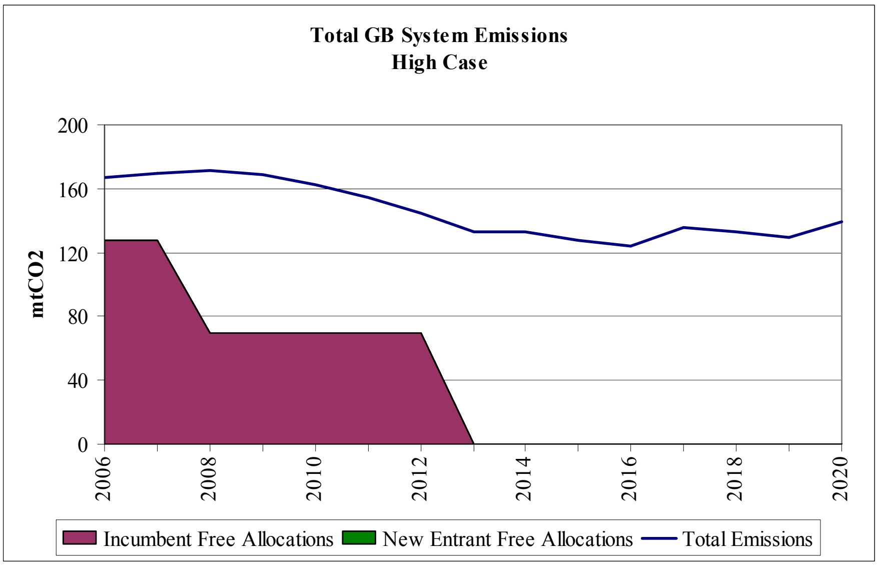
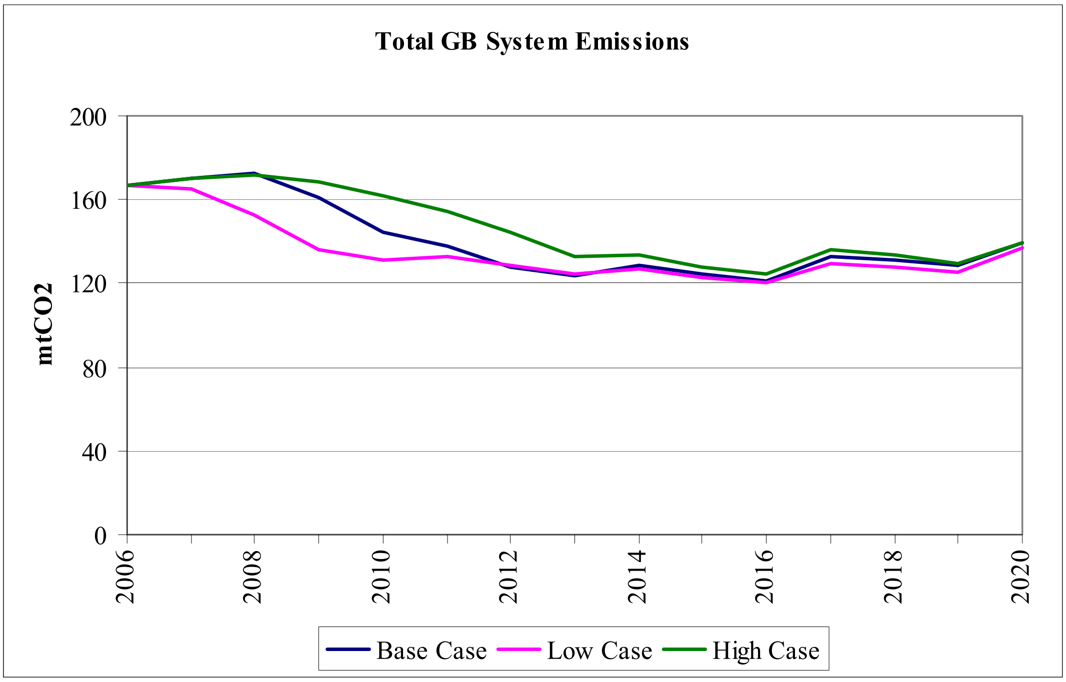
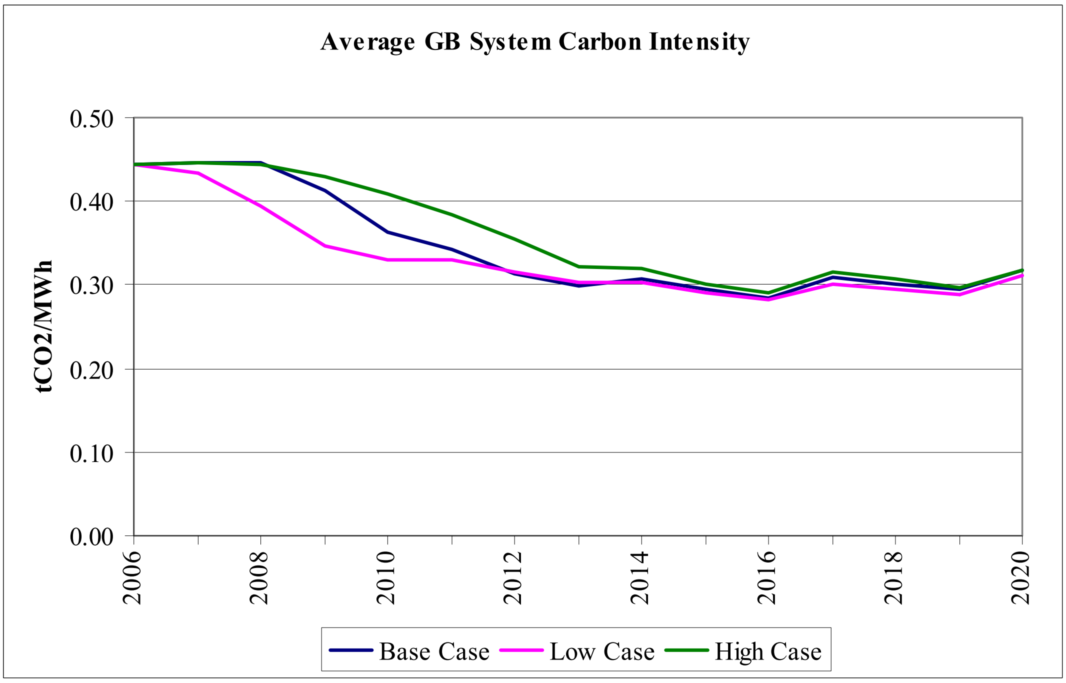


Figure 17: Comparison of Base, Low and High Scenarios' System Emissions and System Carbon Intensity[16]





16 Including emissions from CHP, some of which may be included in the Power Generation Sector.

6.6. Security of Supply

This section discusses the security of supply over the three scenarios. Two measures of security of supply are provided, in Figure 18 and Figure 19 for each of the three scenarios. These are:

- Peak power margins for GB: expected peak demand against expected peak plant capacity (allowing for average unplanned outages and average wind output); and
- Expected annual unserved electricity: the expected volume of electricity that would not be met on average given the distribution of annual demand[17] and the availability of both conventional and renewable generation.

It can be seen that over the period to 2012 the volume of expected annual unserved electricity increases slightly under all three scenarios, indicating a decreasing level of security of supply. This is due to nuclear and coal closures, mitigated in part by new CCGT and renewable capacity as can be seen in Figure 18. The differences between the scenarios relate to the differences in capacity opening and closure due to different commodity and carbon price assumptions.

In the period post 2012, expected annual unserved electricity is projected to increase significantly. This is despite some growth in expected peak capacity as well as growth in the total volume of generation capacity relative to demand (as shown in Figure 18). This is in part due to the increasing contribution of wind in the generation mix, which due to its intermittency provides a lower contribution to system security than the same capacity of conventional plant. It has been assumed in this analysis that the wind resource over GB is highly correlated, which is a conservative assumption. It is accepted that as the wind resource is developed, and particularly as deepwater offshore wind generation is developed toward the end of the forecast horizon, the correlation may decrease, potentially decreasing the uncertainty associated with output over the GB wind generation portfolio, and so decreasing the expected volume of unserved electricity.

Over the forecast horizon the modelling has assumed that some plant identified as uneconomic within the modelling may be maintained upon the system to achieve a given level of security of supply. This is used to maintain the level of security of supply broadly constant over the first half of the forecast horizon. However, even assuming that there is support for uneconomic plant, the level of expected annual unserved electricity increases under all three scenarios, over the second half of the forecast horizon. This is driven by nuclear closures (mitigated by new CCGT build), and the growth of wind generation, which increases the variability of generation available at any point in time. The issues associated with maintaining generation capacity are discussed in more detail in the next section.

Figure 19 shows a higher level of unserved electricity post 2012 in the Base Case than in either the Low or High Cases. In each case this is for different reasons. The Low Case has a lower level of unserved electricity primarily due to a higher level of construction of new gas-fired plant, leading to a lower plant margin over the second half of the forecast horizon. The High Case also has a lower plant margin over that period, but in this case it is due to a combination of low coal prices maintaining the economics of coal plant (leading to fewer closures), and high wholesale electricity prices leading to slightly increased renewables build, beyond the Obligation levels.

[17] The distribution of annual demand has been estimated from historic data. A ‘noise’ distribution has been added to this to reflect the uncertainty in demand, primarily due to weather effects. Allowing for this uncertainty, at peak demand there is 95% confidence that demand will be at most 3.5GW greater than expectation.

Figure 18: Expected Peak Power Margin

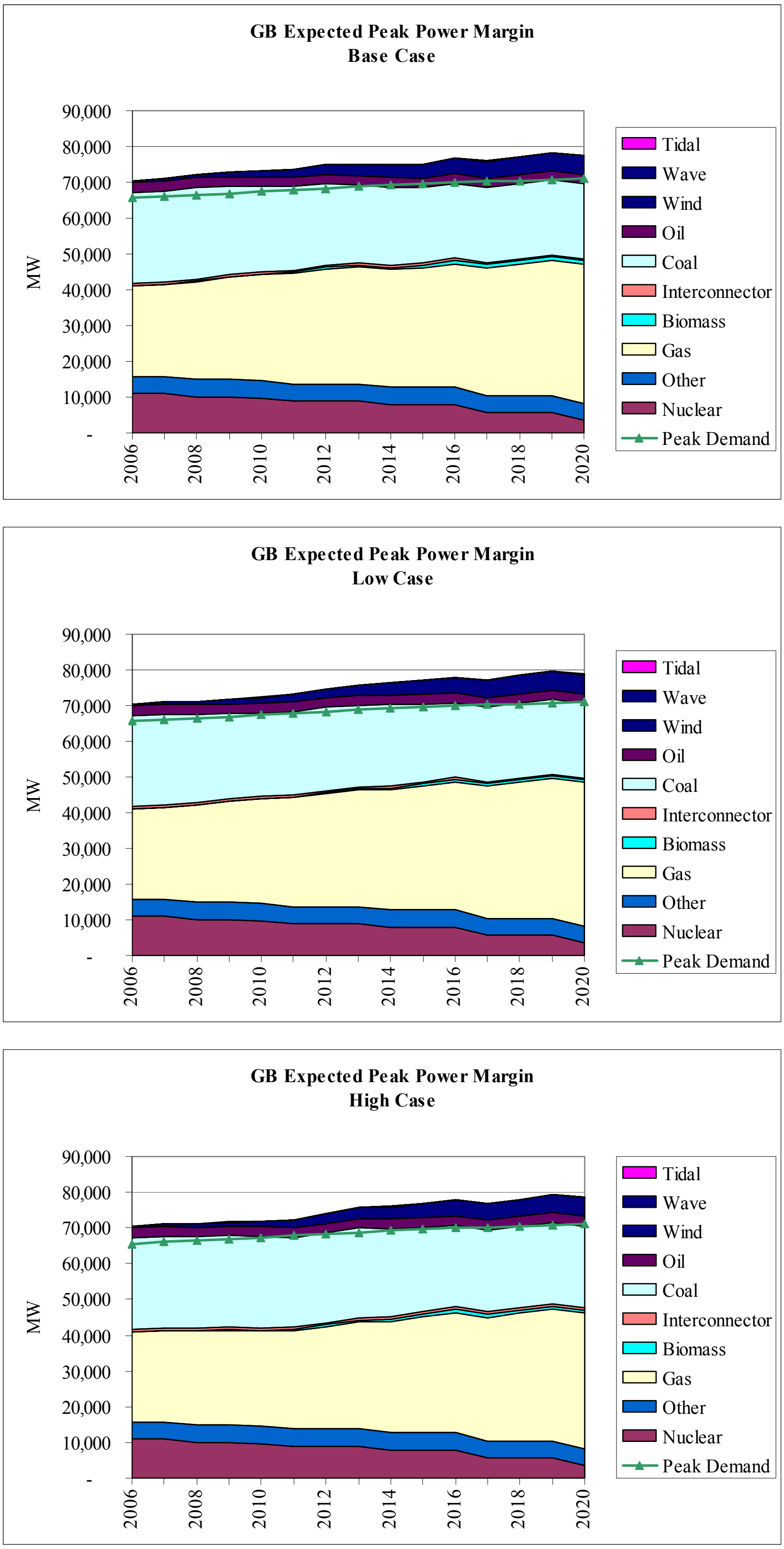
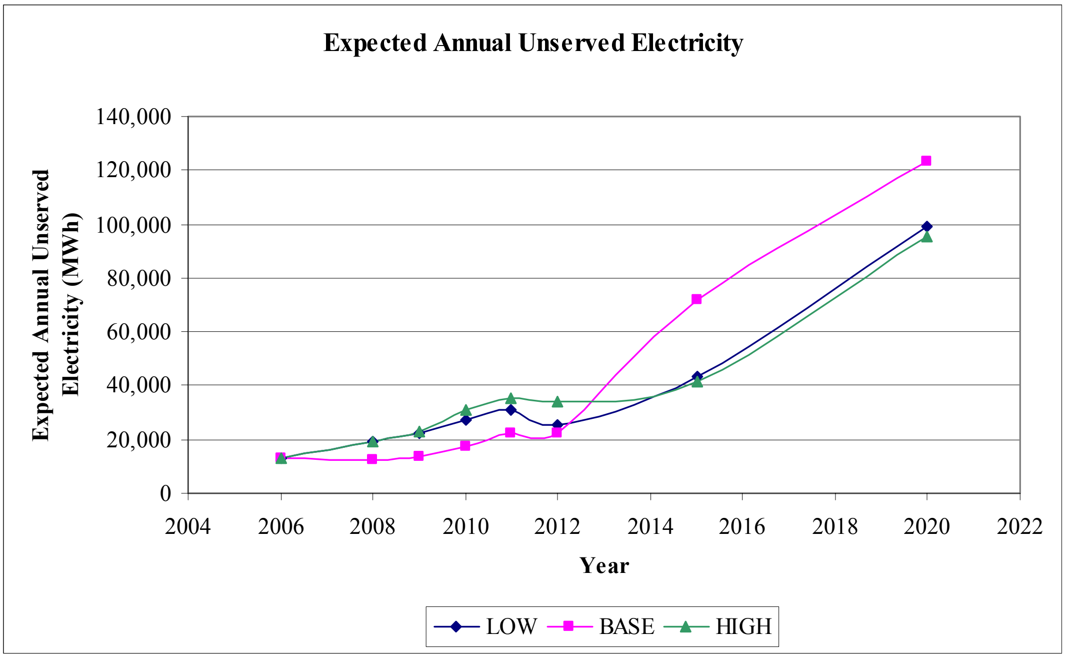


Figure 19: Expected Annual Unserved Electricity



6.6.1. Maintaining Generation Capacity

As discussed in the previous section, the modelling has assumed that some uneconomic generation capacity would be maintained on the system to achieve the modelled level of security of supply. Plant margins could be supported either by maintaining uneconomic (coal) plant, or assuming that new peaking (OCGT) plant would be constructed. It has been assumed in the modelling (based on a simple comparison of plant economics) that maintaining uneconomic coal plant provides the cheapest option.

There are a number of factors that drive the requirement for uneconomic coal plant to be maintained on the system:

- The trajectory of commodity and carbon prices increasingly reduces the relative competitiveness of coal plant, making it less profitable, particularly over the second half of the forecast horizon;
- Increasing volumes of new high merit generation capacity (new CCGT and renewable generation) reduce the running of low merit plant; and
- The increasing contribution of wind within the generation mix leads to an increase in the variability associated with the level of generation available at any time – it provides a lower contribution to system security than the same capacity of conventional plant, other things being equal. Thus it follows from the modelling approach taken that there is a requirement for an increasing volume of installed capacity to maintain the same level of security of supply.[18]

The cost of maintaining the additional capacity has been calculated by summing the losses of the uneconomic plant required to maintain the modelled level of

[18] This approach is not intended to suggest that any particular level of security of supply is socially optimal.

security of supply. This is the minimum level of additional revenue that the plant would require to maintain economic operation.

There are a number of ways that this additional revenue might be recovered. For instance:

- Wholesale electricity prices that ‘spike’ more frequently (in addition to any volatility already captured in the model) thus allowing peaking plant to recover fixed costs over relatively few running hours;
- Large vertically integrated generators internalising the costs, and spreading them more evenly across market prices, reflecting a risk management strategy of balancing their supply and generation portfolios; or
- NGT could purchase additional reserve.

6.6.2. Capacity Mix

The EU ETS provides an economic incentive for the system to evolve to a lower carbon intensity, contributing to the growth in gas and renewable generation capacity and the closure of coal capacity over the forecast horizon. However, it should be noted that commodity prices and the Renewables Obligation are also key drivers of these capacity changes. In addition, a significant volume of gas generation is built in response to the 8GW of nuclear closures over the forecast horizon. Thus, the EU ETS is only one factor in the development of gas generation capacity, and a significant volume would be likely to be constructed over the forecast horizon, irrespective of the implementation of the EU ETS.

Nevertheless, it is the case that the EU ETS provides an additional incentive for capacity changes, and this alone may impact on security of supply, as capacity is brought in and out of service, often in large units, and the system attempts to evolve rapidly to changing economic signals.

The significant growth in gas fired generation will increase the reliance that the power sector has on secure gas supplies. In future, GB will have a greatly increased reliance on gas imports, with decreasing volumes of gas sourced domestically. However, over the forecast horizon it is likely that gas infrastructure will be built to enable gas to be imported through three major pipelines and three LNG terminals, with domestic gas landed at a number of terminals around GB (St Fergus handling the largest volume). Increasing volumes of gas imports will place a dependence on energy supplies from abroad, although these will be sourced from a variety of countries (e.g., Norway) with LNG facilities giving the ability for flexible gas purchasing from a wide range of gas producing countries, thereby reducing the dependence on any single geographical source.

6.7. Location of New Plant

This section investigates the issues that will influence the location of new generation around GB, as well as some of the non-economic issues that might influence the ability of developers to construct new generation capacity.

6.7.1. CCGT

CCGTs will tend to locate in areas where the costs are lowest and access to fuel and transmission capacity can be provided quickly and easily.

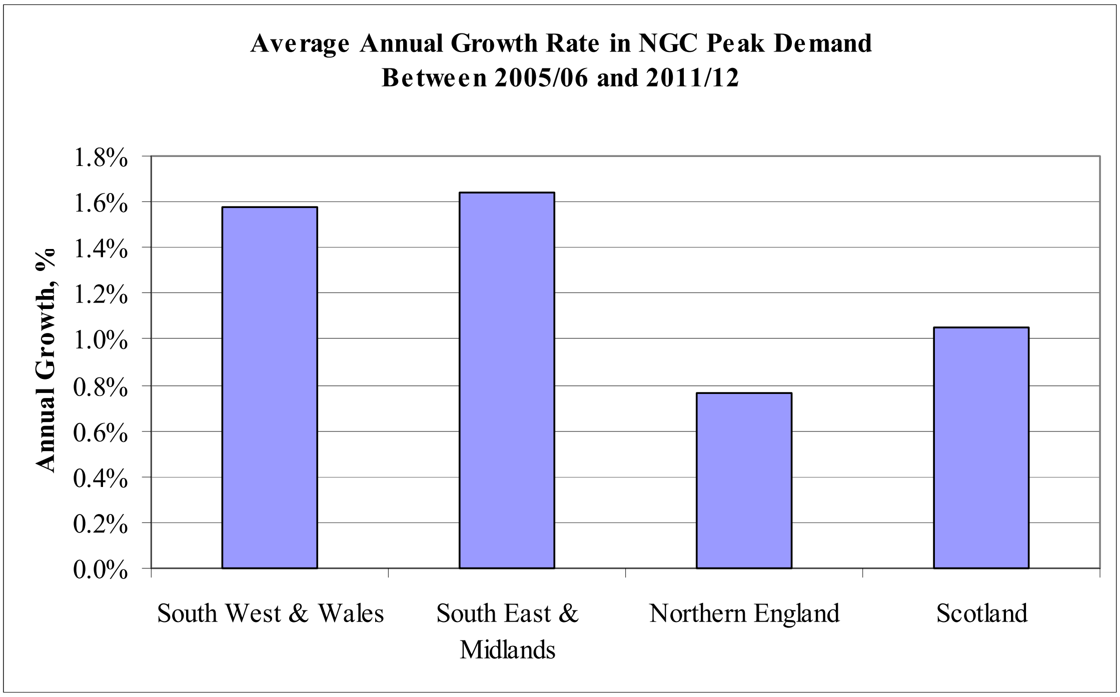
The locational transmission charging methodology used by NGT gives strong incentives to new generation capacity to locate in the South and West of the country. These incentives reflect a shortage of generation in the area, and this means that typically new generation can be accommodated relatively easily onto the transmission system. Since transmission charges are a significant component of fixed costs for generators, and the costs and speed of connection to the transmission system are important parameters for a developer, it is likely that new CCGTs will tend to be located in these regions. The location of the proposed Langage plant in the South West peninsula has undoubtedly been influenced by these factors.

Increases in generation capacity could reduce the locational incentives for in the South and West over time. However, analysis of demand growth (as provided in Figure 20) shows that the relatively stronger demand growth in the South and West may mean that the area remains short of generation at least in the medium term.

Access to the gas network will also be important to new CCGT capacity. There will be significant changes in the structure of the gas network over the forecast horizon. Historically the St Fergus terminal in Scotland has been the main import terminal, with gas then transported to demand points further south. However, Bacton in Norfolk will now be a major import terminal and the commissioning of the interconnector with Holland will increase volumes landed here. A new LNG terminal on the Isle of Grain and at Milford Haven will provide additional gas import capacity. Both RWE (new CCGT at Pembroke) and E.ON (conversion of the existing Grain station) are investigating the possibility of locating CCGT generation capacity with direct access to gas imports from these terminals.

The forecasts for both GB and Europe highlight a significant growth in gas fired generation capacity, partly in response to the EU ETS. This will place significant demands on the suppliers of CCGTs, as well as the companies providing engineering and construction services. It is possible that a shortage of gas and steam turbines and contractors to install them could develop, increasing prices of CCGT capacity and leading to delays in plant development. The market for these products and services is international, so having a national manufacturing capability and contractor resources may not insulate a country from these pressures.

Figure 20: Locational Demand Growth[19]



6.7.2. Wind Generation

Wind generation technology will provide the predominant growth in renewable capacity, and so is the renewable technology discussed in this section. It is important to note that the forecast growth in wind generation is more a consequence of the Renewables Obligation than the EU ETS.

The location of wind generation is to a large extent defined by the resource. A significant amount of the GB wind resource is located in Scotland, and higher wind speeds typically would make projects more economically attractive. However, the higher costs of transmission access for generators located in Scotland compared to elsewhere are significant and can diminish the advantage associated with higher wind speeds in Scotland. Cheaper transmission access can provide an economic advantage to generation sites in England & Wales, if the wind resource is of similar quality.

Transmission capacity constraints are also significantly limiting the ability of the Scottish transmission companies to offer connections to new renewable generators. The amount of renewable generation seeking to connect to the transmission network has dramatically increased over the last few years. There is currently around 500MW of renewable capacity (excluding large hydro) connected in Scotland, but over 6.5GW[20] that have Offers of Connection or are having offers prepared. However, of these around 3.5GW will be conditional offers that are contingent on future transmission reinforcement, or will have an element of constraint included in their connection agreements. In addition there are over 7GW of generation projects with connection feasibility studies, with more at the concept enquiries stage.

[19] Derived from NGC's 2005 Seven Year Statement, Tables 2.2a and 2.2g.
[20] Communications with Scottish Power and SHETL.

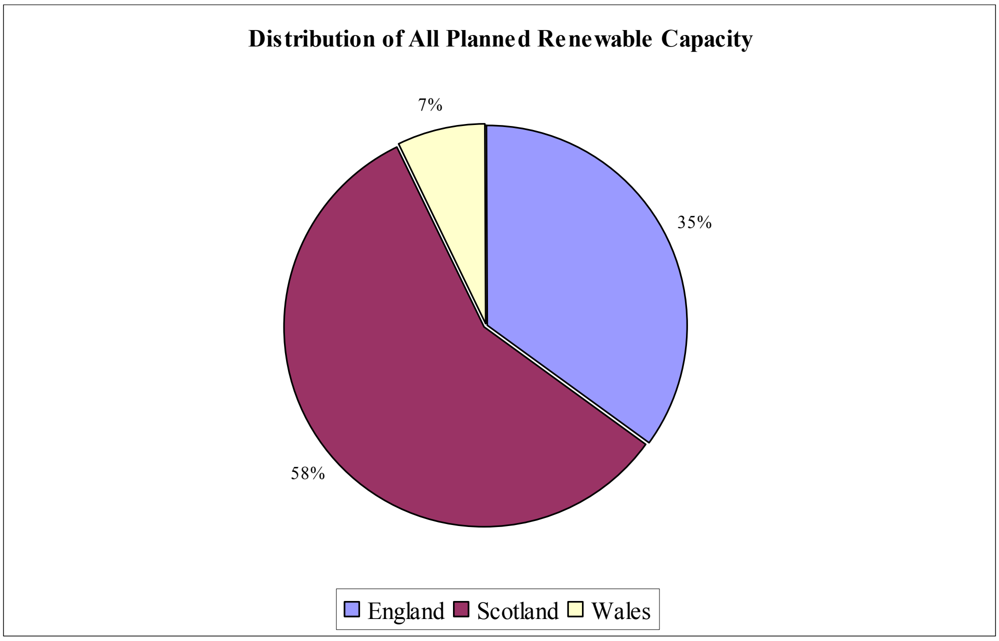
Thus, although there is significant wind resource available in Scotland, as well as a large number of projects in the early stages of development, the number obtaining consents and connections over the medium term will be significantly lower. There will continue to be strong development of wind generation in England and Wales in the medium term, with the Round 1 and Round 2 offshore wind farm leases providing a significant volume of this generation capacity.

An analysis of the location of current planned and approved generation capacity is shown in Figure 21, while Figure 22 shows forecast renewable build rates by location. It can be seen that the forecast initially shows England and Wales with a higher build rate than Scotland, reflecting transmission constraints in Scotland and the commissioning of the Round 1 and 2 offshore projects. However, over the forecast horizon build rates in Scotland exceed those in England & Wales, with relatively even distribution of capacity by the end of the forecast horizon.

It can be seen that the build rates reduce significantly toward the end of the forecast horizon, reflecting the fact that the Renewables Obligation is assumed not to increase beyond 2015, and becomes a binding constraint. It is interesting to notice that the current RO reviews raise the possibility that the RO may have different definitions in each of the different legislatures. Since the RO has an important impact in stimulating renewable build, these differences could also impact upon the location of renewable project developments.

The significant growth in wind generation projects under construction world wide is beginning to lead to a shortage of turbines, as manufacturers are reported to be struggling to keep up with demand. Market information suggests that in some cases this has led to an increase in the price of turbines and delays in construction for some projects. There is also likely to be a shortage of the required engineering equipment and skills for installing turbines. This may be particularly true for off-shore wind farm development which will require specialised vessels, equipment and technical skills.

Figure 21: Distribution of Planned and Approved Renewable Capacity[21]



[21] Source: Platts Power Station Tracker, Power UK, Issue 135, May 2005.

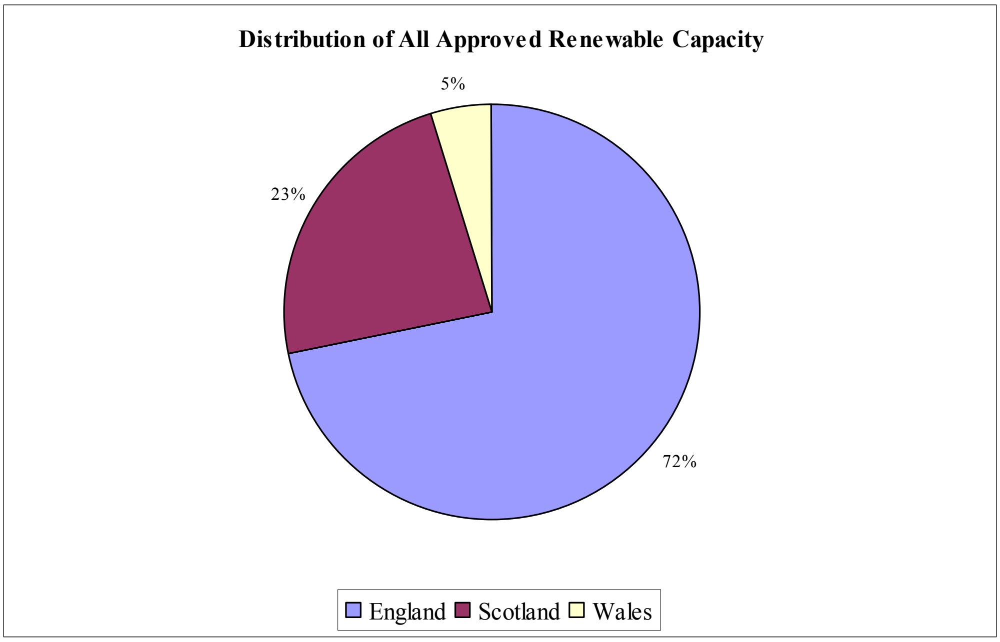
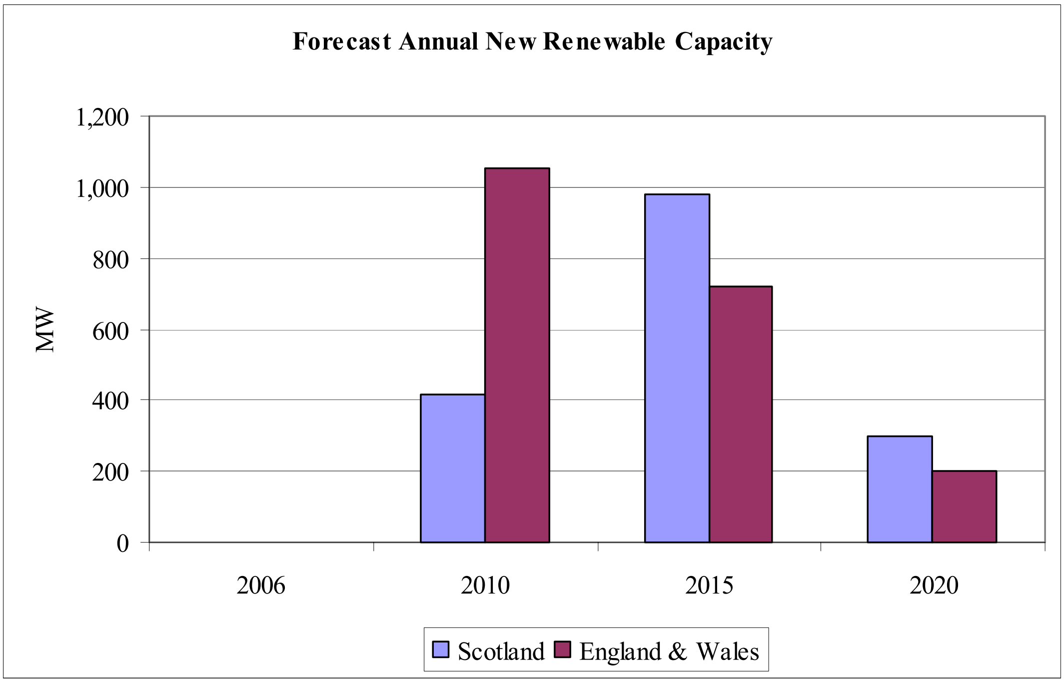
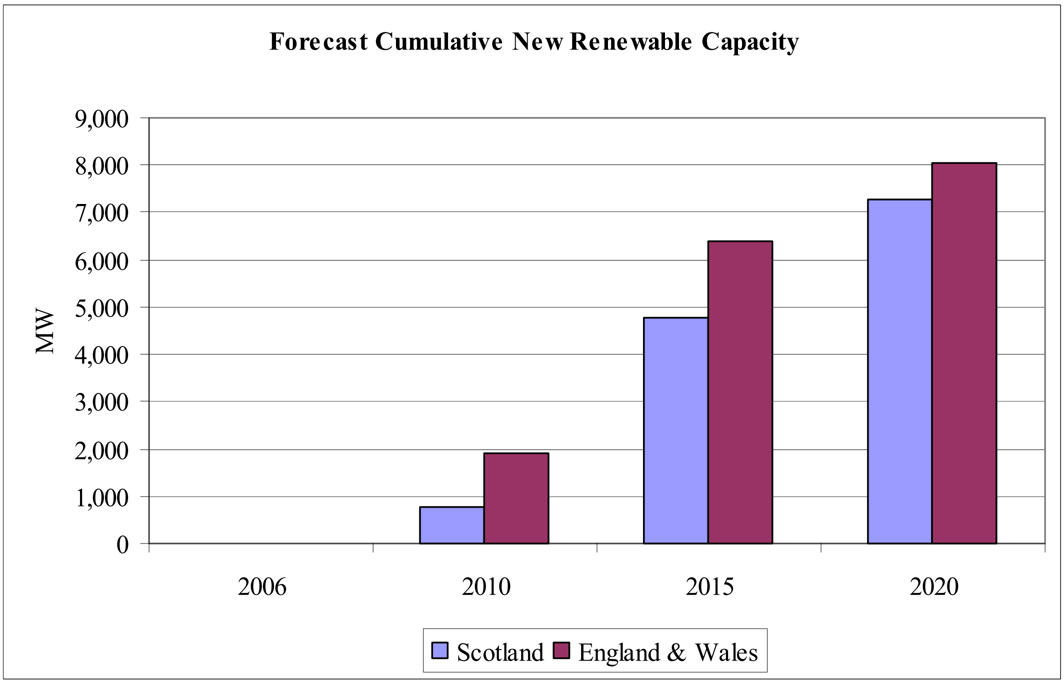

Distribution of All Approved Renewable Capacity
5%
23%
72%
England
Scotland
Wales

Figure 22: Distribution of Forecast Renewable Generation Capacity Development





6.8. Northern Ireland Scenario Analysis

This section discusses the impact of the different commodity and carbon price scenarios upon the power industry in Northern Ireland. It analyses the impact on NI wholesale prices, carbon emissions and system security.

The analysis has used the Irish ECLIPSE model, which represents the power systems in Northern Ireland and the Republic of Ireland. The commodity and carbon price assumptions are the same as used in the GB ECLIPSE analysis (with appropriate uplifts for delivery in Ireland) and GB prices over the Moyle interconnector are outputs of the GB ECLIPSE model.

The Northern Ireland market is relatively small, and is interconnected with both GB through the Moyle Interconnector and to the Republic of Ireland via the North-South Interconnector. Thus, the power market in Northern Ireland is strongly influenced by developments in neighbouring markets, as well as developments in interconnections. The development of an ‘all Ireland’ Single Electricity Market is currently being planned for implementation in July 2007. This has the potential to make prices in Northern Ireland and the Republic converge, although interconnection constraints may ensure that a price spread is maintained.

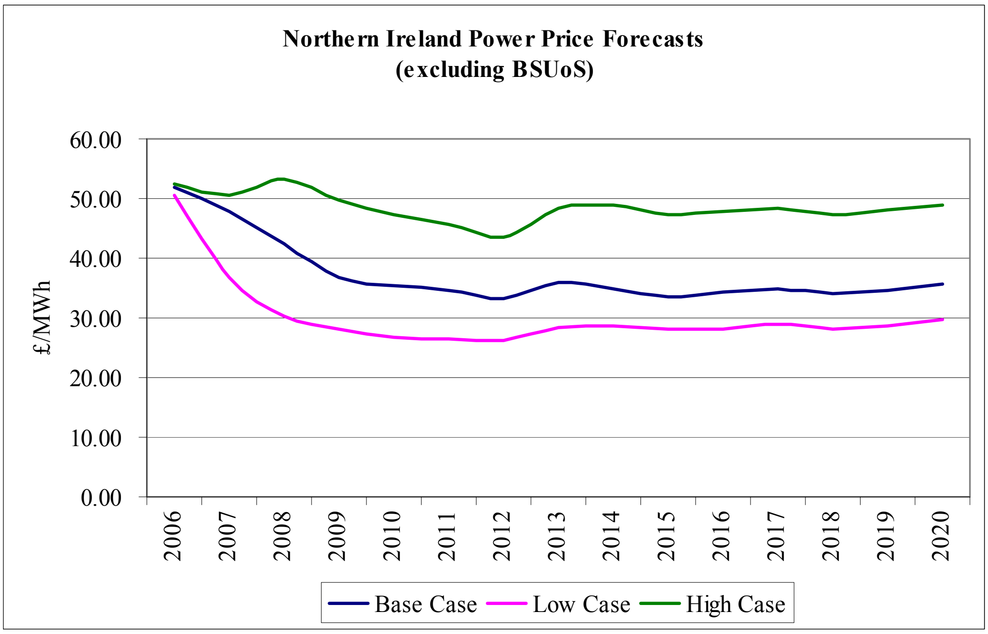
On privatisation in 1992, the NI power stations (Kilroot, Ballylumford and Coolkeeragh) were sold together with long-term Power Purchase Agreements (PPAs) with Northern Ireland Electricity’s Power Procurement Business (PPB), which also subsequently signed new contracts with Coolkeeragh for its new CCGT. PPB sells wholesale electricity to the Northern Ireland Electricity Public Electricity Supplier business, which supplies franchise customers at the regulated Bulk Supply Tariff. It is expected that as some of the long-term PPAs approach expiry or cancellation there will be an increasing proportion of free uncontracted generation and an increase in competition. For the purposes of our modelling of the NI market we have assumed that the current long-term PPAs expire or are cancelled with the introduction of the Single Electricity Market in 2007.

6.8.1. Power Price Forecasts

This section examines the forecast power prices for Northern Ireland and compares them to those forecast for GB. The NI price forecasts are shown in Figure 23, for the Base, Low and High Case scenarios.

Northern Ireland primarily has a mix of coal and gas generation, and so exhibits relatively similar price drivers to GB. The price trajectories are driven by the changing competitiveness of coal and gas generation, in response to changing fuel and developing carbon prices. Prices are typically between £1/MWh and £3.50/MWh greater than in GB, in part due to the increased cost of fuel supply, particularly for gas power stations.

Figure 23: Forecast Prices for Northern Ireland



6.8.2. Generation Capacity

Northern Ireland generation capacity is investigated in Figure 24 and Figure 25, which investigate the peak power margin and the annual energy margin respectively. It can be seen that despite demand growth there is no requirement for new generation capacity within the province, although toward the end of the forecast horizon the system *could* become dependent upon flows over the GB interconnector at times of low wind and high demand.

Figure 24: Northern Ireland Expected Peak Power Margin

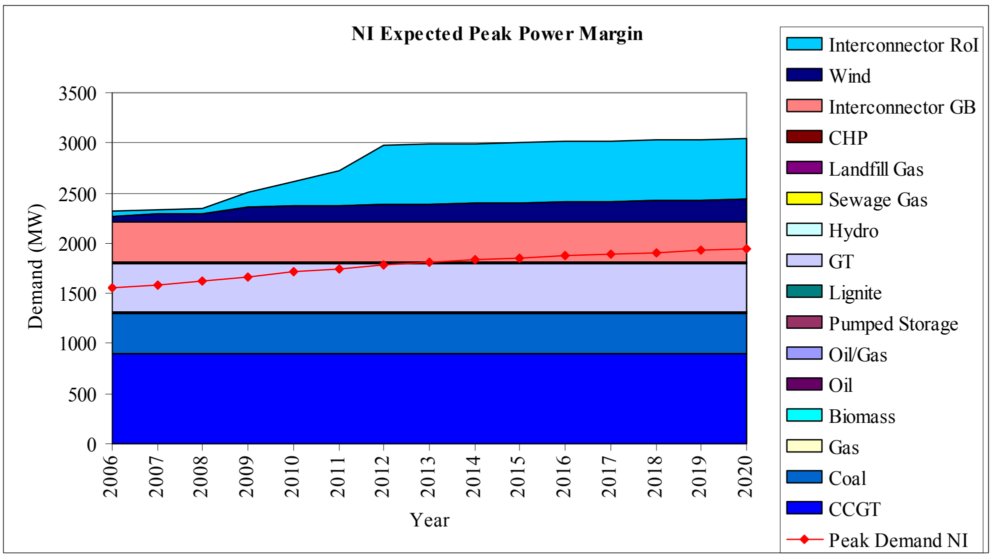
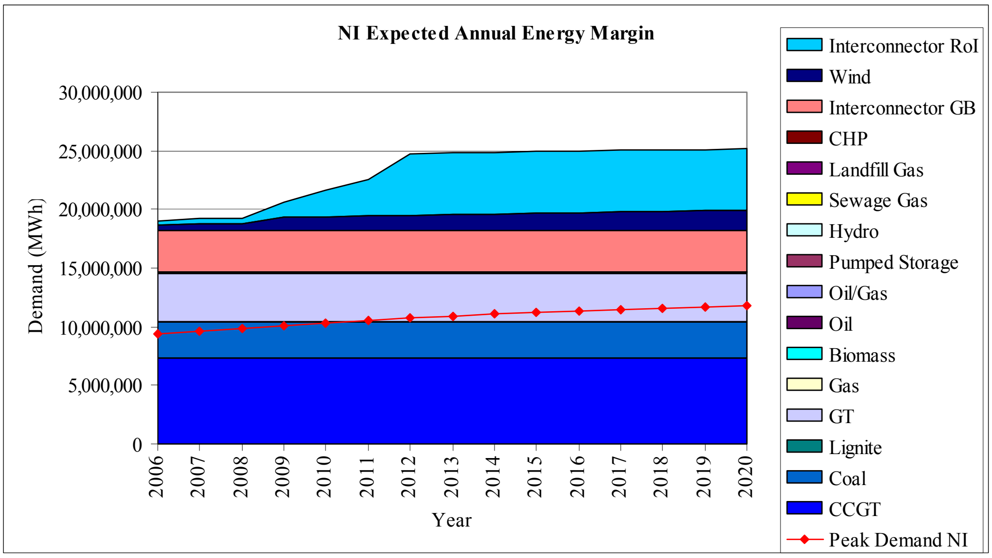


Figure 25: Northern Ireland Expected Annual Energy Margin



The Northern Ireland generation sector has recently undergone significant modernisation, with new CCGT capacity at Coolkeeragh and Ballylumford replacing oil-fired and low efficiency gas fired generation. In addition, FGD is planned for Kilroot, enabling it to maintain output volumes under the LCPD. The construction of CCGTs has significantly reduced the carbon intensity of the system, and so ensured that there will be less requirement for change in response to the EU ETS over the forecast horizon.

The capacity of the Moyle interconnector remains constant throughout the study period at 500MW (constrained in the model to 300-400 MW depending on the time of year, reflecting operational constraints experienced in recent years), while the North-South interconnector grows from 170MW in 2008 to 600MW in 2012, in line with current plans. Although the possibility of an Ireland-Wales interconnector has been widely discussed, there is currently no progress on the project and we have therefore assumed that a GB-RoI interconnector will not be built within the forecast timeframe.[22] As a result there is a requirement for new build in ROI, as well as a dependence on imports from NI.

Since the NI market is interconnected to both GB and ROI, both markets in which capacity requirements allow prices to rise above the cost of new entry, it is unsurprising that NI prices also rise to this level. However, since the Northern Ireland market is relatively small compared to GB, with each individual generation asset being relatively large compared to the size of the system, the development of generation can have a significant impact upon price. The 'lumpy' nature of investment means that the system cannot evolve gradually, but will change through a series of discrete investment decisions. Thus, although prices might support new entry, construction of a new CCGT would have a significant impact on price and potentially cause major price reductions for several years until demand growth caught up with the capacity added. However, toward the end of the forecast horizon new entry becomes more credible, and ultimately the coal station at Kilroot will need to be replaced.

[22] If a decision was made to proceed with the project, a GB-RoI interconnector could still feasibly be constructed before the end of Phase II.

However, it should be noted that with expansion of the North-South interconnector and the development of the 'all Ireland' Single Electricity Market there is the potential for new entry required for RoI to be built within NI, if the economics were more attractive in NI. A major consideration for a new entrant will be the level of free carbon allocation available. This raises the possibility that a generous allocation to new entrants could encourage new build in NI, with output primarily for export to RoI. While this may have positive impacts associated with reductions in price and increased security of supply in NI, it could also significantly increase emissions within the province.

At present the Phase I new entrant regimes for the UK and RoI are similar in methodology, but the greater reduction required of the RoI electricity sector would result in higher allocations for new entrant power generators in NI relative to RoI. The RoI regime allocates free allowances on the basis of projected emissions assuming Best Available Technology, provided that this is not greater than the equivalent amount allocated to existing installations in the sector (74.2%, in the case of the electricity generation sector) and in no instance greater than 97% of agreed projected emissions.[23] According to the DTI spreadsheet for calculating allocations to new entrants,[24] a new 500MW CCGT plant in NI would be allocated 1,017,239tCO_2/year during Phase I, or 85.6% of projected emissions of 1,187,917tCO_2/year, whereas the same plant in RoI would receive only 881,434tCO_2/year (74.2% of projected emissions). The difference (135,805tCO_2/year) would be worth €2.7m/year at a carbon price of €20/ tCO_2, thus already providing a substantial incentive to locate in NI rather than RoI during Phase I.

It should also be noted that currently, the Bulk Power Agreement between ESB Power Generation and ESB Public Electricity Supply in the Republic of Ireland only includes the cost of additional allowances required to be purchased by ESB Power Generation (over and above its free allocation). ESB Power Generation expected to incur carbon costs of €3m in 2006 and zero in 2007. Independent generators are not regulated, but it is expected that they will have to similarly limit carbon pass-through to remain competitive with ESB Power Generation. It is not known how this will be resolved when the Single Electricity Market is introduced.

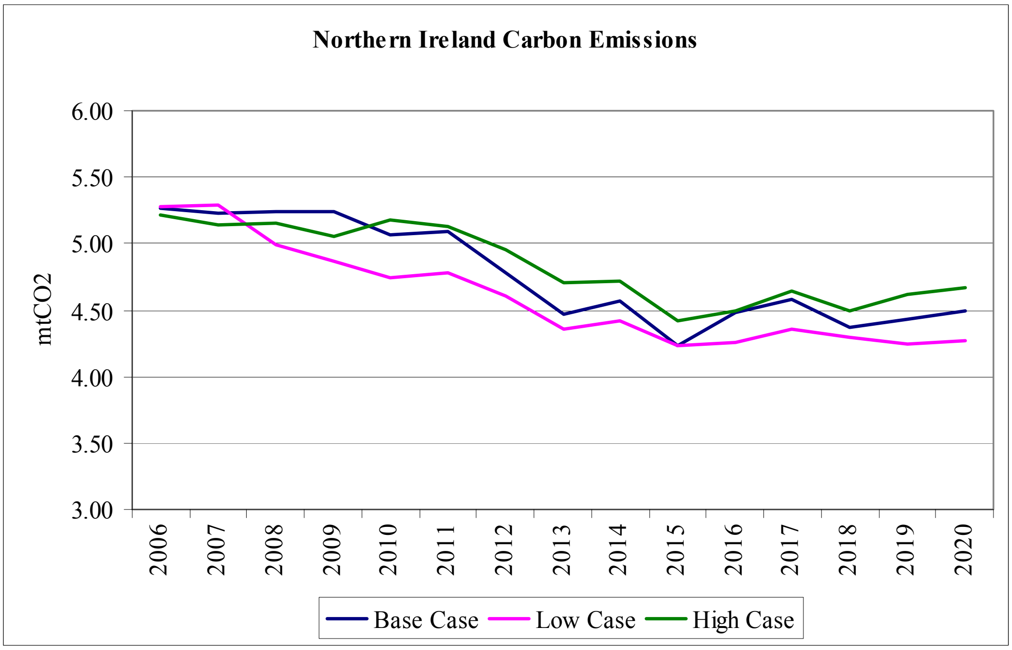
6.8.3. Emissions

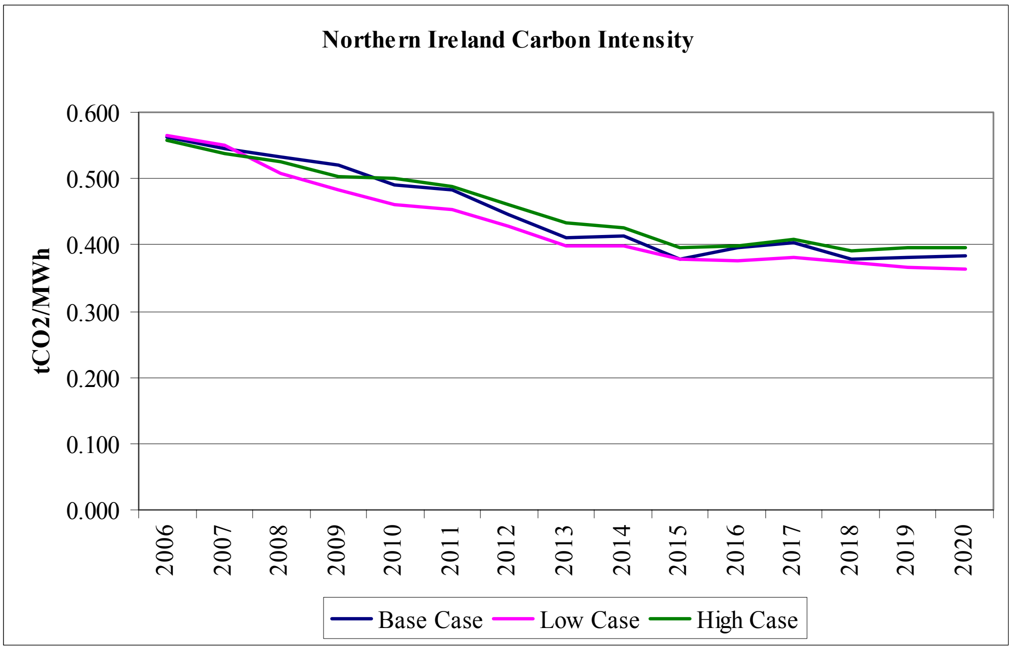
The total carbon emissions and carbon intensity of the Northern Ireland power system for the Base, Low and High Cases are shown in Figure 26 below. It can be seen that under all three scenarios the level of carbon emissions and the carbon intensity of the power system reduce over the forecast horizon. This reflects the changing competitiveness of gas and coal, with coal increasingly the marginal plant, and achieving lower running over the period.

In comparison to the GB system the carbon intensity of the NI system is higher by around 0.1tCO_2/MWh, reflecting the lack of zero-carbon nuclear capacity in the generation mix. However, the reduction in carbon intensity in GB is slighter lower than in NI over the forecast horizon, due to the retirement of nuclear capacity within GB.

[23] Final Allocation Decision 2005-2007, EPA, 2005.
[24] http://www.dti.gov.uk/energy/sepn/calculating_allocations.xls

Figure 26: Northern Ireland Power System Carbon Emissions and Carbon Intensity





7. SENSITIVITY ANALYSIS

This section provides a view of the sensitivity of the power sector to the price of carbon and the different parameters of the EU ETS over Phase II of the scheme. It analyses a range of sensitivities and their impact on Base Case results in terms of power price, profitability, emissions and security of supply.

7.1. Carbon Price

This section provides a view of the sensitivity of results to different carbon price assumptions. It examines the relative cost of carbon and fuel for different generation technologies and the sensitivity of results under the Base Case scenario to different carbon price assumptions over Phase II of the EU ETS.

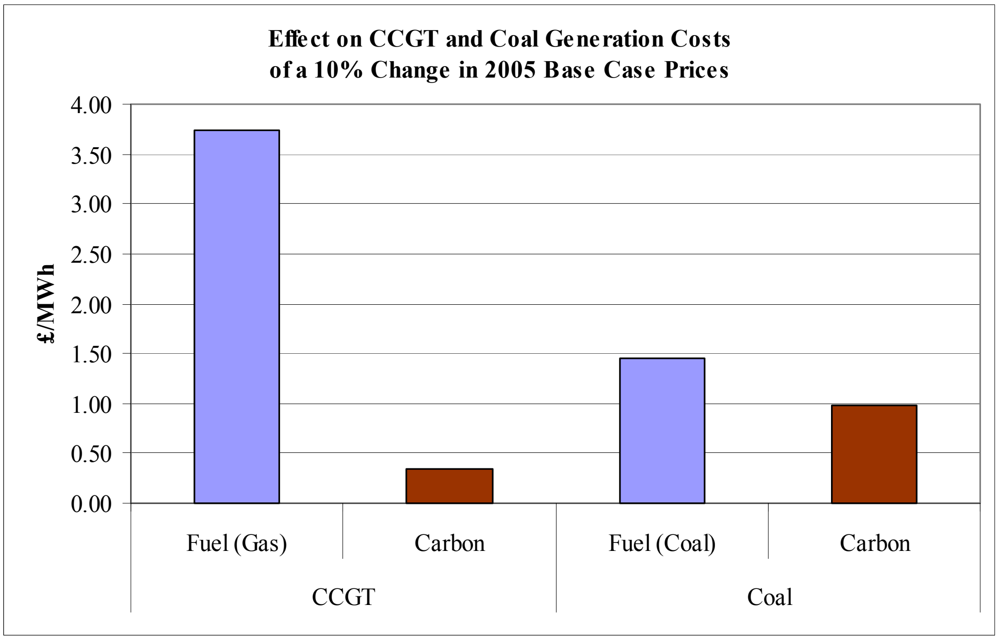
7.1.1. Relative Cost of Carbon

In examining the sensitivity of results to carbon prices it is important also to consider the relativity of carbon prices and fuel costs for the different generation technologies, as illustrated in Figure 27. This shows the change in the short run marginal cost of a MWh of electricity given a 10% increase in fuel or carbon prices (starting from the prices assumed for 2005 under the Base Case scenario); a credible price movement, given the recent volatility in carbon and commodity prices.

This analysis highlights that the short run marginal costs of a CCGT are significantly more sensitive to a proportional change in fuel costs than they are to carbon costs. Coal plant are also more sensitive to a change in fuel costs than carbon costs, but the difference in impact on marginal costs is much less pronounced.

The implication is that, while carbon prices can have a significant influence on power prices, generation running and sector emissions, commodity prices are a relatively more significant driver. The impact of different commodity prices was illustrated under the three scenarios investigated in Section 6 above.

Figure 27: Sensitivity to a 10% Change in Carbon and Fuel Prices by Technology



7.1.2. Carbon Price Sensitivity

This section investigates the sensitivity of Base Case scenario results to changes in the assumed market price for EUAs over Phase II of the EU ETS. In addition, under the sensitivities it is assumed that the CER price is equal to the market price for EUAs, and so the price of carbon to which generators are exposed is the EUA price. The sensitivity of carbon prices to the assumption on CER price and the volume of CERs that may be surrendered is discussed in section 7.2 below.[25]

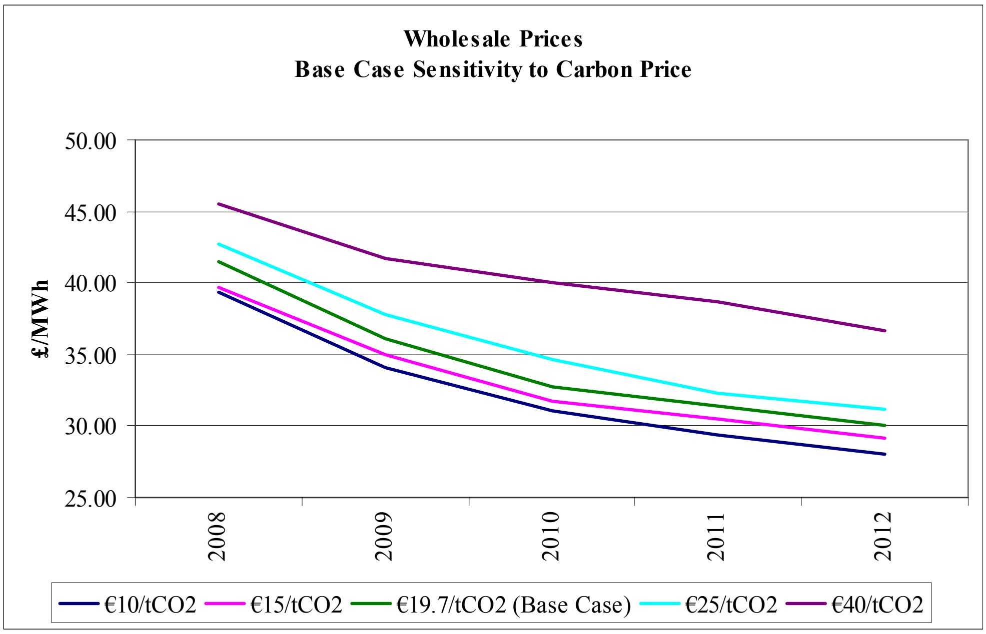
- ***Wholesale Prices***

  The impact of an increase in carbon costs is to increase the short run marginal costs of generation for coal and gas plant, and so place upward pressure on power prices. However, an increase in carbon prices also has the potential to influence the merit order,[26] so changing the running order of plant. This means that the impact of carbon prices on power prices is not linear. The impact of carbon price on wholesale prices is shown in Figure 28.

  At low carbon prices coal is more competitive, so gas is frequently the marginal plant – resulting in a relatively low sensitivity of power price to carbon price. At high carbon prices coal is less competitive, so coal is frequently the marginal plant – resulting in a relatively high sensitivity of power price to carbon price. In the Base Case the competitiveness of coal reduces over Phase II, and this results in an increased sensitivity to Carbon prices over the phase. In the chart below, this is illustrated by the widening gap between the €25/tCO_2 and €40/tCO_2 curves over time.

[25] The impact of CERs leads to the effective carbon price reducing from €20/tCO_2 to €19.7/tCO_2 for the Base Case (see section 7.2.1).
[26] The ranking of generation plant in order of short-run marginal cost. 'High' merit plant has the lowest costs and is scheduled first; 'low' merit plant has the highest costs and is scheduled last (or not at all).

Figure 28: Sensitivity of Wholesale Power Prices to Phase II Carbon Price



- ***Profitability***

  The section examines the sensitivity of the profitability of different generation technologies to different carbon price assumptions over Phase II of the EU ETS. A comparison of the profitability of the main generation technologies measured on the basis of EBITDA (see section 6.4) is shown in Figure 29.

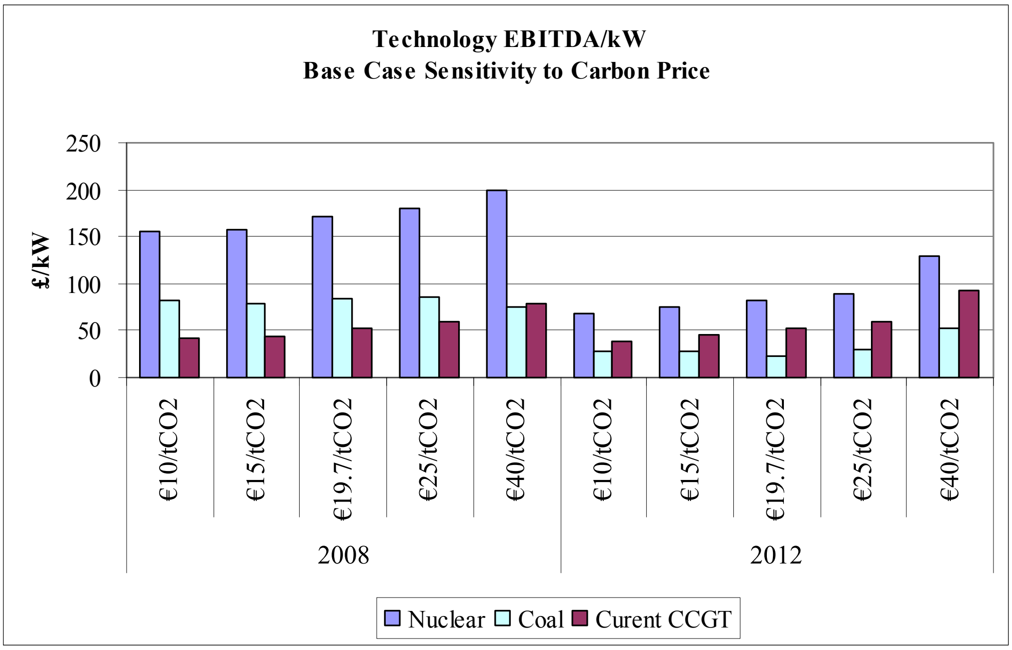
  It can be seen that the profitability of individual generation technologies is extremely sensitive to carbon price:

  - Profitability of nuclear stations is broadly correlated to the wholesale power price since they run baseload and have no carbon costs. Higher carbon prices tend to increase wholesale electricity prices and so result in higher profitability for nuclear sets;

  - The profitability of existing CCGTs is also reasonably well correlated to carbon prices, despite the fact that free allocations reduce direct exposure to the carbon price. This is due both to the pass through of carbon into the power price, and the impact of carbon on the relative competitiveness of gas and coal. Higher carbon prices result in gas stations being higher merit, so achieving higher load factors and higher levels of profit on operations; and

  - The profitability of coal stations is not simply correlated to carbon prices. Higher carbon prices increase the value of free allocations, but reduce the competitiveness of coal relative to gas (reducing load factors and profit on operations). The interplay between these two factors is non-linear. In 2008, profitability from operations is relatively high, but higher carbon prices reduce profits from operations. Towards the end of the Phase, profitability of operations is much lower, and overall profitability is more strongly affected by the value of free allocations, resulting in higher profits at higher carbon prices in the higher €40/tCO_2 sensitivity result.

Figure 29: Impact of Phase II Carbon Prices on Profitability by Technology



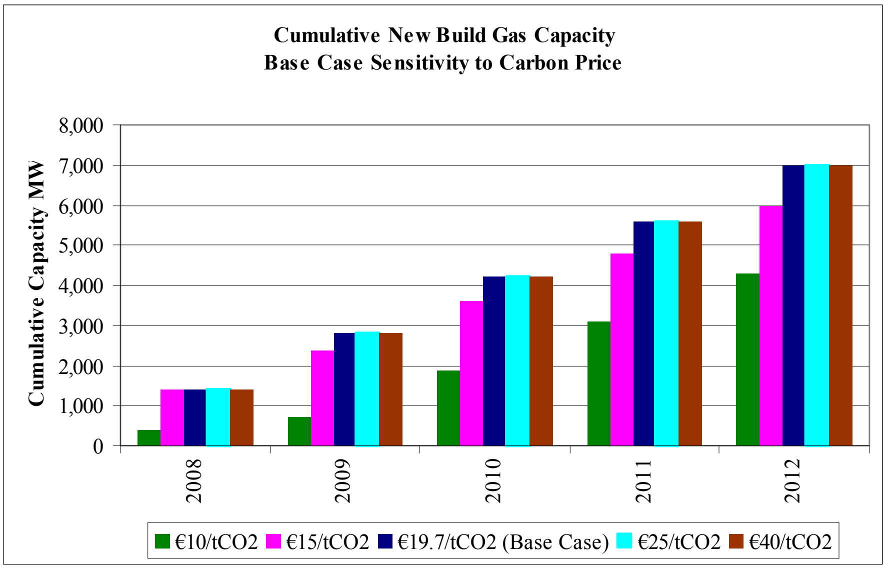
- ***Capacity***

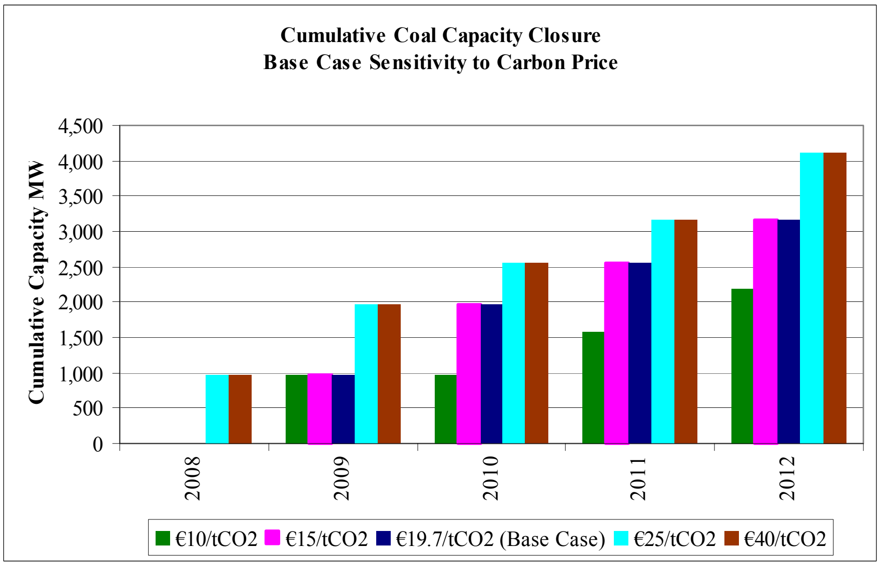
The sensitivity of the volume of new build and capacity closures to a range of Phase II carbon prices is investigated in Figure 30. It can be seen that under higher carbon prices the volume of new build CCGT capacity over Phase II could be around 3GW higher than under the lowest carbon price sensitivity. This reflects both the impact of higher power prices improving the economics of new build, as well as the improved competitiveness of CCGTs relative to coal plant.

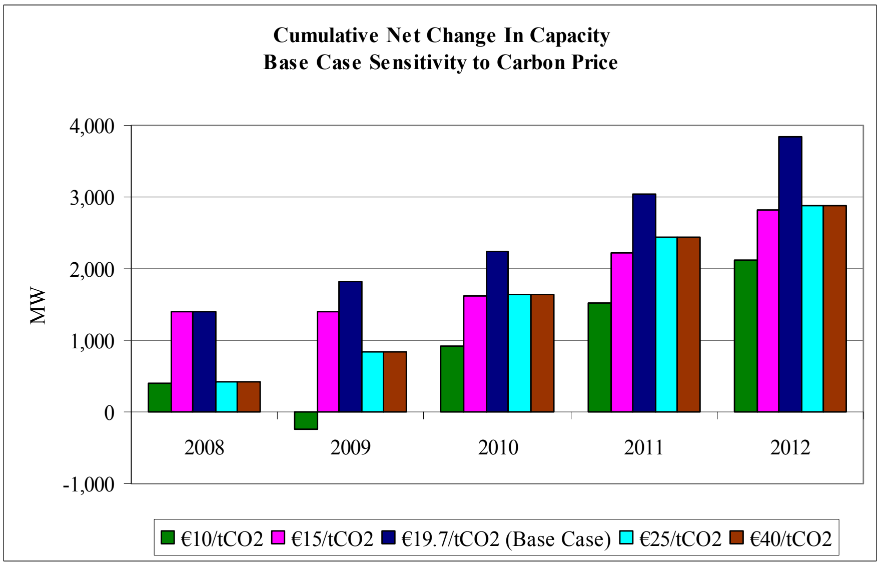
Higher carbon prices result in a higher level of coal closures over Phase II, than with lower carbon assumptions. This reflects both the fact that higher carbon prices erode the competitiveness of coal, and that the construction of new efficient CCGT plant will typically reduce the running of coal plant. Both factors will put pressure on coal plant economics, and increase the level of closures over the period.

The two highest carbon price sensitivities give very similar capacity build and closure results. This is due to limits placed in the model that restrict how quickly the industry can evolve in response to economic signals. These reflect the fact that in a market where there is significant uncertainty about commodity prices, carbon prices, allocations etc, developers tend to be relatively conservative. It would be unlikely for a significant volume of new CCGTs all to be developed in a short time-frame, since this could result in a collapse of wholesale prices, while the market readjusts and plant is retired. In addition, there are likely to be a number of non-technical limitations on new build, for example imposed by delays in purchasing and permitting of new plant.

Figure 30: Impact of Phase II Carbon Prices on Capacity Build and Closures







- ***Emissions***

  The sensitivity of power sector carbon emissions to the price of carbon over Phase II of the EU ETS is investigated in Figure 31, with emissions broken down by technology for 2008 and 2012 in Figure 32.

  It can be seen that higher carbon prices generally yield lower emissions over the phase, with a difference of around 30MtCO_2 in sector emissions between the highest and lowest sensitivities in 2012. This is driven by higher carbon prices eroding the competitiveness of coal, as well as the cumulative effect of new CCGT plant and coal closures over the Phase. Both factors result in a reduction in coal plant running relative to CCGT output, and so a reduction in sector emissions.

  It can be seen that the highest carbon price sensitivity leads to a significant reduction in emissions at the beginning of the phase as significant volumes of running switch from coal plant to CCGT. In other sensitivities the effect is more gradual, with CCGT becoming more competitive over the phase with reducing gas prices, and this is coupled with cumulative CCGT capacity build reduces sector emissions over time.

  It should be noted that the reductions in sector emissions are primarily driven by reductions in output from existing coal plant. Thus, in addition to reductions in CO_2 emissions, there will also be corresponding reductions in sulphur dioxide and other emissions as a result of higher carbon prices.

Figure 31: Impact of Phase II Carbon Prices on Sector CO_2 Emissions[27]

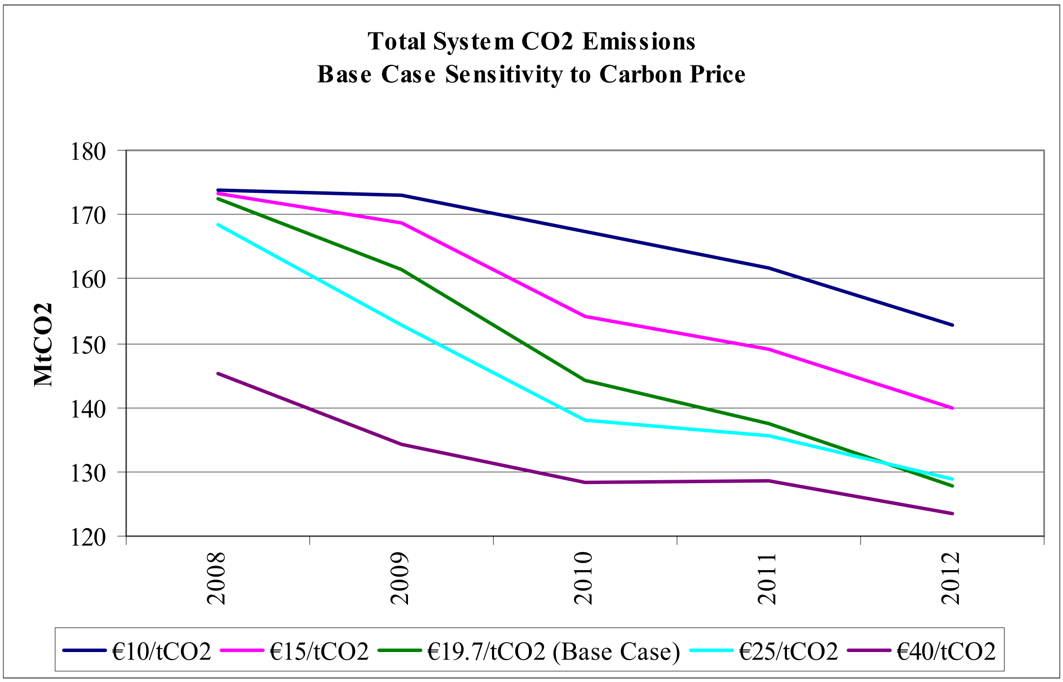
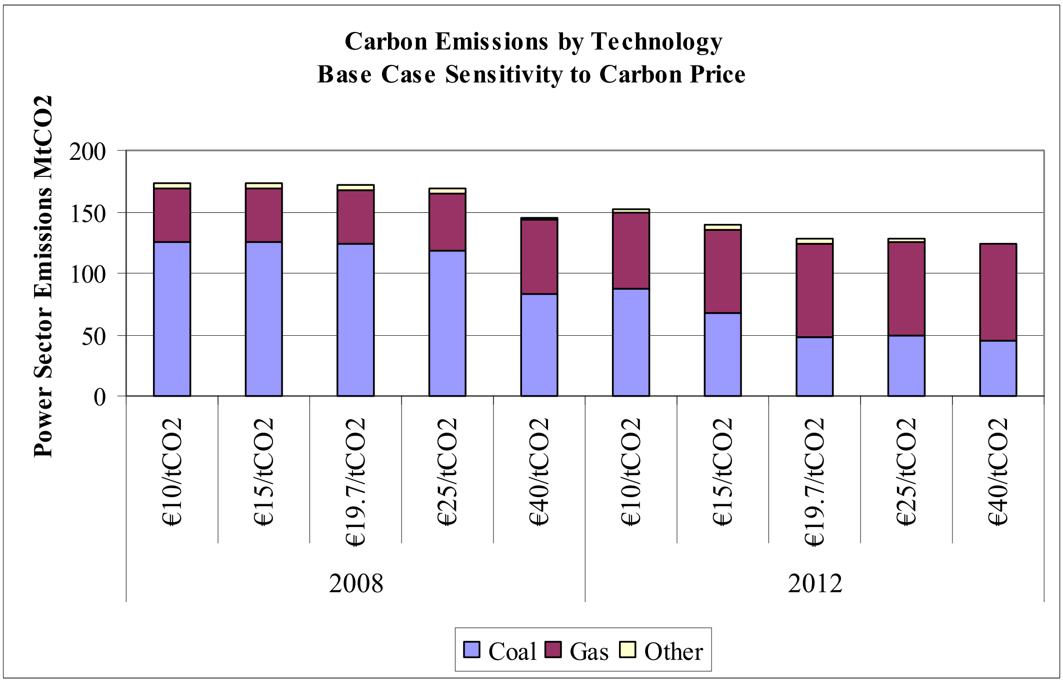


Figure 32: Impact of Phase II Carbon Prices on CO_2 Emissions by Technology[28]



[27] Including emissions from CHP, some of which may be included in the Power Generation Sector.
[28] Including emissions from CHP, some of which may be included in the Power Generation Sector.

7.2. JI & CDM Credits

Additional carbon credits from Joint Implementation (JI) and Clean Development Mechanism (CDM) projects will be able to be brought into the EU ETS during Phase II, under the so-called 'Linking Directive' (2004/101/EC).[29] The implementation of the Linking Directive within the UK is currently under consultation.

For the purposes of this discussion we have focussed on the credits available from CDM projects, denoted Certified Emission Reductions or CERs. In practice, there may be a number of different prices in the market for different kinds of CER, as well as for Emission Reduction Units (ERUs) from JI projects. These complexities have been reduced to a single variable, namely the existence of another class of carbon 'allowance' with potentially different price and availability to EUAs.

7.2.1. Sensitivity to Price and Volume

There are two key parameters that will influence the impact of CERs on the operation of the EU ETS from the perspective of the power sector. These are: the price of CERs, and any limitation on the volume of CERs that may be surrendered. These two parameters are not independent, since the price of CERs will be influenced by the net demand from EU ETS participants.

The price of CERs is extremely difficult to assess. There are a large number of potential projects that could yield relatively low *cost* emissions reductions. However, the practical difficulties of developing projects will tend to lead to a delay in the availability of CERs and under-supply could result in *price* increases.

It has been assumed that any limit on the use of CERs will be defined as a limit on the percentage of certificates surrendered by an installation that may be met with CERs. Under this methodology, the effective marginal price of carbon that a generator is exposed to can be defined as the weighted average price of the EUAs and CERs surrendered.[30]

Allowing the use of CERs (dependent upon implementation) could serve to increase the overall cap on carbon emissions, which could reduce the price of EUAs. This interaction has not been captured in the analysis of this sensitivity, since the impact on the price of EUAs will be dependent upon a range of assumptions on the implementation of the EU ETS across Europe. Thus, the analysis presented here investigates only the impact of CERs, assuming a constant EUA price.

In the Base Case scenario it was assumed that EUA price was €20/tCO_2, the CER price was €15/tCO_2, and the volume of CERs utilised was limited to 6% of the total surrendered allowances by an installation. This resulted in an effective marginal price of carbon of €19.7/tCO_2 (€20/tCO_2* 94% + €15/tCO_2* 6% = €19.7/tCO_2).

The marginal price of carbon under different CER price and CER limit assumptions is shown in Table 8 below. It can be seen that if the price of CERs is significantly below the price of EUAs and the limit on the volume of CERs that can be surrendered is high. This could result in significant downward pressure on the effective carbon price to which a generator is exposed.

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[29] CERs may also be used in Phase I (although as of this report's date the UK implementing legislation has not yet been enacted).
[30] In practice, the limit is more likely to be set ex-ante as a percentage of each installation's allocation in the NAP. The net effect on the carbon price across Europe will be the same.

However, the price of CERs and the volume that may be surrendered are not independent variables. As the limit on the use of CERs is relaxed this is likely to put upward pressure on their price, due to increased demand.

The level of CERs that can be surrendered by installations under the EU ETS may vary across the countries of the EU, depending upon their National Allocation Plans for Phase II. If countries across Europe allow relatively generous limits on the use of CERs this will be likely to push the price of CERs close to the EUA price. In this case, a lower limit placed on the use of CERs within the UK scheme would be unlikely to significantly impact upon the overall cost of carbon to which UK generators are exposed. However, if countries around the EU set relatively tight limits on the use of CERs, then CERs could trade at a significant discount to the EUA price. In this case the limits placed on the use of CERs within the UK scheme *could* have a relatively significant impact upon the overall cost of carbon to which generators are exposed, with generous limits on the use of CERs reducing the effective cost of carbon.

If the CER price is greater than the EUA price, due to demand from other Annex 1 countries, then CER limits have no effect on the effective carbon price.

The impact of the effective cost of carbon on power prices, capacity development, and sector emissions was discussed in section 7.1.

Table 8: Effective Marginal Price of Carbon under different CER Price/Limit Assumptions

EUA Price €20/tCO_2		CER Price €/tCO_2 5.00	10.00	15.00	20.00	25.00
Maximum CER %	**0%**	20.00	20.00	20.00	20.00	20.00
	6%	19.10	19.40	19.70	20.00	20.00
	10%	18.50	19.00	19.50	20.00	20.00
	20%	17.00	18.00	19.00	20.00	20.00
	30%	15.50	17.00	18.50	20.00	20.00
	40%	14.00	16.00	18.00	20.00	20.00
	50%	12.50	15.00	17.50	20.00	20.00

7.2.2. Impact on Profitability

Allowing installations to use CERs to meet their obligations to surrender allowances to cover their emissions will also have an impact on installation profitability. In effect, installations will be receiving a second allocation of allowances, with the amount of the allocation being defined by the CER limit and the price being equal to the market price for CERs. An installation may therefore meet its requirement for allowances with a combination of freely allocated EUAs, CERs and EUAs purchased from other market participants.

The overall impact on plant profitability will be the same as for a reduction in carbon price. Thus, the impact upon plant profitability will be dependent upon the plants relative carbon intensity, and position in the merit order.

If CERs may only be used by existing installations (i.e. there is no provision for use by new entrants) then this may serve to increase the differential between existing and new entrant costs. If new entrants receive only a partial free allocation, then a CER 'allocation' would have a similar impact to an increased free allocation, as explained in the paragraph above. The impact of different levels of free allocation to new entrants is discussed at section 7.5.

7.3. Allocation Volume & Methodology

This section investigates the sensitivity of the Base Case scenario to different power sector allocation volumes and allocation methodologies over Phase II of the EU ETS. It looks at how these scheme parameters impact on the level of profitability within the power sector, and how the profitability of generation technologies and companies is affected.

The allocation volume is assumed to have no direct impact on the EUA price, which has been assumed to remain fixed. In practice, the EUA price depends on the sum of the allocations by all 25 EU Member States, and therefore a lower total allocation by the UK would, *ceteris paribus*, cause a small increase in the EUA price across Europe. This in turn would put upward pressure on electricity prices.

A secondary effect on power prices will be caused by changes in the structure of the market, brought about by the impacts on the profitability of plant, in turn caused by the allocation volume and methodology. These impacts have been analysed below.

7.3.1. Allocation Volume

The sensitivity of power sector EBITDA to the total volume of free allocations given to existing plant within the sector is shown in Figure 33. It can be seen that increasing the level of allocations increases the profitability of the sector. This reflects the assumptions that carbon is passed through to power price as a variable cost at the carbon intensity of the marginal plant, while carbon allocations are treated as a fixed revenue item within the sector EBITDA. Thus, increasing the level of carbon allocations typically increases sector EBITDA.

At the individual plant level, the impact on profitability at a given point in time depends fundamentally on the relationship between the emissions intensity of the individual plant and the emissions intensity of the marginal plant. Broadly speaking, a plant will require a free allocation percentage at least equal to the ratio between the marginal plant emissions intensity and its own emissions intensity in order to avoid a negative impact on profitability.[31]

The level of carbon allocations does not only impact upon EBITDA, it also has some impact upon power prices and the plant mix as it influences the level of coal closures and new build.

- Increasing the level of annual free allocations to 170MtCO_2 (approximately the annual forecast volume of CO_2 emitted by the generation sector over Phase I) results in around 3GW less coal closures than in the Base Case over Phase II. However, since these are plant with very low load factors and plant economics are supported by free carbon allocations, maintaining them on the system only marginally reduces power prices (by less than £1/MWh). There is around 0.5GW less new build, due to slightly lower power prices. Therefore, in aggregate the plant margin would be expected to increase by around 2.5GW (relative to the Base Case). However, there is a risk that the lower level of plant closures could send a negative signal to new entrants,

[31] For example, a plant with emissions intensity of 1.2 tCO_2 /MWh in a system with marginal intensity of 0.6 tCO_2 /MWh will require a 50% free allocation in order to remain unaffected.

leading to less new build than predicted, and hence less increase in the plant margin.

- Analysis of the 100MtCO_2 sensitivity shows only marginal capacity and price differences compared to the Base Case.
- In the 70MtCO_2, 50MtCO_2 and 0 MtCO_2 allocation sensitivities there is increasing economic pressure on an additional 6GW of coal plant over Phase II, which could result in additional closures, with greater economic pressure on plant under the sensitivities with lower volumes of free allocations.

The plant that are exposed to significant economic pressure with lower volumes of free allocations are typically running at relatively low load factors toward the end of Phase II. The impact of these plant closing on the expected annual volume of unserved electricity is shown in Figure 34. It can be seen that a lower level of free allocations could result in a higher volume of expected unserved electricity, due to a higher rate of coal plant closure.

However, in order to maintain a system security level of a 91%[32] annual probability of meeting peak demand, a maximum of only 1.5GW additional coal plant could close. In the sensitivities with 50MtCO_2 or 0MtCO_2 free allocations, this would require additional revenues to maintain plant capacity for this particular security level.

It should be noted that this section only investigated the sensitivity of results to a change in the level of free allocations to existing plant. It was assumed that new entrants received 100% free allocations, as in the Base Case. The sensitivity of results to changes in the level of free allocations to new entrants is discussed in section 7.5.

[32] The CEGB historically operated to a long term planning standard for a plant margin above peak demand of 22% (comparable to a 9% annual probability of not meeting peak demand). This standard was based upon a system that was dominated by coal-fired plant, and so may not be an appropriate measure for a different generation portfolio.

Figure 33: Impact of the Volume of Power Sector Phase II Allocations on Sector Average Annual EBITDA

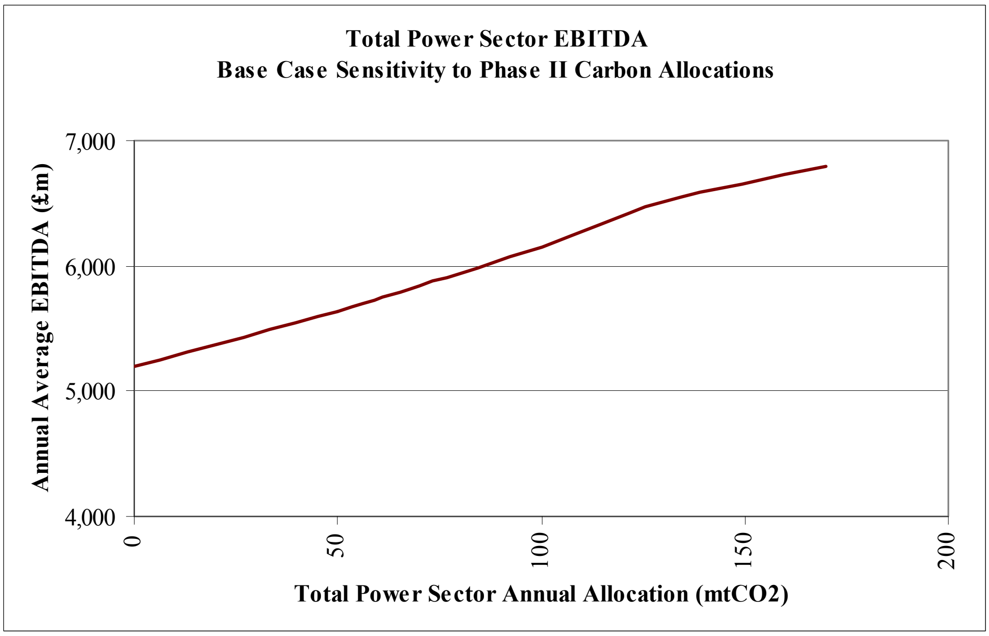
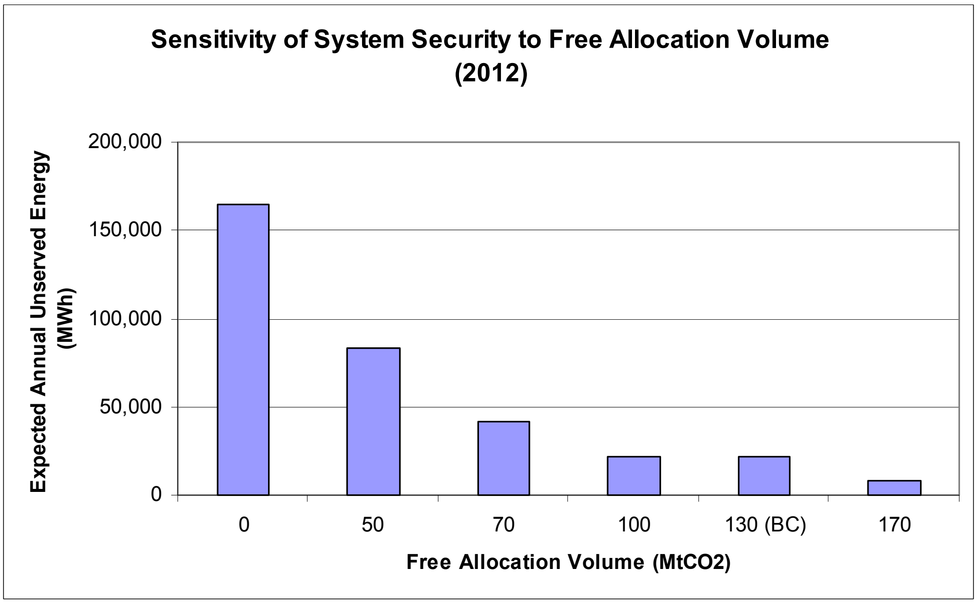


Figure 34: Sensitivity of Security of Supply to Allocation Volume



7.3.2. Allocation Methodology

This section looks at the sensitivity of Base Case results to the allocation methodology in Phase II. It compares three sensitivities:

- Allocations under the Base Case (same as Phase I), total allocations 130MtCO_2 per annum;
- Allocations based upon the volume of running for each plant assumed under Phase I but with emissions calculated at the emissions intensity of an efficient modern CCGT, leading to total allocations of around 70MtCO_2 per annum;
- Allocations re-based upon forecast annual requirements for each plant. This has been modelled as an ex-post allocation and so yields exact allocations relative to emissions. In practice, such a methodology would have to be based upon forecasts and so there would be differences between allocations and actual emissions. Total allocations are around 170MtCO_2 in 2008 reducing to around 130MtCO2 by 2012.

The impact of allocation methodology is primarily on company EBITDA. An analysis of the sector EBITDA is given in Figure 35. It can be seen that the level of free allocations has a direct impact upon sector EBITDA, with a spread of almost £1.5bn between the forecast allocations and allocations based on CCGT emissions in 2008. However, the spread between the sensitivities reduces to around £0.5bn in 2012, with sector EBITDA under the forecast allocations relatively close to the level under the Base Case.

An analysis of the sensitivity to allocation methodology of the profitability of different generation technologies is given in Figure 36, which shows the average annual EBITDA over Phase II per unit of capacity.

It can be seen that the EBITDA of coal generation is the most sensitive to the allocation methodology, since it is the most carbon intensive of the technologies. However, the impact of the allocation methodologies on different coal plant varies considerably. This reflects the fact that coal plant load factors typically reduce over Phase II, with some plant achieving very low load factors toward the end of the Phase. Plant with significantly reducing load factors are typically worse off under the exact allocation methodology, despite the average coal plant EBITDA being greater over the Phase.

Existing CCGTs also show a surprising degree of sensitivity, due to their lower efficiency relative to a modern CCGT (the carbon intensity of a modern CCGT can be up to 35% less than for an older CCGT). New build CCGTs have been assumed to receive 100% free allocations, but would also do well under most allocation methodologies based on some form of benchmarking. Nuclear plant are not directly exposed to the allocation methodology, other than through its impact on power price.

The different allocation methodologies could place significant economic pressure on some coal plant. All coal plant will be worse off than the Base Case under a CCGT emissions factor, but plant with significantly reducing load factors may be even worse off under an exact allocation. Thus, by the end of Phase II, there may be significant economic pressure on around 4GW of low load factor coal plant under either allocation sensitivity.

The impact of 4GW of plant closures on the expected annual volume of unserved energy is shown in Figure 37. However, this would not maintain a system security level of a 91% annual probability of meeting peak demand. To do so a maximum of only 1.5GW additional coal plant could close. Maintaining this level of plant margin would require additional revenues to maintain capacity.

Figure 35: Impact of the Methodology of Power Sector Phase II Allocations on Sector Average Annual EBITDA

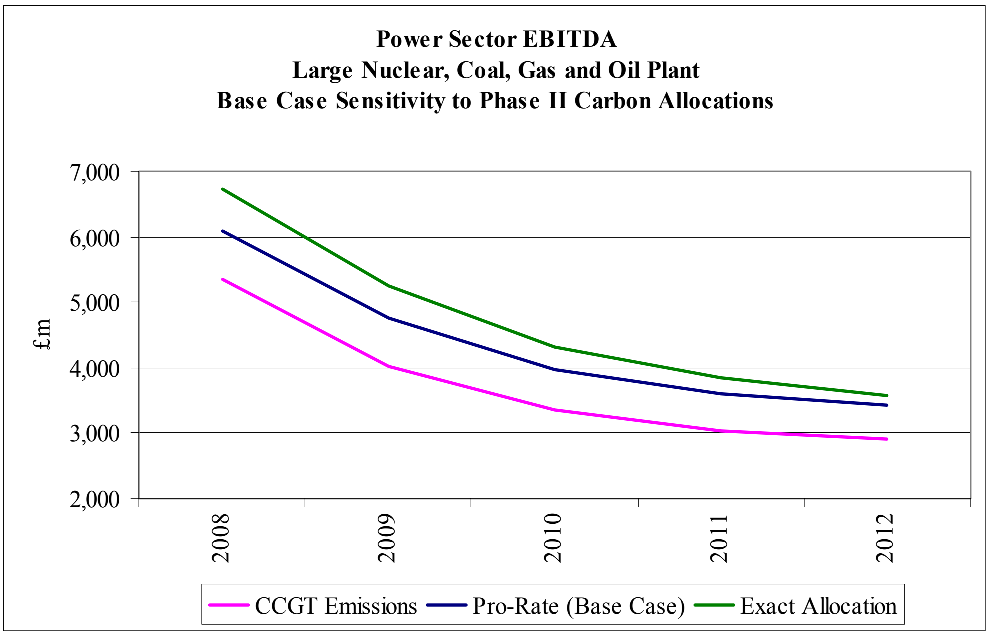


Figure 36: Impact of the Methodology of Power Sector Phase II Allocations on Generation Technology EBITDA

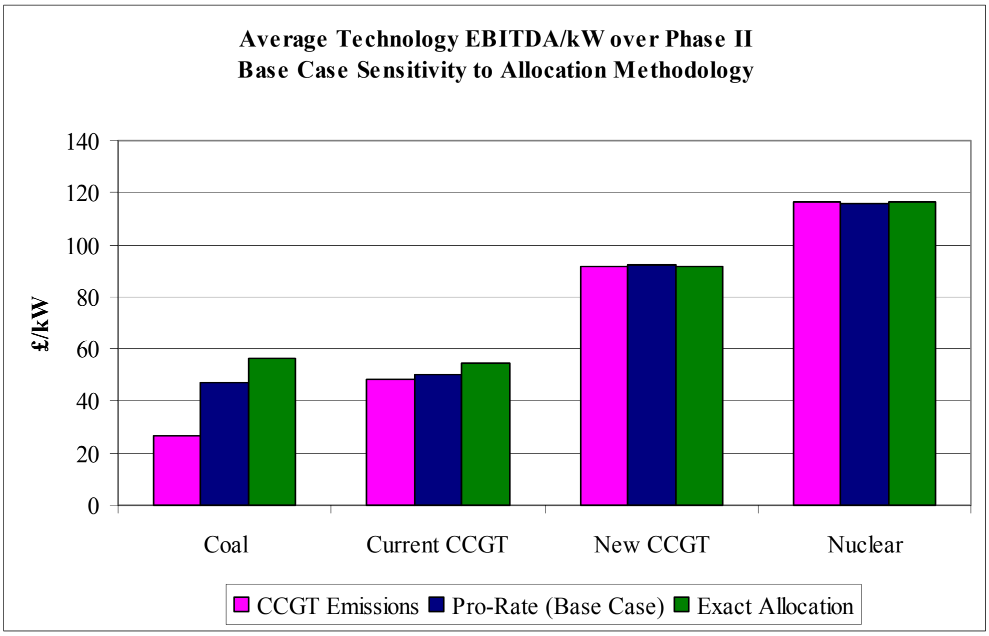
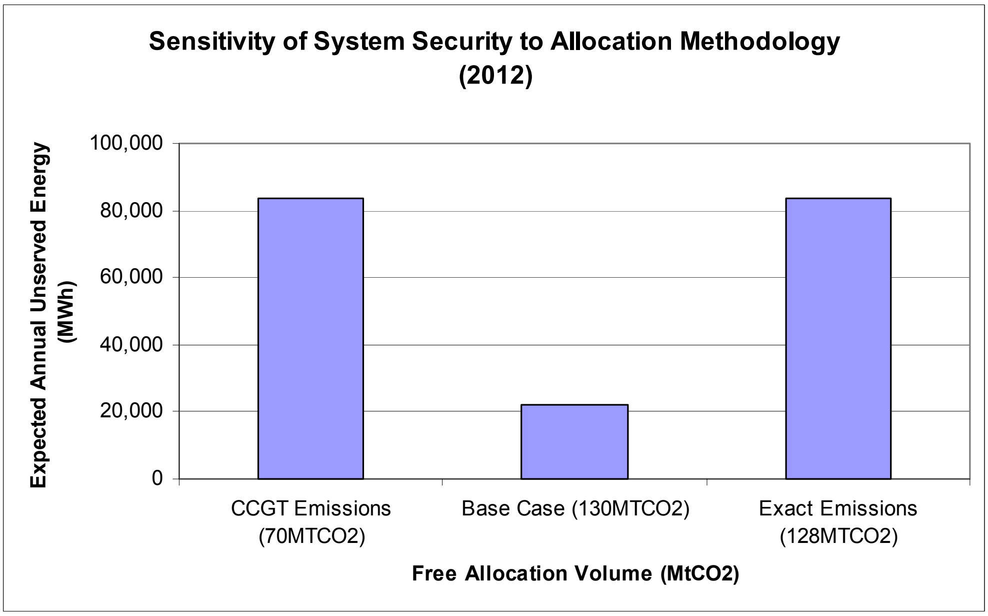


Figure 37: Sensitivity of Security of Supply to Allocation Methodology



7.4. Closure Rules

The different closure rules could have an impact upon the timing of coal plant closures, since they change the economics of a closure decision. The two options considered are:

- **Retain allocations for the year, then surrender all future allocations:** Plant closure will be assessed based upon the estimated NPV of EBITDA compared to the value of the carbon allocations for that year. A plant returning a higher NPV should remain open (although earnings might not cover repayment of outstanding debt). For a plant returning lower earnings than the value of the carbon allocation, it could be more profitable to close the plant at the commencement of an allocation year and sell the allocated allowances.

- **Retain allocations for the Phase, then surrender all future allocations:** Plant closure will be assessed based upon the estimated NPV of EBITDA compared to the value of the NPV of carbon allocations over the phase. A plant returning higher earnings should remain open. For a plant returning lower earnings than the value of the future carbon allocation, it could be more profitable to close the plant and sell the allocations.

In both cases the level of current and future carbon allocations can influence the economic closure decision. The important difference between the methodologies is that allowing plant closures to retain allocations over the phase increases the revenue that can be obtained after closure, and so could advance plant closures. This would happen when plant is only returning a positive EBITDA due to the value of free allocations. In other words, keeping plant open is destroying value, unless by keeping it open it maintains a right to future allocations.

The sensitivity of closure decisions to the closure rules investigated for two illustrative examples in Figure 39.

- In Station A's case, the NPV of their retained annual allocation will be worth more than the NPV of EBITDA from 2011, hence it is likely to close at some point after this. However, if Station A is allowed to retain allowances for the rest of the Phase after closure, the NPV of their retained allocation will be worth more than the NPV of EBITDA from 2009, bringing forward the closure date by at least two years.

- Station B's NPV of EBITDA, on the other hand, remains above the NPV of retained allowances under both closure rules for the entire Phase. It is therefore unlikely to close during Phase II under either closure rule.

The key impacts of the different closure rules are:

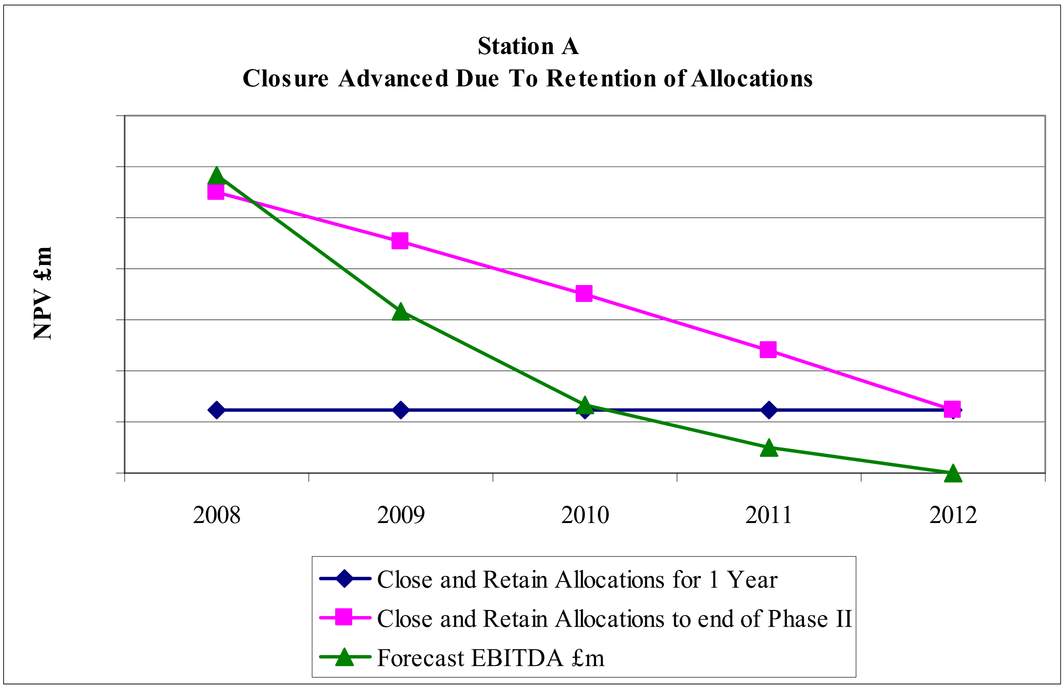
- Retaining allocations for the remainder of Phase II would provide an incentive to maintain plant that is uneconomic in Phase I to the start of Phase II in order to receive Phase II allocations, with plant then closing as soon as allocations were guaranteed. However, under the Base Case there were no plants that became uneconomic in Phase I, so this is unlikely to have a significant impact on Phase I closures in practice;

- Retaining allocations for Phase II would be likely to advance the closure of plant during the Phase, since the value of retained allocations is higher earlier in the Phase. For all of the 3GW of plant closed during Phase II under the Base Case, value would be increased by earlier closure (where allocations are retained for the Phase).

- At the end of the Phase, the value of allocations under either closure rule is the same. Thus, retaining allocations for Phase II is unlikely to increase the aggregate amount of plant closure during the Phase;

The impact on the expected annual volume of unserved energy of advancing all 3GW of Phase II plant closures so that they all occur in 2008, is investigated in Figure 39. However, this would not maintain a system security level of a 91% annual probability of meeting peak demand. To do so, some of the plant closures would have to be delayed to later in the Phase. This would require additional revenues to maintain capacity. This might be provided through the market either through increased price volatility, internalising of capacity costs by portfolio generators, or alternatively through reserve or capacity payments.

Figure 38: Economics of Closure under different Closure Rules



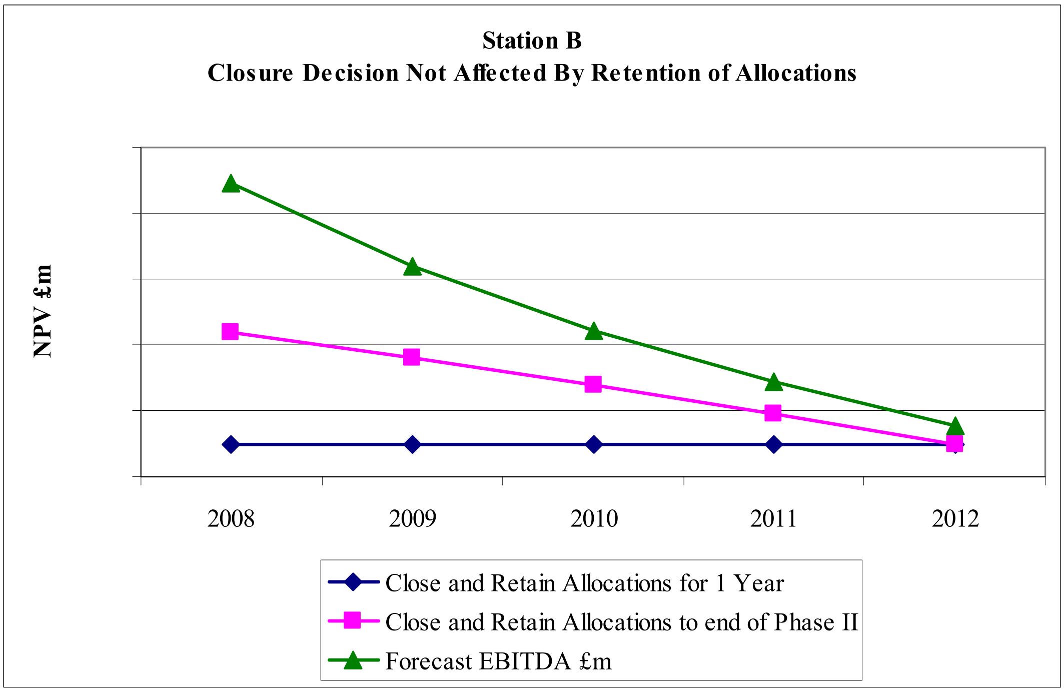
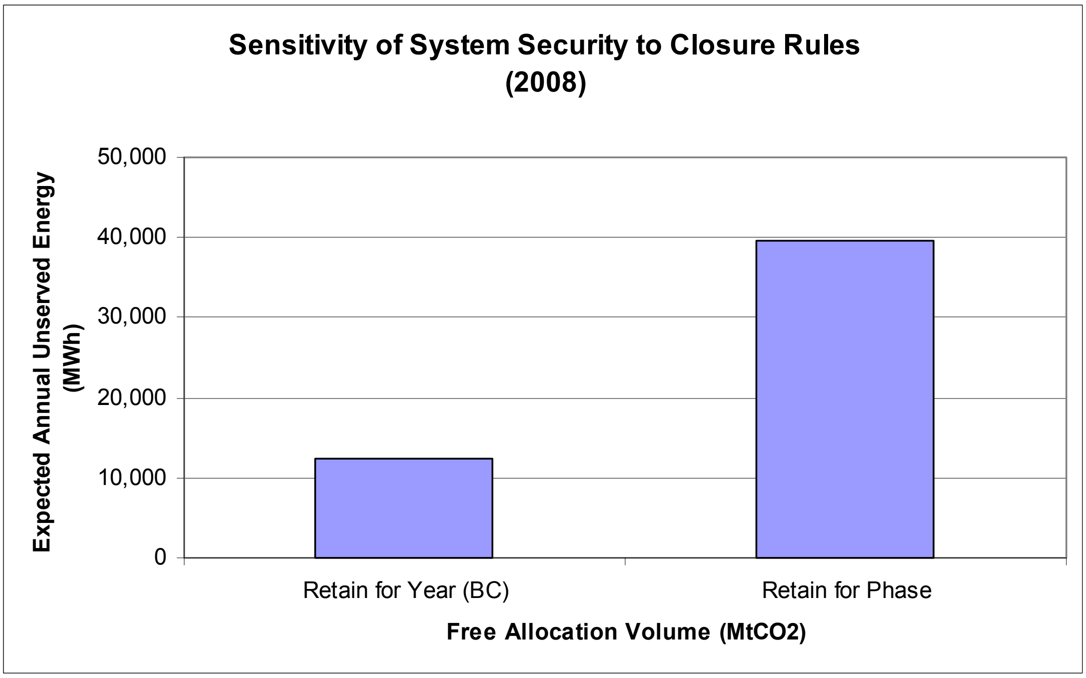


Figure 39: Sensitivity of System Security to Closure Rules



7.5. New Entrant Allocations

New entrant allocations have the potential to provide a new entrant generation project with a hedge against carbon prices, as well as reducing project costs. Thus new entrant allocations reduce the risk associated with a new entrant project (reducing financing costs) and have a direct impact upon project profitability. Both of these components serve to significantly reduce the cost of new entrant capacity.

7.5.1. Scenarios

The three scenarios presented in section 6 above investigated, amongst others, the impact of different new entrant allocations in Phase II of the EU ETS, as shown in Table 9 below. The effect of a reduction in the level of new entrant allocations was seen in the High Case scenario, where the costs of new entry CCGT capacity were significantly greater than in the two other scenarios. In the High Case new CCGT entry was delayed by 3 years when compared to the Base and Low Case, with the new entrant allocation being one of a number of factors contributing to this result.

Table 9: Phase II EU ETS New Entrant Allocations under the Three Scenarios

Low Case	Base Case	High Case
100% Free	100% Free	No Free Allocations

7.5.2. Sensitivities

This section investigates the sensitivity of the Base Case results to changes in the assumptions on the level of free allocations to new entrants.

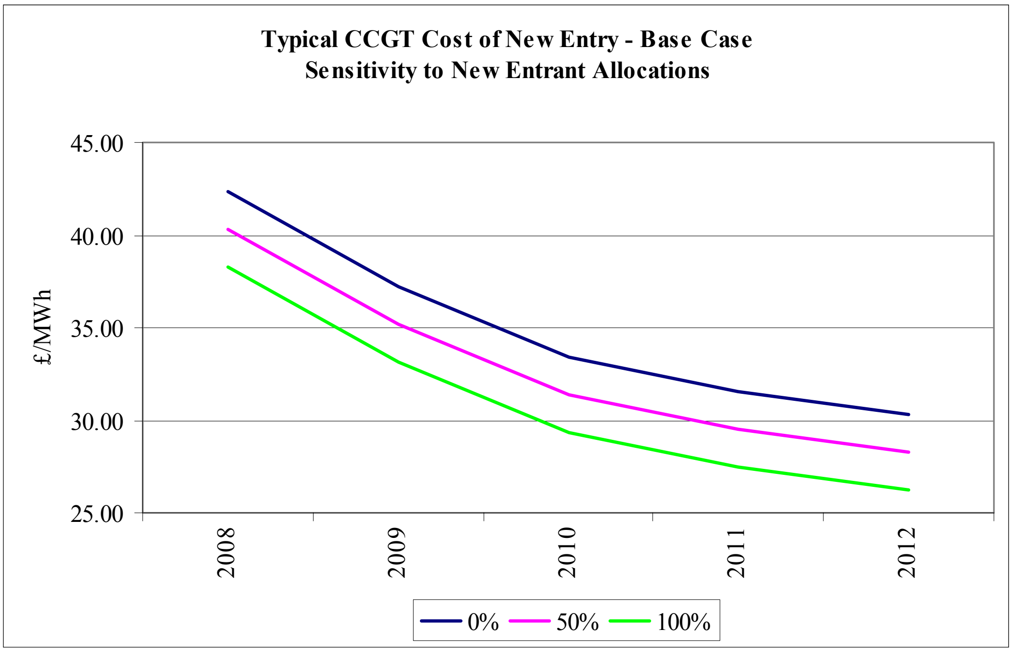
Table 10 shows the main parameters used in the calculation of New Entrant costs for 2010, with and without the free carbon allocations. It should be noted that it is assumed that a new CCGT would operate most of the year, providing baseload power. Decreasing the annual power output would significantly increase the total built-up costs for a unit of electricity.

Table 10: New Entrant Assumptions for Base-load Plant

	2010
Capital Cost	
Total Project Capital Cost £/MW	465,000
Real Pre-Tax WACC	8.5%
Duration (years)	20
Annualised Capital Cost £/MW/year	£49,025
Fixed Cost	
Total, £/MW/year	£27,020
Variable Cost	
Total, £/MWh	23.25
Total Cost Excluding Free Carbon Allocations	
Total, £/MWh	***33.71***
Free Carbon Allocations	
Percentage Free Allocations	100%
Value of Free Allocations, £/MWh	£4.19
Total Cost Including Free Carbon Allocations	
Total, £/MWh	***29.52***

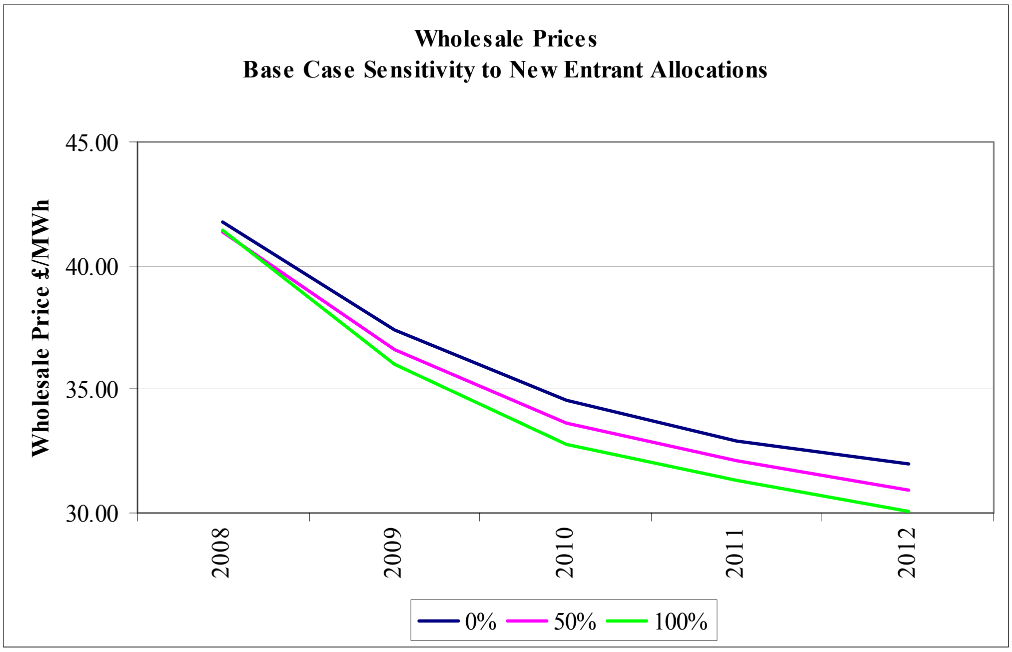
The impact of the level of new entrant allocations on the cost of new entry for a typical CCGT plant is shown in Figure 40, for Phase II of the EU ETS. It can be seen that 100% free allocations reduces the fully built-up costs for a new entrant CCGT by over £4/MWh, relative to the position with no free allocations. The level of this reduction in costs is obviously dependent upon the level of carbon prices, which have been assumed to be €19.70/tCO_2 over EU ETS Phase II in the Base Case. The total built-up cost of new entry CCGT reduces over the Phase due to the reduction in gas prices in the Base Case scenario.

Figure 40: Impact of Phase II New Entrant Allocations on New Entrant Cost



Under the Base Case scenario, build of new gas plant was economic at the start of EU ETS Phase II, and the construction of new plant helped restrict wholesale price increases. Reducing the level of allocations to new entrants would increase the costs of new entry and thus could lead to higher wholesale prices. The level of wholesale prices under different new entrant allocations is investigated in Figure 41. It can be seen that the impact of 100% free allocations is to reduce wholesale electricity prices by around £2/MWh in 2012, relative to the position without free allocations. The impact is significantly smaller at the beginning of Phase II and increases over the Phase as the cumulative effects of capacity build and changes to the generation mix feed into the wholesale price.

Figure 41: Impact of Phase II New Entrant Allocations on Wholesale Prices



The level of capacity build and closures is explored in Figure 42. It can be seen that the impact of 100% free allocations for new entrants results in around 3GW more new gas generation capacity constructed over the whole of Phase II, relative to the position with no free allocations. The impact of the construction of high merit gas fired generation build is in part to displace lower merit generation, resulting in closure of some of the coal generation sets. With 100% free allocations to new entrants, the higher volume of new gas fired generation build results in over 500MW more coal closures compared to the position where no free allocations are given to new entrants.[33]

With 100% free allocations to new entrants, the volume of capacity on the system (the net position of new build and closures) is greater than in the position where there are no free allocations. The higher plant margin is supported where free allocations are given to new entrants, since there is in effect a greater level of *subsidy* given to the generation sector, and thus it is economic to maintain a higher volume of plant at a particular wholesale price level.

The impact of the new entrant allocation sensitivities on the expected annual volume of unserved electricity is investigated in Figure 43. It can be seen that the lower new entrant allocations result in an increased volume of unserved demand. However, in order to maintain a system security level of 91% annual probability of meeting peak demand, it is likely that some of the coal closures under the Base Case would have to be delayed under the lower new entrant allocations sensitivities.

The impact of the differences in gas build and coal closures means that the level of new entrant allocations also has an impact upon the volume of CO_2 emissions from the power sector, as shown in Figure 44 and broken down by technology in Figure 45. It can be seen that the impact of 100% free allocations to new entrants is to decrease emissions by around 13MtCO_2/year in 2012 relative to the position with

[33] It has been assumed that the applicable closure rule is for retention of the year's allowances only.

no free allocations[34]. The decrease in the volume of emissions grows over Phase II, due to the cumulative impact of the growth in gas fired capacity. It can be seen that whilst emissions from gas fired stations increase, this is more than compensated by a reduction in emissions from coal plant. The reduction in coal burn would mean that in addition to the reductions in CO_2 emissions, there would be a corresponding reduction in the volume of SO_2 emissions over the sector.

The sensitivity of the volume of new entry generation capacity to the level of free new entrant allocations has been investigated here. However, it is important to note that the treatment of CHP plant will be more complicated than the treatment of CCGTs, since CHP capacity may fall out-with the power sector allocation. The treatment of free allocations to new CHP plant could have a significant effect on the economics of new build CHP plant, and so may have a significant impact on the volume of new CHP capacity constructed.

[34] The similarity between the level of emissions under the 0% and 50% allocation sensitivities is undoubtedly in part due to the discrete nature of plant opening and closure decisions.

Figure 42: Impact of Phase II New Entrant Allocations on Capacity Build and Closures

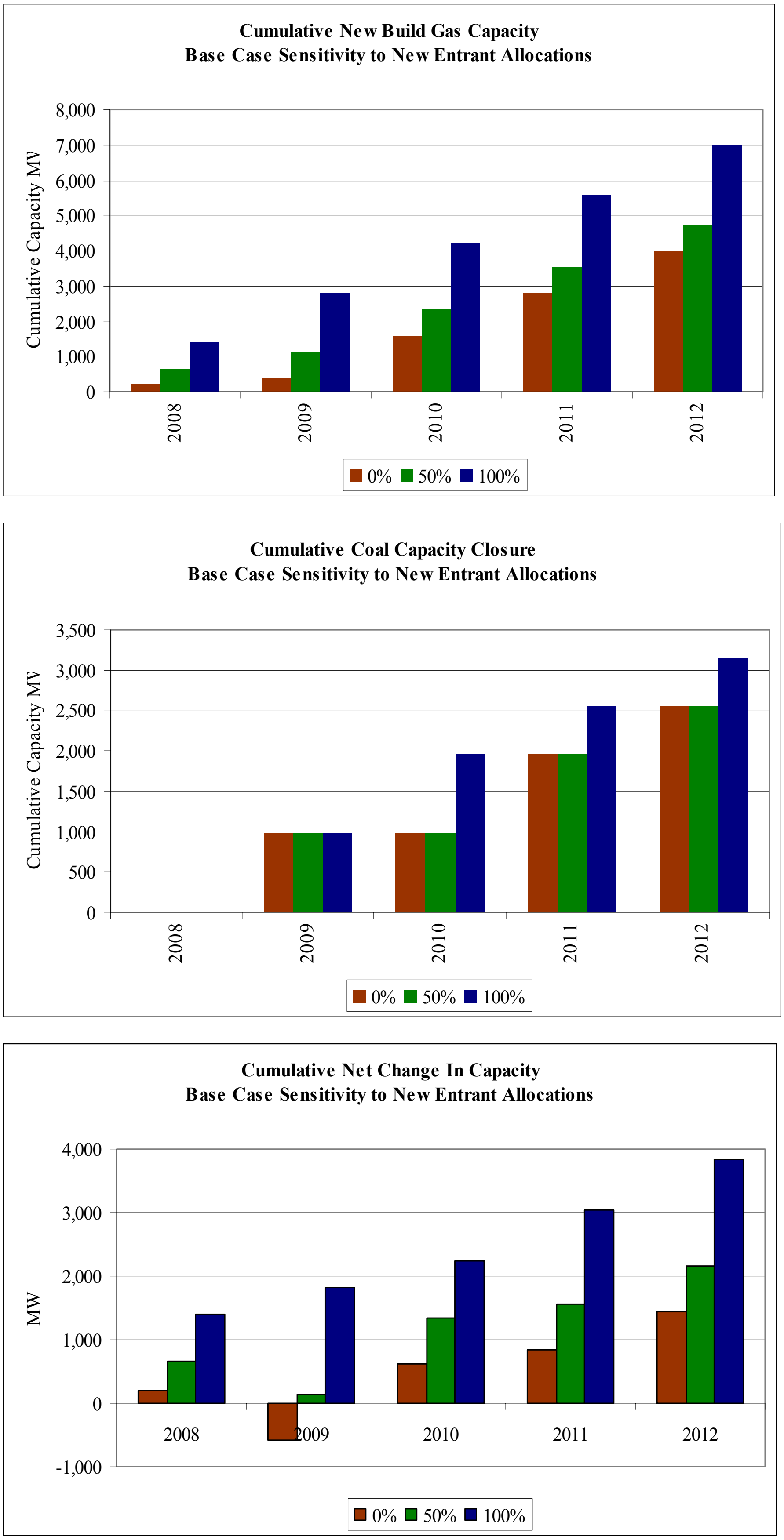


Figure 43: Sensitivity of System Security to New Entrant Allocations

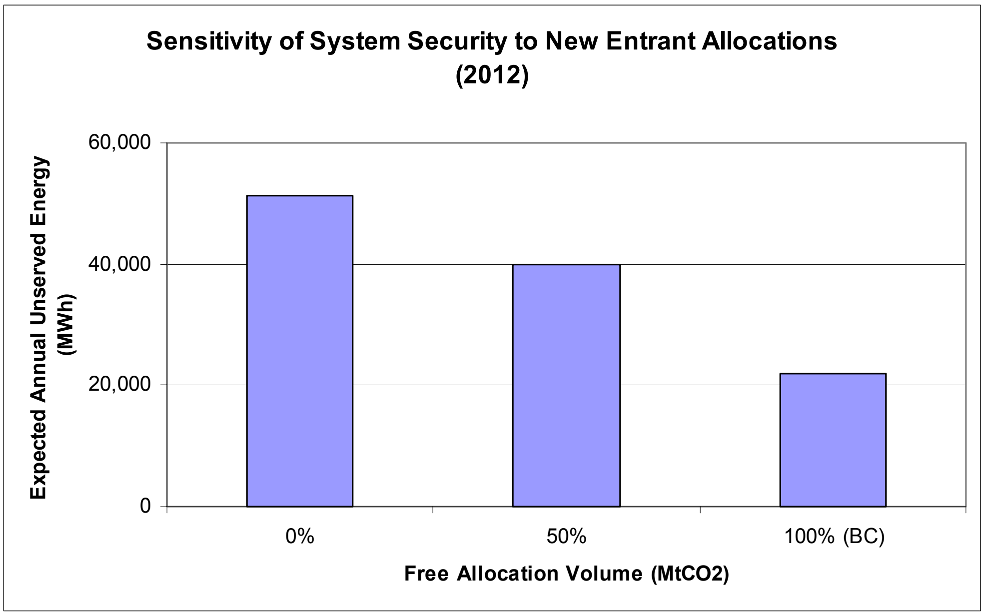
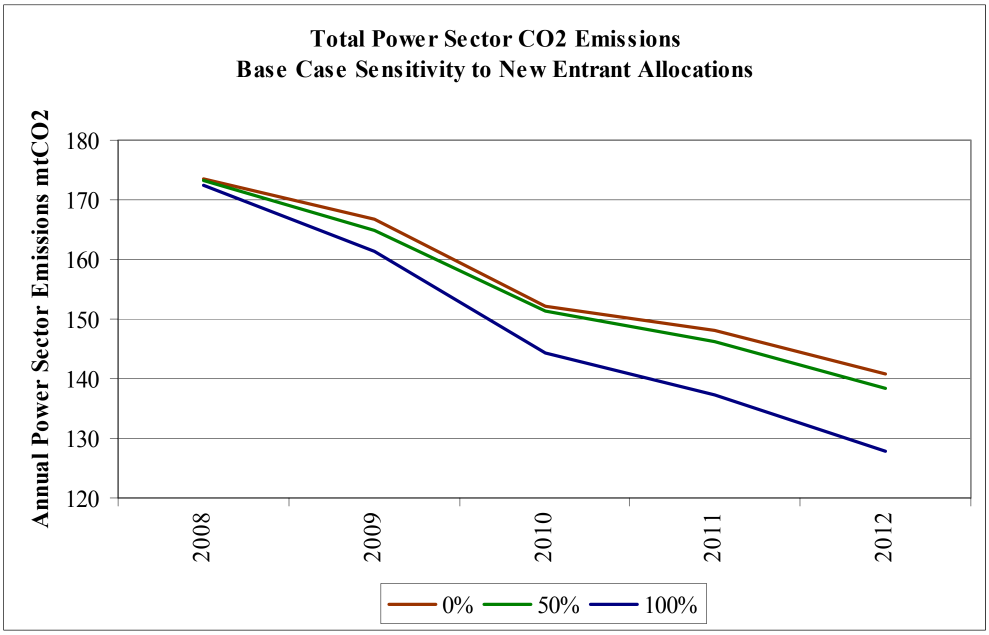
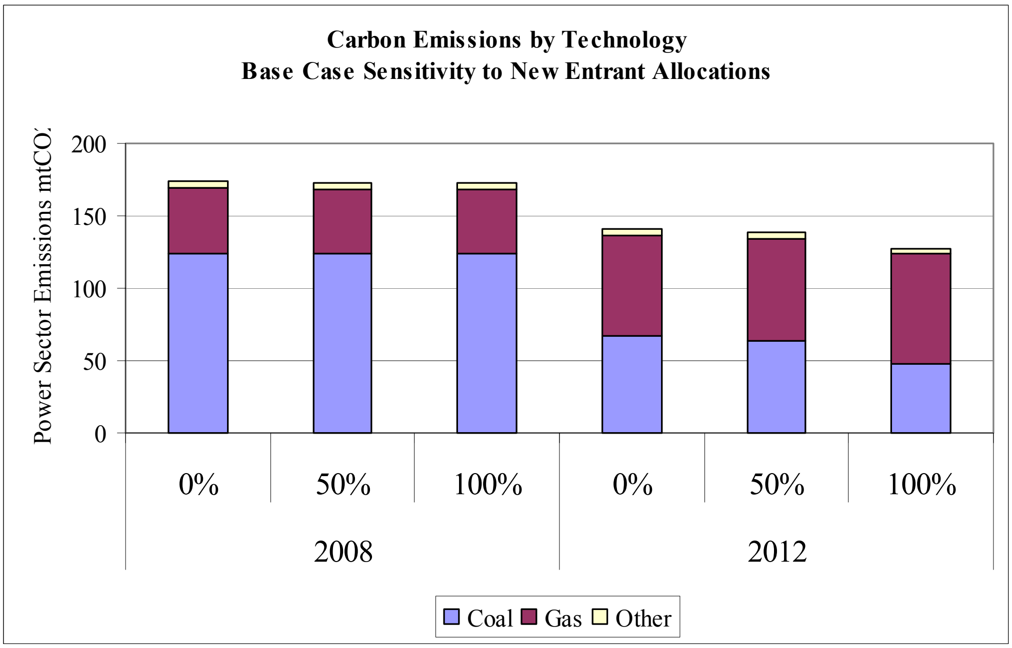


Figure 44: Impact of Phase II New Entrant Allocations on Sector CO_2 Emissions[35]



[35] Including emissions from CHP, some of which are included in the Power Generation Sector.

Figure 45: Impact of Phase II New Entrant Allocations on CO_2 Emissions by Technology[36]



7.5.3. Impact of Uncertainty

The sensitivity analysis of the level of free allocations to new entrants has assumed that the allocation methodology is known sufficiently ahead of time, such that optimal economic decisions are taken by project developers. However, in practice the development and construction of a CCGT project is likely to take at least 3 years, so a developer currently examining the possibility of constructing new CCGT plant would not know the methodology to be used for allocation in Phase II when the project would be commissioning.

This uncertainty means that a developer would be likely to take a conservative view on the level of free allocations, and for a project financed plant, debt providers' lending decisions would be likely to based upon forecast project revenues on the assumption of *no* free allocations. The analysis shown in Table 10 above shows the direct revenue impact of free allocations. However, in addition the receipt of free allocations reduces a project's exposure to the volatility of the carbon market, reducing the overall risk exposure of the project. This could lead to a reduction in the cost of capital associated with constructing a new CCGT, further reducing the cost of new entry.

The analysis presented in the previous section indicates that if the current state of uncertainty associated with the level of free allocations for new entrants was maintained it could result in delays to construction of new plant, and a lower level of CCGT build over Phase II. However, if an announcement were made in the near future about the level of free allocations to new entrants, this would allow developers to incorporate the value of these allocations within the economics of new plant, and would ensure that developments are progressed where economic.

[36] Including emissions from CHP, some of which are included in the Power Generation Sector.

New plant will also have to make assumptions about the level of free allocations in Phase III of the EU ETS. While it may not be practicable at this stage to give a firm commitment on the level of free allocations, developers may be concerned that plant commissioned in Phase II may not receive the same treatment as plant in existence at the beginning of the EU ETS. It should be considered whether any commitment can be made on the methodology for Phase III allocations, since any reduction in uncertainty will improve the economics of new entrant capacity.

8. PRICING ANALYSIS

8.1. Impact of Carbon on Historic Wholesale Prices

This section analyses the impact of the EU ETS on historic wholesale prices. It examines how electricity market prices have been impacted by the EU ETS and to what extent the price of carbon has been passed through to the wholesale price. The analysis compares market data across the EU, examining the experience in GB, Germany, the Netherlands, France, Italy and Spain.

The analysis looks at the correlation between the price of carbon and the spark and dark spreads. The spark spread is defined as the price of power less the cost of gas to generate a unit of electricity at a typical efficiency for a CCGT (assumed at 50% GCV). The dark spread is defined as the price of power less the cost of coal to generate a unit of electricity at a typical efficiency for a thermal coal plant (assumed at 35% GCV).

The spark and dark spread give a measure of the margin that generators can extract from the power price, over and above their direct fuel costs. Carbon can be seen as an additional marginal cost to the generator, the level of correlation of the spark or dark spread with carbon prices can indicate the extent to which carbon costs are being passed through to the wholesale price as a marginal cost.

8.1.1. GB

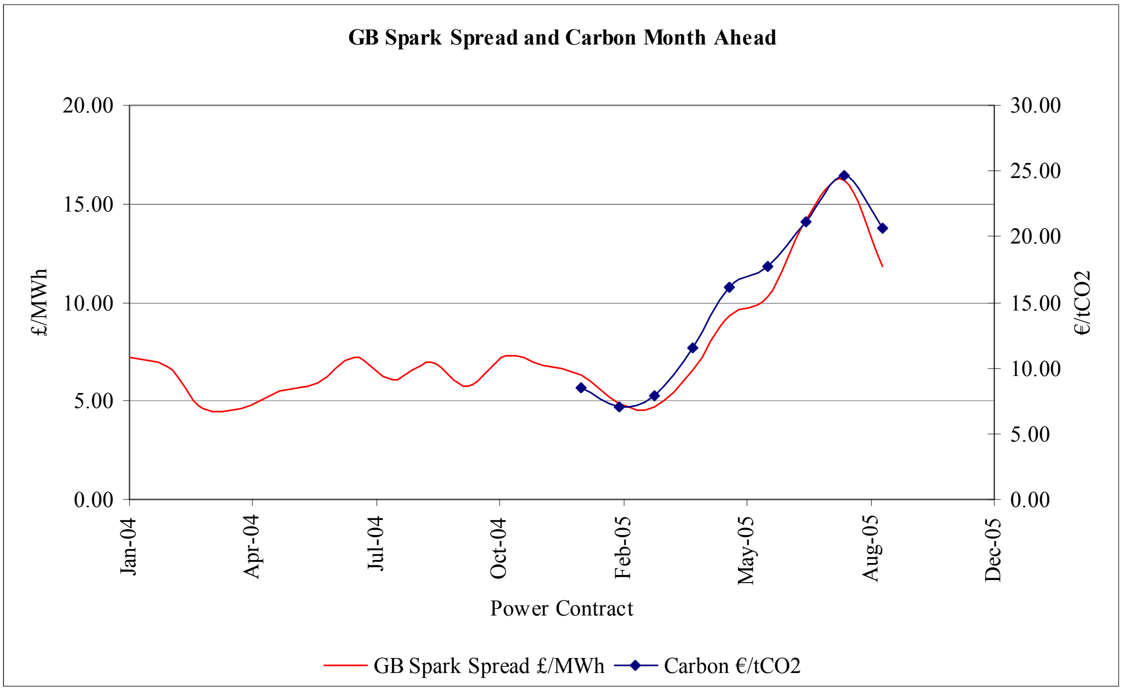
An analysis of both the spot and term markets can be used to assess the level of pass through of carbon prices to wholesale prices. Spot markets arguably have the advantage that they are close enough to real time that prices tend to be more influenced by fundamental drivers and short-run marginal economics. However, they are also subject to significant volatility which can mask the impact of fundamental price drivers. Price signals within the term market have the advantage that they have significantly lower volatility, but market price responses are not always so easily related to market fundamentals, in part due to the lower liquidity of the term market.

- ***Month-Ahead Spark Spread Analysis***

  The month-ahead spark spread is compared to the carbon price (trading over the same period) in Figure 46. It can be seen that over Calendar 2004 the spark spread was range bound between around £5-7/MWh. However, with the introduction of carbon trading in January 2005, the spark spread has closely followed the carbon market with a 98% correlation. The spark spread peaked in July 2005 (when the August power contract was trading month ahead) at around £16/MWh, then softened in August (to-date). This analysis suggests that there is a significant pass through of the cost of carbon to power price.

  An analysis of the level of carbon pass through in the spark spread suggests that the carbon price pass through is at around the carbon intensity of coal units. This is perhaps surprising considering the spot markets imply that CCGTs have been the marginal technology over most of the year (although coal may have been marginal during the June-August 2005 contracts, due to peaking carbon prices). The carbon price pass through at the carbon intensity of coal units implies that carbon costs are being completely passed through to spot market prices, and may indicate that there has been over-recovery of carbon costs in some periods where CCGTs may have been the marginal technology.

Figure 46 GB Month-Ahead Spark Spread Analysis[37]



- ***Month Ahead Dark Spread Analysis***

Analysis of the month ahead commodity prices suggests that coal units were the marginal technology from June to August 2005. Thus, it is interesting to investigate the level of carbon pass through by looking at the correlation of carbon price to dark spread. The month-ahead dark spread (using an API#2 index price) is compared to the carbon price (trading over the same period) in Figure 47.

It can be seen that the correlation between the dark spread and the carbon price is not as close as for the spark spread. This reflects the fact that although coal is an international traded commodity, the market for coal is not as liquid as for gas, and importantly, since it can be stored but is not as easily transportable as gas, short term movements in coal market prices do not have such a direct impact on generators' short run marginal (or opportunity) cost.

Nevertheless, an analysis of the change in the dark spread over the period of the 2005 calendar year to date shows that there is a strong relationship with the carbon price, yielding a correlation of around 89%. The analysis suggests that the level of carbon price pass through is around the carbon intensity of coal generation technology.

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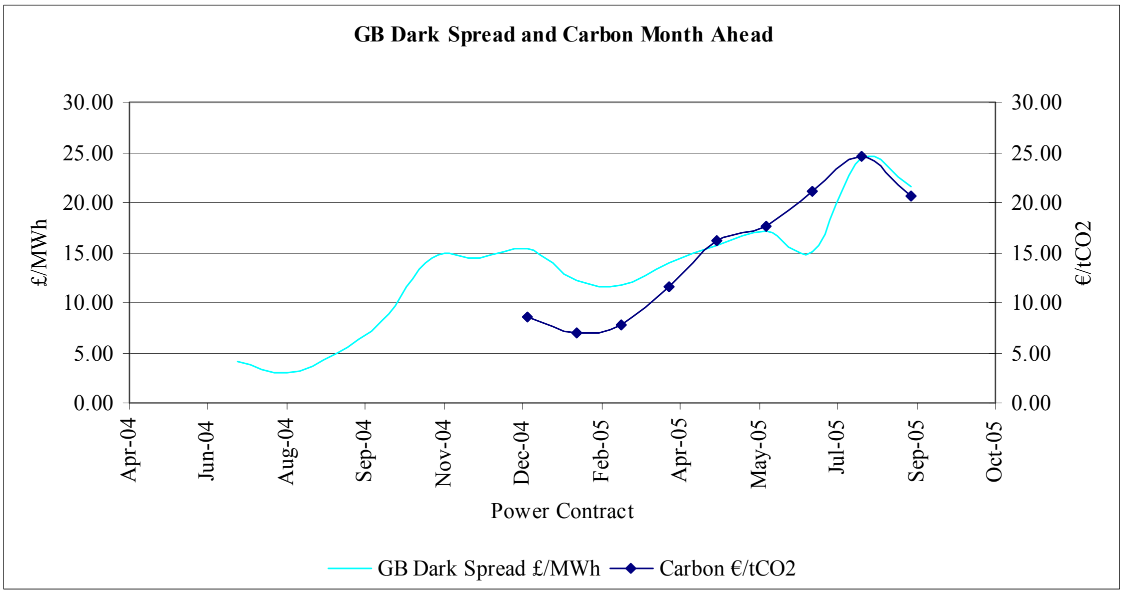
[37] Spectron Data

Figure 47 GB Month-Ahead Dark Spread Analysis[38]



- ***Cal-06 Spark Spread Analysis***

The daily trading of the Calendar 2006 (Cal-06) spark spread is compared to the price of carbon for delivery in 2006 in Figure 48. It can be seen that despite no obvious relationship between the power and carbon markets in January 2005, over the remainder of the year to-date there has been a strong correlation between the prices.

Prices in the forward commodity markets for Cal-06 imply that CCGT should be the marginal generation technology (allowing for the cost of carbon), over the entire period.

An analysis of the level of carbon pass through in the spark spread suggests that the carbon price pass through is between the carbon intensity of CCGT and coal units. This implies that carbon costs are being completely passed through to term market prices on a marginal cost basis, and may indicate that the market is over-recovering carbon costs.

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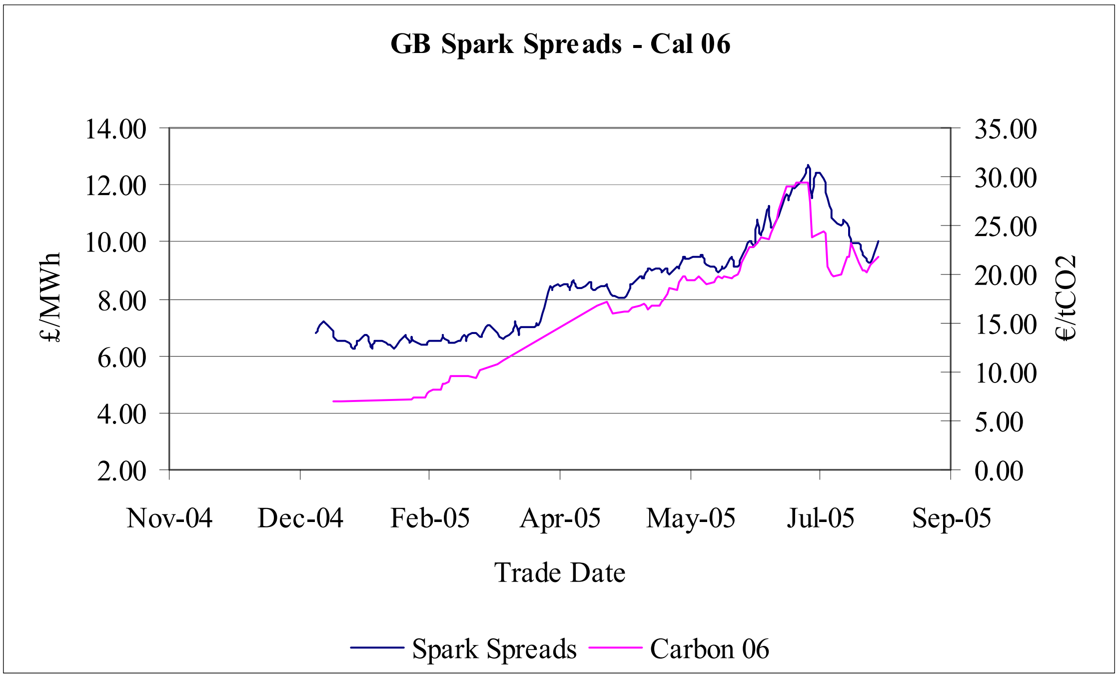
[38] Spectron Data

Figure 48 GB Cal-06 Spark Spread Analysis[39]



8.1.2. Germany, France and Netherlands

The month-ahead spark spreads are compared to carbon price for Germany, France and the Netherlands in Figure 49. The spark spread is calculated using gas prices at Zeebrugge for France and Germany (with an uplift to allow for transportation), and the Dutch TTF contract for the Netherlands. The gas price at Zeebrugge is not necessarily reflective of the delivered price in Germany or France, although in-country prices should be well correlated. Zeebrugge was chosen as the most liquid of the European gas trading hubs and so most likely to be representative of the spot value of gas in NW Europe.

It can be seen from the chart that despite lower correlation in the early months, there appears to be strong correlation as carbon prices increase from March 2005, with correlations of over 90% for the year to date. The level of the pass through to the power price is around the carbon intensity of coal generation technology. As in the GB analysis this is surprising since the spot markets suggest gas fired generation was the marginal technology over most of the period, again implying over-recovery of the carbon costs on a marginal cost basis.

An analysis of the dark spreads show a very similar picture to the spark spread analysis, with carbon passed through at the marginal carbon intensity of coal, as shown in Figure 50.

An analysis of the Cal-06 power and gas products for Germany, France and Netherlands shows no strong relationship between the spark spread and the level of the carbon price in these countries. This is surprising, considering there appears to be a strong relationship in the month ahead markets. It perhaps reflects the fact that the term markets for both power and gas are not as liquidly traded as in GB. It may

[39] Spectron Data

also reflect the fact that most power stations will not be exposed to the year ahead traded price of gas, since many will have long term oil-indexed gas contracts.

Figure 49: Month Ahead Spark Spread Analysis for Germany, France and Holland[40]

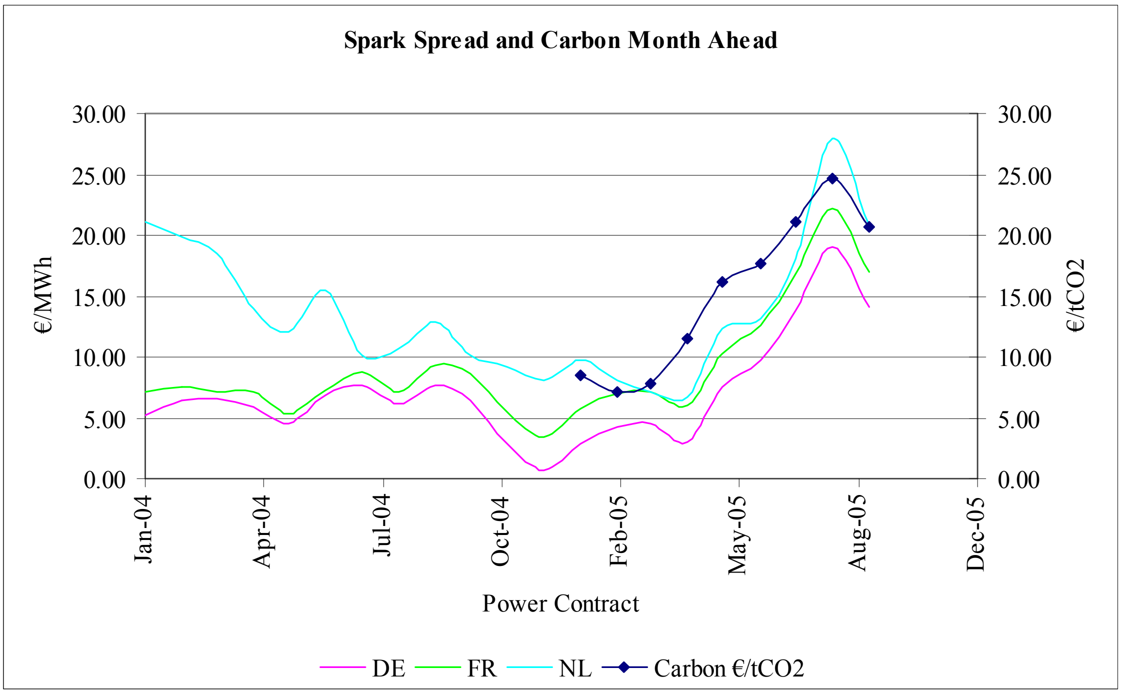
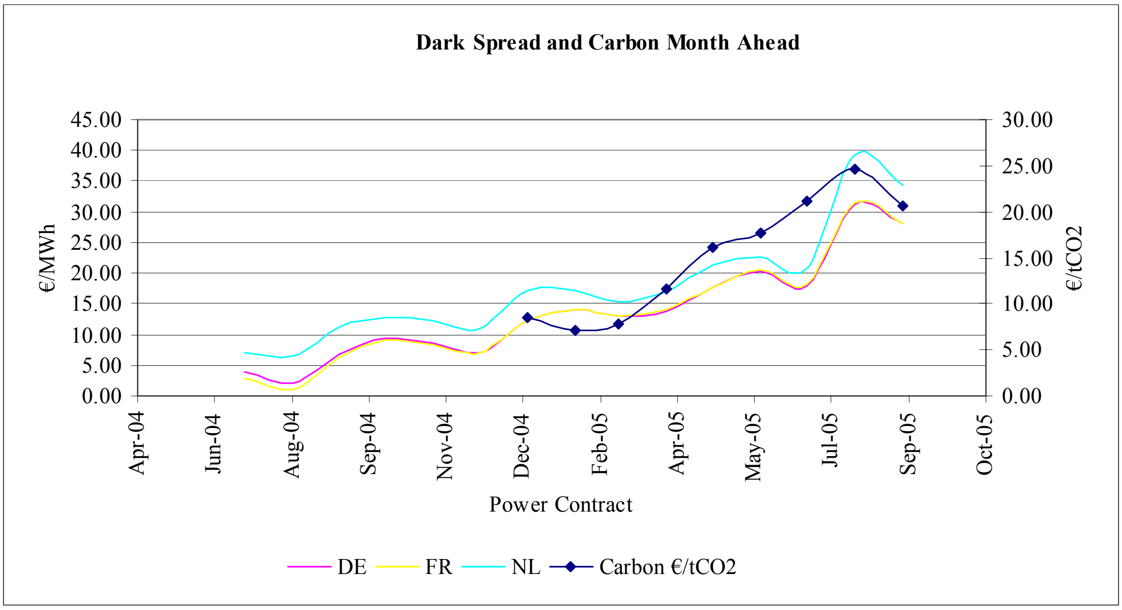


Figure 50: Month Ahead Dark Spread Analysis for Germany, France and Holland[41]



[40] Spectron Data
[41] Spectron Data

8.1.3. Italy and Spain

Power and gas markets in Italy and Spain are not as liquid as in Northern Europe, which complicates undertaking an analysis of the correlation of spark and dark spreads to carbon. An analysis of the prices in Italy and Spain has been undertaken using day ahead market data.[42] Day-ahead markets are significantly more volatile than month-ahead markets, since they respond to the daily events such as plant outages and changes in weather. Thus, it could be harder to strip out the macro-economic effects of carbon price from the day-ahead prices, than it was from month ahead prices.

The day-ahead spark spread analysis is shown for Italy and Spain in Figure 51. It can be seen that although there is some correlation between the Spanish spark spread and carbon price (around 70%), the increase in the spark spread over the year to-date is much greater than could be explained by carbon pass-through, and has probably been predominantly driven by the current dry hydro conditions. The Italian spark spread shows no obvious correlation with the carbon price.

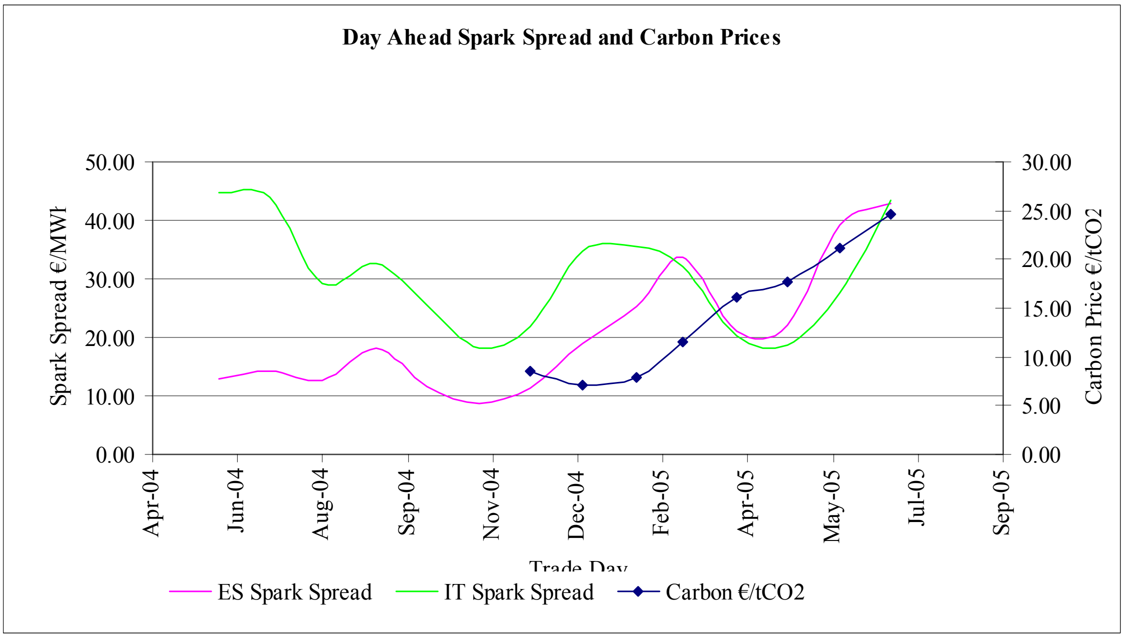
Italy and Spain do not show the same evidence of carbon pass through as the other markets. There are several reasons why this may be the case:

- The volatility observable particularly in the Italian markets over the last year is significantly greater than the other markets analysed, serving to mask fundamental economic price drivers;
- The dry hydro conditions observed this year particularly in Southern Europe have provided a significant fundamental price driver, which again serves to mask other fundamental macro-economic price drivers; and
- The relatively high level of power prices and spark spreads means that there may already be a significant uplift included within the wholesale price, over and above short run marginal cost. This means that changes in short run marginal costs may not lead directly to a change in power prices, as would be the case in more competitive markets, where power prices may be driven down close to the short run marginal costs. Thus, in particular in Italy and to a lesser extent in Spain, power plant may already be capturing sufficient economic rent from the market, to ensure that prices already cover the increases in costs due to carbon trading.

An analysis has also been undertaken of the dark spread in Italy and Spain. However, the results are similar to those for the spark spread and are not shown in this report. An analysis of the term markets has not been undertaken, since there are no liquidly traded term markets for these countries.

[42] Italian electricity market data from IPEX, Gestore Mercato Elettrico; Spanish electricity pool data from Omel.

Figure 51: Day Ahead Spark Spread Analysis for Italy and Spain



8.2. Impact of Carbon on Forecast Wholesale Prices

This section analyses the impact of the EU ETS on wholesale power prices around Europe and compares the level of uplift in power price that results from the pass through of carbon costs.[43] The analysis uses the three commodity and carbon price scenarios developed previously.

The analysis examines the impact of the carbon costs on wholesale power prices under different commodity and carbon price assumptions, over the period to 2020. The analysis is designed to highlight the potential annual sensitivity of each of the European power markets to carbon prices. The power price uplift is calculated for each year based on fixed annual plant capacity and demand assumptions. Thus, the uplift only represents the direct uplift due to carbon prices, with all other parameters fixed. It is *not* an analysis of the total impact on each market of the EU ETS, which would require the development of a different set of generation capacity assumptions for the no-carbon case.

The model assumes that the costs of carbon will be passed through to the power price at the carbon intensity of the marginal generation technology. This assumption is broadly supported by the analysis of European power markets presented in section 8.1. It is interesting to note that the two countries (Italy and Spain) where the analysis is less conclusive are also the two countries where the most significant reduction from 'Business As Usual' emissions is likely to be required in Phase II. Thus, arguably, free allocations to the power sector under Phase II of the EU ETS may not be as generous as in other European countries, ensuring a significant level of pass through of carbon costs to wholesale power prices in future. Indeed, in general over the forecast horizon the level of

[43] 'Uplift' in this context simply means the additional cost of carbon, calculated as the average carbon intensity of the marginal plant multiplied by the assumed carbon price for the period.

free EUAs given to the power sector is likely to reduce, ensuring that carbon costs will have to be passed through to wholesale power prices.

8.2.1. GB Analysis

The analysis of the impact of carbon on the GB wholesale price has been undertaken using the ECLIPSE model, and is based upon the ECLIPSE runs for the three scenarios presented in section 5.2. The analysis fixes the annual capacity calculated within the original ECLIPSE runs (with carbon), and looks at the difference in wholesale power price when the carbon price is set to zero.

A comparison of the power price uplift and the carbon price is given in Figure 52 for the Base Case. It can be seen that there is significant power price uplift, and it is strongly related to the level of carbon price. However, the sensitivity does not remain constant over the period, but develops as capacity changes, altering the marginal carbon intensity of the power system. It can be seen that the power price uplift increases over the first half of the period, reflecting both carbon price increases, and coal becoming lower merit, increasing marginal carbon intensity. However, beyond 2014 the power price sensitivity decreases, reflecting increasing gas burn, and the cumulative effect of new CCGT build and coal closures, slowly reducing the marginal carbon intensity of the marginal plant.

The extent of the impact of carbon on wholesale power prices is shown in Figure 53 for each of the scenarios. It can be seen that the level of uplift broadly reflects the relativity of the carbon prices under the scenarios, but there are differences in power price sensitivity reflecting different capacity assumptions. The scenarios broadly all show similar characteristics, with the sensitivity increasing over the first half of the study, peaking over the period 2012-2015, then decreasing toward the end of the forecast horizon. Thus, the analysis suggests that under the three scenarios investigated, the sensitivity of GB power prices to the price of carbon will peak over the period of Phase III of the EU ETS.

Figure 52: Carbon Price versus Power Price Uplift, GB Base Case

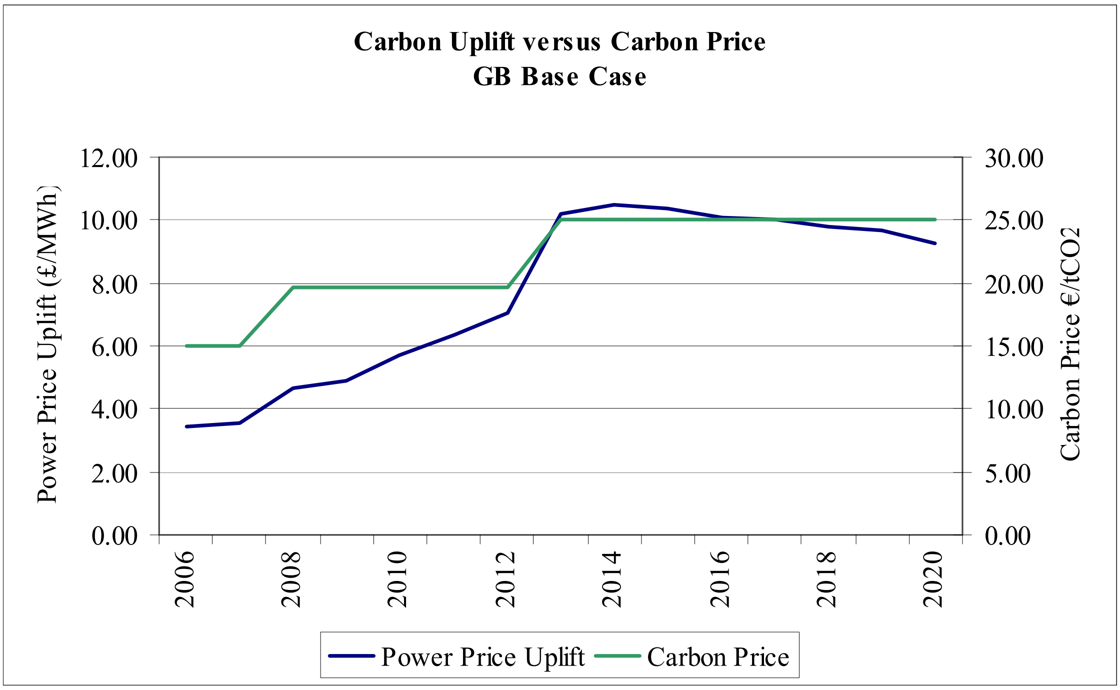
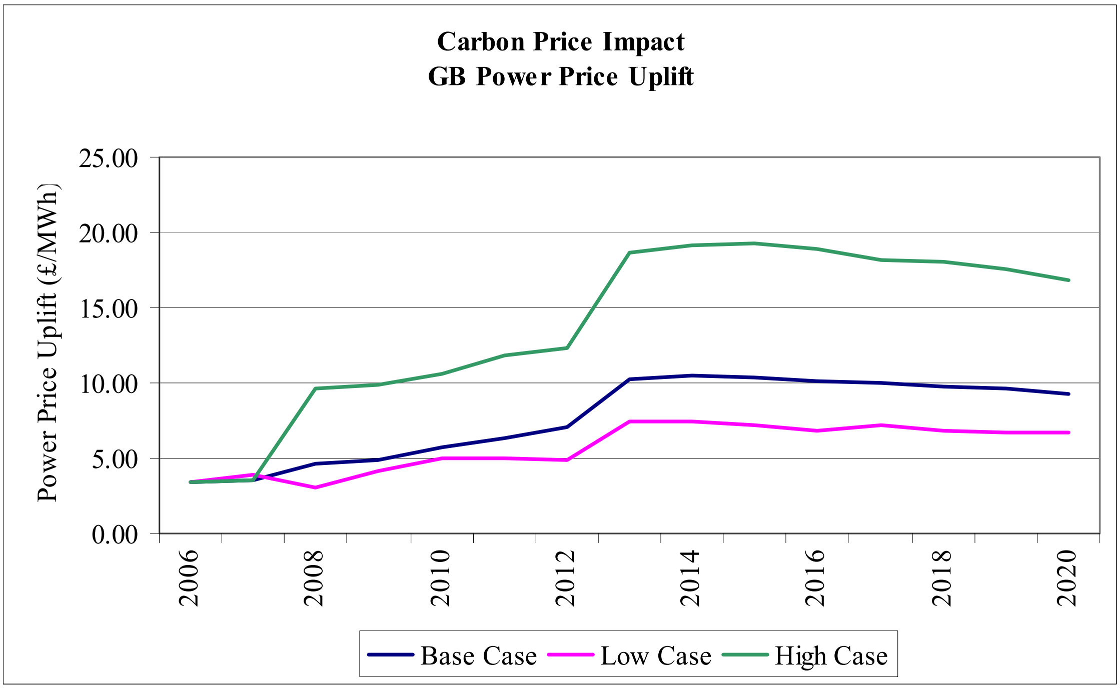


Figure 53: GB Carbon Impact on Baseload Wholesale Power Prices



8.2.2. European Analysis

This section analyses the impact of carbon trading on wholesale prices across Germany, Italy, Spain and France, and compares this to the impact in GB and NI.

The analysis uses results from IPA's European Power System Model (EPSYM), which simulates the power markets in all of the major European Countries and their interconnections. A brief description of EPSYM is given in Annex A. Capacity assumptions are based upon data from Eurelectric,[44] and are assumed to be constant across the scenarios. The commodity and carbon prices have been specified to be consistent with the scenarios investigated previously, with appropriate uplifts for commodity delivery around Europe. Results for GB and NI are from the ECLIPSE analysis of these markets.

A comparison of the wholesale price carbon uplift across Europe is given in Figure 54 for each of the three scenarios. It can be seen that:

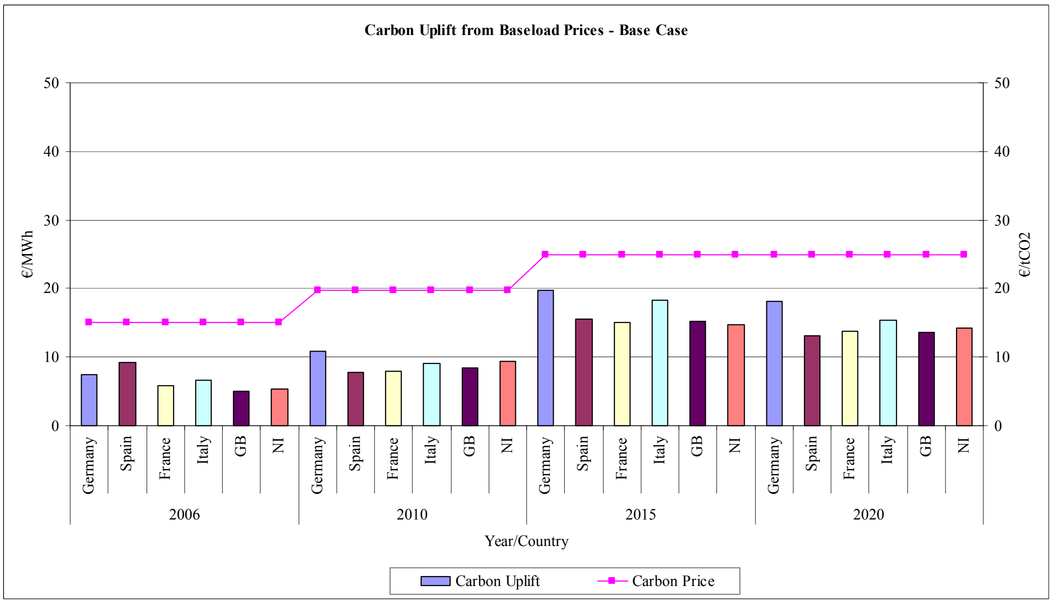
- For all countries the carbon uplift associated with the wholesale price is broadly correlated with carbon price, so the uplift is highest in the High Case scenario, and lowest in the Low Case scenario. However, the level of uplift varies across countries, depending on the carbon intensity of the generation mix, and changes through time, depending upon the rate of evolution of the capacity mix;

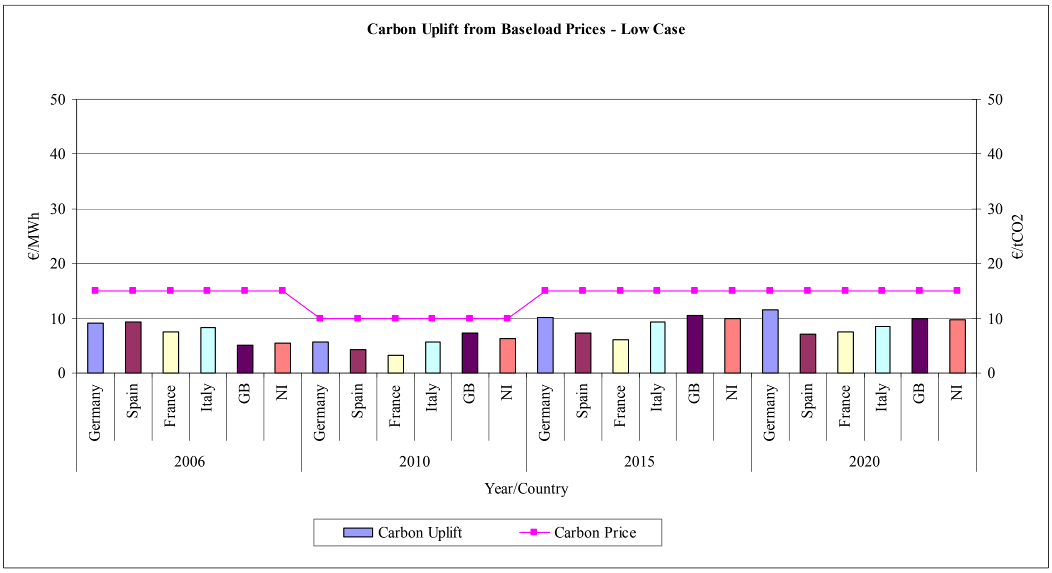
[44] Statistics and prospects for the European electricity sector (1980-1990, 2000-2020) (EURPROG 2004), Eurelectric

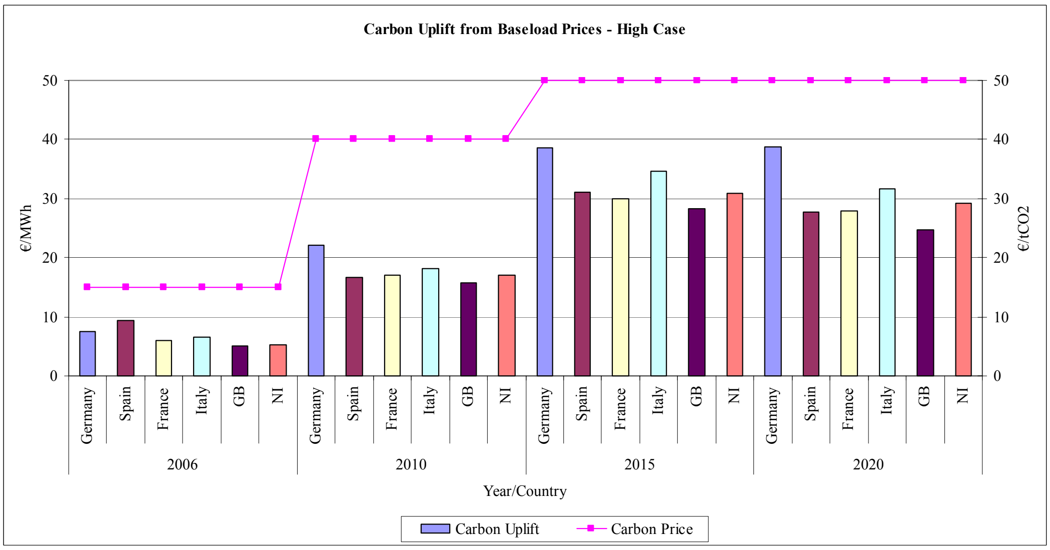
- Under all three scenarios and across all countries, the carbon uplift associated with the wholesale price increases to 2015. This reflects the underlying increases in carbon price (under the Base and High Case scenarios), as well as the decreasing competitiveness of coal which typically serves to increase the carbon intensity of the marginal plant. However, beyond 2015, the carbon uplift typically decreases, reflecting the evolution of the power sectors to a lower carbon intensity capacity mix, primarily through the construction of CCGT and renewable capacity;
- Germany typically has the highest wholesale price uplift due to carbon, reflecting their relatively high dependence on coal and lignite for power generation. The uplift does not decrease in later years to the same extent as in other countries. This is due to the planned nuclear closures over the period, which ensure that despite significant renewable and CCGT build, they still are reliant on coal plant;
- Italy also shows a relatively high uplift, initially due to a reliance on coal and oil plant. Despite significant CCGT build within Italy over the forecast horizon, there is also significant demand growth. This means that the older, more carbon intensive generation has to be maintained to provide system security, increasing the carbon intensity of the generation mix;
- Under all the scenarios GB commences the forecast period with one of the lowest uplifts – reflecting gas stations being used as the marginal plant due to the strength of the gas price.[45] However, across the forecast horizon the uplift in GB tends to increase relative to the other European countries investigated. This reflects the gradual switch of the marginal generation units from gas to coal. However, it also reflects the fact that the retirement of much of the nuclear fleet means that GB is still reliant on coal generation later in the forecast horizon, despite significant CCGT build; and
- NI typically has a slightly higher carbon uplift than GB, due to a reliance on coal and OCGT as peaking capacity across the forecast horizon. For a further discussion of NI results see section 6.8 above.

[45] Note, however, that our analysis of the term markets at section 8.1.1 suggested that in practice, the market appears to be pricing the pass-through of 2006 carbon prices into Cal-06 power prices at a level slightly higher than the marginal intensity of gas plant. Economics would suggest that pass-through at levels higher than the carbon intensity of the marginal plant is not sustainable in the longer term.

Figure 54: Baseload Wholesale Carbon Price Uplift







8.3. Analysis of Historic Retail Prices

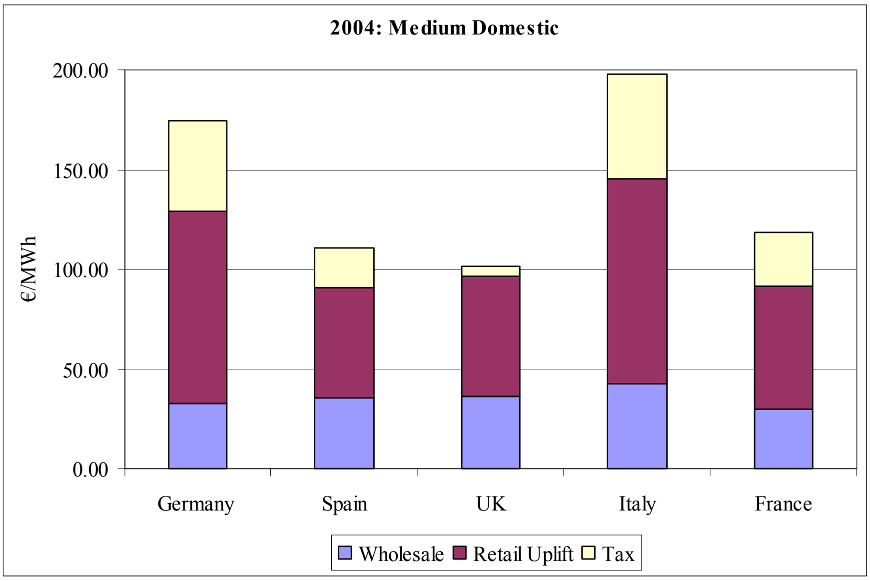
This section provides an analysis and comparison of historic retail prices in Germany, France, Spain, Italy and the UK. It provides a comparison of prices for medium domestic, and small, medium and large industrials. The retail price for each category of consumer is broken down into the wholesale price (adjusted for the consumer profile), the retail uplift (including costs of distribution and supply) and taxation.[46]

8.3.1. Domestic Tariffs

A comparison of retail tariffs for medium sized domestic customers is given in Figure 55. It can be seen that there are significant price differences between the countries, with the UK having the lowest domestic tariff and Italy having the highest tariff. The split between the components of the tariff are also very different between the countries. The wholesale price differences are relatively insignificant when compared to the retail uplift and the taxation differences, which are the main driver for domestic price differences.

The UK prices are comprised of retail prices for both GB and Northern Ireland, although the NI numbers do not significantly bias the UK numbers because of the relatively low proportion of demand in NI. NI prices have historically traded at a significant premium to those in GB. An analysis of NI domestic prices in 2004 suggests that prices (excluding taxation) were the highest of the countries studied, although higher taxation in Germany and Italy meant that the NI delivered tariff including taxation was lower than in these countries.

Figure 55: European Medium Domestic Retail Tariffs (2004)



8.3.2. Industrial Tariffs

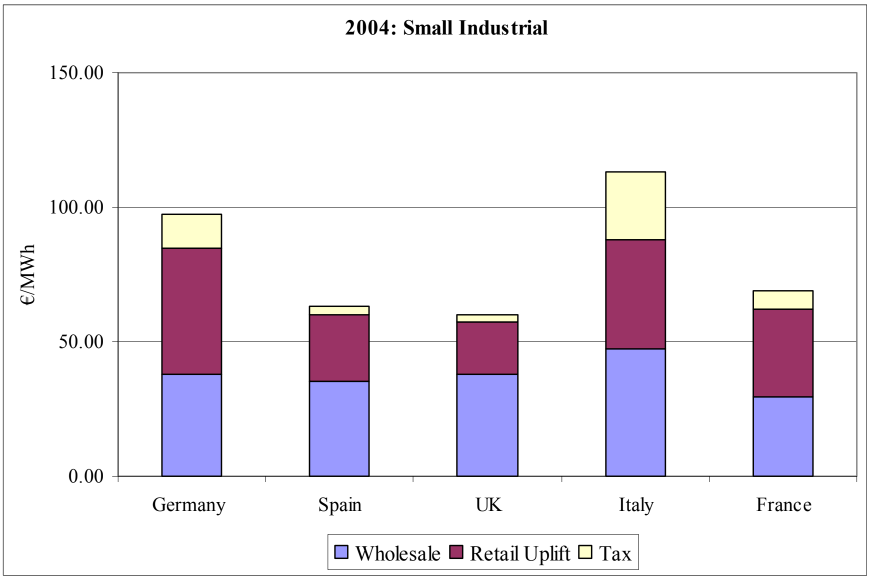
A comparison of retail tariffs for small, medium, large and extra large industrial consumers is provided in Figure 56. It can be seen that again there are significant differences between the countries, with the UK having the lowest tariffs for most of the consumer categories, and Italy having the highest tariffs. The wholesale price

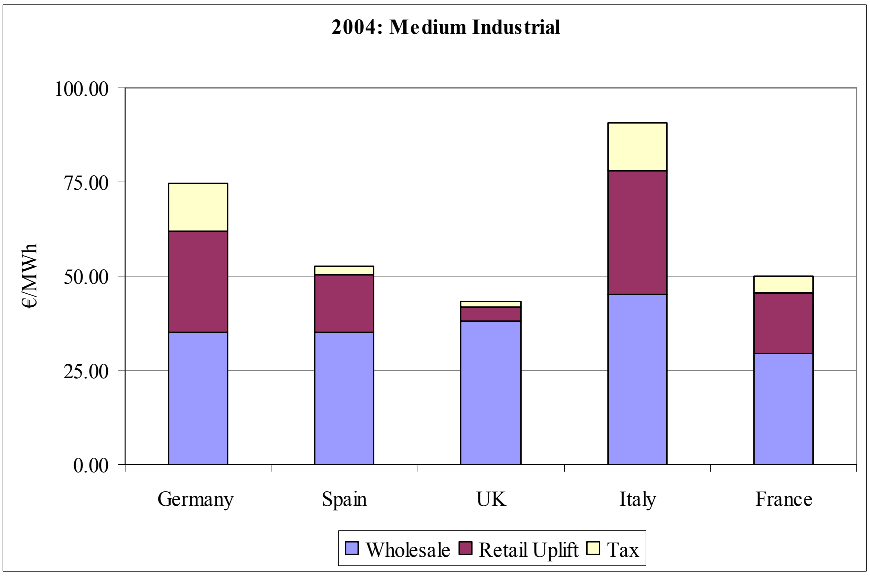
[46] Retail prices & taxes, Quarterly Energy Trends, June 2005 DTI; wholesale prices as in section 8.1.

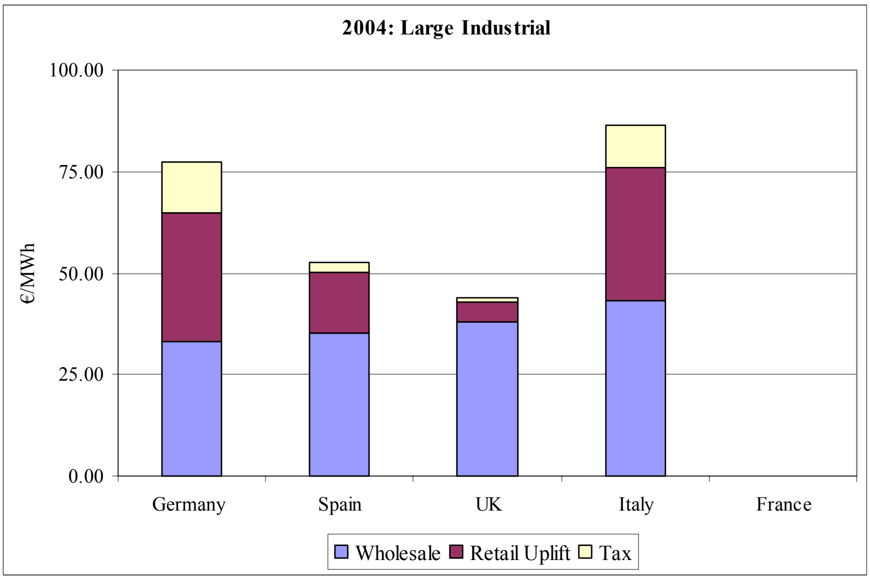
comprises a larger component of the tariff for larger consumers, but nevertheless the differences between wholesale prices across Europe are not a particularly significant driver of the differences between retail prices. The retail uplift and taxation are the components of the retail price that drive the significant differences between the countries.

It has not been possible to construct a direct comparison of the European industrial prices with NI prices due to differences in the way that consumer groups are categorised. However, the analysis does suggest that tariffs in NI are one of the highest of the European countries investigated, despite lower taxation in the province. Unfortunately no data were available for large industrial consumers in France.

Figure 56: European Industrial Retail Tariffs (2004)







8.3.3. Tariff Rankings and Retail Uplift

The ranking of the price of electricity tariffs around Europe for the different categories of consumer is shown in Table 11. It can be seen that broadly, countries achieve very similar rankings across the different categories of customer, with the major exception being the much lower prices for extra large industrial customers in France. Wholesale price differences between the countries are relatively insignificant, and retail uplift and taxation have similar rankings across the customer categories (see Figure 56).

Analysis of the retail uplift suggests that the UK has relatively low retail margins, with margins smallest in the medium and large industrial sectors, reflecting intense competition. Spain has similar domestic retail margins to UK, perhaps reflecting the fully liberalised markets (although regulated tariffs have been used to control price increases), margins are typically slightly larger than in the UK for industrial consumers. Germany also has an open supply market, so it is perhaps surprising that there are significant retail margins, although this may reflect much higher distribution costs, and may indicate more limited supply competition at a regional basis. Italy has extremely high retail margins, perhaps reflecting the fact that supply is only competitive at the industrial scale, although the margins for large industrial consumers are high despite competition within the sector. France has relatively low retail margins, despite only having competition in the large customer sector. Unfortunately no data were available for large industrial consumers in France.

Table 11: European Retail Tariff Rankings – Including Tax (2004)

Ranking Cheapest	Medium Domestic	Small Industrial	Medium Industrial	Large Industrial	Extra Large Industrial
1	UK	UK	UK	UK	France
2	Spain	Spain	France	Spain	UK
3	France	France	Spain	Germany	Spain
4	Germany	Germany	Germany	Italy	Germany
5	Italy	Italy	Italy		Italy

8.4. Analysis of Carbon Impact on Forecast Retail Prices

This section discusses the relative impact of carbon trading on retail prices, across the EU countries over the forecast horizon. It provides a breakdown of retail price into the wholesale price and the level of carbon uplift, retail margin and tax. It goes on to provide a ranking of the price of retail electricity across the customer groups.

The modelling for Germany, France, Italy and Spain has analysed the impact of commodity and carbon price and capacity developments on wholesale prices over the forecast horizon, but not the profitability issues that drive wholesale and retail market prices. In constructing the forecasts of wholesale and retail market prices it has been assumed that the economic rent extracted by generators and suppliers is constant over time. The reasonableness of this assumption is discussed in section 8.4.2 below.

8.4.1. Wholesale Prices

The wholesale prices for each of the counties are investigated over the forecast horizon in Figure 57. The prices over the three scenarios are shown along with the level of contribution from carbon costs.

It can be seen that the level of wholesale prices typically increase from their 2004 levels, with significant correlation in the development of power prices between the countries. The softening of commodity prices and changing relativity of the prices of gas, coal and oil typically lead to reduction in the 'clean' power price over the forecast horizon.[47] However, these reductions are more than offset by the uplift to power prices due to the cost of carbon. The impact of changing commodity and carbon prices is different in each country due to the differences in plant mix, and this results in some changing of price relativities.

The analysis suggests that the EU ETS could result in breaking of the linkage between French and German prices that has been observed over the last few years, due to the increasing spread between fundamental drivers in the two countries. As the EU ETS puts upward pressure on the fundamental price spread this may result in interconnection capacity being fully utilised, allowing prices in the two countries to diverge.

In the Base Case it can be seen that over future years Spain and France typically have the lowest wholesale prices, with Italy having the highest prices, followed by NI and GB. GB and Germany exhibit similar price movements over the forecast horizon, reflecting their similar generation mix and fundamental price drivers. However, GB prices soften slightly more quickly than German prices toward the end of the period. NI prices trade at a slight premium to the wholesale prices in GB.

The Low Case scenario has lower wholesale prices across the analysis, driven in part by lower carbon uplifts. The relativity of wholesale prices across countries is broadly similar to the Base case. However, GB prices typically trade at a slight premium to Germany.

The High Case scenario has higher wholesale prices across the analysis, largely driven by significantly increased carbon uplifts. Again, the relativity of wholesale

[47] By 'clean' power price in this context we mean the wholesale price *without* the uplift due to pass-through of the carbon price.

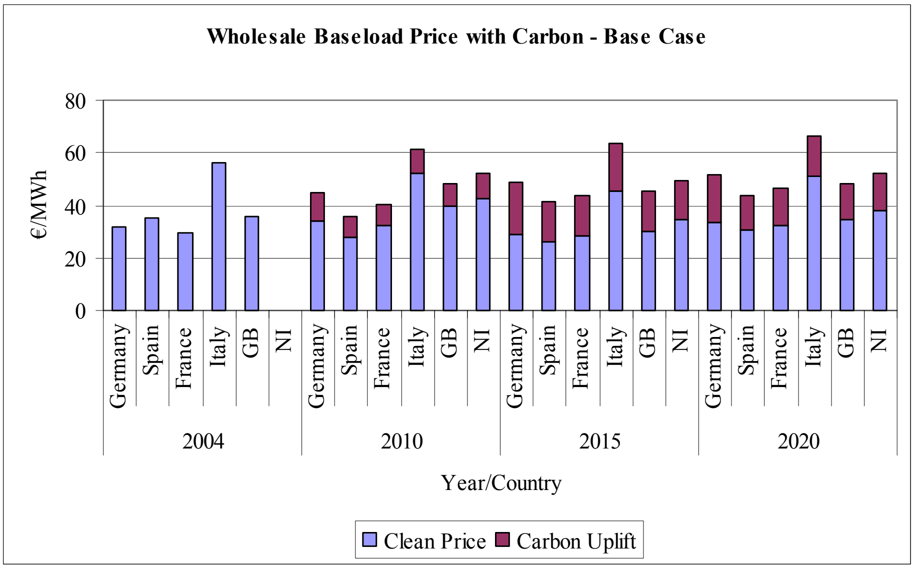
prices across countries is broadly similar to the Base case. However, German prices trade at an increasing premium to GB prices over the forecast horizon.

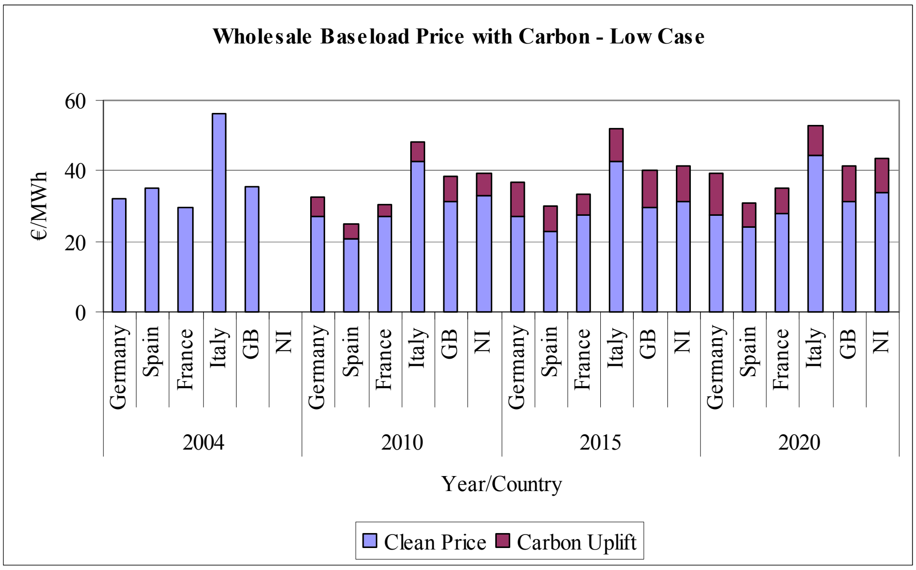
- ***Current Market Signals***

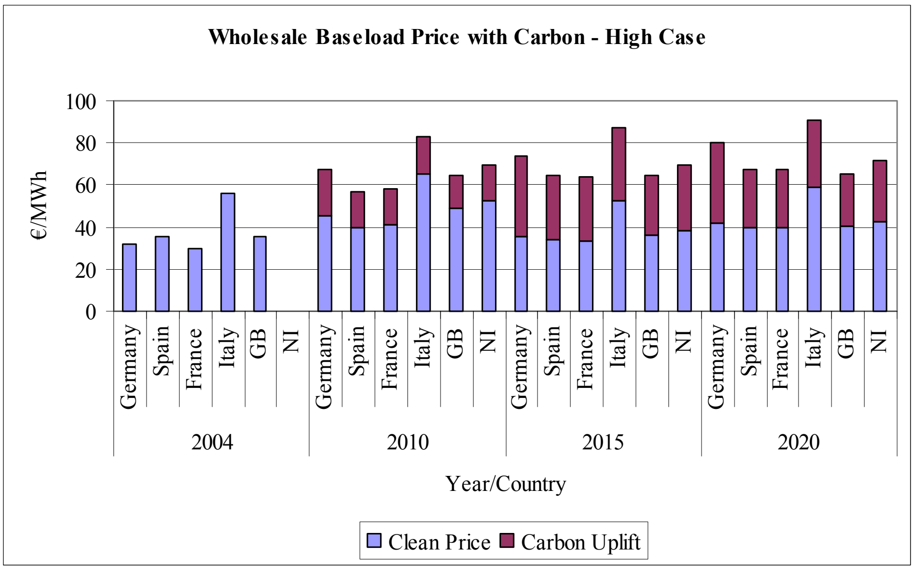
  The current wholesale market prices show GB trading at a significant premium to French and German prices over the next year. We believe there are three key drivers of this:

  - Gas prices both on the continent and within GB are strongly linked to oil (either contractually or through market *sentiment*), so the current strength of oil prices has put significant upward pressure on gas prices. This has had a more significant impact on power prices in GB than in NW Europe due to the higher proportion of gas in the plant mix;
  - In addition, GB gas prices are currently trading at a premium to Zeebrugge and continental prices, fuelled by the currently tight plant margin in GB. However, as increased import capacity comes on line, including interconnectors with Holland and Norway, as well as LNG import capability, it is forecast that this spread will reduce significantly, although the forecast maintains GB prices at a slight premium to the continent; and
  - Although there was strong evidence of carbon pass through in both GB and NW European month ahead power prices, only GB shows the strong evidence of carbon pass through in the term (year ahead) markets. This appears to be an inconsistency in market pricing, since fundamental drivers of spot prices must ultimately drive the term markets. It is unclear whether this is a function of limited liquidity in the NW European term markets, or whether prices will adjust to reflect carbon as the contracts come in. However, it does currently result in a spread between GB prices and NW Europe prices in the term market. The modelling has assumed that the carbon pass through observable in the spot markets will continue over the forecast horizon.

Figure 57: Actual & Forecast Wholesale Prices with Carbon Uplift







8.4.2. Retail Prices and the Impact on Customers

This section investigates the Base Case retail tariffs in the different countries over the forecast horizon. It analyses how the ranking of the countries varies through time, and what impact this might have on consumers.

The analysis presented here considers the impact of commodity and carbon prices and generation capacity development, as developed in the previous section, but assumes that the market rent component of the wholesale price and the retail uplift is constant. The section goes on to discuss how reasonable these assumptions are and considers what impact market and regulatory developments could have in the future.

- ***Domestic Tariffs***

  The domestic tariff forecasts are shown for the forecast horizon together with the country rankings in Figure 58 and Figure 59 respectively. It can be seen that upward pressure on wholesale prices over the forecast horizon puts upward pressure on domestic tariffs. However, the relative changes in wholesale price are small when compared to the differences in retail uplift and taxation, and so the ranking of the countries remains relatively constant. It can be seen that GB domestic retail prices are maintained within the two cheapest tariffs of the countries studied.

  Domestic consumers are exposed to absolute increases in retail prices within their country of residence. The Base Case analysis suggests that retail prices could increase by around 12% (in real terms) from 2004 levels, with most of this increase occurring over the period to 2010. Considerable increases from the 2004 values, are already observable in current (2005) prices. Increases in retail tariffs have the potential to increase *fuel poverty*, but could also increase the take-up of domestic energy efficiency improvements.

- ***Industrial Tariffs***

  The industrial tariff forecasts are shown for the forecast horizon together with the country rankings in Figure 60 and Figure 61 respectively. It can be seen again that wholesale price increases put upward pressure on retail tariffs, with percentage increases in tariffs of 23-28% from 2004 levels, with a substantial proportion of the increases occurring over the period to 2010. However, the relative rankings of the different industrial retail tariffs does not change significantly over the forecast horizon, and GB industrial retail prices are maintained within the two cheapest tariffs of the countries studied for each of the three categories of industrial consumers.

  The impact for industrial consumers arises both from increasing tariffs, and the changing relativity of prices around Europe. Increasing price will typically increase the cost of products and services, with a potentially detrimental effect on competitiveness, especially for industries that compete within international markets. The changing relativities of tariffs between European countries could change the competitiveness of industry within Europe, although the analysis suggests that these effects are likely to be small. In addition, price increases could lead to an increased take-up of energy efficiency improvement schemes.

Figure 58: Actual & Forecast Domestic Tariffs (Base Case)

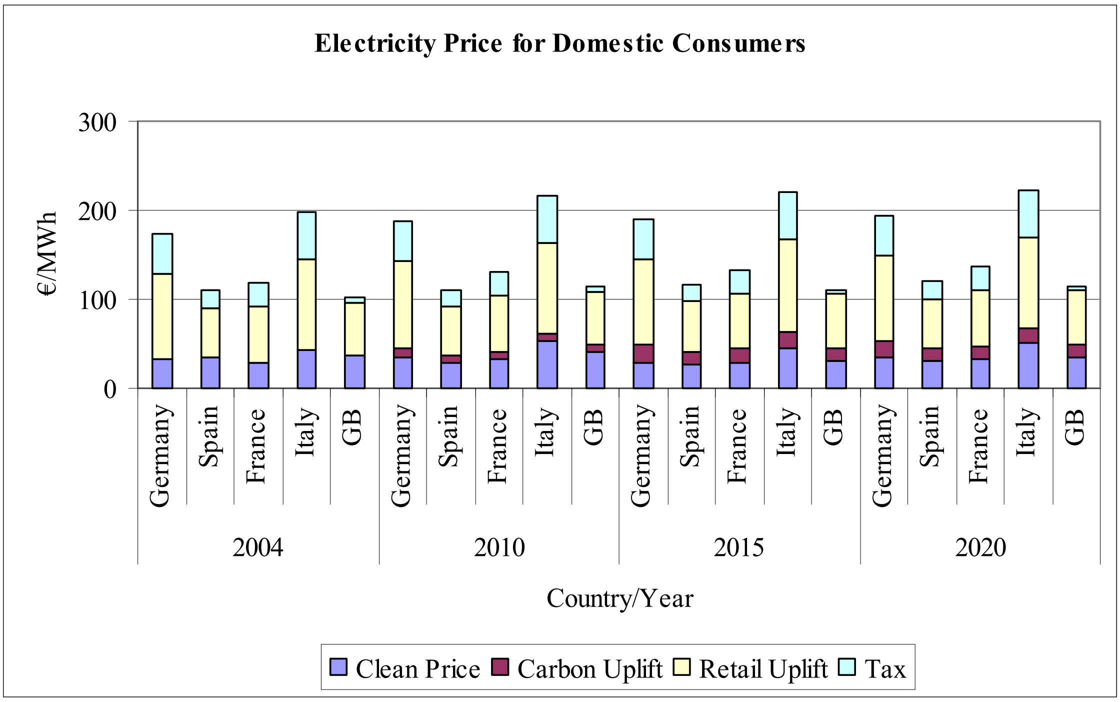


Figure 59: Actual & Forecast Domestic Tariff Rankings (Base Case)

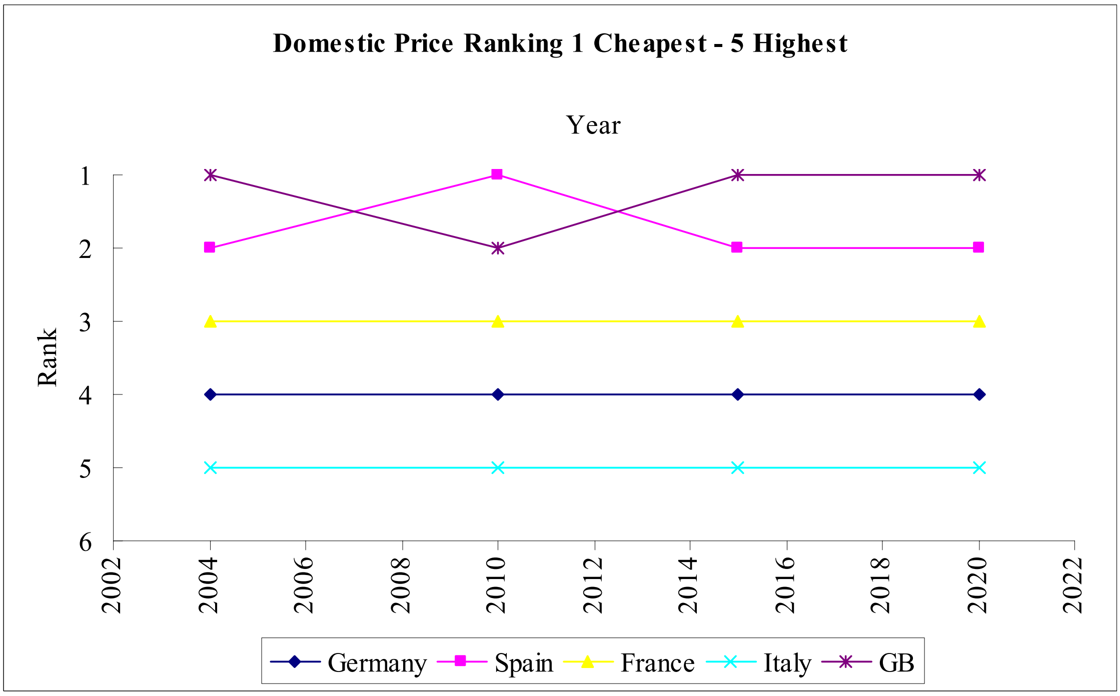
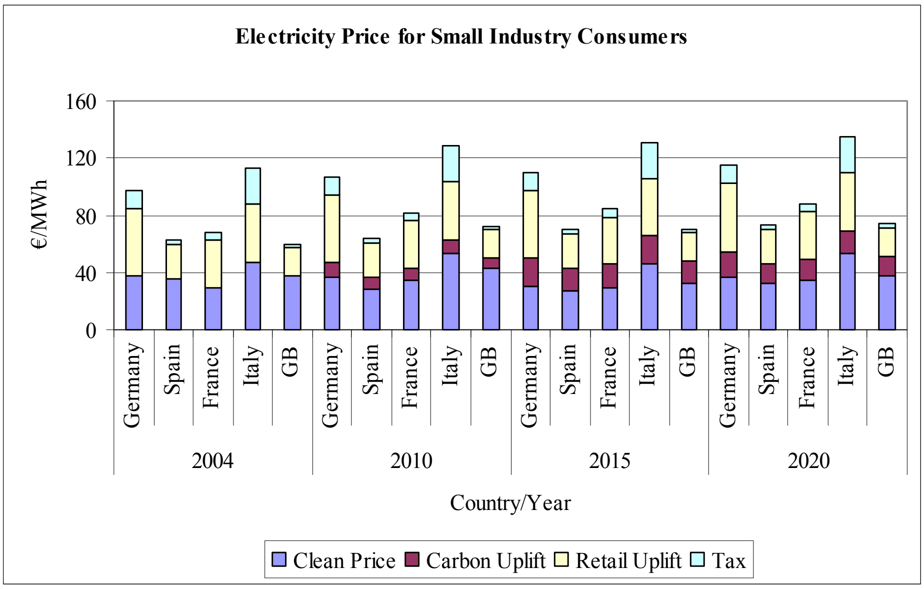
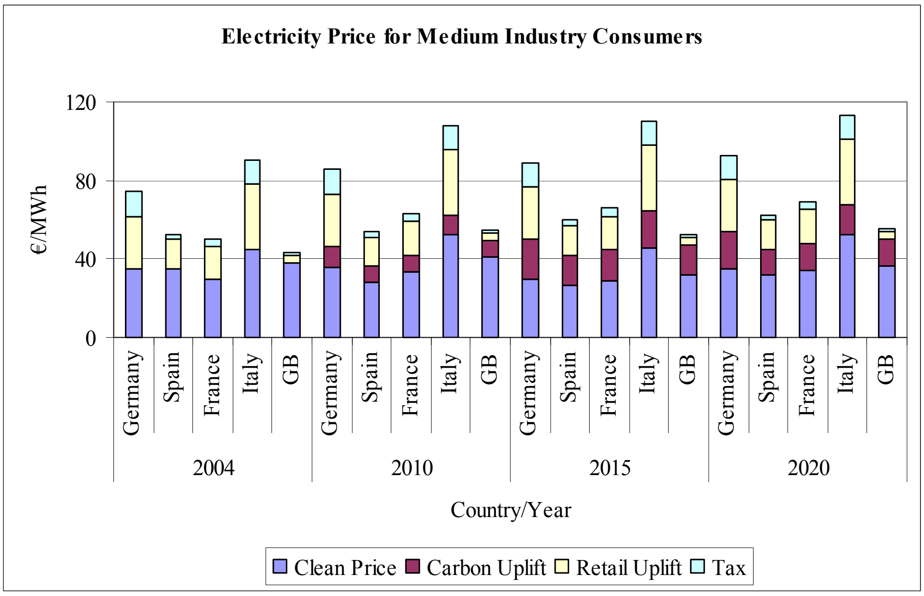


Figure 60: Actual & Forecast Industrial Tariffs (Base Case)





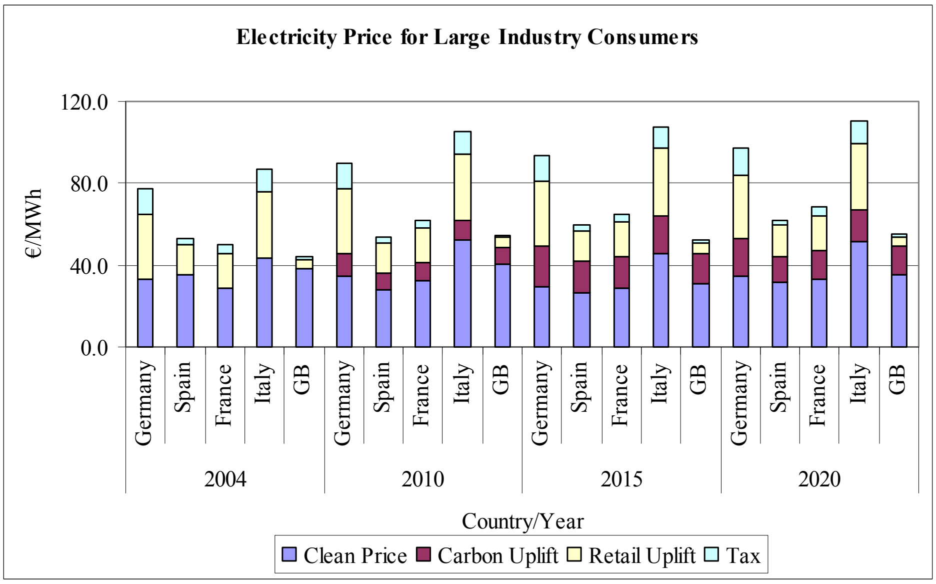
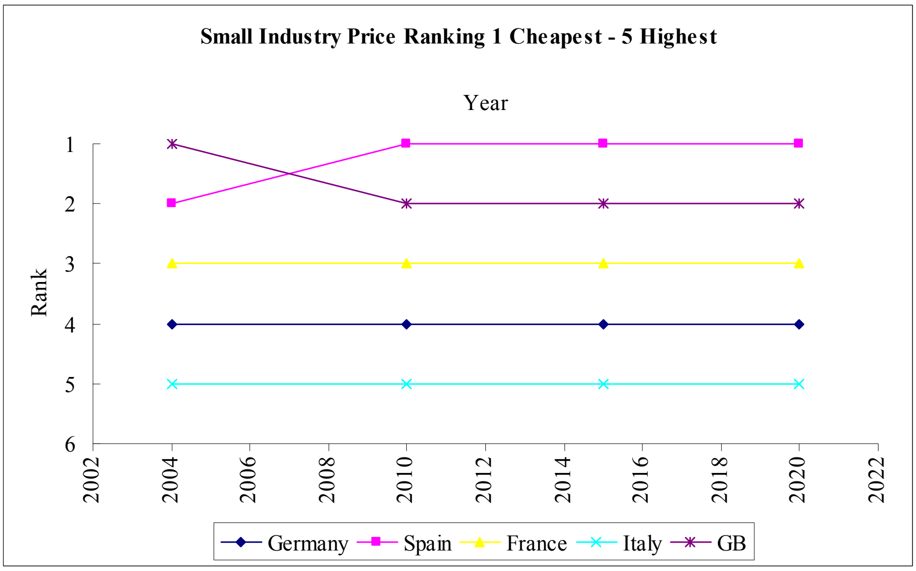
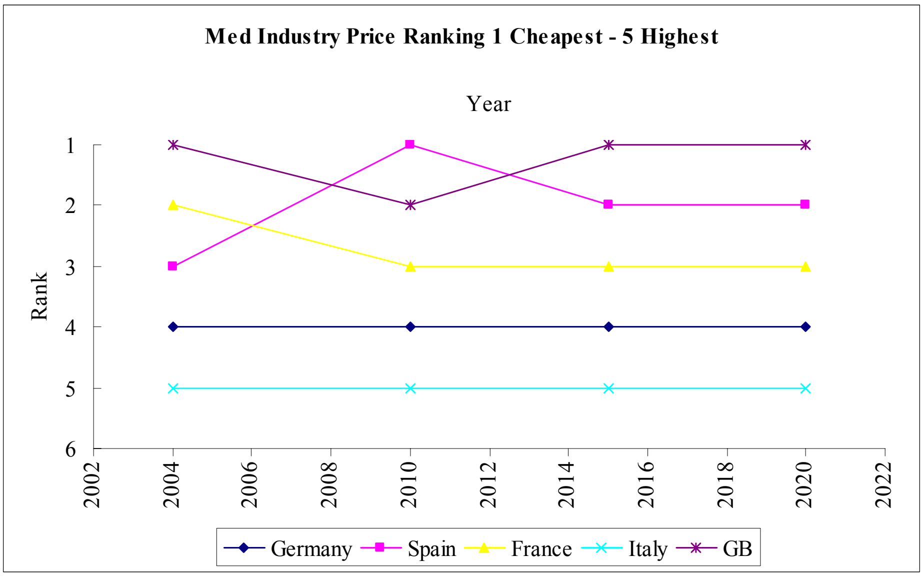
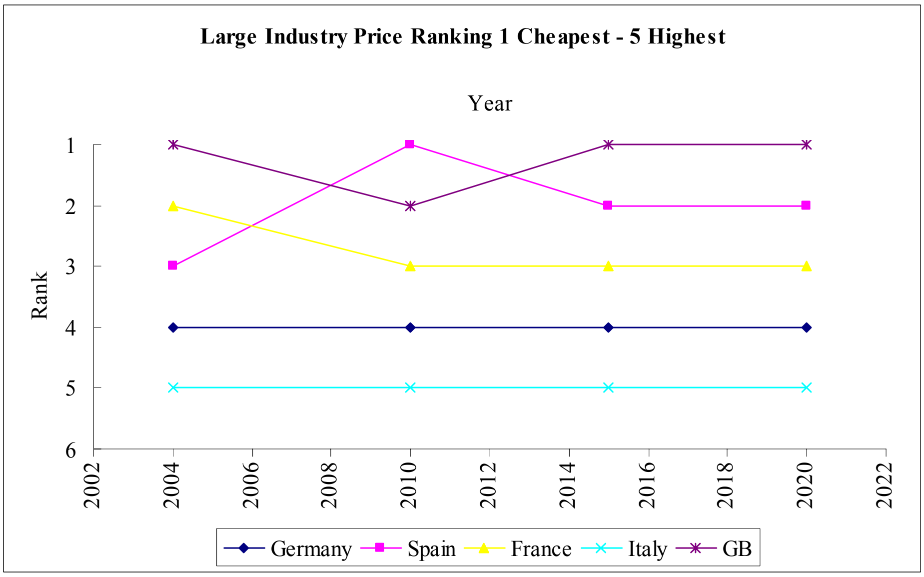


Figure 61: Actual & Forecast Industrial Tariff Rankings (Base Case)







- ***European Competition***

The European analysis has investigated the fundamental price and capacity drivers of wholesale prices and retail tariffs. The results suggest that the EU ETS will have a significant impact on wholesale prices and the evolution of the power sector. However, the differences in wholesale price due to the EU ETS are relatively small compared to the differences in retail uplift and taxation. Thus, it is likely that fiscal, regulatory and market developments will have a greater impact upon the relativity of retail prices around Europe than the impact due to the EU ETS alone.

The analysis has assumed that the economic rent extracted by generators from the wholesale market and the retail uplift charged by suppliers remains constant. This section briefly discusses the market and regulatory developments that could impact upon this assumption, and how they may influence retail prices.

- **France**

The French market has historically been dominated by EDF, who remain dominant in both generation and supply. There has been progress towards liberalisation through the development of a power exchange, legal separation of the transmission operator (RTE) from EDF, opening of retail competition for the 4% of largest customers (70% of demand), limited new entry by independent generation (CCGT and renewable), as well as EDF selling generation capacity in virtual power plant auctions. However, progress remains slow.

EDF has a dominant share of the generation market, which may have discouraged new entry, but it is likely that competition in generation will increase, whether this is through organic growth of independent generation, or forced divestment of plant. However, France has historically been an exporter of power, with pricing closely tied to the German price. The analysis suggested that upward wholesale price pressures from fundamentals is not as significant in France as in Germany, but with a dominant generator there is the possibility that French prices could still follow German prices, especially if there is increased interconnection, leading to the possibility of increasing wholesale margins over time.

The retail market is still dominated by EDF, with the number of consumers eligible to choose a supplier the lowest of the countries investigated. However, the requirement to have full retail competition by 2007[48] should ensure that competitiveness increases, although the dominance of one vertically integrated market player may stifle new entry. Retail margins are not exceptionally high in France, and so the introduction of competition may not see margins greatly reduced. Margins are most likely to be reduced within the industrial sector, which arguably has the greatest potential for competition.

- **Germany**

Germany has only relatively recently introduced an independent regulator and is currently putting in place legislation to strengthen the

[48] Gas and Electricity Acceleration Directives of the European Union: Directives 2003/54/EC and 2003/55/EC.

regulator's role. Germany has historically had negotiated grid access, but is now putting in place regulated third party access, with distance independent charges.

The generation sector is dominated by the big four regional German energy companies. However, there is a reasonably liquid wholesale market, with competition aided by the relatively large volumes traded over interconnectors, linking German prices closely with French prices over the last few years. Germany will require a significant evolution of generation capacity as it seeks to replace nuclear plant and reduce dependence on coal. The requirement for capacity evolution is likely to sustain wholesale prices, but to what extent independent companies will contribute to new plant and increase competition is unclear. The zonal nature of the German generation market means that a single company dominates in each balancing zone, which may be a factor that will discourage new entry.

The supply market has been completely liberalised with all customers having a choice of electricity supplier, and there has been a relatively significant level of switching. However, retail margins remain relatively high, in part due to the high level of distribution charges. Increased regulation of distribution and increased competition in the retail sector could serve to place downward pressures on retail prices, across all customer groups.

- **Italy**

There has been some progress in terms of the deregulation of the Italian electricity industry, with unbundling and part privatisation of the state-owned vertically integrated company, Enel. The transmission network has been unbundled, and a market operator and power exchange have been established. In addition, the dominant generator, Enel, has divested some of its generation capacity.

Italian wholesale prices are currently the highest of the countries studied. Although there are some fundamental drivers that have put upward pressure on prices, this may, in part, be driven by the dominance of ENEL in generation, and in particular its ownership of the price setting plant. However, Italy requires significant new investment in generation to meet relatively high levels of demand growth, and it is likely that a large volume of new capacity will be constructed by independents. This could increase competitiveness in the wholesale markets in the medium term. Nevertheless, the evolution required in the generation mix is likely to provide upward pressure to sustain wholesale prices.

The retail market has been liberalised in several phases, with full liberalisation planned for 2007. However, supply to larger customers is still relatively concentrated, with three companies dominating the market. Italy exhibits high retail margins, with margins highest in the sectors not yet liberalised. It is likely that increasing liberalisation, coupled with increasing counterparties in the generation market, could see increasing retail competition, resulting in downward pressure on retail margins in the medium term.

- **Spain**

Despite retail competition, a wholesale pool, and no single dominant generator, there is still significant regulatory intervention in Spain.

This has taken the form of stranded asset payments, the possible introduction of rules excluding plant from the wholesale pool, and regulated tariffs in supply. Spain and Portugal are working to set up a single Iberian Electricity Market, and increase interconnectivity, in part with the hope of promoting competition.

Although there is no single dominant generator in Spain, Endesa and Iberdrola maintain a significant share, limiting competition within the wholesale markets. It is likely that in the medium term reforming the stranded asset compensation payments, and the creation of an Iberian market could increase competitive pressures. Spain will need a significant volume of new plant, at least in part to keep up with significant demand growth; this could yield opportunities for new entrants. Increasing competition could reduce relative wholesale prices in the medium term, although the potential for sustainable price reductions is probably limited.

The retail market has been fully liberalised, with all consumers having a choice of supplier. However, tariffs will remain regulated until 2007, and there is current discussion about extending regulated tariffs for industry to 2010. The existence of regulated tariffs reflects the dominance of Endesa and to a lesser extent Iberdrola in the supply market, which may stifle competitive pressures. The existence of regulated tariffs has kept the retail margin relatively low in Spain, however greater competition, particularly in supply for industrial consumers, could reduce the level of retail uplift in the medium term.

8.5. GB Demand Elasticity

This section discusses the impact that the EU ETS may have on the demand for power in the UK through its impact upon power price. Demand side response can be characterised in a number of different ways, but here it is broken down into response to short term price volatility and response to prolonged price increases.

Our analysis has assumed fixed underlying total GB system demand growth of around 1.4% per annum to 2011, gradually reducing beyond this to 2020. Growth in peak demand has been assumed to be approximately half the growth in total system demand, which results in a flattening of the load curve over the forecast horizon in all scenarios. These assumptions are in line with assumptions in NGT’s Seven Year Statement, and implicitly take into account factors such as growing awareness of energy efficiency and technology enabling increased participation of demand-side response in the power market.

8.5.1. Response to Price Volatility

The EU ETS may lead to some increases in power price volatility. This is primarily due to the impact of the EU ETS tightening plant margins and the direct increases in costs for carbon intensive peaking plant. However, it should be noted that the increasing penetration of intermittent wind generation is likely to lead to greater increases in volatility than due to the EU ETS.

Large industry has the potential to reduce energy costs by reducing power take over relatively short (hours to days) high cost periods. For instance many industrial installations reduce their transmission charges by reducing demand at ‘triad’ times[49] (the three half-hours of maximum system demand), demonstrating a degree of elasticity of demand over short time periods. NGT estimates that 1,100 MW of demand reduction takes place over triads. In addition, NGT manages a number of other short-term demand-side management schemes covering around 500 MW.[50]

A recent report for the DTI and Ofgem[51] observed that demand response by large industrial customers to high power prices mainly takes the form of reduced production (rather than back-up supply, as relatively few firms have back-up power generation). The analysis found higher responsiveness to high power prices over short periods (e.g. one hour each day) than over longer periods of four to twenty-four hours; increasing again if the high power prices persist for as long as a week. The amount of capacity likely to respond in this way was estimated as being just under 2% of national demand, or around 1,200MW.

Increased power price volatility due to the EU ETS could result in a greater volume of demand side response. However, evidence from past studies suggests that the short-run elasticity of demand for power is very weak,[52] and so it is perhaps unlikely that the EU ETS will have a significant impact upon levels of demand side response.

8.5.2. Response to Price Increases

It has been shown in Section 8.2 that the EU ETS causes a significant uplift in electricity prices (although underlying prices are on a downward trend due to reducing commodity prices). The analysis highlights that power prices over the period 2004-2010 are likely to increase by around 10-25% over the different categories of consumer, with some of this increase due to the EU ETS. All categories of electricity consumers may respond to these long term signals by investing in energy efficient technologies or by reducing demand. Industry is typically significantly more price sensitive than the domestic sector and so may be more likely to respond to price signals. Industry consumes around 1/3 of total demand within the UK and so has significant reduction potential.

In the longer term, the EU ETS could drive more fundamental changes in demand, for example through closure or down-sizing of energy-intensive plant, particularly for industries exposed to international competition from outside the EU. A recent study for the Carbon Trust[53] found that the aluminium sector would be the most severely impacted by the EU ETS, as it is highly exposed to both power prices and international competition, and therefore has little opportunity to pass through power price increases. The UK's three aluminium smelters consume a little over 500 MW between them, or around 1% of peak national demand.

An additional impact of increased power prices and increased price volatility could be that industrial sites will investigate the possibilities of on-site generation. Where installations are less than 20MW they would fall outside the EU ETS, and so the EU ETS would help support the economics of this type of plant, especially under high carbon price scenarios.

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[49] Quoted in Global Insight (2005) *Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices.* Report for DTI and Ofgem.
[50] Ibid.
[51] Ibid.
[52] Kirschen, D. (2003) "Demand-Side View of Electricity Markets." *IEEE Transactions on Power Systems*, 18 (2): 520-527.
[53] Oxera (2004) *CO_2 emissions trading: How will it affect UK industry?* Report for the Carbon Trust.

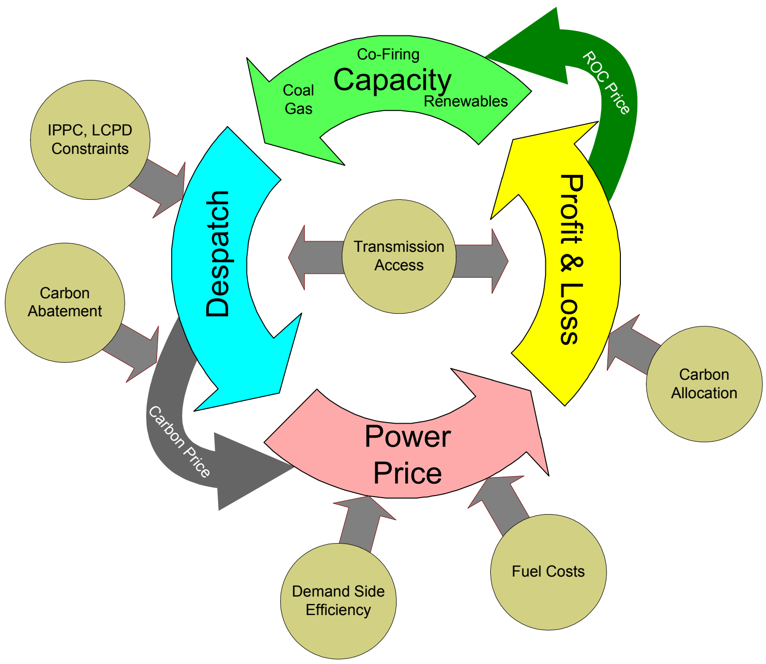
ANNEX A: IPA'S POWER MARKET MODELS

ECLIPSE

Historically, traditional models of the power sector have modelled separately or at best iteratively the various elements of the power market – starting from a forecast of demand and a 'merit order' of generation costs leading to a price and despatch schedule. More recently, this simplistic approach has become less and less effective – increasingly the operation of the market has been strongly influenced by the introduction of policy drivers such as the Renewables Obligations, the Large Combustion Plants Directive and IPPC Directive and – most recently – the EU ETS. Because all these elements of the market are inter-related, to understand effectively the impacts of the various policy measures it is important to model them in a consistent, coherent and fully integrated framework, rather than simply to combine disparate forecasts of power price, renewable build etc.

IPA's proprietary power system model ECLIPSE has been designed to address this interface between policy instruments (such as emissions trading, the Renewables Obligations, and emissions restrictions) with the power market. The structure of the model is summarised in the illustration below. It explicitly models all of the complex interactions in the market and is capable of generating consistent forecasts for all of the significant market parameters. In particular, ECLIPSE can produce generation prices, ROCs, and operating patterns and profitability (EBITDA, with and without carbon allocations) on a station by station basis, making use of a database of all centrally despatched plant in the UK. Our modelling also provides consistent forecasts of system balancing costs which are used to forecast changes in BSUoS levels in the UK market.

A graphical representation of ECLIPSE is provided below.



ECLIPSE is also capable of identifying the likely relative impact of a variety of factors, including the EU ETS, on wholesale power prices (in particular compared to fuel prices and emissions restrictions) by modelling the operation of the market with various carbon prices (and without the ETS). At a plant level, the impact of different allocation methodologies and quantities can also be explored to establish their likely impact on plant profitability, new build and closure decisions.

EPSYM

EPSYM (European Power System Model) is a proprietary simulation model of the European power markets. It models the main Western European Markets and the interconnections between them, as well as capturing flows to countries external to the model.

The markets represented in EPSYM for this study are:

- Germany;
- France;
- Spain;
- Italy;
- Benelux;
- Switzerland;
- Austria; and
- Portugal.

EPSYM is a fundamental economic power model: it undertakes an economic despatch of the different generation technologies around Europe, including economic despatch of interconnectors (allowing for constraints, losses and exit costs), daily optimisation of pump storage, and annual optimisation of hydro reserves. The despatch algorithm allows for all commodity costs, carbon costs, other variable costs, average availabilities, and average load factors for renewable sources.

The model despatches the system over a number of typical weekdays and weekends throughout the year, and calculates the marginal costs associated with each country for every hour modelled. This yields an annual baseload and peak price for each country.

For this study EPSYM has been populated using data for forecast capacity and demand growth data from Eurelectric,[54] as well as data from UCTE, ETSO and PRIMES. Assumptions associated with commodity prices and carbon prices are consistent with those used in developing the GB scenarios, with appropriate uplifts for delivery around Europe.

[54] Statistics and prospects for the European electricity sector(1980-1990, 2000-2020) (EURPROG 2004), Eurelectric