Report

Severn Barrage Costing Follow-On Analysis

to

The Renewable Energy Forum Ltd

December 2008

IPA Energy + Water Economics

Severn Barrage Costing Follow-On Analysis

to

The Renewable Energy Forum Ltd

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EXECUTIVE SUMMARY

This report builds on a earlier study conducted by IPA Energy + Water Economics for The Renewable Energy Forum Ltd into the comparative cost of electricity generation of the Severn Barrage (Cardiff-Weston scheme) to include an appraisal of the CO_2 reduction potential of the barrage in relation to alternative technologies, including other renewables (a mix of onshore wind, offshore wind, and biomass), CCGT, supercritical coal with carbon capture and storage, and nuclear.

We have developed a bespoke high-level model of the Great Britain electricity generation system to simulate future electricity generation and hence CO_2 emissions in a single representative year, and compared the reduction in total annual CO_2 emissions achieved with each technology against the total system cost of meeting demand in each case, including the annualised capital cost of the respective technology under test.

The analysis has been conducted under three different market scenarios derived from the latest edition of our quarterly publication, *PowerView*.

The main conclusion from our analysis is that, while the Severn Barrage has considerable potential to help with reducing CO_2 emissions by the electricity generation sector, the overall cost of doing so is extremely high in comparison to doing so with other technologies. Specifically, despite comparatively good reduction in both system CO_2 emissions and variable costs of generation, the extremely high total capital cost (resulting from a similar unit cost to other technologies such as offshore wind, coal + CCS, and nuclear, but a considerably greater capacity requirement because of the low load factor) results in a CO_2 abatement cost above £50/te (real 2008) and potentially as high as £180/te depending on the actual capital cost.

Of the other technologies examined, new nuclear and other renewables could achieve slightly higher levels of total CO_2 reduction than the barrage (because of steadier operation throughout the day), with nuclear broadly expected to do so at a negative abatement cost with renewables mainly positive but less expensive than the barrage. Coal with CCS does not achieve as great a reduction in absolute emissions, but is expected to do so at less than £50/te; while new CCGTs only reduce about half as much CO_2 but have a narrow range of ±£10/te.

1 INTRODUCTION

In March 2008, IPA Energy + Water Economics (IPA) undertook a study for The Renewable Energy Forum Ltd into the Severn Barrage (Cardiff-Weston scheme)[1]. In this we examined the comparative cost of generation from a barrage against those for alternative electricity generation technologies, and investigated the contribution that a barrage could make towards security of electricity supplies as well as the resultant impact on the Great Britain electricity system.

In this report we have been asked to build on this work to include an appraisal of the CO_2 reduction potential of the barrage in relation to alternative technologies, including other renewables (a mix of onshore wind, offshore wind, and biomass), CCGT, supercritical coal with carbon capture and storage, and nuclear. We have developed a bespoke high-level stack model to simulate future electricity generation and hence CO_2 emissions, and compared the reduction in total annual CO_2 emissions achieved with each technology against the total system cost of meeting demand in each case, including the annualised capital cost of the respective technology under test.

Section 2 outlines the methodology and assumptions we have adopted for this analysis, including details of the generation stacks we have tested and the commodity price scenarios examined.

Section 3 provides an analysis of the expected resultant generation mix and sector CO_2 emissions, identifies the total costs of satisfying demand in each case, and derives an abatement cost for each technology.

Section 4 provides some conclusions from the analysis.

In addition, our forecast of GB electricity market developments which forms the basis for this report, *PowerView GB Power & ROC Price Forecast Period 2009 – 2032* (October 2008), is attached in **Annex A**.

[1] *Severn Barrage Costing Exercise*, IPA Energy + Water Economics (March 2008)

2 METHODOLOGY AND ASSUMPTIONS

2.1 Generation Stack

In order to examine the potential impact of the Severn Barrage on CO_2 emissions, we have developed a high-level model of the Great Britain electricity generation system. Using an assumed plant mix, the model determines the optimum way of satisfying demand at minimum total variable cost, using input fuel prices.

For the purposes of this study, we modelled a single representative future year when the generation market might be expected to have reached a relatively stable situation following expected "disconnects" over the next decade through regulation-enforced plant retirements. As we also wanted to model the situation at a point by which the Severn Barrage could reasonably be expected to be operational, we selected 2025 as the representative year.

We tested various plant stacks, starting with a baseline case, and then with individual new builds added to what is already forecast to be built to 2025 in the baseline: the Severn Barrage, renewables (onshore and offshore wind, biomass), CCGT, supercritical coal, supercritical coal with carbon capture and storage (CCS), and nuclear. In each case, the intent was to replace the 17 TWh of energy assumed to be produced by the barrage each year, albeit at appropriate availabilities for each technology. Details of the respective assumptions are given below.

2.1.1 Baseline

We have used IPA's latest view of the potential development of the Great Britain electricity market, published in October, as the basis for the baseline 2025 generation stack. Our report, *PowerView GB Power & ROC Price Forecast Period 2009 – 2032* (October 2008), provides a forecast of market and corresponding wholesale electricity price development from April 2009 to March 2033. The full document is attached in Annex A to this report.

In deriving this view on market development, we have taken into account the various policy, regulatory, and technical constraints that are expected to impact on the industry over the next years. These include, *inter alia* carbon trading under the EU Emissions Trading Scheme (EU ETS), emissions constraints under the Large Combustion Plants Directive (LCPD) and Integrated Pollution Prevention and Control (IPPC), and subsidy mechanisms such as the Renewable Obligation (RO), as well as plant lifetime considerations.

The resultant plant mix assumed for 2025 is shown in Figure 1 and detailed in Table 1 below:

Figure 1: Assumed 2025 Baseline vs. Current Generation Stack

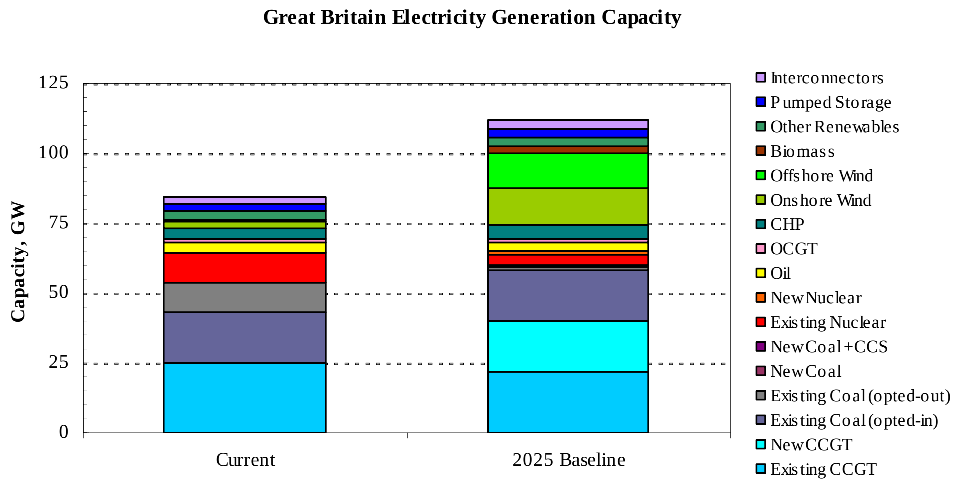


Table 1: Assumed 2025 Baseline vs. Current Generation Capacity, MW

Plant Type	Current	2025
Existing CCGT	24,903	22,173
New CCGT	0	17,675
Existing Coal (opted-in)	18,367	18,367
Existing Coal (opted-out)	10,191	1,390
New Coal	0	0
New Coal + CCS	0	490
Existing Nuclear	11,007	3,593
New Nuclear	0	1,000
Oil	3,681	3,681
OCGT	1,080	1,080
CHP	4,118	5,118
Onshore Wind	2,110	12,815
Offshore Wind	598	12,754
Biomass	304	2,193
Other Renewables	2,918	3,582
Pumped Storage	2,828	2,828
Interconnectors	1,988	2,998
Total Capacity, MW	**84,093**	**111,737**

The principal developments assumed to occur by 2025 are:

- **CCGT**: The bulk of the existing CCGT fleet are assumed to still be operational. In addition, there is over 17 GW of new CCGT (or large-scale CHP) capacity built –about 7 GW currently under construction and/or planned to commission by 2013, about 4 GW up to the end of the next decade, and the remaining 6 GW from 2020 onwards.
- **Coal**: All the opted-in coal plant is assumed to retrofit selective catalytic reduction (SCR) in order to comply with LCPD constraints on emissions of nitrogen oxides (NOx) from 1 January 2016. About

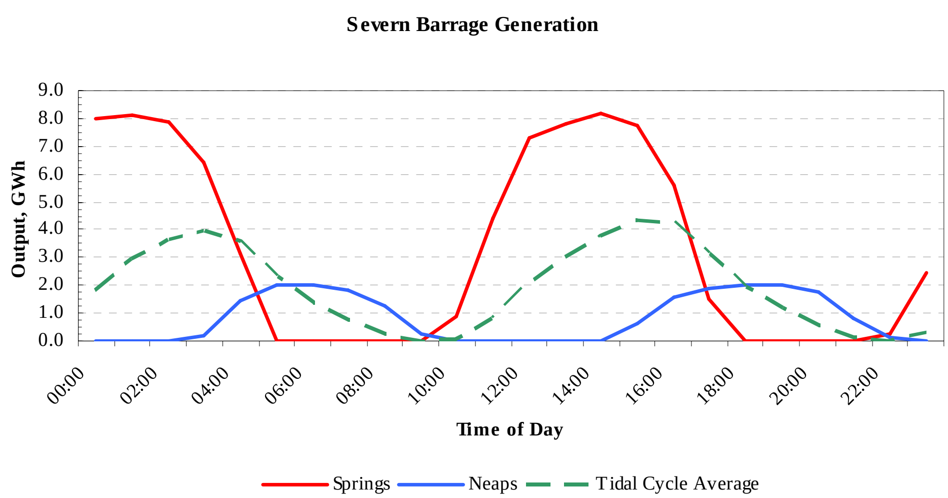
1 GW of opted-out coal plant is assumed to receive derogations from LCPD restrictions for security of supply purposes, with annual operation limited to 1,500 hours *per annum*, i.e. peak supply only. The only new build is a carbon capture and storage (CCS) demonstration unit under the Government's competition.

- **Nuclear**: Existing AGRs are assumed to receive five-year life extensions from their currently scheduled closure dates, hence in 2025 Sizewell B, Heysham 2 and Torness are all still operational. A single 1 GW new nuclear unit is also assumed to be constructed.
- **Renewables**: There is a massive growth in renewable capacity, supported by the Renewable Obligation (RO) subsidy mechanism, with almost 11 GW of new onshore wind build, 12 GW of offshore wind, and almost 2 GW of biomass plant.
- **Other**: There is an additional 1 GW of new (small-scale) CHP built. Oil plant is assumed to receive a similar derogation as opted-out coal and remain available for peak purposes. The 1 GW BritNed interconnector to the Netherlands is due to commission in 2010, while further interconnections to Ireland are assumed to essentially export only and hence are treated on the demand side.

2.1.2 Severn Barrage

We have used the same assumptions for the Severn Barrage in this analysis as in our previous study, i.e. the 8,640 MW Cardiff-Weston scheme. In terms of operation, we have used the maximum energy production patterns rather than any delayed operation to match peak demand. The assumed typical daily generation at spring and neap tides is shown in Figure 2, along with the resultant average over a full tidal cycle:

Figure 2: Assumed Severn Barrage Operating Pattern



This operating pattern replicated over the 29½-day spring-neap tidal cycle results in an annual generation of 17 TWh, i.e. an annual load factor of 22.5%.

2.1.3 Renewables

As an alternative to the Severn Barrage, we tested a mix of onshore wind, offshore wind, and biomass plant, added to what is already assumed to be constructed under the baseline case.

As part of our *PowerView* analysis, we have derived a high case view for renewables build, and this was used as the basis for this analysis. In particular, onshore wind build will be limited by the availability of suitable sites, while biomass plant will tend to be restricted by sources of appropriate fuel, whereas on the other hand the offshore wind resource is projected to be much greater than we have assumed is utilised in the baseline case.

For this analysis, we have therefore added an additional 3,013 MW of onshore wind to the baseline, taking the total capacity to 15.8 GW by 2025, plus 306 MW of additional biomass plant to give 2.5 GW in total. With our average load factor assumptions of 27% and 59% respectively, this additional capacity would generate 8.8 TWh *per* annum and we therefore made up remaining 8.2 TWh (to equal the 17 TWh from the Severn Barrage) with further offshore wind build – 3,097 MW more was needed at the 34% load factor assumed.

In this case we are thus assuming about 25% additional build of these renewable technologies than under the baseline over the timeframe to 2025.

2.1.4 Fossil (CCGT and Coal) Build

For the three fossil-fuelled alternatives – CCGT, coal, and coal with CCS – since all of these are assumed to have a high annual expected availability (and hence load factor, albeit somewhat dependant on the exact fuel price situation) of ~84%, we added 2.3 GW of new build to produce the required 17 TWh.

2.1.5 Nuclear

New nuclear would be expected to operate baseload (at ~86% load factor) and hence 2.3 GW additional build was also assumed.

2.2 Commodity Price Scenarios

Within our *PowerView* report, we derive three alternative scenarios for commodity price development – Base, Low and High Cases. These are self-consistent forecasts for oil, gas, coal, and CO_2 prices representing the 50%, 25%, and 75% confidence limits respectively. The assumptions for 2025 used in these generation stack analyses are detailed in Table 2 below:

Table 2: Forecast 2025 Commodity Prices (real 2008)

Commodity	Base Case Prices	Low Case Prices	High Case Prices
Crude Oil [Brent], $/bbl	60.00	45.54	74.46
Gasoil [CIF ARA], $/te	532.78	404.38	661.17
Heavy Fuel Oil [CIF ARA], $/te	271.51	214.71	328.32
Coal [API #2], $/te	64.83	54.99	74.30
Gas [NBP], p/th	44.19	33.02	59.23
CO_2, €/te	40.40	32.95	48.57

The Base Case slightly favours gas- over coal-fired generation. The Low Case is even more favourable to gas, as the low gas price outweighs the low CO_2 price. The opposite is true for the High Case with the very high gas price meaning that coal-fired generation is preferred despite the seasonality of gas prices and high CO_2 prices.

2.3 Capital Costs

As part of our previous study, we evaluated the relative costs of generation of various technologies based on a survey of four publications from 2006 and 2007. However, in the eighteen months since the reviewed reports were published there has been a very sharp increase in power station capital costs (and those of other infrastructure) as a result of a high global demand for plant and a corresponding tightness in manufacturing capability as well as strong increases in the cost of raw materials (such as steel, nickel and copper) and wages. For example, the 1 GW London Array offshore wind farm is now quoted as costing £2.8bn, i.e. £2,800/kW, well above the £1,500/kW upper end of the range in the previous analysis. Similar increases have been cited for CCGT, coal, and nuclear projects, while the costs of CCS and a barrage are even more uncertain.

It is possible that this is a temporary blip which will ease over time as more manufacturing capability becomes available, but it may be that this cost inflation is permanent as demand for new power plant grows worldwide. Hence for this analysis, we have extended the range of capital costs considered, as shown in Table 3 below:

Table 3: Range of Capital Costs for New Build, £/kW (real 2008)

Technology	Minimum	Maximum
Severn Barrage	2,000	3,500
Onshore Wind	600	1,500
Offshore Wind	900	3,000
Biomass	1,500	2,500
CCGT	300	700
Supercritical Coal	600	1,200
Supercritical Coal + CCS	1,200	2,500
Nuclear	1,000	3,000

(This range is quite wide for many of the technologies, but it should be noted that current prices are closer to the top than the bottom.)

The total capital costs which would thus be incurred in each of the alternative new build scenarios tested are shown in Table 4 below:

Table 4: Range of Capital Costs in Each New Build Scenario, £bn (real 2008)

New Build Scenario	Capacity, MW	Minimum	Maximum
1 Severn Barrage	8,640	17.3	30.2
2 Renewables, comprising:	6,417:	5.1:	14.6:
Onshore Wind	3,013	1.8	4.5
Offshore Wind	3,097	2.8	9.3
Biomass	307	0.5	0.8
3 CCGT	2,319	0.7	1.6
4 Supercritical Coal	2,319	1.4	2.8
5 Supercritical Coal + CCS	2,319	2.8	5.8
6 Nuclear	2,253	2.3	6.8

This clearly highlights the potential huge investment which would be required to build the Severn Barrage as against other technologies to generate the same total energy.

2.4 Other Modelling Assumptions

A number of other assumptions were required for the calculation of the annualised capital cost of each technology, and these are detailed in Table 5 and Table 6 below:

Table 5: Technology Economic Lifetimes

Technology	Lifetime, years
Severn Barrage	50
Onshore Wind	20
Offshore Wind	20
Biomass	20
CCGT	20
Supercritical Coal	25
Supercritical Coal + CCS	25
Nuclear	40

Table 6: Macroeconomic Assumptions

Parameter	Value
Discount Rate, post-tax nominal	8.0%
Inflation Rate	2.8%
Corporation Tax Rate	28%
Exchange Rate: US$/£	1.7881
Exchange Rate: €/£	1.2295

3 RESULTS

3.1 CO_2 Emissions

The 17 TWh generated by the Severn Barrage is approximately 4% of the total system demand of 425 TWh assumed in 2025 (~15% increase from current levels or a compound annual growth rate of ~0.8% *per annum*). The substitutive plants displace the most expensive generation at the top of the merit order, either existing relatively low efficiency gas- or coal-fired plant depending on the time of year. In all except the case with new supercritical coal, this fuel switching also reduces CO_2 emissions – with new coal replacing old CCGTs there is actually an increase in emissions.

Figure 3, Figure 4 and Figure 5 below show the forecast total emissions in each of the different build cases assuming Base, Low and High commodity prices respectively.

Figure 3: Forecast 2025 CO_2 Emissions with Base Case Commodity Prices

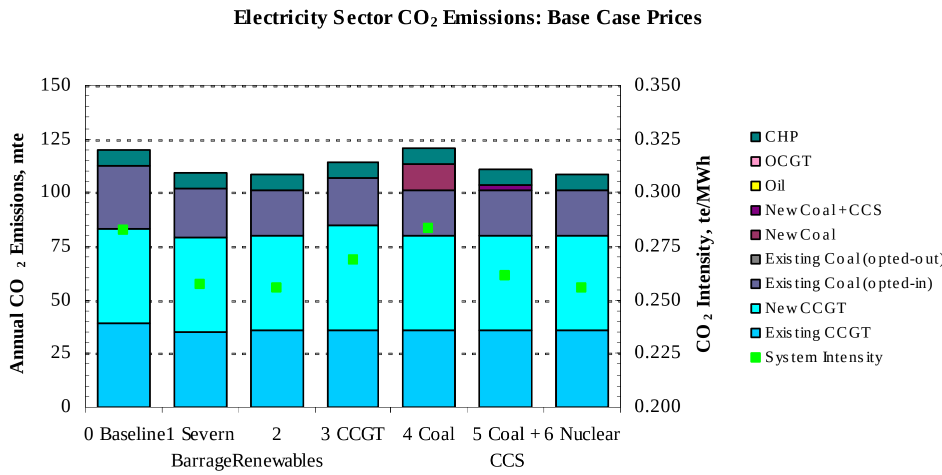


Figure 4: Forecast 2025 CO_2 Emissions with Low Case Commodity Prices

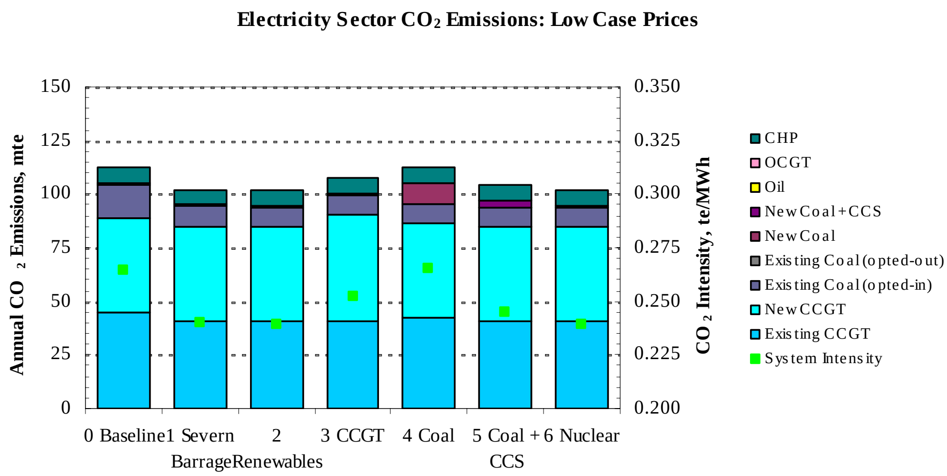
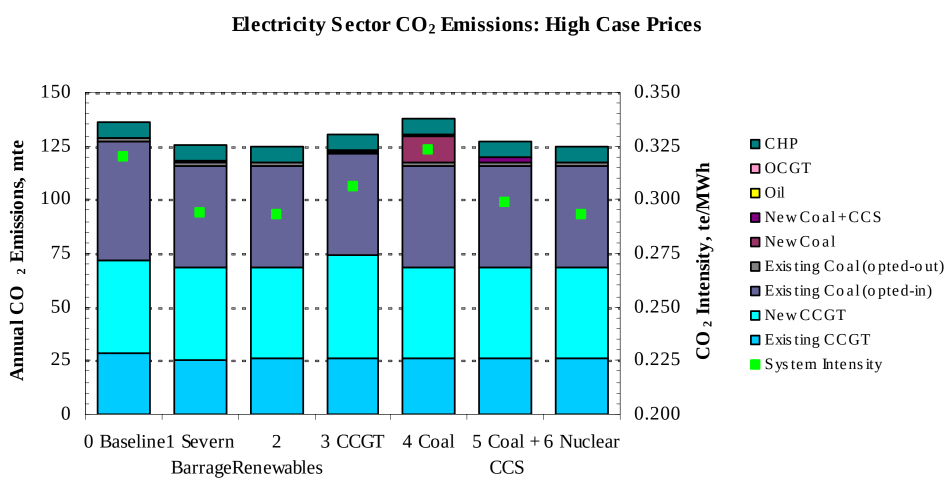


Figure 5: Forecast 2025 CO_2 Emissions with High Case Commodity Prices



Absolute emissions are highest with the coal-favoured High Case prices and lowest under the gas-dominated Low Case price environment (although it should be noted that the system CO_2 intensity is less than half of today's level in all cases).

However, as shown in Figure 6 and Table 7, the reduction relative to the baseline is broadly similar across all price cases. The zero-carbon technologies – Severn Barrage, renewables and nuclear – obviously achieve the greatest reductions, with coal + CCS about 20-30% less and CCGT about half thereof. The Severn Barrage is not quite as effective as renewables and nuclear because of its unique daily generation profile: the timings of maximum generation do not quite match the times of peak demand and hence the Barrage does not displace as much of the high intensity coal-fired generation as the baseload (assumed flat daily profiles) renewables and nuclear plants.

Figure 6: Reduction in Annual CO_2 Emissions Compared to Baseline

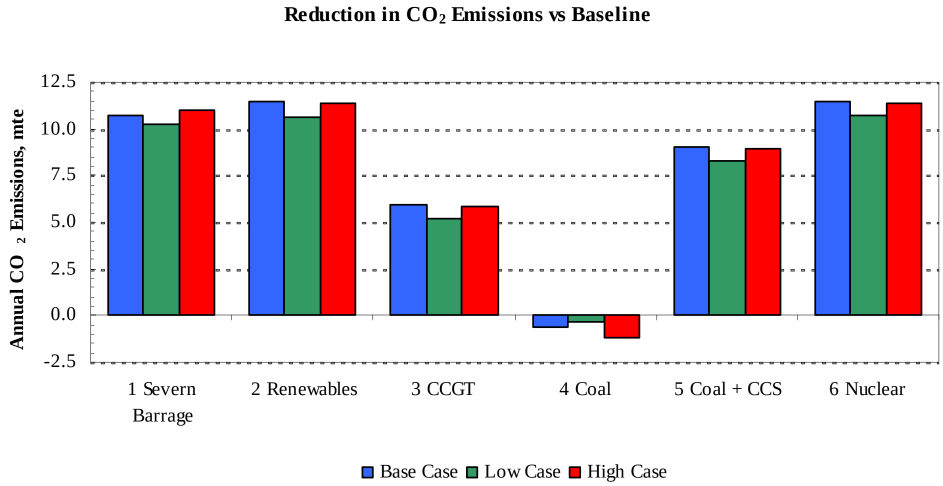


Table 7: Reduction in Annual CO_2 Emissions Compared to Baseline, mte (percentage)

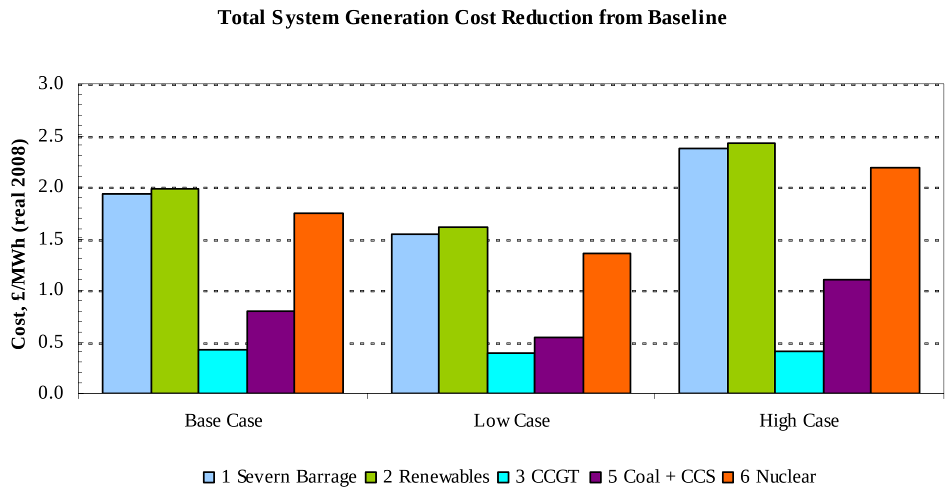
New Build Scenario	Base Case Prices	Low Case Prices	High Case Prices
1 Severn Barrage	10.75 (9.0%)	10.22 (9.1%)	10.99 (8.1%)
2 Renewables	11.48 (9.6%)	10.64 (9.5%)	11.38 (8.4%)
3 CCGT	5.89 (4.9%)	5.17 (4.6%)	5.83 (4.3%)
4 Coal	-0.60 (-0.5%)	-0.32 (-0.3%)	-1.19 (-0.9%)
5 Coal + CCS	9.02 (7.5%)	8.30 (7.4%)	8.96 (6.6%)
6 Nuclear	11.45 (9.5%)	10.68 (9.5%)	11.39 (8.4%)

Since the new supercritical coal option does not reduce CO_2 emissions, we can ignore it for the purposes of assessing the CO_2 abatement cost of each technology.

3.2 Abatement Cost

From our generation stack model we can calculate the total variable cost (fuel, CO_2, and variable O&M, i.e. the short-run marginal cost) of meeting demand over the year for each plant portfolio. Since in each new build case we are displacing the most expensive marginal plant, compared to the baseline the total system generation cost decreases. The extent of this benefit is shown in Figure 7, expressed per unit of generation. This increases in absolute terms as the underlying commodity prices increase, although the percentage benefit is roughly the same across the prices cases for each technology.

Figure 7: Reduction in Total Cost of Generation Compared to Baseline



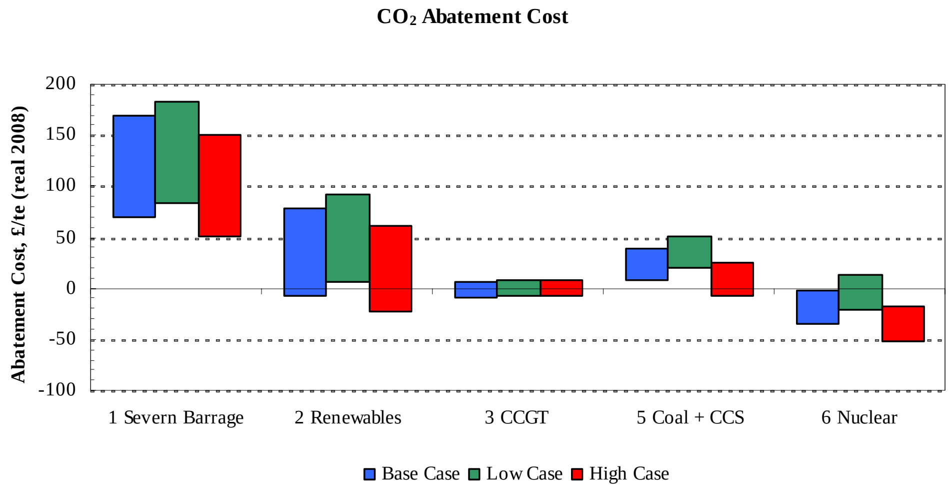
This variable cost benefit could broadly be expected to translate into electricity price reductions (all else being equal) compared to not having the new technology.

To properly determine the CO_2 abatement cost, we need to include the cost of building the plant which has achieved this reduction. The annualised capital cost of the new technology (plus its relatively small annual fixed costs) needs to be deducted from this generation cost benefit. By dividing by the achieved reduction in CO_2 emissions in each case, we can express the results as CO_2 abatement costs (which if negative would indicate a "win-win" option). These results are detailed in Table 8 and Figure 8 for the three price cases:

Table 8: Range of CO_2 Abatement Costs for Each New Build Scenario, £/te (real 2008)

New Build Scenario	Base Case Prices	Low Case Prices	High Case Prices
1 Severn Barrage	69 – 169	84 – 184	52 – 151
2 Renewables	-7 – 78	7 – 92	-23 – 62
3 CCGT	-9 – 7	-8 – 9	-8 – 8
5 Coal + CCS	8 – 40	20 – 52	-7 – 25
6 Nuclear	-35 – -2	-21 – 12	-51 – -18

Figure 8: Range of CO_2 Abatement Costs for New Builds



Some clear trends emerge from these results:

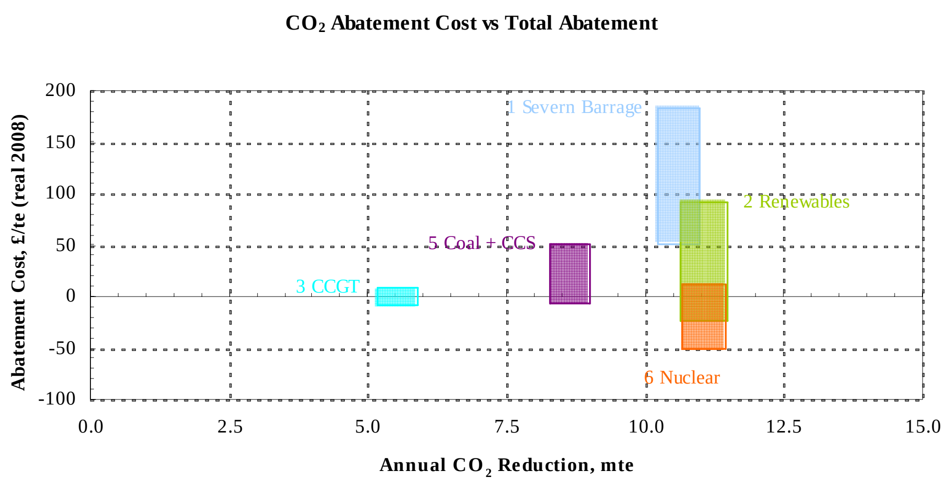
- Since the generation cost benefit increases in absolute terms with the underlying prices, the abatement costs correspondingly decrease from Low to Base to High Case prices.
- Because of its extremely high capital cost, the abatement cost of the Severn Barrage is at least £50/te (real 2008) and could be as high as £180/te.
- At the other end of the scale, although it has a similar per unit capital cost, since it operates at much higher load factors and thus requires a quarter of the capacity for the same energy production, new nuclear plant would generally be expected to have a negative "cost" of CO_2 abatement, i.e. a benefit as much as £50/te, although with the potential for cost increases, it could cost as much as £12/te.
- Other renewables suffer from the same issue as the Severn Barrage in that their relatively low load factor means that a large capacity of plant must be built per unit of generation and CO_2 abated, and hence a high capital expenditure is required. At current capex levels, the abatement cost could be as high as £90/te, although if capital costs do reduce towards historic levels renewables could have a negative "cost" of as much as £20/te.
- Carbon capture and storage on new supercritical coal appears to cost about up to £50/te of CO_2 abated, as it has a very high specific capital cost and not as much abatement as the full zero carbon technologies. If capital costs were to decrease as the technology became proven, the abatement cost could be negative.
- The CO_2 abatement cost of new CCGTs is fairly insensitive to commodity prices, largely because gas tends to be the marginal price-setting plant, and varies with in a narrow band of ±£10/te (real 2008) depending on the capital cost. At current levels it is slightly positive, but if prices fall towards historic levels, it would become negative.

4 CONCLUSIONS

From this analysis of potential future generation market portfolios, it is clear that while the Severn Barrage has considerable potential to help with reducing CO_2 emissions by the electricity generation sector, the overall cost of doing so is extremely high in comparison to doing so with other technologies.

Figure 9 summarises the potential ranges of abatement cost and total abatement for the five technologies tested:

Figure 9: Summary of Range of Technology CO_2 Abatement Cost and Potential



In this diagram, being in the lower right is better: larger amount of emissions reduction at a lower cost.

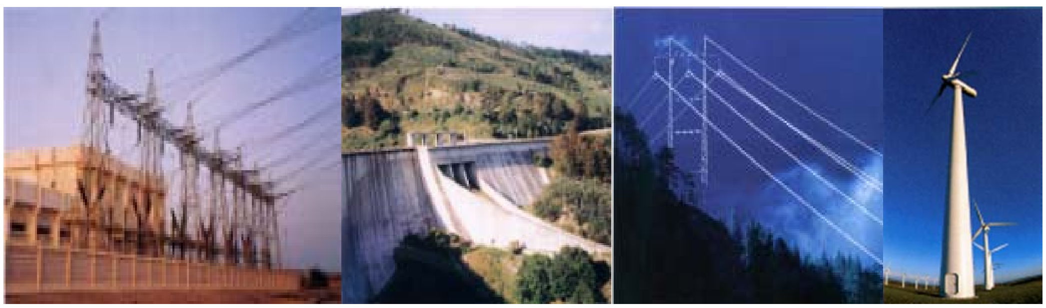
- **Severn Barrage**: While the reduction in both system CO_2 emissions and variable costs of generation are among the best of all the technologies, the extremely high total capital cost (similar unit cost to other technologies such as offshore wind, coal + CCS, and nuclear, but considerably more capacity required because of the low load factor) means that the CO_2 abatement cost is very high.
- **Other Renewables**: Onshore and offshore wind and biomass can achieve slightly better CO_2 and variable cost reductions than the Severn Barrage because of their more evenly distributed (on average) operation, and with lower capital costs thus have a lower abatement cost. If construction costs drop back towards historic levels (which may be difficult given the expected level of demand for these technologies) then the abatement cost could even become negative.
- **Nuclear**: As another zero-CO_2 emitter, nuclear can achieve similar levels of CO_2 emissions reductions as the renewable technologies although at a slightly higher variable operating cost. However, with a high baseload load factor and similar unit costs of construction, it's overall CO_2 abatement cost would be expected to be negative in most situations – only with extreme capital cost increases (which is entirely feasible especially for the first builds of the next generation of reactors, viz. the cost increases and delays being experienced on the plant being constructed at Olkiluoto in Finland) does the abatement cost become positive.

- **Supercritical Coal with Carbon Capture and Storage**: CCS would help reduce CO_2 emissions, albeit not quite as much as the zero-emission technologies, and also generation costs would only reduce by about half as much. However, with capital costs expected to be similar to those of new nuclear (although this is an completely unproven technology as yet so cost estimates are very uncertain), the CO_2 abatement cost would be up to ~£50/te and could just about become negative.
- **CCGT**: New CCGTs would only reduce CO_2 emissions by about half of the other technologies, and variable costs would not reduce greatly. Their low capital cost though means that the abatement cost is fairly small, either positive or negative, ranking just behind nuclear. There is a limit to the total amount of CO_2 which could be abated through this means, as the benefit is through the replacement of coal and older, less efficient CCGTs and once these have all the been replaced no further reduction could accrue.

ANNEX A: *POWERVIEW*

Our full report on the potential development of the Great Britain electricity market, *PowerView GB Power & ROC Price Forecast Period 2009 – 2032* (October 2008), which has provided the baseline 2025 generation stack on which this analysis has been based, is attached below.

PowerView
GB Power & ROC Price Forecast



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1. EXECUTIVE SUMMARY

This report provides a forecast of GB wholesale electricity and ROC prices under Base, Low and High scenarios over the period from 2009 to 2032.

The forecast uses IPA's proprietary model ECLIPSE (Emissions Constraints and Policy Interactions in Power System Economics). ECLIPSE models the macro-economics of the power industry and captures the complex interactions between market developments, governmental policy and regulatory instruments, in shaping the industry. Specifically, ECLIPSE models the impact of the Climate Change Levy (CCL), the Renewable Obligation (RO), emissions constraints under the Integrated Pollution Prevention and Control (IPPC), the Large Combustion Plant Directive (LCPD) and carbon trading under the EU ETS, as well as estimating the penetration of different generation technologies over the forecast horizon.

The report provides an analysis of current markets, commodity prices and carbon prices, and investigates the impact these have had on the power markets. The report goes on to develop commodity price scenarios that explore a credible range of outcomes over the forecast horizon given potential market, regulatory and political drivers. The report also investigates other regulatory drivers of the power markets in terms of the implementation of the LCPD, allocations under the EU ETS, the development of the RO, and the impact these will have on the development of the generation mix and the maintenance of security of supply over the forecast horizon.

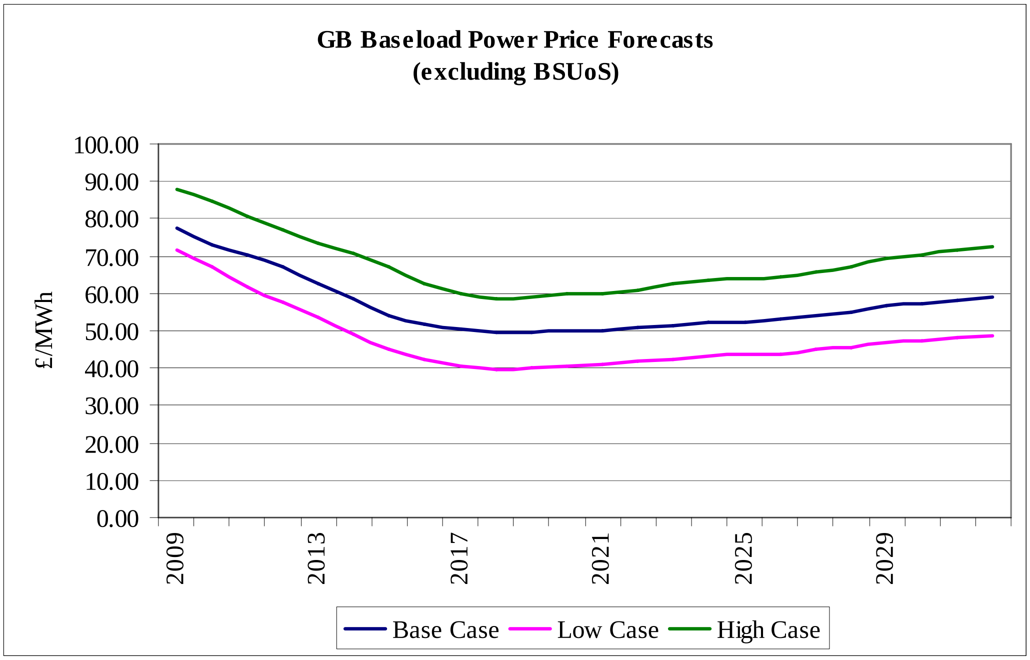
The power market modelling investigates the evolution of the industry over the forecast horizon, as it responds to emissions constraints, carbon trading, the development of renewable generation and the steady closure of nuclear capacity. It explores the running and profitability of generation at a station level, and investigates the economic response of generation companies and developers to plant closures and new build decisions.

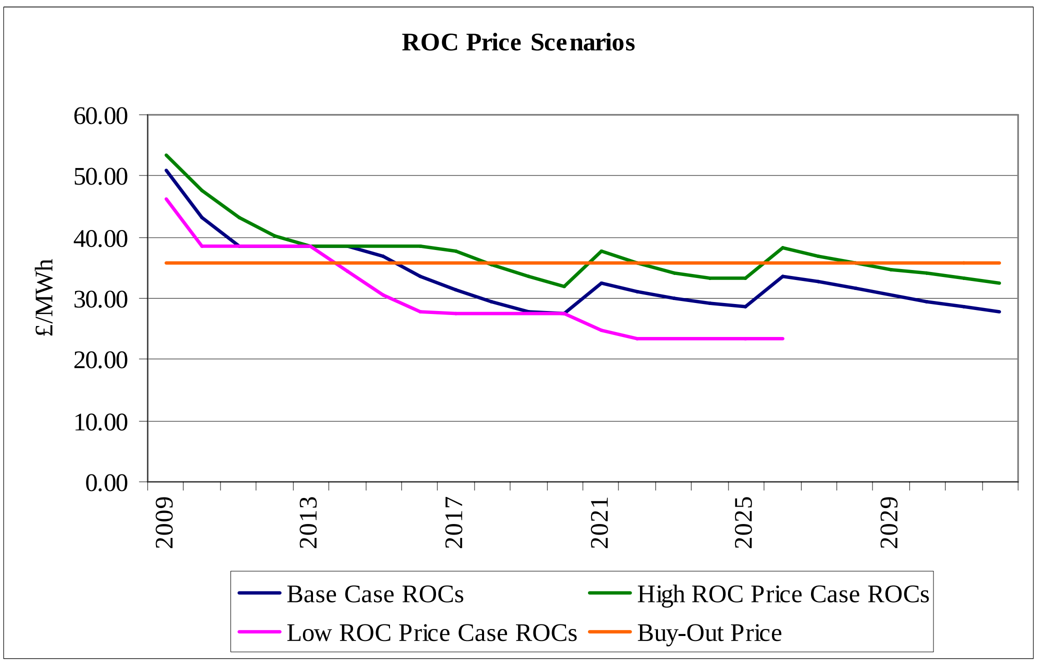
The report presents forecasts for power market prices and Balancing Services Use of System (BSUoS) charges over the forecast horizon. Market prices are compared to the short run marginal costs of the system and the costs of new entry generation capacity. The analysis investigates the evolution of the industry in terms of the relative costs of different generation technologies, peak capacity margins, generation fuel mix and system carbon intensity over the forecast horizon.

The potential developments of the Renewable Obligation are investigated and their impact on renewable development is explored. The level of current renewable projects is investigated, and the restrictions on renewable development, in terms of the transmission system, availability of energy crops, generation economics and resource availability are discussed. A forecast of ROC prices is presented along with an analysis of the economics of generation over the forecast horizon, renewable generation capacity by technology, and renewable output relative to RO targets.

The power and ROC forecasts are shown in Figure 1 overleaf.

Figure 1: Power and ROC Price Forecasts





2. INTRODUCTION

This report provides a forecast of GB baseload wholesale electricity prices and ROC prices under Base, Low and High scenarios over the period from 2009 to 2032. The report covers the following aspects:

- Section 3: Provides an overview of current power and commodity market trading, and comments on the latest regulatory and policy developments;
- Section 4: Provides an overview of the oil price scenarios, and compares forecasts from a number of providers;
- Section 5: Provides an overview of the gas price scenarios, and a brief analysis of gas supply over the forecast horizon;
- Section 6: Provides an overview of the coal price scenarios, and analysis of some of the issues associated with sourcing coal for the GB coal generation fleet;
- Section 7: Provides a detailed look at some of the issues that will influence carbon prices, and presents three carbon price scenarios;
- Section 8: Provides a detailed analysis of the LCPD and IPPC, and their impact on coal station running and investment;
- Section 9: Provides an overview of the assumptions on generation capacity;
- Section 10: Details electricity demand scenarios;
- Section 11: Presents the Base Case Power Price forecast and BSUoS forecast. It discusses the drivers of power price over the forecast horizon, investigating plant running, capacity additions and closures, the developing generation mix, carbon intensity and security of supply;
- Section 12: Presents analysis of the three power price scenarios, and compares the different drivers and the impact upon power price and the evolution of the generation mix;
- Section 13: Presents the assumptions used in constructing the ROC price scenarios, including assumptions on the development of the RO, transmission capacity and the development of renewable generation capacity; and
- Section 14: Investigates the ROC price forecasts under the three scenarios exploring the different price drivers and the development of a mix of renewable generation capacity.

In addition:

- Annex A: Presents modelling results and assumptions in tabular form;
- Annex B: Provides an overview of the ECLIPSE model; and
- Annex C: Provides a glossary of terms.

2.1. High Level Assumptions

- The power price forecasts from ECLIPSE are exclusive of BSUoS.
- A BSUoS forecast is included, and this should be added to the ECLIPSE power price forecast to calculate wholesale prices.
- The power prices quoted throughout this report reflect the GB wholesale baseload power contract.
- Unless otherwise stated all numbers are quoted for financial years, with 2008 representing the financial year commencing April 2008.
- All prices are quoted in real terms (April 2008 money).

3. MARKET SUMMARY

This section provides a brief overview of some of the current issues associated with the power markets, and the recent developments in terms of regulation and policy. Further details of most of the issues are given in the main body of the report.

3.1. Traded Market Analysis

Recent market movements in gas, oil, carbon and power markets are shown in Figure 3 to Figure 6 and discussed below.

3.1.1. Oil

Oil prices have dropped over the quarter with month ahead prices falling to $110/bbl at the end of August on the back of reduced global demand and the current financial instability affecting global markets.

The current Brent forward curve is slightly backwardated in real terms, with delivery in 2013 trading around the $100/bbl level. This represents a decrease in the forward curve over the quarter broadly reflecting the recent falls in the prompt.

3.1.2. Gas

The gas market has seen significant movement over the last three months. There has been upwards movement in the front winter contract, and along the curve, following the oil market's upwards trend. As was stated in the July edition of PowerView, the rise in the gas contract has outstripped the BAFA oil indexed price, indicating a significant risk premium has been added on fears over supplies – especially LNG deliveries – that saw NBP at a premium to the BAFA price. Brent Oil prices reached a peak at around $146/bbl at the start of July 08 and have seen a considerable fall since then, falling to $89/bbl by mid-September, though have seen something of a rebound since then partly as a result of the turbulence in the financial markets. An additional factor is the changing exchange rate, with sterling falling by 10% against the dollar meaning that the oil price has fallen from £73/bbl in July 08 to £50/bbl in September 08.

The UK gas curve is backwardated with prices in 2014 trading at around 13p/th lower than 2009 prices. This backwardation reflects both the likelihood of greater Norwegian flows once this winter's problems have been overcome and higher Ormen Lange flows, potentially greater LNG flows when Japanese power problems have been overcome and a backwardated oil curve and hence a backwardated BAFA curve.

3.1.3. Coal

Coal prices maintained their strength of the past six months, although they have dropped slightly from the peaks reached in early July. Month-ahead API#2 prices were around \$190/tonne at the end of September having peaked at nearly \$220/tonne. Prices have been driven by continued high demand, particularly from China and India, and on-going supply constraints in Australia and South Africa.

The forward curve has also seen considerable upward pressure over the last quarter, but remains backwardated in real terms, with delivery in 2011 trading around the \$155/tonne (real) level. The softening of prices along the curve reflects both softening in the underlying price of coal as well as softening of freight rates along the curve.

3.1.4. Carbon

Carbon prices have fallen over the previous quarter in response to falling oil prices. At the beginning of July, the price of EU allowances was at a two-year high of almost €30/tCO_2. The price dropped throughout July, reaching around €21/tCO_2 at the beginning of August, later recovering to around €25/tCO_2 towards the end of August.

3.1.5. Power

Prices over the last quarter have seen continued upward pressures due to increases in gas prices, as well as pressures on plant margin which have resulted in market volatility. Towards the end of September, power prices for the imminent winter jumped sharply on forecasts of very tight capacity margins as a result of a number of plant outages, even though National Grid in their *Winter Outlook 2008/09* suggested demand should be comfortably met in all but the most extreme cases.

There has been speculation that the implementation of the LCPD has created instability in the system because the single stack definition of plant means that it is uneconomical for power stations that have opted out from the LCPD to run below full capacity.

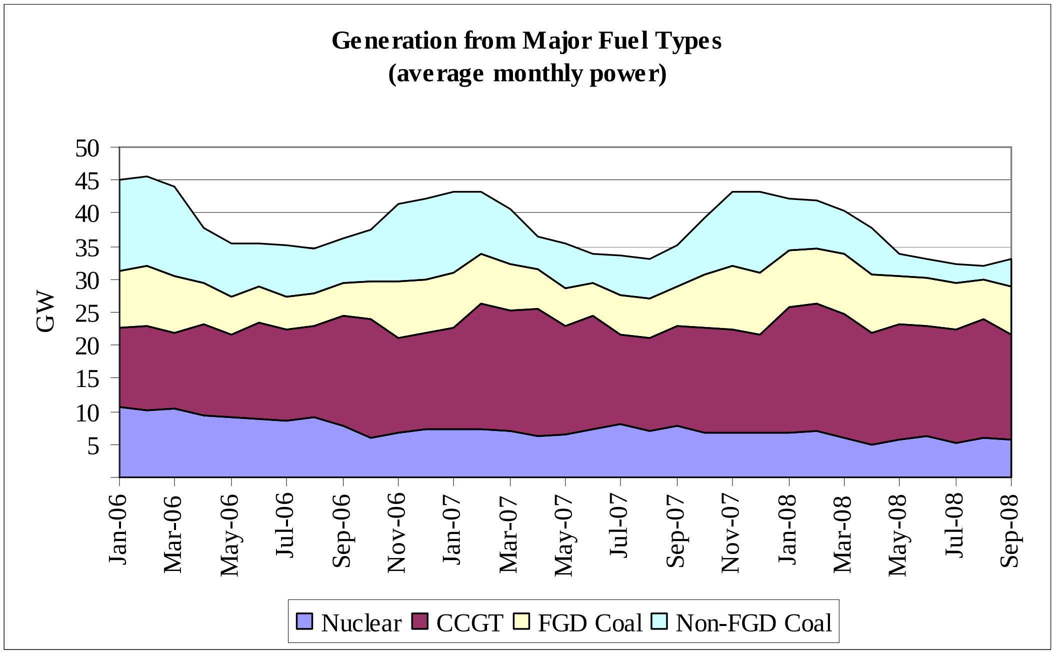
Summer-09 and Winter-09 have seen upward pressure over the previous months, predominantly reflecting upward pressure on gas prices along the curve.

Beyond 2009, the curve is slightly backwardated in real terms, reflecting the shape in the commodity markets, as well as the planned commissioning of new CCGT capacity in 2009.

3.1.6. Plant Running

Figure 2 below shows generation from major fuel types since January 2006. Particularly apparent during 2008 has been the impact of LCPD on the opted-out non-FGD coal plant, with much reduced operation during the past summer compared to previous years. Despite problems with FGD installation at Fiddler's Ferry, Ferrybridge and Rugeley, opted-in coal running as a whole actually increased slightly compared to the previous year as a result of the high gas prices seen this year. Nuclear output was much reduced as a result of the outages at Hartlepool and Heysham 1.

Figure 2: GB power generation from major fuel types[1]



[1] Elexon

Figure 3: Historic NBP Gas and Oil Prices

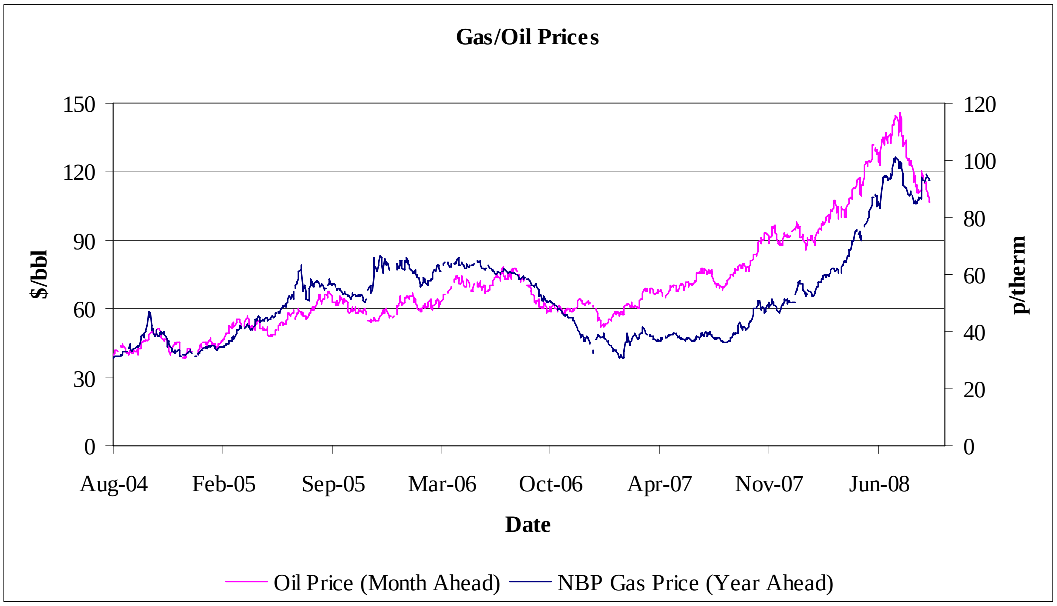


Figure 4: Historic Coal Prices

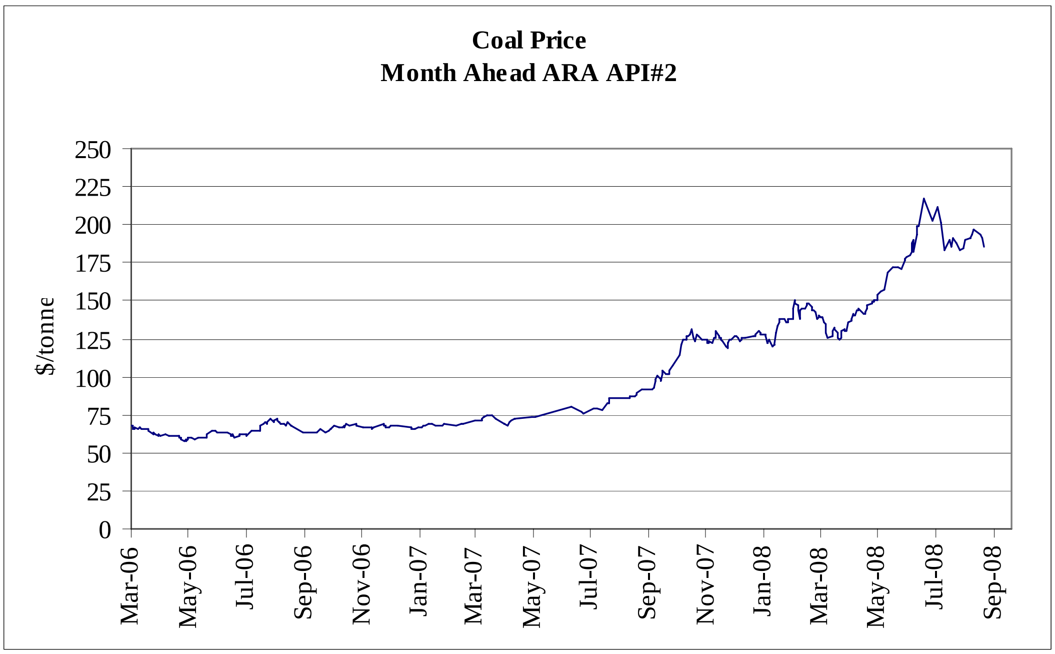


Figure 5: Historic Carbon Prices

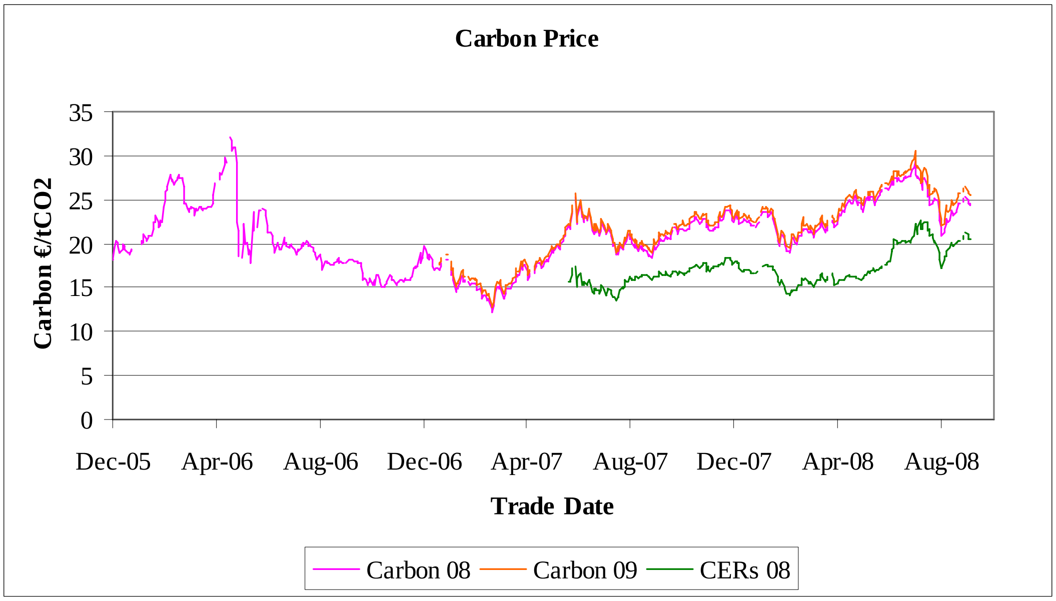
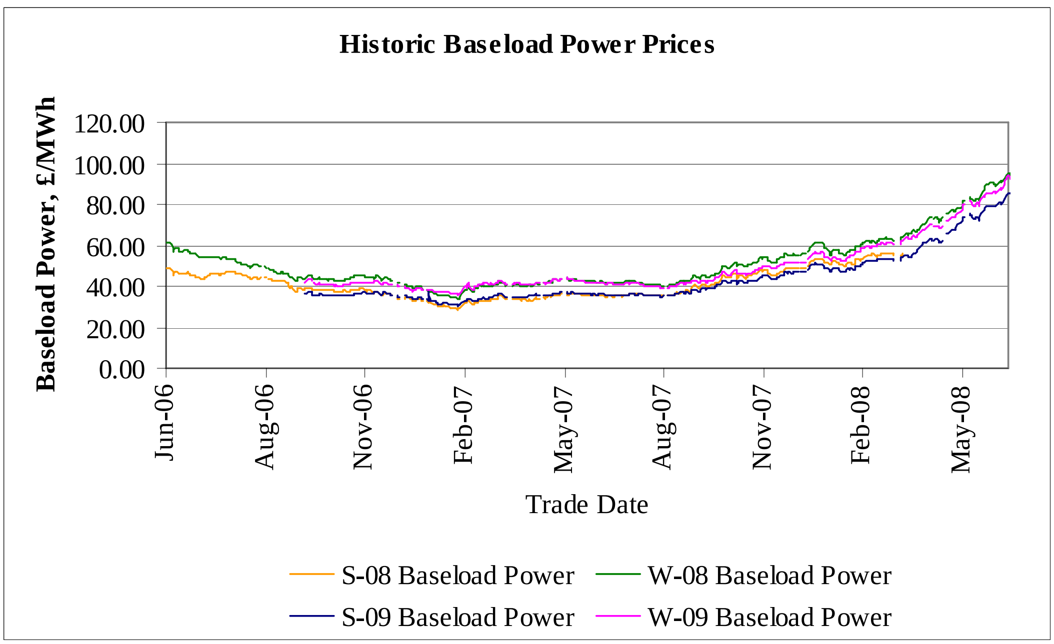


Figure 6: Historic Baseload Power Prices



3.2. Market Rules

3.2.1. Imbalance Prices

There are three BSC modifications covering the calculation of imbalance prices:

- **P211 (EdF Energy) Main Imbalance Price based on ex-post unconstrained schedule**

  The least costly bids and offers that were available to the GB SO in each half hour and are required to resolve the net imbalance on the system would be used in the calculation of SSP and SBP in a similar way to the current price stacks (the average-marginal 500MWh is used to set the main imbalance price).

  The BSC Panel has recommended to the Authority the proposal be rejected. Ofgem have recently published their impact assessment and state that the case is finely balanced but they are currently minded to approve the modification. Ofgem has deferred a decision on this modification so that it can be considered in parallel with P217 (the two modifications being mutually incompatible).

- **P212 (Bizz Energy) Main Imbalance Price based on Market Reference Price**

  The main price would be calculated from the Market Reference Price plus or minus a predetermined percentage adjustment (proposed at 5%). This modification also considers changes to the calculation of system length.

  The BSC Panel recommended to the Authority the proposal be rejected and in February 2008, Ofgem rejected this modification.

- **P217 (RWE) Revised Tagging Process and Calculation of Cash Out Prices**

  P217 seeks to introduce a revised tagging process to the current main Energy Imbalance Price methodology. The proposed revised tagging process would enable Bid Offer Acceptances (BOAs) and forward trades to be tagged as ‘system’, ‘energy plus system’ or ‘energy’ actions, based on the primary reason for the action. ‘System’ actions would be excluded from Energy Imbalance Prices, whilst ‘energy’ and ‘energy plus system’ actions would be included.

  The Modification Group issued its assessment report to the BSC Panel on 12th June 2008. This recommended that the Alternative Modification P217 be adopted. The Alternative Modification is identical to the original, apart from that it retains the current Price Average Reference (PAR) volume of 500MWh (the original Modification proposed reducing this to 100MWh).

Ofgem has announced it is “minded-to accept” P217. Ofgem estimates that the new way of calculating prices could lead to annual savings of around £19 million. The regulator, however, does have some concerns about the resulting complexity that would be added to the trading arrangements and the impact on new entrants. The earliest that changes could come into place is winter 2009-10.

3.2.2. Zonal Transmission Losses

There have been a number of BSC modification proposals (see Table 1) seeking to change the charging for transmission losses from the current postage stamp charge to a zonal charging methodology.

Table 1: Transmission Losses Modifications

Modification	Description
P198	Zonal Transmission Losses Scheme
P200	Zonal Transmission Losses Scheme with Transitional Scheme
P203	Seasonal Zonal Transmission Losses Scheme
P204	Scaled Zonal Transmission Losses

The BSC panel considered all of these modification proposals (and alternative proposals) and concluded that none of the modifications should be made. The proposals went to Ofgem who have published an impact assessment and consultation, and in June published a consultation on a 'minded to' decision to approve P203 with an implementation date of 1 October 2008, and reject the other proposals. However, on 14 September Ofgem published an open letter effectively delaying a decision on zonal losses. It stated that it had considered responses to the consultation, some of which considered Ofgem had placed too much weight on the quantitative analysis of the schemes in coming to a minded to decision. Ofgem is currently reviewing the analysis of the schemes and intends to consult on the findings of the review before it makes it final decisions on the proposals[2].

Teesside Power, Immingham CHP, Drax Power and British Energy have taken Ofgem to court over the proposed introduction of zonal transmission system losses. The judicial review is on a legal technicality – specifically whether the proposed rule change could be implemented other than in accordance with the proposed implementation date timetable set out in the Final Modification Report of the BSC panel. Judgement was handed down in June and found against Ofgem, although the judge granted the regular leave to appeal.

In July 2008[3], Ofgem announced that it would not be appealing in light of the resource implications and regulatory uncertainty that an appeal might cause. However, they state that it is possible that BSC parties may re-raise similar proposals in the future and as such Ofgem intent to publish the additional analysis that was commissioned from Oxera.

Although the implementation of a zonal losses scheme has clearly been delayed, Ofgem has been keen to implement this type of scheme for a long time. Thus, it is likely that the regulator will attempt to approve such a scheme in some form at some time in the future and that given the work and analysis that has already been

[2] Ofgem letter: 'The Authority's decisions on the Balancing and Settlement Code (BSC) modification proposals on zonal transmission losses', 28 March 2008.
[3] Ofgem letter: "Balancing and Settlement Code Modification Proposals on Zonal Transmission Losses", 17 July 2008

undertaken, the time frame to consider any similar proposals would be much shorter than would otherwise be the case.

It has been assumed in the modelling that a zonal losses scheme based on P203 will be implemented in 2010 and will continue to apply for the remainder of the forecast period.

3.2.3. Transmission Access and User Commitment

In recent years, the emergence of the 'GB queue' of generators seeking to connect to the GB transmission system has exposed limitations in the process through which new generators seek to connect to the transmission system. A particular problem has been the financial security that the generator must provide - once they have accepted a connection offer - to secure the transmission companies against stranded assets in the case that the generator cancels the project. This financial security is known as Final Sums Liability (FSL). When a number of new generators seek to connect in the same location, their FSL can be large and volatile, creating problems for the financing of projects. National Grid has introduced an interim set of arrangements to make FSL more stable and predictable while a more permanent solution is developed.

National Grid proposed the CUSC amendment CAP 131 in October 2006 to address this issue. Industry has raised 32 alternative proposals, leading Ofgem to state that "*CAP 131 provides a good example of the failure of the existing CUSC governance processes to come forward with proposals on this important issue*".

In June 2008, Ofgem published an impact assessment/consultation[4] on CAP 131 (responses were due by 18th July 2008). This states that Ofgem is currently minded to reject all the proposals because they appear to give existing generators preferential treatment.

3.3. Renewables Obligation

BERR have published a statutory consultation on the Renewables Obligation Order 2009. This Government's response to the consultation has now been published (January 08).

The key elements of the consultation are:

- Obligation changed to be an obligation on ROCs rather than energy supplied;
- Banding of the RO dependent upon generation technology, with bands from 0.25 to 2 ROCs, with grandfathering of rights;
- Extension of RO to 20% in 2020, with a fixed headroom of 8% of expected ROCs to be used in setting intermediate targets;
- Retaining the indexation of the buyout to RPI;

[4] Ofgem Consultation – Impact Assessment: CAP 131 – User Commitment for New and Existing Generators.
http://www.ofgem.gov.uk/Licensing/ElecCodes/CUSC/Ias/Documents1/080606_CAP131_IA_final.pdf

- Managing ROC price collapse in an over-supplied market is not proposed to feature as the 20% maximum obligation limit is considered sufficient in the immediate future.

Further details of the RO consultation are provided in the Renewables Assumptions section of PowerView, Section 13.

3.3.1. Scottish Renewables Obligation

In September 2008, the Scottish Government launched its statutory consultation on the Introduction of Banding to the Renewables Obligation (Scotland) with responses due by the 12th of December 2008.

In this document, the Scottish Government plans to adopt the same changes to the statutory obligation as those outlined in the main BERR consultation outlined above but with the following proposed differences:

- The MSO will be disbanded and replaced with an equivalent ROC multiple. Wave will receive 5 ROCs and tidal stream will receive 3 ROCs;
- Advanced Conversion Technologies in Scotland will have their eligibility for double ROCs linked to regard for SEPA's Thermal Treatment guidelines for waste; and
- Island wind will not be granted the 1.5ROC/MWh support BERR has proposed for wind. Instead the Scottish Government will continue to work to amend the current transmission charging models.

3.4. Capacity

There have been a few recent generation capacity developments:

- Centrica has applied for Section 36 consent to a build a 1,020MW extension to its 340MW CCGT plant at Kings Lynn;
- BP Energy submitted a Section 36 consent application for an 870MW CCGT on a site adjacent to GE's existing Baglan Bay power station in South Wales;
- Bridestones Development have been awarded consent to build a 860MW CCGT at Carrington (called Partington); and
- Thor Cogeneration has been granted consent for their 1,020MW Seal Sands cogeneration plant.

Further details of generation capacity developments are provided in Section 9.

4. OIL PRICE SCENARIOS

4.1. Oil Markets

Oil prices have dropped over the quarter with month ahead prices falling to $110/bbl at the end of August on the back of reduced global demand and the current financial instability affecting global markets.

The current Brent forward curve is shown in Figure 8. It can be seen that prices are slightly backwardated in real terms along the curve, with delivery in 2013 trading around the $100/bbl level. This represents a slight decrease in the forward curve over the quarter broadly reflecting the recent falls in the prompt.

Figure 7: Oil Market Price Trends

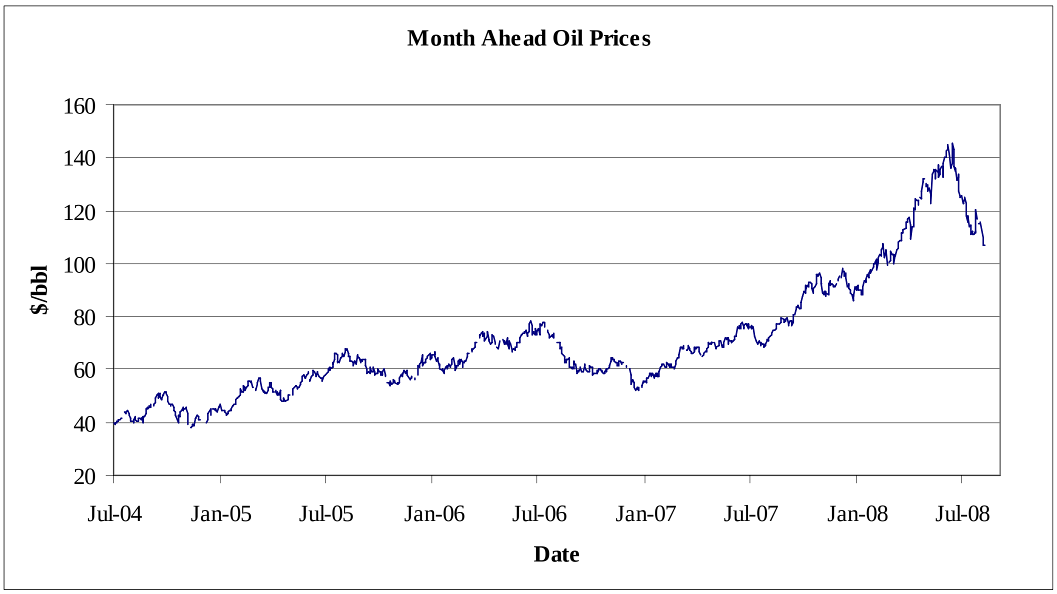
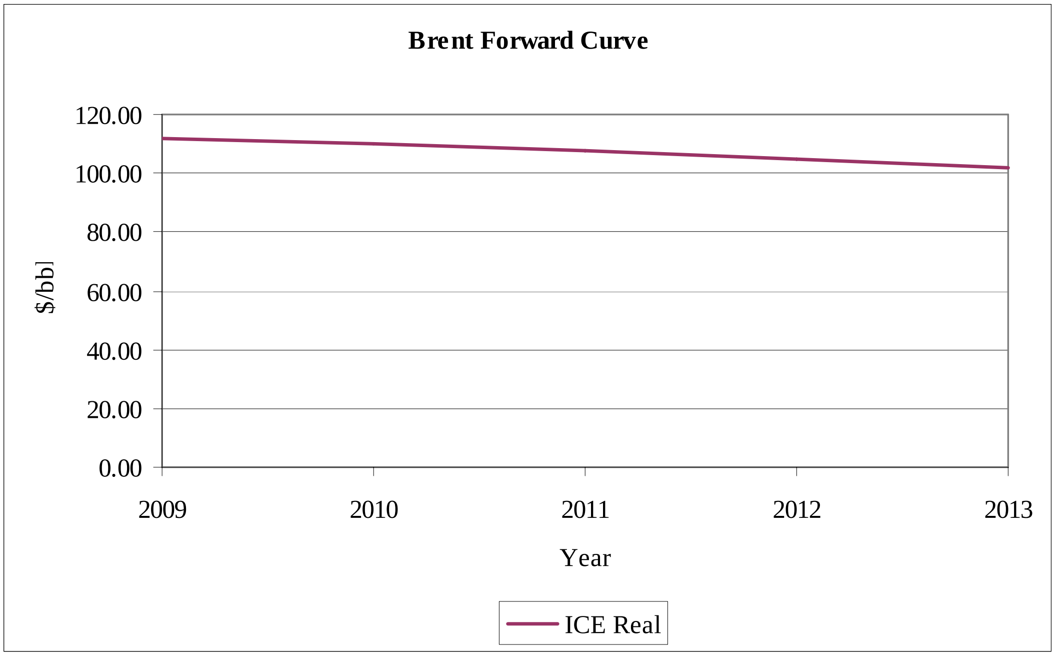


Figure 8: Oil Forward Curve (Real)[5]



4.2. External Oil Price Forecasts

IPA analysis of a number of external oil price forecasts is shown in Figure 9, including the IEA WEO[6], OPEC[7] and BERR and the latest US DOE Annual Energy Outlook 2008[8].

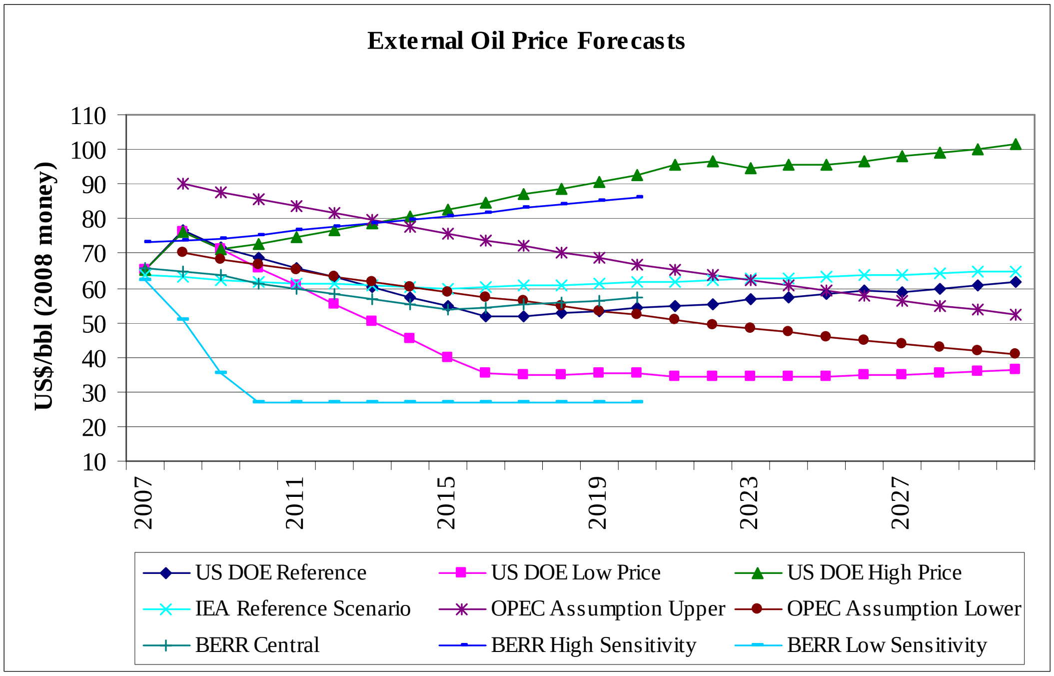
The differences in the forecasts reflect a wide range of assumptions including:

- Oil Demand: Driven both by economic growth and demand side policies to reduce consumption;
- Development of Production and Refining Capacity: Timing of capacity developments both within OPEC and other oil producing countries;
- Market and Economic Drivers: The level of market share of OPEC and the level of control they have on market prices, and the costs of oil production particularly for developments outside OPEC; and
- Worldwide Crude Oil Reserve.

Most of the external forecast scenarios have prices softening over the medium term and then increasing over the back-end of the forecast period. The US DOE AEO 2008 Reference Case and the BERR Reference Cases show oil prices in the $50-$60/bbl range over the medium term. The latest IEA WEO and AEO forecasts have long term prices around the $65/bbl. The OPEC scenarios are below the reference cases provided by the other institutions, with long term prices settling in the range $35-40/bbl.

[5] Source: Spectrometer 3rd September 2008
[6] World Energy Outlook 2007, International Energy Agency
[7] World Oil Outlook 2007, OPEC
[8] Annual Energy Outlook 2008, U.S. Department of Energy, March 2008

Figure 9: External Oil Price Forecasts



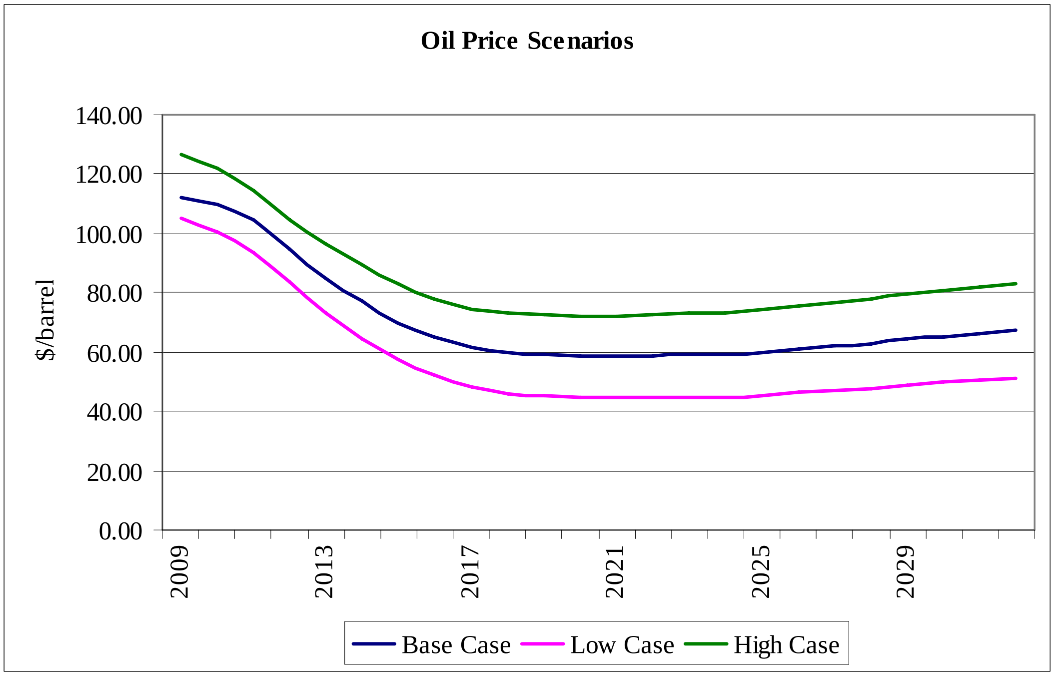
4.3. Oil Price Scenarios

The oil price scenarios used in this forecast are illustrated in Figure 10 below, with further details of the oil price forecast scenarios provided in the following sections.

The IPA Base Case reflects current market forward prices over the traded horizon and trends toward the forecast provided by the US DOE Annual Energy Outlook (2008) Reference Case over the medium to long term.

The High and Low oil price scenarios have been defined around the Base Case, reflecting a credible range of oil prices given observed market volatility, and reflecting the range of external oil price forecasts analysed.

Figure 10: Oil Price Forecast Scenarios



4.3.1. Base Case Scenario

While current levels of oil prices are seen as unsustainable in the longer term, there is no expectation that oil prices will fall significantly in the short term. Even though there has been a recent drop in global oil demand, it is still relatively high in historic terms –particularly from developing countries. With new production capacity also having not been developed as quickly as might have been expected given these recent high prices (largely because of significant increases in capital costs) there has been a squeeze on both supplies and inventory. Currently, Saudi Arabia (traditionally OPEC's swing producer) has been reported as producing at record or near record levels reflecting the lack of spare capacity in the market, thus leaving the short term market susceptible to price spikes. The demand for oil products is largely driven by expanding consumption of "light" products (petroleum, kerosene and diesel) compared to HFO and other residual oils. A lack of new refinery capacity capable of processing heavier crudes into the light fractions required by the market has pushed prices for the lighter crudes (which form the benchmark for the oil price indices) up strongly compared to many new sources of oil. In the longer term, investment in new sources of oil and additional refinery capacity is expected to place downward pressure on prices but this process will be relatively slow in coming.

In the Base Case, the average world crude oil price declines to 2018 as new supplies enter the market. However, it is now widely accepted that a return to $20-30/bbl price regime is unlikely and most institutions project long term prices in the region of $50-$60/bbl. This reflects rises in infrastructure costs, the need for higher prices to drive investment, an assumption of a relatively tight supply-demand balance and the fact that demand has proven considerably more resilient to higher prices than previously thought.

Prices are projected to increase over the second half of the forecast horizon, reflecting a number of different factors:

- Relatively tight supply situation;
- Continued strong worldwide economic growth despite high oil prices, (with growth particularly focused in Asia);
- Demand growth in part mitigated by technology development reducing energy intensity, as well as increasing penetration of alternative sources, bio-fuels and potentially coal-to-liquid projects;
- Considerable investment required in new facilities, reflecting declining production at existing fields;
- Continued market dominance of OPEC with a significant amount of the additional production capacity coming from OPEC countries, mainly in the Middle East, and thus a continued ability by OPEC to influence world prices through collective production and investment policies;
- Growing dependence upon exploiting more expensive resources, likely to include investment in resources in non-OPEC countries such as Brazil, Russia and the Caspian;
- Growth in supply of fuels from non-conventional sources such as oil sands;
- Higher costs of developing resources in areas where there is considerable political risk. Even in areas where foreign investment by international oil companies is permitted, the legal environment is often unreliable and complex and lacks clear and consistent rules of operation. For example, Venezuela is now attempting to change existing contracts in ways that may make oil company investments less attractive. In 2005, Russia announced a ban on majority foreign participation in many new natural resource projects and imposed high taxes on foreign oil companies (even the UK has changed its taxation regime in response to high oil prices);
- Higher costs and delays associated with developing resources in areas where there are security risks;
- Restrictions on International Oil Companies' access and contracting in some key resource-rich regions; and
- Shortages of contractors and equipment such as rigs, slowing the investment response to high oil prices.

4.3.2. Low and High Case Scenarios

The IPA High and Low scenarios have been developed to explore a reasonable range of oil prices over the forecast horizon. They have been developed to give a balanced view of the wide range of potential prices indicated by the assembled external forecasts. As such, the forecasts do not represent specific assumptions, but reflect a range of assumptions used by external providers in developing their scenarios. The main drivers for the range of prices are summarised below:

- Oil Demand: Driven both by economic growth and demand side policies to reduce consumption. A key difference between scenarios is the energy future that might emerge and the extent that governments pursue new policy measures, including promoting energy efficiency and switching away from fossil fuels, for environmental or energy security reasons.

- OPEC: Under all scenarios a significant amount of the additional production capacity required is expected to come from OPEC countries, mainly in the Middle East. Thus, OPEC's capital investment in the development and enlargement of production and refining capacity has a significant impact on oil price trajectories. The market dominance of OPEC under different scenarios has a significant impact on price, as does their ability to impose higher prices through collective production and investment policies.
- Non-OPEC Development of Production and Refining Capacity: The timing of capacity developments in non-OPEC oil producing countries, and the costs of development and production have a significant impact on price. Scenarios have different assumptions on the level of growth in market share of these countries, in part reflecting uncertainty over the investment environment and security concerns for international companies in many parts of the world. Scenarios have different estimates of marginal production costs outside OPEC, with variations of at least 30% between high and low scenarios.
- Worldwide Crude Oil Resource: Estimates of the worldwide crude oil (primarily undiscovered and inferred) also have a significant impact on oil prices over the longer term, with variations in resource of at least 30% between high and low scenarios.

4.4. Oil Products

There have historically been strong correlations between the price of crude and the price of oil products such as HFO and Gasoil. However, with increasing volatility in oil prices, there has been a degradation of the level of correlation between crude and oil products, at least in terms of spot prices. Analysis of market data suggests that these pricing effects, due both to high levels of crude volatility and supply-demand imbalances in oil products, are likely to be short term in nature, with market fundamentals re-establishing themselves over the longer term. Thus, the scenarios for oil products are based upon long term price correlations with crude. However, it is accepted that over the short term there may be significant volatility in the relationship between the prices of oil products and the price of crude. The forecasts for Gasoil and HFO prices, based upon the long term correlations with crude prices, are shown in Figure 11 and Figure 12.

Figure 11: Gasoil Price Scenarios

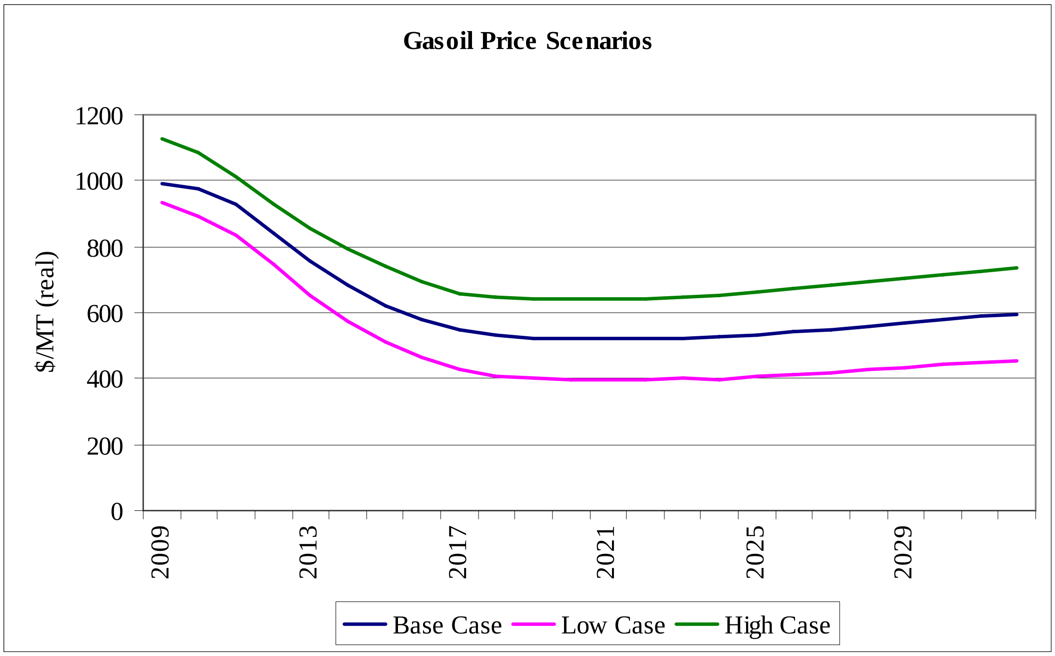
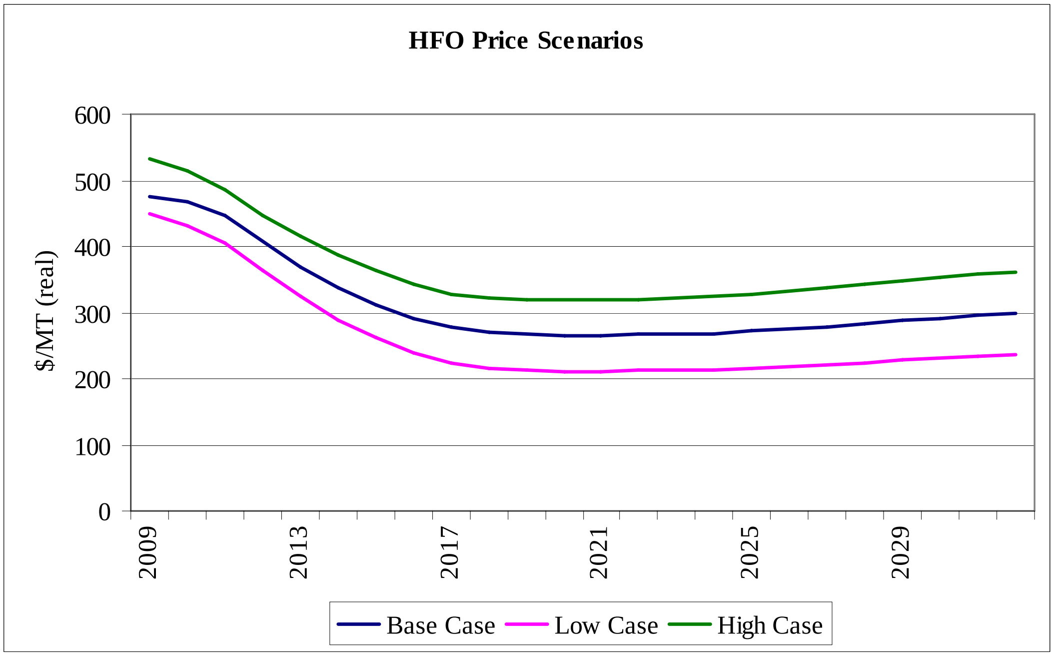


Figure 12: HFO Price Scenarios



5. GAS PRICE SCENARIOS

This section investigates recent gas prices, developments in gas supply and demand and describes the gas price scenarios over the forecast horizon.

5.1. Gas Market

The gas market has seen significant movement over the last three months. There has been upwards movement in the front winter contract, and along the curve, following the oil market's upwards trend. As was stated in the July edition of PowerView, the rise in the gas contract has outstripped the BAFA oil indexed price, indicating a significant risk premium has been added on fears over supplies – especially LNG deliveries – that saw NBP at a premium to the BAFA price. Brent Oil prices reached a peak at around $146/bbl at the start of July 08 and have seen a considerable fall since then, falling to $89/bbl by mid-September, though have seen something of a rebound since then partly as a result of the turbulence in the financial markets. An additional factor is the changing exchange rate, with sterling falling by 10% against the dollar meaning that the oil price has fallen from £73/bbl in July 08 to £50/bbl in September 08.

Over the first half of the quarter, the front winter NBP contract reflected this decline in prices, dropping to 90p/th by mid August. However, on-going problems at the Kvitebjorn field in Norway caused a sudden price increase and have only recently begun to recede.

Norwegian production is set up to firstly meet Continental European demands, based on long standing oil-indexed contracts, and then any excess gas is exported to the UK. This means that any shortfall in production is likely to fall disproportionately on the UK, lowering potential UK gas imports. There is debate, however, about whether such a lowering of production from Norway should have produced such a dramatic impact on UK prices, though concerns about how the UK would cope in a cold winter, with potentially lower imports, has increased the risk premium attached to the current winter and also fed into the curve.

There is an assumption that very little gas will be imported through the Milford Haven LNG facilities. Asian prices are estimated at around 100p/th and UK prices would need to exceed this to see cargoes heading to the UK. The Asian price is also indexed to oil and tends to be more expensive than comparable European prices and with Japanese demand still strong due to on-going maintenance problems at nuclear plants and continued strong Chinese demand for LNG, there appears a constraint in the global LNG supply/demand picture. This also poses a question mark over future LNG deliveries and these fears have had a bullish impact on the gas curve.

These developments have seen the spread between NBP and BAFA increase from 7p/th to 20p/th over the last quarter. These supply problems have greater impact in the winter months rather than the summer and there has been an increase in the summer winter spread from 8p/th to 15p/th for the front winter gradually falling towards 10p/th by the middle of the next decade.

Storage levels, as shown in Figure 14, are currently at normal seasonal levels.

The LCPD limitations that came into force in January 2008 have continued to give a boost to gas demand from power stations (as shown in Section 3), although this is mitigated by rising gas prices.

The UK gas curve is backwardated with prices in 2014 trading at around 13p/th lower than 2009 prices. This backwardation reflects both the likelihood of greater Norwegian flows once this winter's problems have been overcome and higher Ormen Lange flows, potentially greater LNG flows when Japanese power problems have been overcome and a backwardated oil curve and hence a backwardated BAFA curve.

Figure 13: Gas and Oil Spot Price Trends

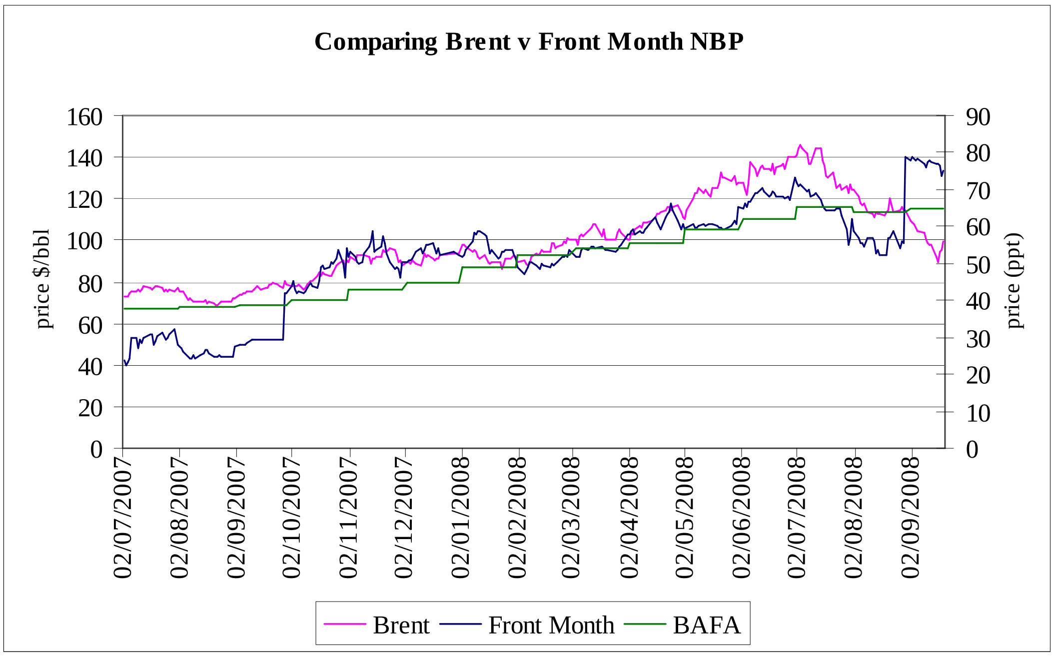


Figure 14: Historic Rough Storage Levels

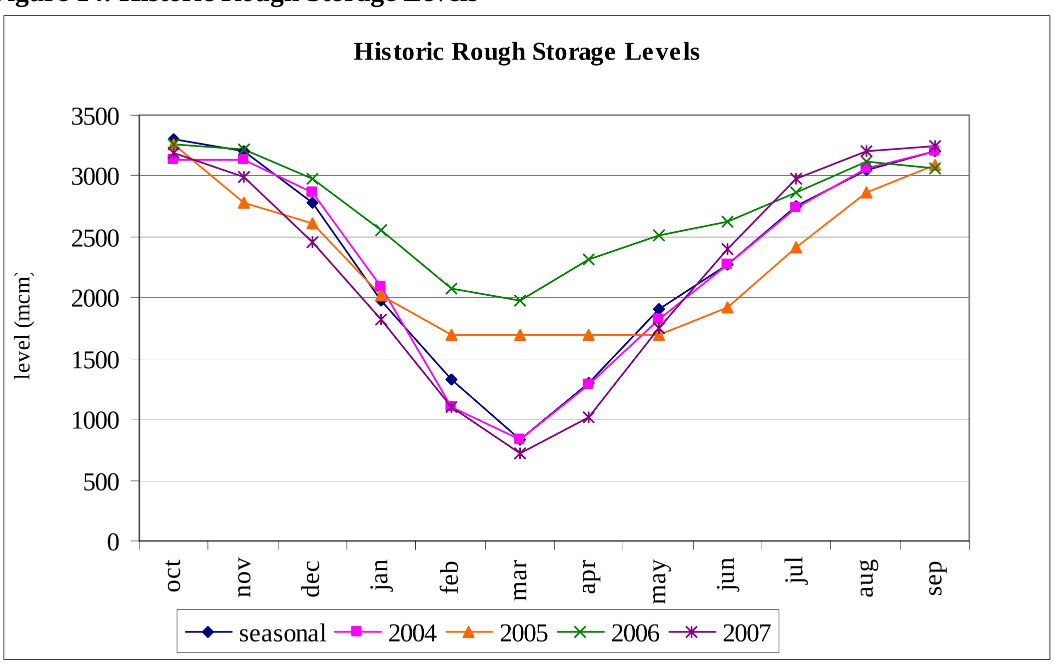


Figure 15: Gas Forward Market Prices[9]

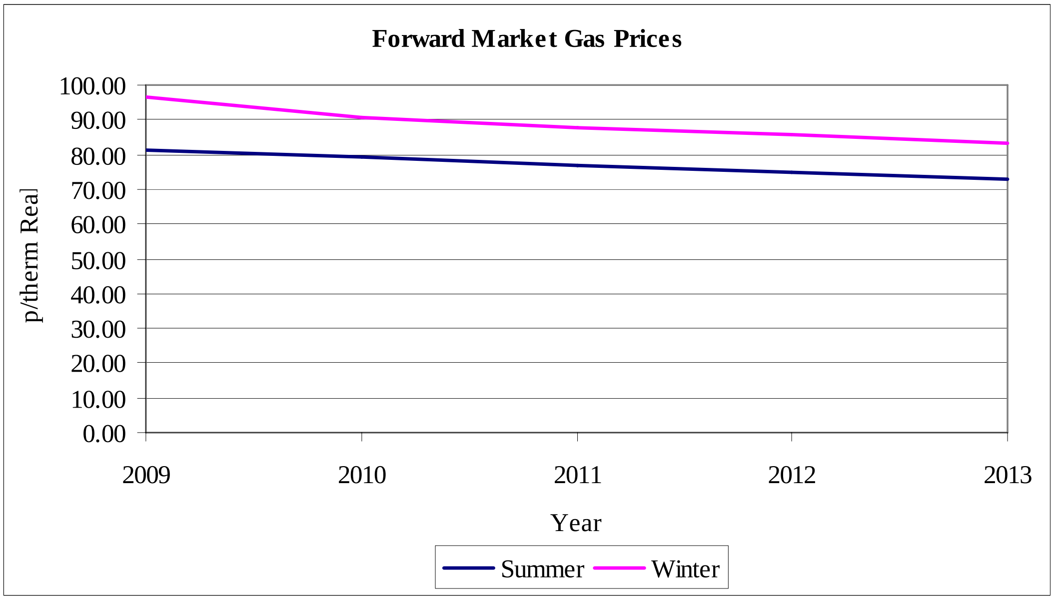


Table 2: Forward Gas Market Prices (real 2008 money)[10]

	Annual	Summer	Winter
2009	88.73	81.06	96.40
2010	84.91	79.31	90.50
2011	82.29	77.07	87.51
2012	80.31	75.06	85.56
2013	78.18	73.02	83.35
2014	76.20	71.03	81.37

5.2. Gas Demand

Gas demand is based on forecasts provided by National Grid[11]. The demand forecast is shown in Figure 16 and Figure 17 and discussed below:

- LDZ demand (i.e. that taken off from a local distribution zone, essentially domestic heating and small scale industrial and commercial users) to grow at approximately 2% per annum over the medium term. However, over the second half of the forecast horizon LDZ demand growth will slow as there is increasing focus on energy conservation measures;
- Industrial demand is forecast to grow by approximately 30% over the forecast period (~1% per annum);
- Exports to Ireland are likely to reduce as developments on the Irish Continental Shelf (especially the Corrib field) commission from 2009 onwards. IUK flows are

[9] Spectrometer, 3rd September 2008
[10] Spectrometer, 3rd September 2008
[11] Transporting Britain's Energy 2008, National Grid

forecast much lower than before due to lower assumptions of LNG deliveries in the UK and an increase in the price premium for NBP with respect to the BAFA price.

- Over the period to 2012 gas burn in the power sector is predicted to reduce as forward coal prices reduce more rapidly than gas prices, making coal running more economic; and
- Overall, NTS gas demand will increase throughout the forecast horizon, with the key driver being the increase in power station burn as new plant is commissioned.

Figure 16: NTS Demand Growth

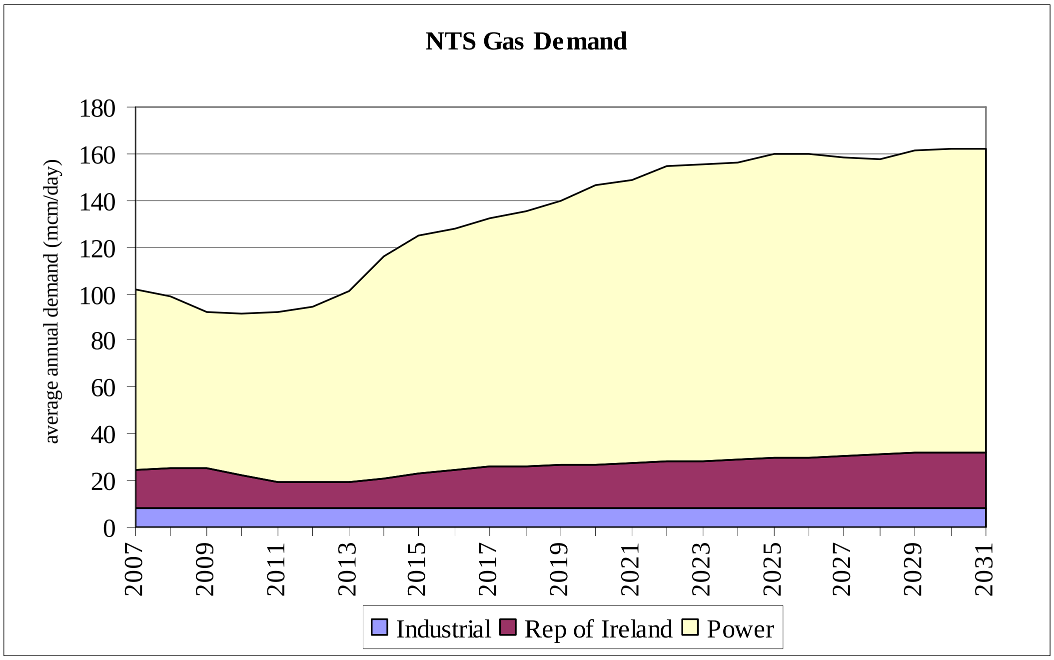
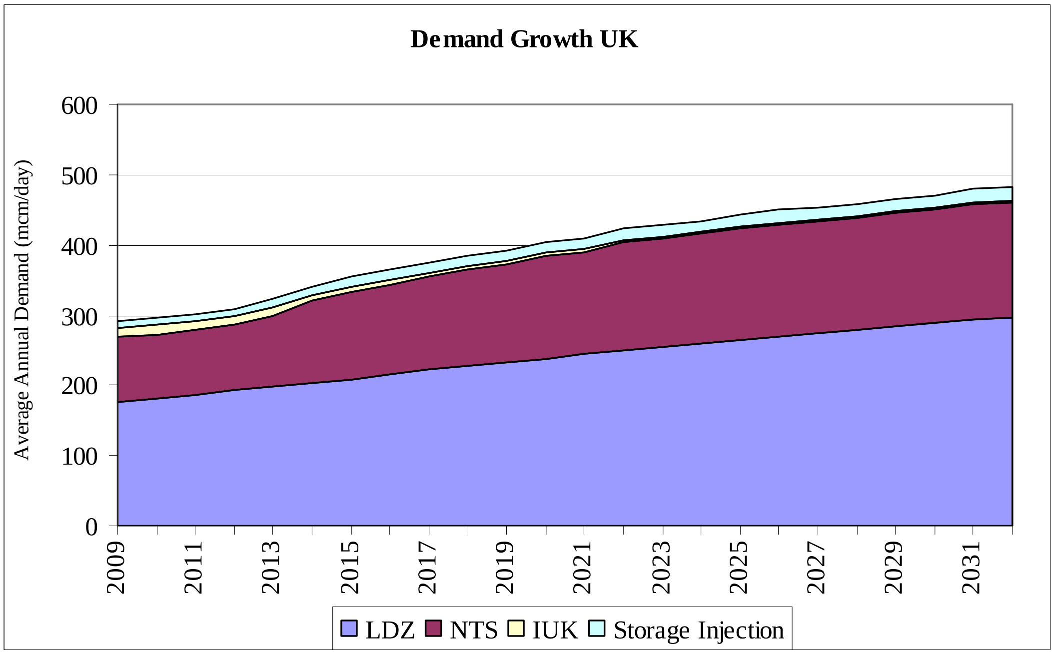


Figure 17: Total UK Demand Growth



5.3. Supply

The supply of gas into the UK is characterised by declining production from UKCS. In its place, gas will be sourced from pipelines from Norway and continental Europe and from new and expanded LNG regasification facilities as well as an increase in storage facilities.

National Grid's Transporting Britain's Energy 2008 document suggests some factors which may slow the rate of decline of UK Continental Shelf (UKCS) gas supply:

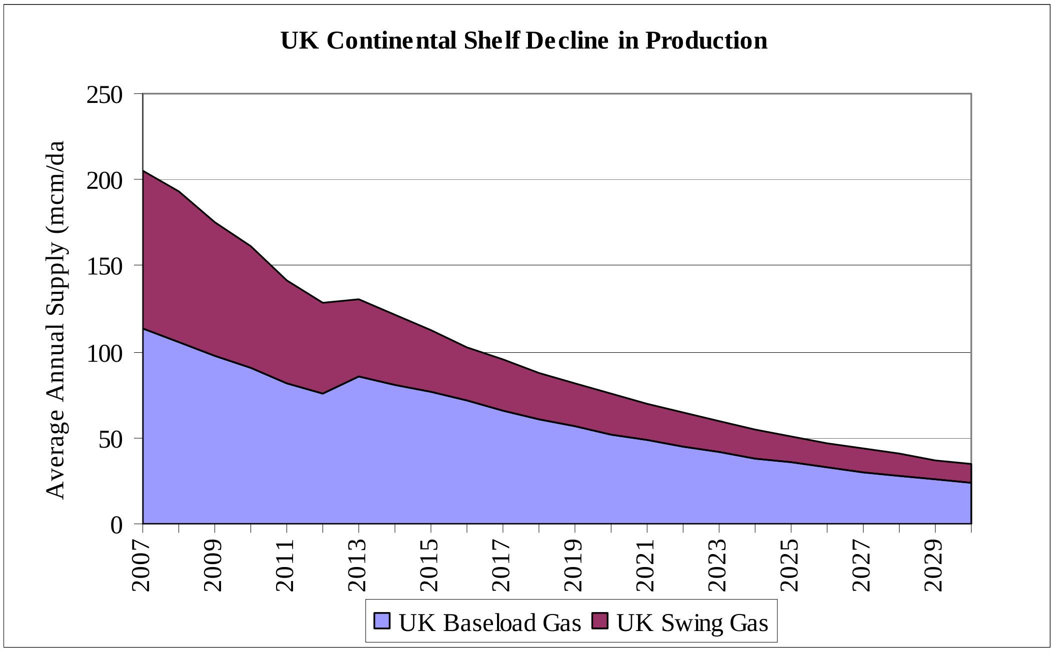
- Higher prices feeding into life extensions of existing fields, including the greater potential for exploiting West of Shetland gas which is assumed to come onstream in 2013; and
- Fields being used more sparingly, especially with Morecambe Bay fields being used more as peak fields last winter, which has helped prolong the expected lifespan of UKCS fields.

Supply is divided into the following categories: UKCS production (comprised of UK baseload and UK swing gas), imported gas (comprising Norwegian imports, continental imports and LNG imports), and storage.

5.3.1. UKCS Production

UK Continental Shelf (UKCS) production reached its peak in the years 2000 to 2003 at over 300mcm/day on average. Since then, production has declined and this is expected to continue by around 10% per annum (Figure 18) in the Base Case. The expected development in the West of Shetland area in 2013 results in a temporary halt to this decline.

Figure 18: Decline in UKCS Production[12]



UK Continental Shelf production is split into two main components:

- **UK Baseload** is defined as flows into the UK terminals of St Fergus (without Vesterled), Teesside and Bacton SEAL. These fields are located in the Central and Northern North Sea. They largely represent associated gas fields, i.e. gas that is essentially a by-product of oil or liquids production. As such, we can assume these fields must-run whatever the gas price.[13]
- **UK Swing Production** is defined as flows into the UK terminals of Barrow, Burton Point, Easington (not Langeled), Theddlethorpe and Bacton (not SEAL or IUK). These fields, which tend to be located in the Irish Sea or Southern North Sea, are predominately “dry” gas fields and flow gas to maximise revenue rather than being dependent upon oil output. Some of these fields, which have been flowing since the 1960’s, are depleting at a more rapid rate, as they approach the end of their production lifespan, although many are used more sparingly to meet peak demand prolonging their lifespan.

5.3.2. Gas Pipeline Imports

With the decline in UKCS production, import dependency is expected to reach around 70% by 2015, as shown in Figure 19. As import dependency is projected to increase, so is import capacity, with developments in pipeline and LNG infrastructure as shown in Figure 20.

[12] Transporting Britain’s Energy 2008, National Grid
[13] There are a couple of anomalies to this with Nuggets as a dry gas field, and reinjection of gas to aid oil extraction, but the principle remains the same.

Figure 19: Import Dependency

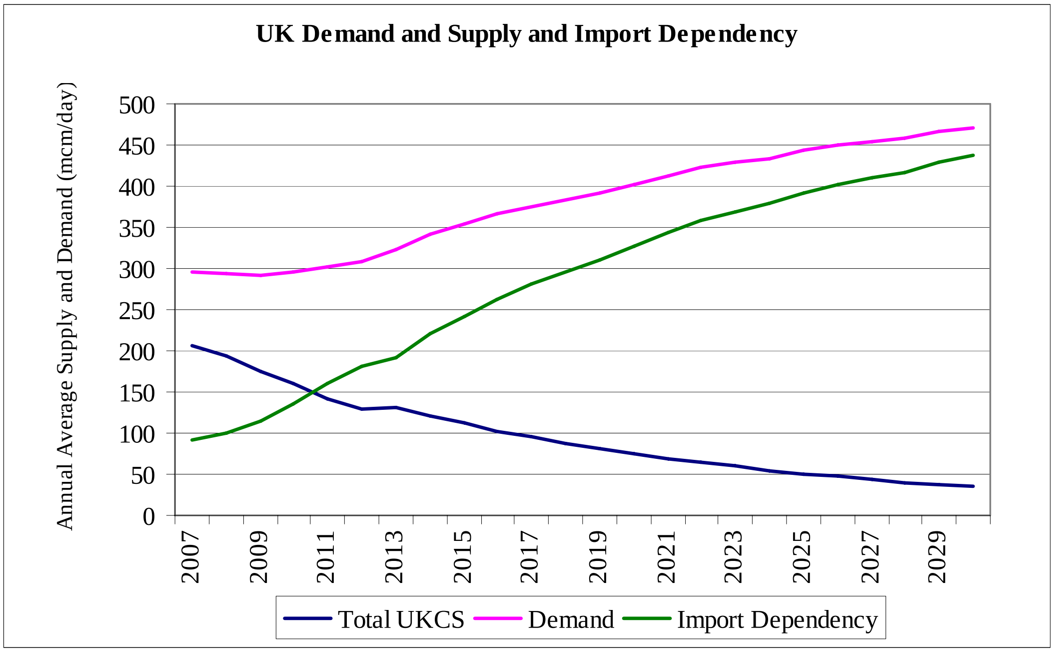
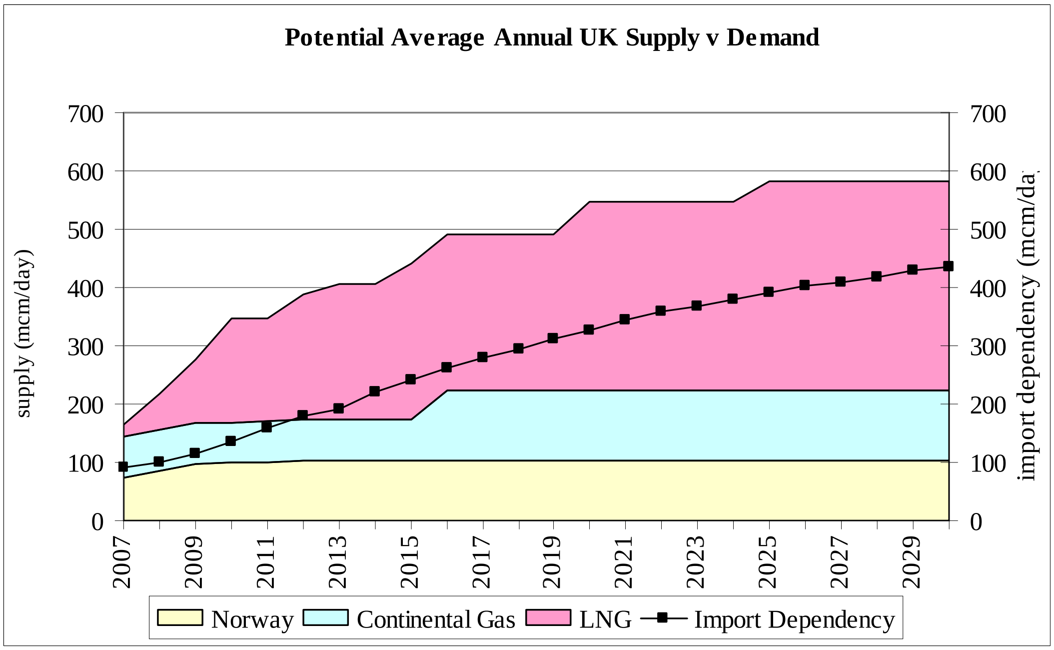


Figure 20: Import Capacity expanding greater than Dependency



New pipeline projects are shown in Table 3.

Norwegian flows are expected to steadily increase over the next couple of years. Flows from Ormen Lange will gradually increase and there will be extra flows via the Tampen link. The problems at Kvitebjorn are likely to limit the increases for winter 2008, but flows should increase beyond that with Norway becoming the most important exporter of gas for the UK.

Ormen Lange is increasing production and 2009 is likely to see maximum production increase to 90 mcm/day compared to an average of 60 mcm/d in winter 2007. Capacity constraints at Easington may limit the amount of gas imported from Norway.

The Tampen Link which became operational in October 2007 has seen around 10 mcm of extra gas arrive at the St Fergus terminal from Norway.

It is assumed that the North Europe pipeline from Russia is commissioned around 2016, with the potential for additional UK/continental pipeline interconnection. This will present an opportunity to increase supplies to the UK and make-up any shortfall in gas due to declining Netherlands production, which will maintain IUK and BBL flows. It is also assumed that current flow levels from Europe will continue (including the shaping of gas over the winter i.e. flows at half capacity in the front half of the winter, increasing to full capacity by the end of the winter – reflecting storage concerns on the European continent).

Norwegian gas supplies should be maintained over the forecast period. Even though oil fields will decline in production as they mature, this will free up gas currently injected into these fields to maintain oil production for export. It is also assumed that Russian gas will make up for any decline in Netherlands production in Europe, maintaining IUK and BBL flows.

Table 3: New pipeline projects[14]

Import project	Developer	Location	Size (pa)	IPA assumed completion date
Russian pipeline			20bcm	2016

5.3.3. LNG Imports

One of the major developments of last winter, and continuing into this winter, has been the diversion of LNG cargoes away from the UK which have occurred even when NBP prices exceeded Henry Hub prices. The LNG that was due to head to the UK has instead gone to the Far East, a situation that is likely to continue into winter 08/09, as problems with nuclear stations in Japan are likely to persist until then, creating extra demand for power station gas burn and LNG imports.

As a result, a greater risk premium is expected along the curve to reflect the lower probability of LNG arriving. Additionally, as LNG becomes one of the marginal supplies to the UK, the UK may be forced to pay the highest world price and not just Henry Hub prices. In terms of economics, the highest costs in the LNG chain are the liquefaction capacity, followed by the cost of shipping (including the ship itself), followed by the cost of regasification. This means that there is a surplus of regasification capacity to create optionality over deliveries. How long the Asian markets will dictate global LNG prices is a question of debate. It is likely to continue for the forthcoming winters, certainly until the problems at Japanese nuclear facilities continue, but as the LNG global market increases, it is increasingly likely that Henry Hub will begin to dominate global prices. This is assumed to happen by the middle of the next decade. Also, Asian

[14] Ten Year Statement 2007 and IPA Analysis

prices tend to be indexed to oil prices, but charging a premium compared to BAFA, which suggests that any expected real decrease in the price of oil will produce a lower Asian price.

Most of the LNG that has entered the UK is via the Isle of Grain facilities. The Excelerate project became live in January 2007 but has delivered little gas. The Milford Haven developments of Dragon and South Hook (Phase I) have added around 45 mcm/d of extra capacity but have yet to commission any gas, indicating no immediate deliveries from these terminals.

On aggregate, import capacity is expanding at a greater rate than the UKCS supply/demand gap. National Grid's Ten Year Statement (2007) notes that taking existing infrastructure (including current storage), UKCS, and all new developments, peak capacity could exceed demand by 1bcm post 2010, more than double the peak day demand. It is possible that the merit order of these sources of supply may change in the future depending on differing price drivers – not least with seasonality in the Henry Hub price.

It is assumed that any new import capacity developments required beyond 2015, other than the Russian pipeline discussed in Section 5.3.2, will be LNG import facilities[15].

In line with the current NGT Ten Year Statement, generic LNG facilities have been used instead of making an assumption on the probabilities of planned projects coming to fruition. The deliverability of these projects is consistent with the NGT forecasts.

Table 4: New LNG projects

Import project	Developer	Location	Size (pa)	IPA assumed completion date
South Hook LNG (Phase 1)	Qatar Petroleum/ Exxon Mobil	Milford Haven	10.5bcm/a	2008
Dragon LNG	Petroplus/ BG/Petronas	Milford Haven	8bcm/a	2008
Isle of Grain (Phase 2)	National Grid	Isle of Grain	Additional 9bcm/a	2008
South Hook LNG (Phase 2)	Qatar Petroleum/ Exxon Mobil	Milford Haven	10.5bcm/a	2009
Isle of Grain (Phase 3)	National Grid	Isle of Grain	Additional 7bcm/a	2010
Generic LNG			15 bcm/a	2014
Generic LNG			15bcm/a	2020
Generic LNG			15bcm/a	2025

5.3.4. Storage

As well as new import infrastructure there will be an increase in storage infrastructure in the UK. In line with the generic storage assumptions in NGT's

[15] Note that three extra LNG facilities are added. From forecast prices these appear economic and, as the import dependency widens, there will be extra requirement for further developments. The same rationale applies to the building of a new continental pipeline to be built after the completion of the Russian North European pipeline.

10 Year Statement, a further generic storage facility has been added for 2014 as can be seen in Table 5 and three more spaced at equal intervals beyond that reflecting a willingness from some major players, most notably EDF and Centrica, to build new storage facilities. One consequence of the greater probability of LNG diversions is that there is a greater importance placed on storage facilities and this too adds to the greater likelihood of more facilities being built in the future, although storage facilities still require deliveries to be filled in the summer. Aldbrough is currently being commissioned and is filling up with gas, so should have some operational deliverability for winter 2008.

These are likely to be Medium Range Storage facilities, rather than seasonal storage as offered by the Rough storage facility. These new storage facilities will add a level of insurance to supply in the UK and should reduce volatility in the gas markets. These developments may also marginally increase demand (for injection) over the summer, which leads to a slight reduction in the Summer-Winter spread.

Table 5: New Storage Facilities[16]

Name	Developer	Location	Date	Additional Capacity (mcm)
Aldbrough	SSE/statoil	Aldbrough	2008	420
Holford	E.ON	Byley	2010	165
Stublach	Ineos Chlor	Cheshire	2012	550
Saltfleetby	Wingas	Lincolnshire	2012	700
GDF			2013	400
Generic			2014	1000
Generic			2020	1000
Generic			2025	1000
Generic			2030	1000

5.4. Supply/Demand Balance

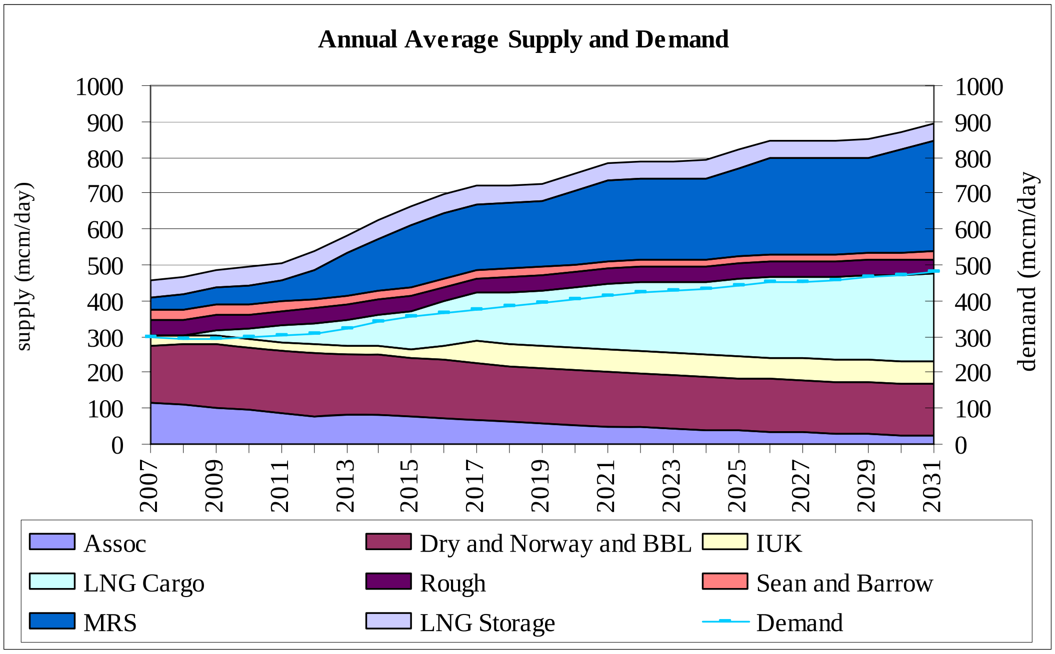
The new infrastructure developments should provide potential for a more comfortable supply and demand balance in the forthcoming years, though this might be brought about by UK prices being competitive (i.e. high) and competing against Asian developments, with prices being high enough to draw in LNG cargoes. In the nearest winters, there is sufficient gas available from other sources to cover a normal winter. A cold winter would be more problematic and might see the need for LNG deliveries to cover any storage shortfall. By the next decade, it is likely that even a seasonal normal winter will require LNG deliveries. With fewer LNG deliveries expected then there is likely to be little oversupply in summer and hence a fall in exports.

The ratio of January demand to maximum possible supply becomes harder to assess, although it is expected to fall until around 2015, reflecting a potentially more comfortable supply/demand balance, and then steadily picking up towards the back end of the forecast period. However, this is dependent on adequate LNG deliveries and hence the supply curve becomes increasingly price dependent. The extra storage facilities reduce the ratio, but with these medium range storage facilities, then they have much lower load factors than the baseload UKCS supplies that are currently being received.

[16] Transporting British Energy 2008, National Grid

Gas from the UK North Sea (with the UK being the only destination) has a higher load factor than those provided by LNG, Continental pipelines or storage facilities. Winter load factors for UKCS gas are currently around 90% whereas load factors for LNG facilities are likely to be lower (assumed to be around 75% in winter). Global load factors for LNG are around 50% over the year[17] and the NW European LNG load factor was around 70% for January 2007. The Isle of Grain facility had a load factor of around 85% in winter 2006 was nearer to 20% in winter 2007 and is likely to be closer to 0% in winter 2008.

Figure 21: Annual UK Supply and Demand[18]



[17] GTS Presentation, Transporting Britain's Energy 2007 Seminar

[18] Note that although LNG cargoes are placed above IUK in the illustration, this depends on their relative prices. It is likely that seasonal shape in Henry Hub prices will see similar prices to the BAFA prices and they will share the same place within the stack.

Figure 22: January Supply and Demand

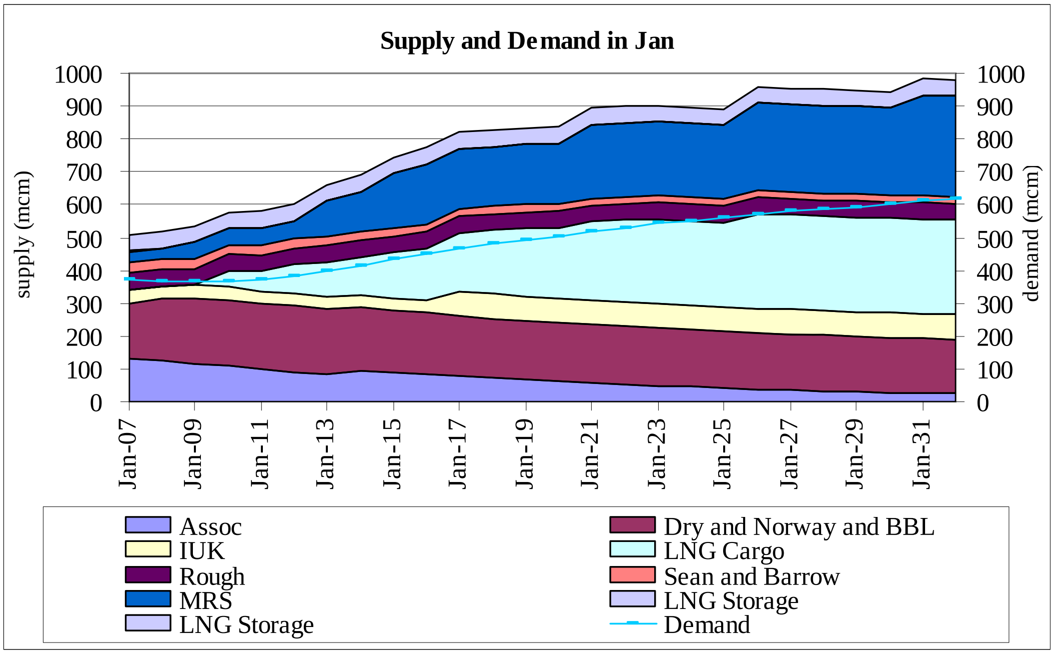
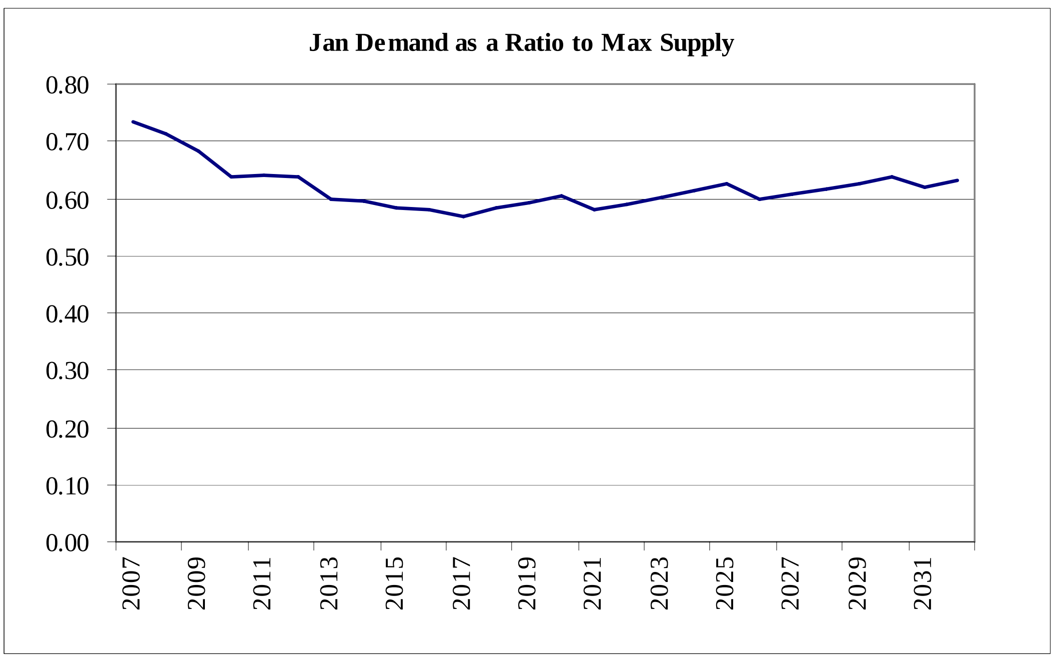


Figure 23: January Demand as a Ratio of Maximum Possible Supply



5.5. Oil Price Linkages

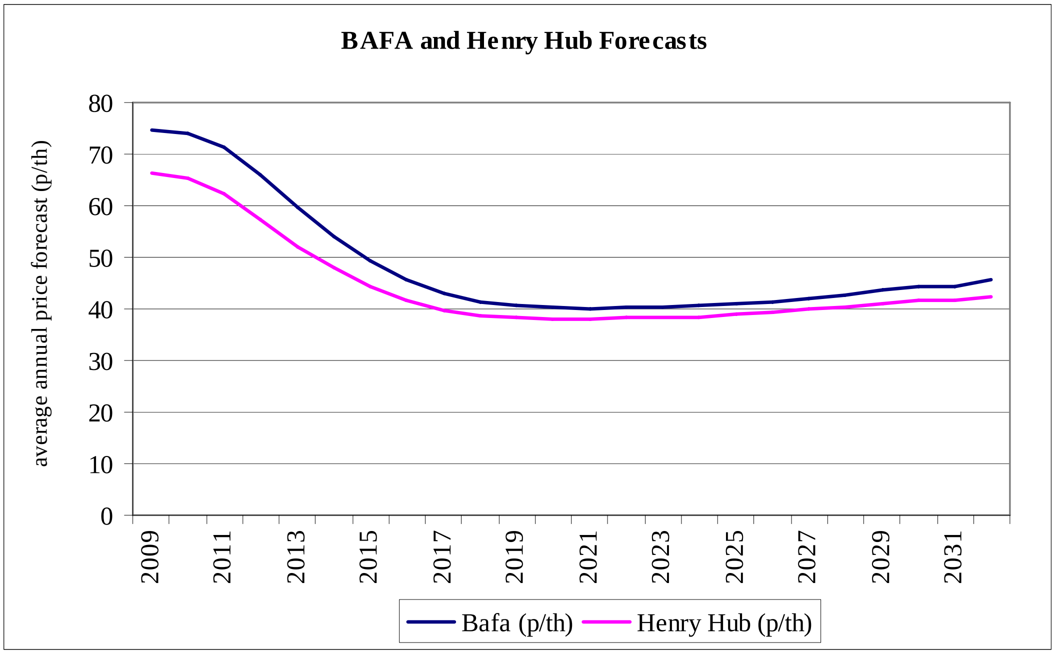
A major consideration in constructing the gas price forecast is the extent to which European prices will remain indexed to oil products (European gas prices are typically indexed to gasoil and heating oil, lagged by 6 or 9 months). There are pressures from the European Commission to develop more liberalised gas market structures, and there has been limited progress in developing trading hubs in Europe. However, long term gas contracts remain oil indexed and there is some evidence to suggest that more recent contracts - for instance some LNG supply contracts - are following this indexation model. It is interesting to note that even in liberalised gas markets such as the USA (Henry Hub) there have been relatively strong medium term correlations with oil price, although short term correlations are clearly much weaker than in European markets. Thus, it seems reasonable to assume that oil indexation will continue to drive European gas pricing, at least in the medium term. In the longer term, even if there is a growth in market based pricing of gas in Europe, it would not be surprising if these markets still exhibited longer term correlations with oil for a number of reasons:

- It is likely that there will be a number of long term gas supply contracts that are oil indexed over the forecast horizon;
- The capability of consumers to fuel switch at least in the medium term, will tend to drive correlations between fuels;
- LNG provides a link between pricing at Henry Hub and the European gas markets; Henry Hub has historically shown relatively strong medium term correlations with oil (due to the fact that the fuels have similar markets and there exists the potential for fuel switching); and
- Upstream gas supply is relatively mature, with a number of major players controlling a significant number of upstream assets (indeed, there has been some recent consolidation between Norsk Hydro and Statoil), it is therefore unlikely that a new counterparty will emerge who could introduce a different pricing methodology into gas supply.

This analysis suggests that it does not seem unreasonable to assume that European gas prices are likely to remain correlated with oil products at least in the medium term, and this is the assumption that has been used in the gas price scenarios across the forecast horizon.

The IPA oil price forecasts are presented and discussed in Section 4. The forecasts for the BAFA price (the average German Border price which is used here as a benchmark for European gas prices) and Henry Hub prices are shown in Figure 24. It is assumed that European prices will maintain a strong oil price linkage, and so the projected decline in oil prices over the medium term will feed through to both European and Henry Hub prices.

Figure 24: Henry Hub and BAFA Forecasts



5.6. Base Case Price Forecast

The Base Case gas price forecast is shown in Figure 25 and Figure 26 which shows a comparison of NBP and BAFA prices and highlights NBP seasonal price spreads.

The overall picture is of a steady decline in prices from the current levels of 85p/th down to a level of 40p/th by 2018, with prices gradually converging on the BAFA price. The main driver of this price is the real decline in oil prices, but it also reflects a healthier supply position. As the global LNG market increases in volume and liquidity it is assumed that Henry Hub will gradually become the benchmark price and, as this price is lower than the oil indexed Asian price, this should help the UK attract LNG deliveries. Prices then increase in the back half of the forecast ending over 50p/th reflecting higher real oil prices and a tightening supply/demand position.

The most significant change compared to the July edition of PowerView is an increase in prices in the front half of the forecast period. Prices are higher both in terms of absolute values compared to the last forecast and also higher with respect to BAFA prices meaning the spread between NBP and BAFA prices has increased. In the previous forecast, there was a convergence between NBP and BAFA prices by 2015, whereas the current forecast still has a spread of 7p/th between the contracts by this date and maintains a premium over BAFA throughout the curve, with the lowest spread being 1.5p/th in 2018. These increases are due to concerns over LNG deliveries into the UK. Although Phase I of the Milford Haven LNG projects have now been completed and have a theoretical deliverability of around 45 mcm/d, there is little supply expected from them for Winter 2008.

These concerns have had an effect on the rest of the curve. In the front winters, there is sufficient gas especially with increased Norwegian supplies to cover the decline in the UKCS. There is a significant risk premium priced in however, with a seasonal normal or mild winter likely to see prices at or below the BAFA price. A cold winter, on the other hand, would see large levels of storage withdrawals, which would have a bullish impact on price and probably mean that the UK would have to be at a price sufficient to attract LNG deliveries, and, as the Asian oil indexed prices look close to 100p/th, then this means there is considerable upside to prices. As such, the expected price has a significant premium over the BAFA price.

Heading into the next decade, LNG deliveries are likely to increasingly form the marginal therm, and UK prices are increasingly likely to follow global LNG prices. Although long term these are more likely based on the US Henry Hub price, in the shorter term the Asian oil indexed price is likely to dominate and this currently trades at a premium to both the BAFA and Henry Hub prices, and has dragged the UK price up as a result. Again, it is the threat of paying the highest global price that has created the risk premium, where the upside is greater than the downside, with BAFA prices acting as something of a floor to prices.

The exponential nature of prices exacerbates the upside/downside risk to price too, further adding to the risk premium.

Heading into the second half of the forecast, there is a steady increase in price – increasing from 40p/th in the middle of the next decade to over 50p/th by the end of the forecast period. The increasing reliance on imports will see the UK begin to trade at a premium to both BAFA and the Henry Hub price. This is down to a steady tightening of the supply/demand position as it is more likely that there will be greater usage and load factor on available LNG facilities than new facilities built (although there is an assumption that new facilities will be built, demand growth and UKCS decline are likely to outstrip these developments). There will also be greater convergence to the Henry Hub price as LNG begins to dominate the supply stack compared to the importance of European imports at present.

The fall in prices is also reflected in a fall in the summer-winter spread. As noted earlier, the bullishness in prices is more down to concerns over winter supplies than summer, and as these ease we should see the spread fall from the current level of 15p/th down to 7p/th by the middle of the next decade. Again, as prices pick up towards the end of the forecast period, the seasonal spread picks up to 8.5p/th reflecting the tighter supply/demand position. Additional downwards pressure is exerted on seasonal spreads as the UK price begins to converge on BAFA and Henry Hub prices as both curves exhibit lower seasonality than the NBP at present so that even though the supply/demand position is similar to current levels, the greater correlation to Henry Hub and BAFA means that the spread is narrower. Another effect is that larger storage capacities help smooth out seasonal spreads with greater demand in summer for injection and greater supply in winter.

Figure 25: NBP Price Forecast

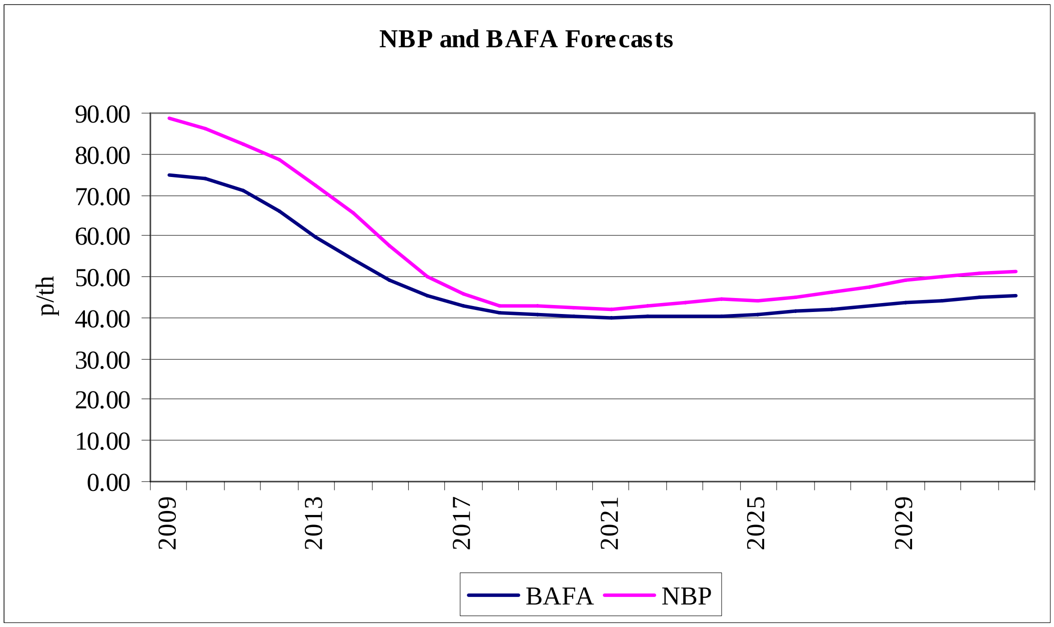
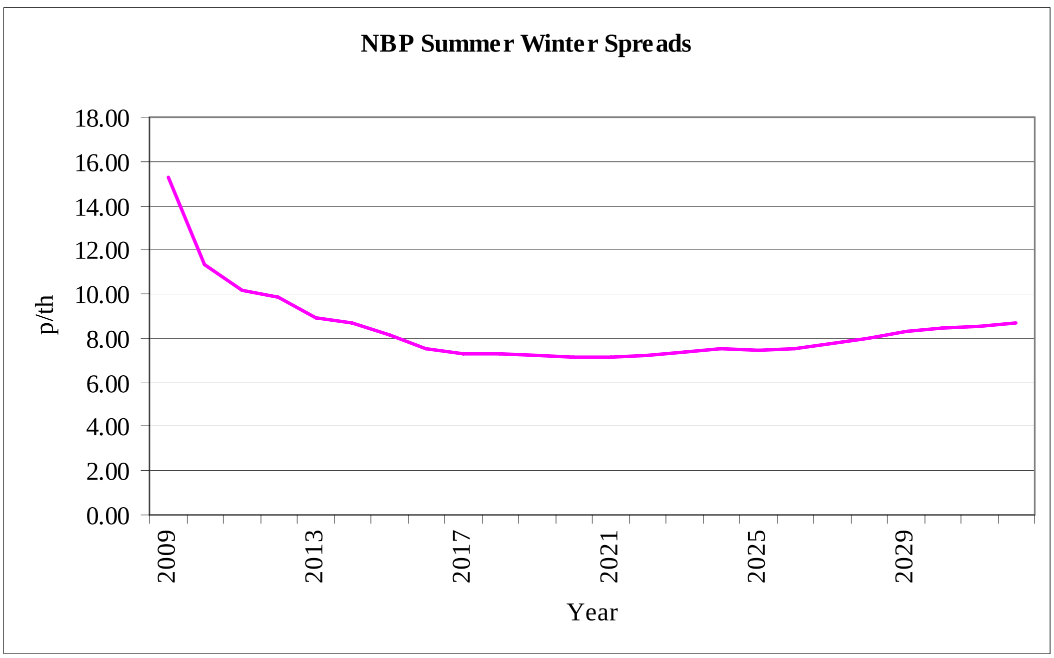


Figure 26: NBP Summer-Winter Spread



5.7. Gas Price Scenarios

The High and Low gas price scenarios use different assumptions from the Base Case as described below:

- Differing oil price assumptions;
- Different assumptions in terms of the UKCS peak beach supplies. Supplies are assumed to be higher in the Low Case and lower in the High Case, as illustrated in Figure 27.
- Different assumptions on the different categories of demand growth. The assumptions for CCGT gas burn are consistent with the power price scenarios.

The gas price scenarios are shown in Figure 28, and are discussed below;

- All three scenarios show a similar price profile, with high prices in the early years dropping off until the middle of the next decade and then increasing slightly thereafter. The strength of this rebound is greatest for the High Case and lowest for the Low Case;
- Commissioning of new import and storage capacity ensures a growing supply margin to 2010, tending to put downward pressure on prices. However, in the High Case more rapid declines in UKCS production means the supply margin is less generous than in other scenarios, although this is offset somewhat by the potential for higher LNG deliveries than assumed in the Base Case;
- Increasing dependence on oil-indexed imports means that softening oil prices to 2020 put downward pressure on NBP;
- Beyond 2020, growth in demand is likely to outstrip increases in supply, leading to a gradual tightening of the supply/demand balance, particularly in the High Case;
- Increasing dependence on LNG imports will lead to increasing convergence with Henry Hub rather than BAFA, and put upward pressure on NBP prices. The forecast shows NBP trading at a premium to BAFA across the forecast period in the High Case, though narrowing from a 23p/th premium to a 5p/th premium by 2018. The Base Case converges almost to the BAFA price by 2018, and re-establishing a premium beyond that, whereas the Low Case prices converge to the BAFA price by 2016 with only a small premium to the BAFA price for the rest of the forecast period;
- Compared to the July-08 edition of PowerView, both the premium to BAFA are greater and the time of convergence to the BAFA price is slower, reflecting concerns over the availability of LNG deliveries and also an impact of Asian oil indexation on the price of LNG; and
- Increasing oil prices over the second half of the forecast result in increases in both BAFA and Henry Hub prices, and puts upward pressure on NBP in all scenarios.

Figure 27: UKCS Gas Production Decline

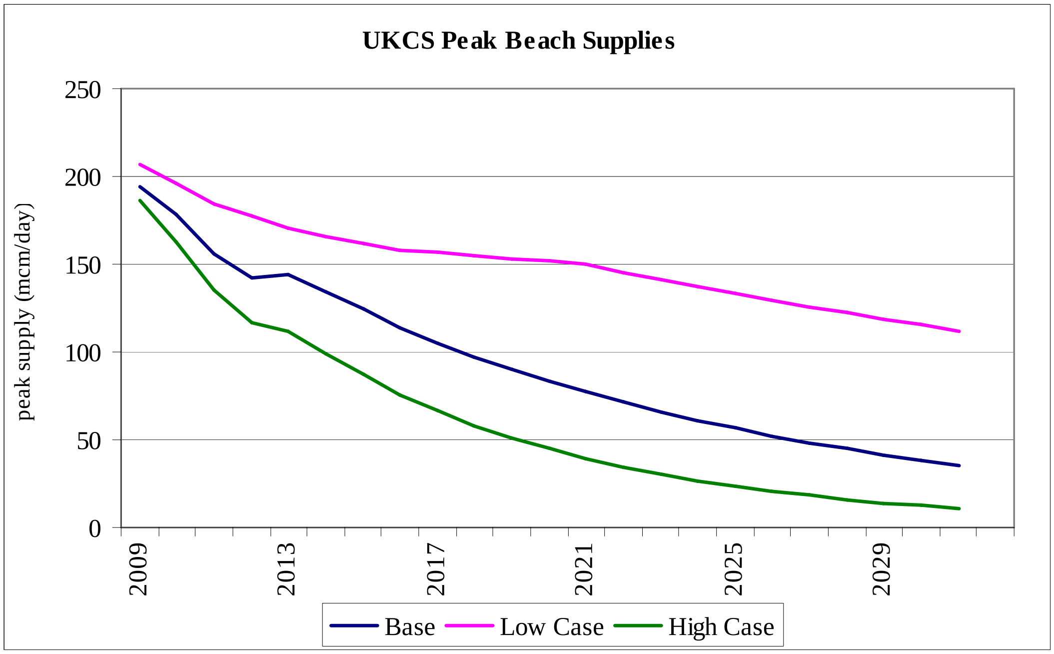
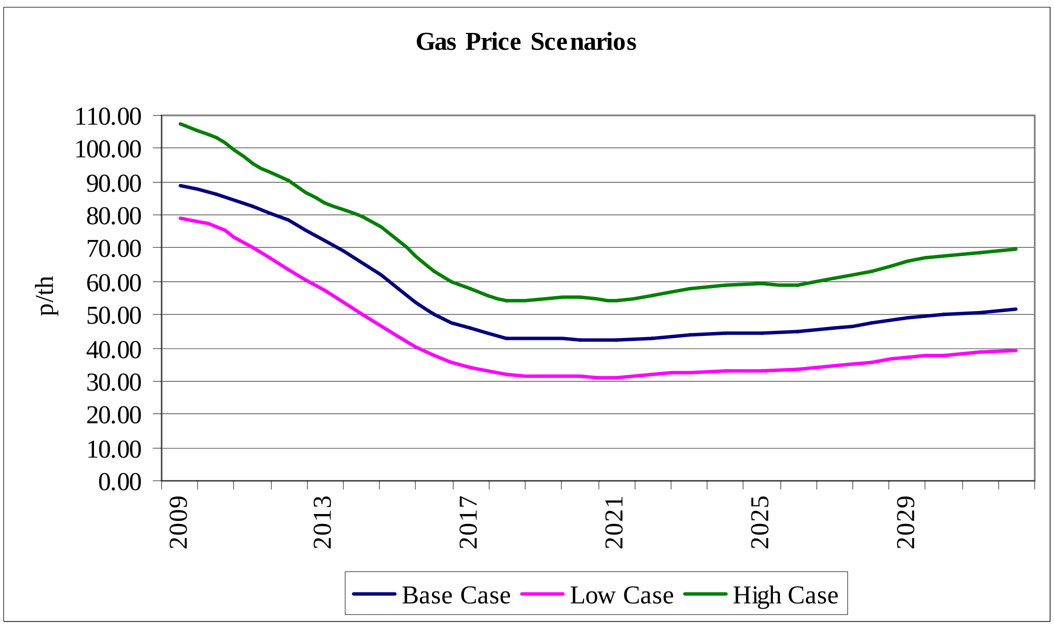


Figure 28: Gas Price Scenarios

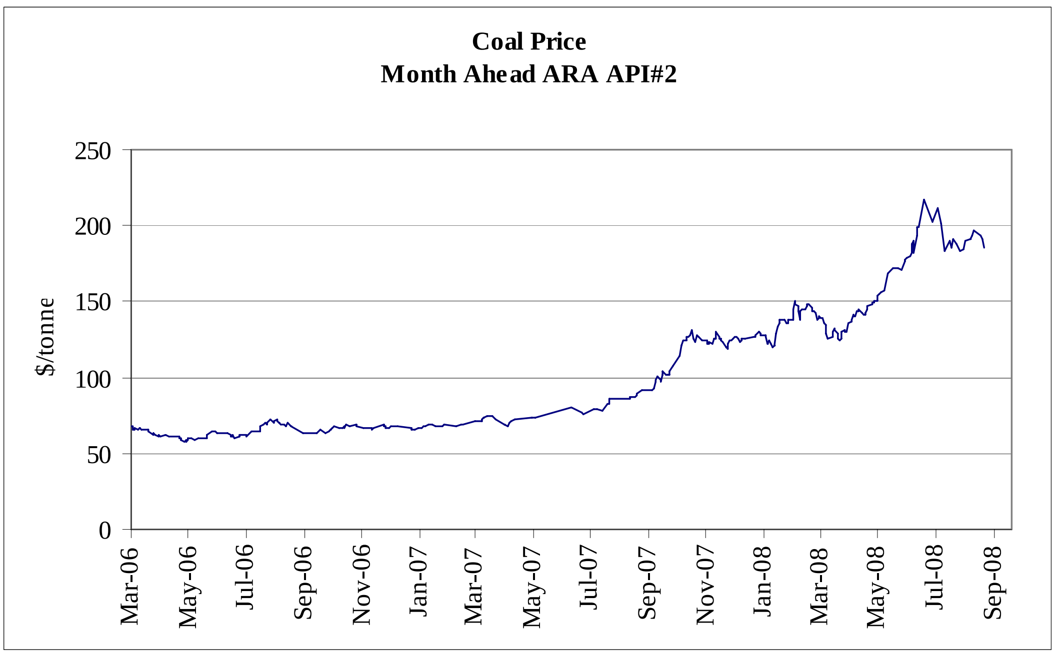


6. COAL PRICE SCENARIOS

6.1. Coal Market

Coal prices maintained their strength of the past six months, although they have dropped slightly from the peaks reached in early July. Month-ahead API#2 prices were around $190/tonne at the end of September having peaked at nearly $220/tonne (see Figure 29). Prices have been driven by continued high demand, particularly from China and India, and on-going supply constraints in Australia and South Africa. High coal prices have led to concerns in coal exporting countries about coal supplies to their own power sectors. This has led Vietnam (a major supplier of coal to China) to raise export tariffs. Some Chinese provinces have imposed price freezes on coal. Surging domestic demand has also lead to fears that Indonesia may implement export restrictions. In South Africa, which has also faced difficulty meeting demand from its own power sector, the Department of Minerals and Energy has commissioned a study to draft a "coal master plan". There has been speculation that the plan might recommend export restrictions, although this remains uncertain. Production delays and bad weather have restricted exports from Australia's Newcastle port. Elsewhere in Australia, good progress has been made on easing export bottlenecks, particularly in Queensland.

Figure 29: Coal Price Market Trends



The contribution of freight rates in the delivered North Western European coal price is shown in Figure 30 (based upon delivery from South Africa). The costs of freight have risen steadily over the last couple of years from approximately $10/tonne to a peak of around $35/tonne in late 2007. However, the cost has since dropped back to around $25-30/tonne over the last quarter. The increase in freight rates has been primarily driven by demand for dry bulk carriers to supply both iron-ore and coal demand in Asia (particularly China which became a net importer of coal in 2007). However, this has been exacerbated by port delays at Newcastle (Australia) reflecting the fact that coal transport infrastructure is currently lagging the demand for exports. The freight market shows prices reducing rapidly along the curve with freight rates falling by around 40% by 2011 from the current prompt price. This reflects the large number of bulk carriers under construction and due to be delivered in the next couple of years. However, there is much lower backwardation in the underlying commodity price reflecting the expectation that demand is likely to remain high and some export restrictions may be put in place.

The continuing weakness of the dollar means that although the international price of coal has increased over the last couple of years, the domestic currency price of coal has not seen the same level of upward pressure. Thus increases in the cost of coal in GBP - which impact upon the fuel costs for electricity generation in Great Britain – have not been so marked. Nevertheless the hike in coal prices over the last couple of quarters will have put significant upward pressure on the cost of coal for generators across GB.

The forward curve has also seen considerable upward pressure over the last quarter, but remains backwardated in real terms, with delivery in 2011 trading around the $155/tonne (real) level. The softening of prices along the curve reflects both softening in the underlying price of coal as well as softening of freight rates along the curve (see Table 6).

Figure 30: Year Ahead Historic Coal Prices

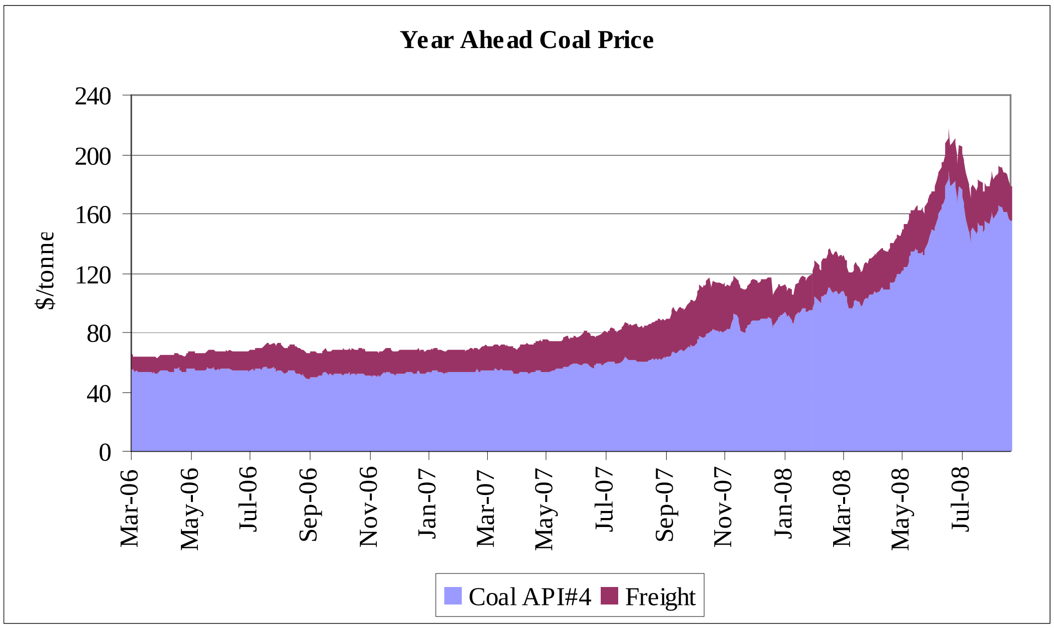


Table 6: Forward Coal Prices

Year	API#2 $/tonne (real)[19]
2009	173.32
2010	162.36
2011	153.64

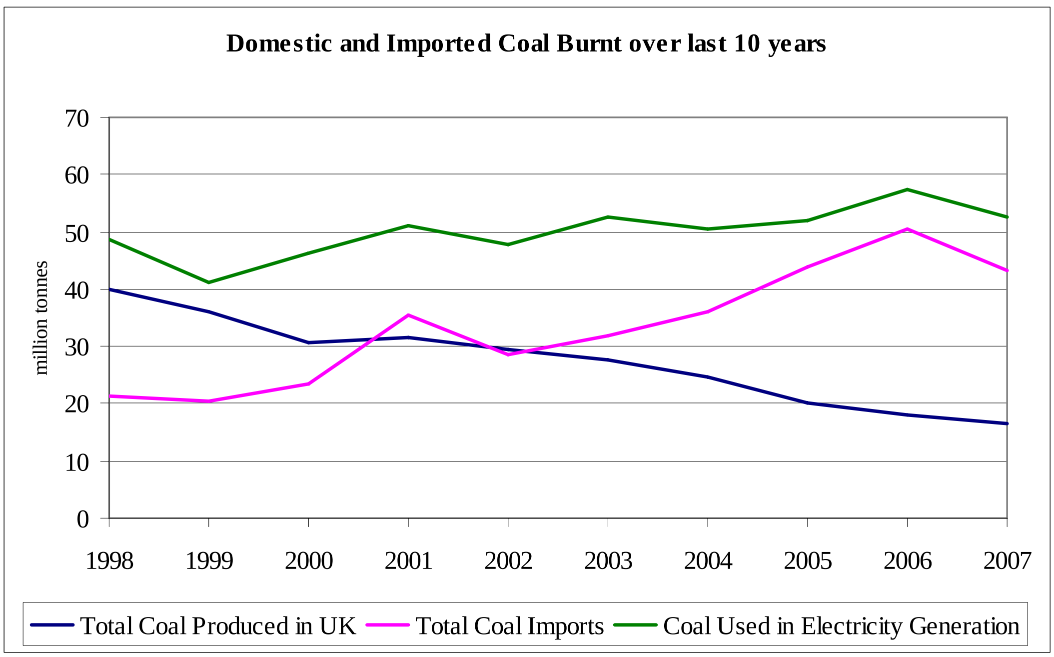
[19] Spectrometer 3rd September 2008

6.2. Power Station Coal Demand

The last few years has seen coal-fired power stations taking a greater share of the fuel mix, primarily driven by relatively high gas prices. However, commissioning of new gas infrastructure has put downward pressure on gas prices (although the market has seen upward pressure– in part reflecting the strength in oil prices), which has served to reduce the competitiveness of coal. Coal generation levels have reduced from the high levels seen over 2005/6, although the level of coal generation is still relatively high when viewed over a longer time horizon.

UK coal production continues to decline, with the increased demand for coal being met by increased levels of imports. Figure 31 below illustrates that coal use for power generation has exceeded 50 million tonnes in six of the past seven years, and total UK production has fallen to 18 million tonnes. Total imports, including coal for domestic use, metallurgical coal and coal for other industries was around 44 million tonnes last year, of which around 35 million tonnes was used for power generation. The UK demand for coal is significant globally and has the potential to become the world's 3rd largest coal importer.

Figure 31: Coal Use for UK Power Generation[20]



6.3. International Coal Supplies

The UK imports coal from a number of the largest coal producers, but Russia and South Africa dominate as major coal suppliers. Russia's importance as a UK coal supplier continues to grow due both to the relatively low sulphur content of Russian coal, as well as their use of handy size vessels for shipping, which can be handled by most of the UK coal ports.

[20] DUKES 2008

Several UK buyers, particularly SSE and RWE, have been conducting trials with the ultra-low sulphur Indonesian coals, with significant success. These coals are very volatile and have a tendency to spontaneously combust in transit or if not stored adequately, and earlier trials were not very successful. Recent trials seem more successful, so more product may come from Indonesia which has low production costs and developing export infrastructure. However, as Asian demand increases – particularly in China and India – competition for Indonesian coal is likely to intensify which may make it uneconomic for import into the UK especially as there has been evidence in recent times of supplies being diverted from Europe to meet Pacific commitments.

The sulphur content of coal has been an increasingly important factor when sourcing coal. Table 7 shows typical ranges of sulphur content for each of the major coal exporting countries. There is currently no significant price premium for low sulphur coal despite the requirements of the European power generation sector to control sulphur emissions. However, divergence in prices between high and low sulphur coal could occur in the future, and would be particularly likely if international coal prices began to soften, reducing the net back price to producers in Russia currently a major source of low-sulphur coal.

Table 7: Typical Sulphur Content by Country

Country	Sulphur Content
Russia	0.3% - 0.6%
Indonesia	<0.1% (ultra low sulphur Adaro); 0.2% (Kideco)
South Africa	0.8% - 1.2%
Australia	1%
USA	2%
Scotland	1%
England	1.3% - 1.7%
Wales	1.0% - 1.4%

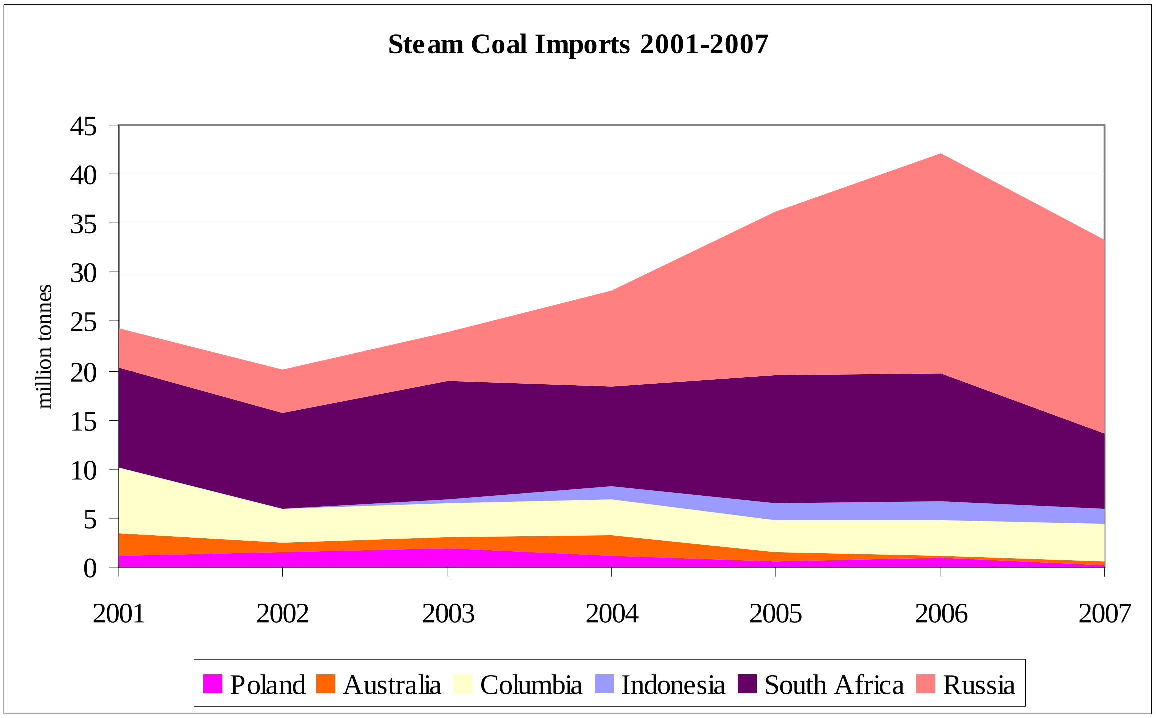
The Large Combustion Plant directive puts tighter limits on emissions from January 2008. A significant amount of the coal fleet has invested in flue gas desulphurisation (FGD) equipment. This will mean that whilst the non-FGD stations will continue to source low sulphur coal, the FGD stations will be capable of using a more varied diet, and may import coal from a greater range of sources. Thus, it is likely that there will be some changes to the approach to sourcing international coal. However, constraints on UK port capacity, and the lack of capacity for handling large coal vessels, means that Russian coal, which is typically shipped in Handy sized vessels, may still be a major source for the UK generation market.

Table 8 shows the source of coal burned for power generation in 2007. The evolution of the coal imports to the UK over the last 5 years is shown in Figure 32 which shows the sizeable increases in Russian imports over the last 3 years and the reduction in Australian coal imports as Australian coal producers concentrate on the Pacific market. The sharp fall in South African imports in 2007 against 2006 can be largely attributed to mining and logistics problems within country.

Table 8: Steam Coal Imports (million Tonnes) in 2007[21]

Coal Source	Poland	Australia	Columbia	Indonesia	South Africa	Russia	Others
Total	0.1	0.5	3.8	1.5	7.7	19.7	1.7

Figure 32: Steam Coal Imports 2001 - 2007



6.3.1. International Coal Supply Costs

The costs of coal production vary significantly round the world, dependent upon a wide variety of criteria including the structure of the coal deposits, local wage costs, and distance from deepwater ports. Figure 33 shows the production cost associated with the major exporting countries and compares these with the published average FOB price (as horizontal lines) for these countries in 2005.

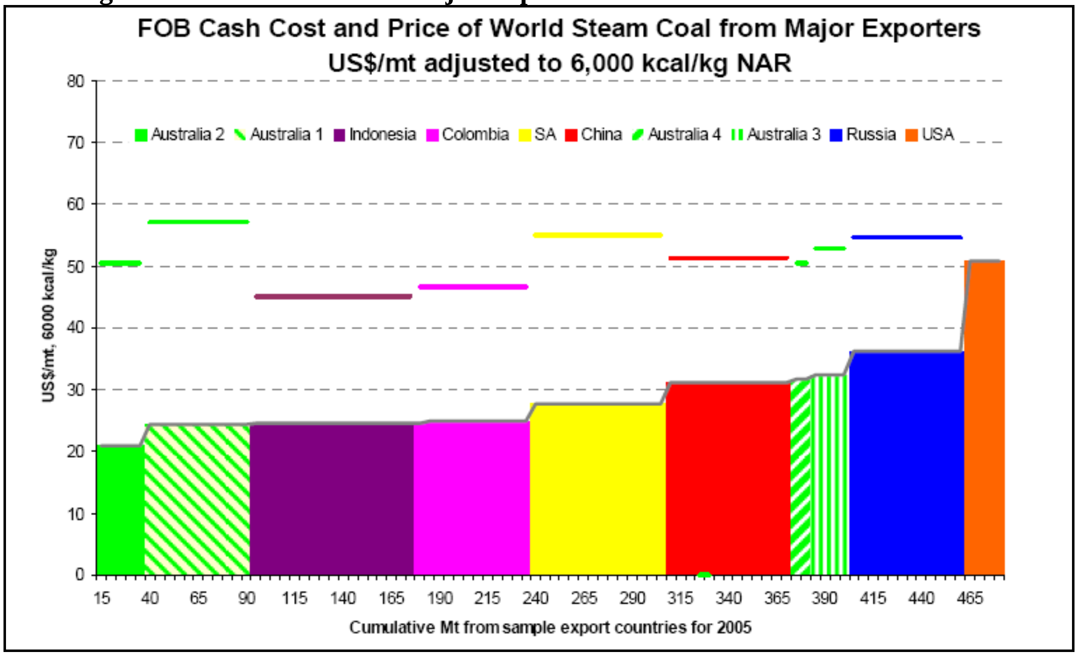
The difference between the price and cost shows that there are significant margins available in all of the major coal exporting countries which should ensure that there is continuing investment in mine capacity to meet demand growth.

It is noticeable that Russia (the major supplier of coal to the UK) is at the top of the cost curve (with the exception of USA). This reflects its high cost structure (particularly high inland rail costs to Baltic ports) as well as the impact of a relatively strong Rouble. Russia's importance as a major coal supplier to the NW European steam coal market is likely to remain, and so it is likely that the cost of

[21] DUKES 2008

Russian coal will effectively set a floor price for the market at least over the medium term.

Figure 33: Price of Coal for Major Exporters[22]



6.3.2. UK Coal Production

While UK coal production has fallen year-on-year over the past decade as deep mines closed due to exhaustion or geological problems, and environmental barriers to planning consents for opencast production have increased, there are indications that the high prices seen over the past year are providing incentives for new developments.

- Deep mined coal production continues to diminish, following a series of mine closures and collieries at Harworth and Rossington being put into care and maintenance during 2006. The four UK COAL deep mines that continue to operate in England & Wales produced 6.4 million tonnes in 2007, compared to 7.5 million tonnes of coal during 2006. In addition, in January 2008, the last deep mine in Wales closed as the coal had effectively run out.
- However, development of the Hatfield deep mine continues with new Russian backers. New face gear has been ordered at a cost of £37 million, and total investment currently stands at over £50 million. Projected total mine investment at Hatfield is around £110 million with the aim of producing 2.2 million tonnes annually to supply their proposed IGCC power plant.
- Additionally, Energybuild are currently developing the Aberpergwm Mine in South Wales with proven and probable coal reserves in excess of 7 million tonnes with the aim of producing around 0.5 million tonnes annually.

[22] Supply Costs for Internationally Traded Coals, IEA Clean Coal Centre

- UK COAL's surface mine production rose in 2007, with production increasing from 0.6 million tonnes to 1.5 million tonnes due to the opening of three new surface mines in the fourth quarter of the year.
- A large number of additional surface mines have been granted planning approvals including the giant Ffos-y-fran Land Reclamation scheme near Merthyr Tydfil which will produce around 11 million tonnes of low volatile coal, primarily for use at RWE's Aberthaw Power Station, over a fifteen year period.

In July, Scottish Coal signed a five-year contract to supply ScottishPower with up to 10 million tonnes of coal from 2009. This follows on from announcements in Q4 2007 of contracts between UK COAL and E.ON and EDF Energy, showing that domestic supplies are still viable. Recent high coal prices have improved the profitability of UK COAL, and have led it to consider reopening its Harworth colliery which was mothballed two years ago. In their recent half-year results, UK COAL indicated they expected to produce more coal this year than last.

The UK coal industry is continuing to lobby Government for a statement of need for UK coal production for energy security of supply, which could make it easier to obtain planning permission and ensure that sites are not sterilised by other developments. However, Government representatives and ministers have so far resisted any target for coal production going forward.

6.4. Coal Transport

International coal prices in north-west Europe are a combination of the international mined price of coal, transport and handling. The cost of transport to the load port, bulk sea freight shipping cost from the producing country to Europe, Port costs together with storage/handling at the major ports, transshipping in smaller sea going vessels, UK port costs and handling charges and inland rail freight costs. The commodity costs and international shipping costs are denominated in US$ per metric tonne, and the UK port costs and inland rail transport are in sterling. The US$/£ exchange rate fluctuations therefore play a significant role in the delivered fuel cost to the generator which is based upon the cost of supplies on a £/GJ basis at the power station gate.

Coal to UK coal-fired power stations is generally delivered by sea, rail or road haulage or a combination of methods depending upon the location of the power station site. The Thames and Medway power stations, Tilbury and Kingsnorth, have no rail connections, and coal is delivered in small coastal vessels of up to 30,000 tonne capacity, trans-shipped at the ARA ports. Most of the inland coal stations generally receive imported coal by rail via the most convenient port where there is available capacity.

The differential in the delivered costs of coal at GB power stations, due to onward delivery from ARA is not insignificant. It varies from around 19p/GJ to 30p/GJ depending upon the location of the plant and the contractual arrangements for deliveries through the nearest port and rail infrastructure. The cost to the Aire Valley and North Midlands stations is around 27p/GJ above the traded ARA price, whereas the differential to the Thames and Medway stations is around 19p/GJ. Highest costs are for delivery to the South Wales stations, Didcot and the stations in the Midlands.

6.4.1. Port Capacity

Considerable increases in UK port capacity during 2006 eased concerns regarding the ability to maintain year on year increases in coal imports. The increased coal imports from Russia have tended to be delivered in smaller vessels that can be accommodated within Russian load port restrictions. This has provided opportunities for smaller UK ports to compete with the larger ports that accommodate very large bulk carriers. These factors will tend to stabilise port and sea freight costs going forward, and increased competition will provide new opportunities for import routes to the power stations together with increased infrastructure efficiencies.

Associated British Ports completed the extensions to their Humber International Terminal at Immingham in 2006, with increased quay space, larger unloading grabs and two stacker re-claimers. This investment to increase the capacity by 9.5 million tonnes annually was made possible by forward long term contracts provided by major UK generators and coal importers. This port serves around ten power stations that can consume up to 41 million tonnes of coal annually, with five of these power stations within 75 minutes rail journey time. Rapid rail loaders, together with rail flow enhancements will also enable greater efficiencies in the use of rail capacity.

The Port of Tyne was traditionally the UK's major coal exporting port, and has new coal importing facilities targeted at Russian coal imports. The port has captured valuable coal import business especially for Drax, and from a modest start in 2005, the port handled 2 million tonnes in 2007. Recent dredging has been completed with the port receiving its first 60,000 tonne coal shipment at the start of the year.

Another former coal loading port at Blyth developed coal import capacity in 2006 with capacity for 1.3 million tonnes annually, and it is estimated this will increases to 2.2 million tonnes once rail enhancements and additional infrastructure upgrades are completed. The traditional large international coal importing terminals at Bristol, Liverpool, Hunterston, Redcar and Port Talbot continue to import significant quantities of coal, as do the smaller ports at Hull, Newport and Avonmouth. Increased capacity at English ports will diminish the requirement for long rail hauls from Hunterston to the Aire and Trent Valley power stations, and increased capacity should ensure competitive pricing.

6.5. Coal Price Scenarios

This section presents the coal price scenarios over the forecast horizon.

The current strength of coal prices in NW Europe reflects in the main the strong underlying commodity price. Commodity prices have been driven upwards by continuing strong world wide demand (particularly from India and China), as well as supply side constraints including disruptions to production or export facilities in Australia and South Africa. Delivered prices are backwardated, reflecting the short term nature of some of the current price pressures as well as the ability of the coal and freight industry to respond to price signals in the longer term. However, coal prices remain relatively strong over the medium to long term reflecting high levels for forecast world-wide demand.

The demand for coal is likely to remain strong in the medium to long term, supported by the relatively high price of competing fuels. The IEA World Energy Outlook 2007 forecasts global coal demand to increase by 2.2% per annum between 2005 and 2030 driven by higher demand particularly from India and China and increasing its share of total energy demand from 25% to 28%[23].

India and China already account for 45% of world coal use, and are forecast to drive over 80% of the global demand increase to 2030. China, which became a net importer of coal in the first half of 2007, is expected to need to add more than 1,300GW of electricity generating capacity, with most new generating capacity fuelled by coal. It is expected that capacity in India, most of which is coal-fired, will more than triple between 2005 and 2030. Coal use in the OECD is forecast to grow slowly. In all regions, the outlook for coal use depends on relative competitiveness with gas, environmental legislation and fuel diversification policies.

Continued strong demand is likely to continue to support prices but coal supply globally should expand to meet demand without vast increases in price. This reflects the fact that there are significant additional sources of coal and enormous proven reserves compared to other fuels (Oil: 40 years, Gas: 65 years and Coal: >160 years). Thus, supply should continue to develop to match demand without significant resource problems. In addition the margins that most coal producing countries are able to extract from the coal market are currently sufficient to incentivise investment, with investment in new coal supplies in countries such as Indonesia and Columbia. The cost of mining coal is likely to stay largely constant in real terms, but the cost of fuel required for mining equipment and transport of coal will vary with some indexation to oil prices.

The scenarios investigating coal price over the forecast horizon are shown in Figure 34, and are compared with forecasts from the IEA, US DOE and The Coal Forum (McCloskey Coal) in Table 9.

The Base Case represents the current market to 2011 and reflects the current strength of traded prices for both the underlying commodity as well as freight rates. However, the market shows prices reducing along the curve due mainly to a 40% reduction in freight rates by 2011 from the current prompt price. The longer term price forecasts have coal prices reducing to a long term equilibrium of around \$65/tonne. It can be seen that this is broadly in line with other forecasts which indicate a long term coal price in the range \$60-\$70/tonne.

The short term spread between High and Low scenarios reflects the continued volatility in coal markets. In the Low scenario prices fall over the medium term to an equilibrium of around \$55/tonne. This reflects the fact that there is likely to be a floor price, at which Russian supply will reduce. Russian producers have generally been price takers, and whilst they can economically supply coal at current international prices, the high cost of inland rail transport between the mines and the Russian exporting sea-ports means that if the NW European ARA CIF coal price fell significantly below \$55/tonne the net-back to their producers would be unlikely to remain economic. Thus, the cost of Russian supplies are likely to provide a floor price, particularly for low sulphur coal for power generation. Indeed it is possible that if coal prices were to soften further, then low sulphur coal could trade at a premium, supporting the coal price paid by power generators in Europe.

The High scenario has prices settling to a long term equilibrium around \$75/tonne over the medium term. This reflects strong demand, with price effectively capped by

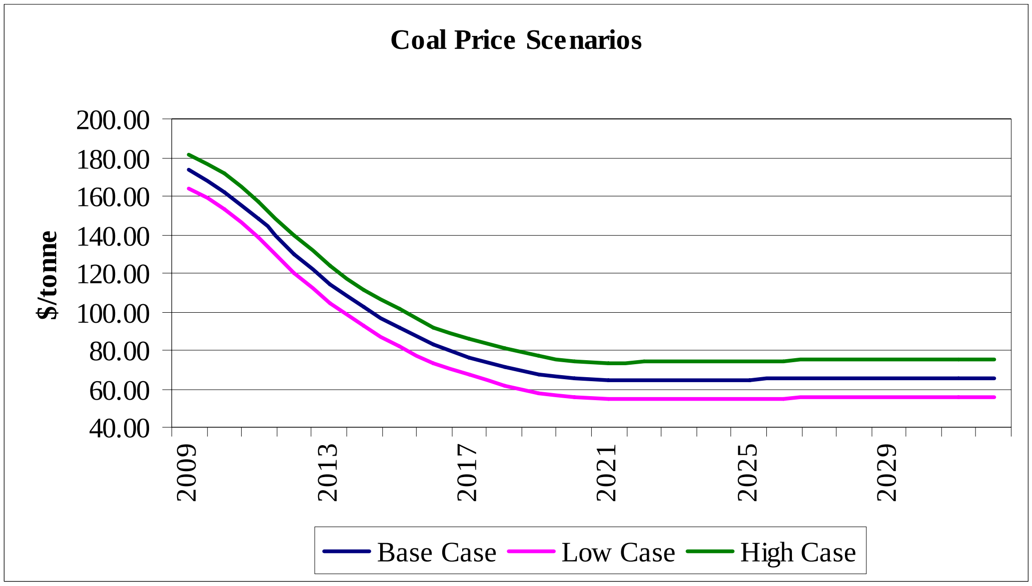
[23] IEA World Energy Outlook 2007

producers short term capability to increase output globally, and the medium term flexibility to develop existing reserves.

Table 9: Comparison of Forecast Coal Prices ($/tonne)

Year	AEO 08 (US price)	WEO 07	Coal Forum (McCloskeys)	IPA Oct 08 Base Case
2010	69.92	56	66.5	162.4
2020	63.88		67	65.25
2030	68.58	61		65.5

Figure 34: Coal Price Scenarios (CIF ARA)



7. CARBON PRICE SCENARIOS

This section details recent price movements in the carbon markets, highlights developments in the EU ETS for Phase II and beyond, and discusses the three carbon price forecast scenarios.

7.1. Carbon Markets

Carbon prices have fallen over the previous quarter in response to falling oil prices. At the beginning of July, the price of EU allowances was at a two-year high of almost €30/tCO_2. The price dropped throughout July, reaching around €21/tCO_2 at the beginning of August, later recovering to around €25/tCO_2 towards the end of August.

The European Commission has announced mid-October as a date for the link between the EU and UN transaction logs. This will enable CDM credits (CERs) to be transferred to the registry which tracks ownership of allowances in the EU ETS. The establishment of this link will remove a significant source of uncertainty about the ability to use CDM credits for compliance in the EU ETS. The spread between EUAs and CERs has narrowed from around €8.40/tCO_2 at the beginning of June to around €4/tCO_2 at the beginning of September.

Figure 35: Carbon Market Trends

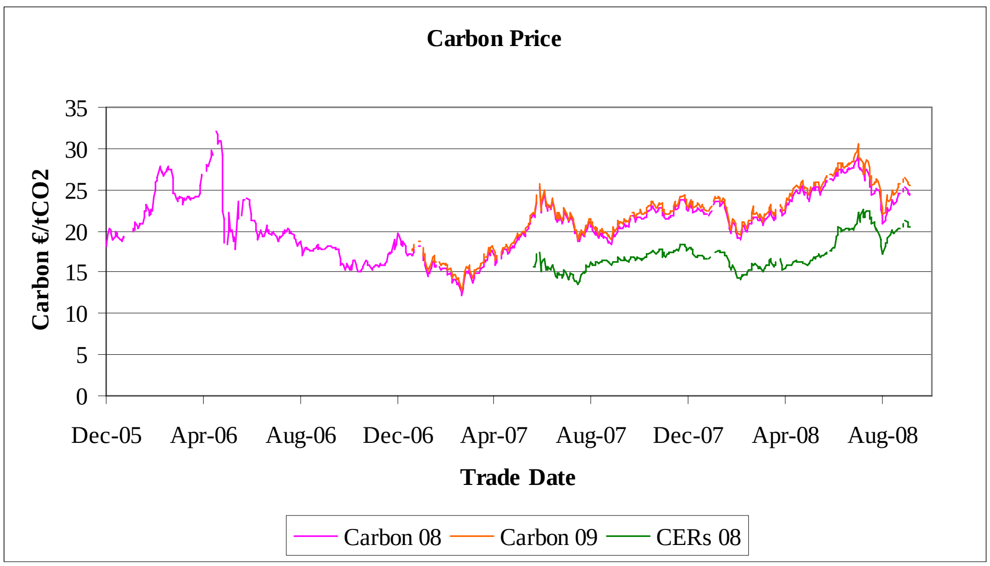


Table 10: Forward Carbon Market Prices[24]

	EUAs (€/tCO_2)	Secondary CERs (€/tCO_2)
2008	24.96	21.00
2009	26.06	21.70
2010	27.00	21.91
2011	28.14	22.34
2012	29.45	23.10
2013	31.27	
2014	31.98	

[24] European Climate Exchange, 1st September 2008 nominal prices

The European Parliament, the Council and the Commission will further discuss the details of the proposed climate change package[25], including the proposed Directive outlining the period 2013-2020 of the EU ETS. The proposal is discussed under the co-decision procedure. In case of no agreement at the first reading stage, a second reading will take place, allowing for further discussions and negotiations amongst the institutions. The French presidency hopes to finalise discussions in December this year at the end of the first reading stage.

International negotiations on a post-2012 climate change agreement have continued, with UNFCCC meetings taking place in Bonn and Accra. These continue to be at a "pre-negotiation" stage, where debates are about what issues should be on the table during negotiations. Formal negotiations on a post-2012 agreement are expected to begin after the UNFCCC conference in Poznan at the end of this year.

7.1.1. Impact of credit crisis

The banking crisis of the last months is considered to have a potential impact on the carbon market, in particular with regard to obtaining credits and funds raising money to spend on carbon credits. The main concern is with regard to financing CDM/ JI projects and the impact on demand and supply of CERs/ERUs. A spread of the credit crisis to countries such as China could mean that project developers will require more upfront financing from credit buyers. Confidence by the buyer in the project's delivery will become more important and due diligence will further slow the pace of deals in the primary market. Also, guaranteed CERs may get more expensive and hedging of primary CERs may become more difficult. However, utilities with larger cash reserves may find this less problematic than funds that are looking to sell CERs forward with delivery at a later stage.

An economic slowdown as a result of the banking crisis is also expected to have an impact on the carbon market. Under a possible recession, energy-intensive industries might produce less carbon emissions which may result in reduced power demand. Some studies suggest that a 1% drop in economic growth would mean about 30million less EUAs are required over a 12 month period.[26]

A fall in carbon prices in the EU ETS may be offset where those industries postpone the expensive installation of emission-cutting technologies. In general, it can be said that the carbon price is influenced by a number of complex factors and GDP development is only one of them.

7.2. Phase II Allocations and CITL/ ITL Link

The overall EU ETS cap for Phase II has been finalised at 2,083 MtCO_2/year. In the light of 2007 verified EU ETS emissions we estimate that the average shortfall of allowances in Phase II of the EU ETS will be between 200 and 230 million per year before adjustment to changes in policy scope.

[25] Further information about the EU climate change package can be found on the website of DG Environment: http://ec.europa.eu/environment/climat/climate_action.htm
[26] Analysis by Societe Generale, http://www.pointcarbon.com/news/1.970171

Currently 12 out of 27 member states have had their national registries enabled for issuance of 2008 EUAs.[27]

Following completion of trials over the past few months, the European Commission has stated that the EU (CITL) and UN (ITL) transaction logs will be linked by mid-October this year. The link will mean carbon credits issued under the CDM can be transferred to the registries of EU member states. The two systems will control and track transactions jointly. Currently, each Member State registry is connected to the CITL. After the ITL and CITL are connected, each member state registry will be connected to the ITL only and each transaction involving an EU Member State will be passed on to the CITL for recording and additional checks. The connection is necessary to allow the use of CERs/ERUs for compliance in the EU ETS. The expected overall effect of the EU and UN transaction log is an increased trading volume on the market and further narrowing of the spread between secondary CERs and EUAs.

A number of EU member states, including Germany and the UK have previously refused to issue allowances for Phase II before a link between the EU and UN transaction logs is in place. This has caused restrictions on spot trading of EUAs. However, subsequent to the Commission's press release, the UK announced the first auction date for Phase II allowances for November 19th, 2008. The exact volume will be announced one month in advance but is expected to be below 23 million.[28]

7.3. Developments on the European Commission's January Climate Change Proposals

The climate change package issued by the EU in January 2008 is currently subject to heavy negotiations between the European Parliament, the Commission and the Council. The process is still in the first stage of the co-decision procedure. This section discusses the implications of these proposals for the evolution of the EU ETS and presents the main discussions and results to date.

7.3.1. Overview of Commission's Initial Proposals

Overall, the main commitment of the EU is to reduce greenhouse gas emissions by 20% on 1990 levels by 2020. This target would be increased to 30% if a global climate change agreement is reached in which other developed countries commit to similar levels of effort, and adequate commitments are made by economically advanced developing countries.

The Commission's January climate change package includes:

- A proposal for the revision of the EU ETS directive[29]. This proposal covers the operation of the EU ETS from 2013 to 2020.
- Proposals for how the contribution of non-EU ETS sectors to the achievement of overall greenhouse gas reduction targets for 2020 should be distributed between member states[30].

[27] Status September 10th (European Commission)
[28] HM Treasury Press Release, 18 September 2008, Angela Eagle announces date for first emissions trading auction, http://www.hm-treasury.gov.uk/newsroom_and_speeches/press/2008/press_95_08.cfm
[29] Proposal for a Directive of the European Parliament and of the Council amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading system of the Community. 23rd January 2008.
http://ec.europa.eu/environment/climat/emission/pdf/com_2008_16_en.pdf

- A proposal for a directive on the promotion of the use of energy from renewable sources[31].

The proposed revision of the EU ETS for the period 2013 to 2020 involves:

- Centralized cap setting by the Commission (rather than cap setting by member states through National Allocation Plans, which has been used so far).
- A linear decrease in the cap each year in the period 2013 to 2020.
- Allocation of allowances through auctioning. Sectors (other than the power sector) that are exposed to international competition may be granted free allowances in 2013, but this will be phased out in a linear fashion up to 2020. It is intended that the rules for allocating free allowances will be adopted by June 2011. They will be based on benchmarking and apply consistently across Member States.
- 5% of the total quantity of allowances for 2013 to 2020 will be set aside for new entrants. Allocation of allowances to new entrants will be based on the same principles as used for existing installations (so there will be no free allocation to new entrants in the power sector).
- The current cap on CERs/ERUs for compliance is 13% for 2008 to 2012. The Commission proposes to not increase the allowances for Phase II. Spread out over eight years from 2013 to 2020, this would represent approximately 5% of the total cap for these years. If an international agreement is adopted, half of the additional effort caused by the higher EU target (30% instead of 20%) could be met through CERs/ERUs.

These aspects have been subject to heavy inter-institutional discussions and industry lobbying over the past months.

7.3.2. Amendments

The Industry, Research and Energy (ITRE) committee of the European Parliament suggested amendments to the EU ETS directive in their committee meeting on September 11th. While the ITRE committee is less powerful to significantly change amendments to the proposal than the Environment Committee, it has traditionally influenced the decisions of the Environment Committee. The Environment committee is still to vote on the proposal and amendments which will then be presented to the Environment Council. The Environment committee has issued a note regarding their position preceding their meeting on October 7th which is summarised in Table 11.

The Council of Environment Ministers is due to meet in October to discuss amendments to the climate change package. The Committee of Permanent Representatives (COREPER) prepares the meetings and sets the agenda of the Council of Ministers. France has encouraged the discussion of the principal

[30] Proposal for a decision of the European Parliament and of the Council on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emissions reduction commitments up to 2020. 23rd January 2008.
http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2008:0017:FIN:EN:PDF

[31] Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources.
http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2008:0019:FIN:EN:PDF

points in COREPER to speed up the decision-making process and meet its target of agreeing the final climate change package by December 2008. However, while COREPER may be able to resolve technical issues upfront, some issues remain on the agenda for discussion. Opposition comes from a number of Eastern European countries who would like to see the reference year for emission reductions set at 1990 rather than 2005 levels. This would mean that Eastern European countries could reap the benefits of the emissions reductions made during their economic downturn in the 90s. The Visegrad group (including the Czech Republic, Poland, Slovakia, and Hungary) signed an agreement mid-September stating their intention to possibly delay the final agreement on the climate change package until March 2009 if their concerns were not taken into account.

The issue of carbon 'leakage' has also been an item of debate. The term refers to the event that other developed countries and major emitters of greenhouse gases do not participate in an international agreement, and where this could lead to an increase in greenhouse gas emissions in third countries where industry would not be subject to comparable carbon constraints(effectively exporting the emissions). This could, at the same time, put certain energy-intensive sectors in the EU which are subject to international competition at an economic disadvantage. Discussion has therefore focused on the criteria for sectors to receive free allocation of allowances and the timing of their publication.

Opinion of the three main institutions on a few particularly relevant points for the carbon price forecast is summarised in Table 11.

Table 11: Relevant discussion points regarding proposed EU ETS Directive

Amendments/Main issues of debate	Original Commission proposal[32]	EP ITRE committee[33]	EP Environment committee[34]	COREPER[35]
Allocation method	Auctioning/ Harmonised allocation rules (e.g. benchmarks)	Auctioning/ Benchmarks Concerns remain on most levels regarding the exact auctioning and benchmarking procedures		
Allocation to electricity sector	100% auctioning from 2013	More need for discussion on 100% auctioning from 2013	100% auctioning from 2013	Gradual increase from 2013 suggested by some countries
Carbon Leakage	Free allocation to sectors with high risk of carbon leakage of up to 100% Review and decision on eligible sectors by 2011	Free allocation to manufacturing sector according to benchmarks Review and decision on eligible sectors by 2010	Free allocation for all industrial installations that are agreed to be at significant risk of carbon leakage of up to 100% Review and decision on eligible sectors by 2010	Free allocation for sectors at risk of carbon leakage but may not be sufficient measure to prevent carbon leakage Review and decision by 2010
Level of CERs/ERUs	Limited to 1.4 tonnes of offset credits if no international agreement If international agreement than additional 10% reduction can be met by 50% CERs/ERUs	35% of effort by 2020 In case of international agreement, CERs/ERUs shall be “high quality”	1.7 tonnes of offset credits or 40% of the overall effort (under discussion) Calls for increased use of Gold Standard projects	Member States request additional credits to be granted for Phase III Possibly create a specific regime in case of no international agreement
New Entrants Reserve	5% of Community-wide allowances over Phase III			Some discussion of increasing NER but adjustment considered difficult overall
Additional points			Shipping shall be included no later than 2015	

7.3.3. Timescale for Introduction of Proposals

The current EU Parliament legislature comes to an end in March 2009. Parliamentary elections will be held in June 2009. If the climate change

32 Dated 23 January 2008
33 Dated 10 September 2008
34 Dated 10 September 2008
35 Dated 12 September 2008

package is to be in place in time for the December UN climate change conference in Copenhagen (at which it is hoped an international agreement will be reached), it must be adopted by March 2009.

France took at the rotating EU presidency in July 2008 and stated as one of its main goals to reach agreement on all elements of the climate change policy package at the First Reading stage by December this year. September has already seen a number of meetings and resolutions from the committees of the European Parliament and the European Council, presenting amendments to the proposed Directive. It is expected that discussions will be ongoing throughout autumn between the Parliament, the Council and the Commission (see Table 12). The European Council meets on December 11^{th} - 12^{th} 2008 to vote on the final amendments and the European Parliament will give it final approval on December 16^{th}. If the European Parliament does not agree with the Council decision, the package will go into the Second Reading stage.

Negotiations are expected to be hard. There appears to be a strong will to have the climate change package adopted in time for the international negotiations in Copenhagen, but there are significant obstacles to overcome. In particular, Eastern European states object to the use of 2005 as a base year for sharing out effort for the 2020 target. Other countries, in particular Germany and also the UK, have raised their voice in favor of an increase in the level of Kyoto credits to be allowed into the EU ETS. Significant compromises may be required if an agreement is to be reached by December.

Table 12: Timetable for Co-decision Procedure - First Reading

	Council of Ministers	European Parliament	Stage in co-decision procedure
September			
		8th-11th: EP Committee meetings	Discussion on amendments
	18-19th: COREPER		Preparing agenda for Council meeting
	29-30th: Possible Working Party		Discussions
October			
		7th: Environment Committee	Vote on amendments
	15-16th: European Council		Discussions
	20-21st: Environment Council (Luxemburg)		Discussions
December			
	4-5th: Environment Council		
	11-12th: European Council		First reading by the Council: adoption or common position (Commission Communication)
		16th: European Parliament	Second reading by Parliament: adoption or amendments to common position

7.3.4. Potential Impact of Proposals on the Carbon Price

In the July edition of PowerView, the following points were listed which would have implications for the carbon price in 2013 to 2020:

- The way that effort is shared between ETS and non-ETS sectors, and the trajectory for emissions reductions over the period.
- The trajectory of ETS reduction targets over the period 2013-2020, and the ability to bank allowances for use in future years.
- The extent to which JI/CDM credits can be used in the EU ETS during this period.
- The extent to which measures taken to promote renewable energy use, other than the EU ETS itself, may reduce emissions in the EU ETS sectors.

There is still uncertainty about some of these issues. In particular concerns remain about the introduction of a high-level of auctioning (100% for generators) in 2013, the arrangements for (and especially the timing of) the auction process, the over-sizing of a New Entrant Reserve and restrictions on the use of project credits from the JI and CDM mechanisms. Assessing the likely trajectory of the carbon price in 2013 to 2020 involves addressing the extent to which the likely form of the policies finally adopted can be deduced from these proposals and subsequent inter-institutional discussions, rather than taking the information contained in the proposals at face value.

Our previous assessment of the four issues listed above has been updated in the light of the recent institutional debate. The French presidency is determined to conclude the climate change package in its first reading stage of the co-decision procedure and will therefore attempt to drive the negotiations towards compromise. Most position papers published by the institutional players to date agree with the French presidency's goal and point out that early agreement will mean to not diverge too far from the original Commission proposals.

- ***The sharing of effort between ETS and non-ETS sectors***

  The Commissions proposals emphasize that the emissions reduction effort should be shared between ETS and non-ETS sectors 'cost-effectively'. Essentially this means that effort is distributed so that marginal abatement costs are the same in ETS and non-ETS sectors. The Commission has calculated this distribution using economic modelling under the assumption that renewable energy targets are also achieved cost-effectively. The resulting distribution of effort calculated by the Commission for a 20% reduction in greenhouse gas emissions on 1990 levels by 2020 is shown in Table 13. Here, effort is expressed as a reduction on 2005 emissions levels, 2005 being the first year for which comprehensive verified emissions data exists. This cost-efficient distribution of effort has been calculated under the assumption that there is no access to JI/CDM credits, and no banking of surplus allowances from Phase II of the EU ETS.

Table 13: Cost-effective distribution of greenhouse gas reduction effort (20% reduction on 1990 levels by 2020) as calculated by the Commission[36]

Sector	GHG reduction by 2020 on 2005 levels
ETS sector including aviation[37]	18%
ETS sector excluding aviation[38]	21%
Non-ETS sector	12%

The reduction of 21% on 2005 levels for the EU traded sector (excluding aviation) has been taken as the 2020 emissions cap in the proposed revision of the ETS directive. The impact assessment states that the

[36] Source: Commission Staff Working Document, Annex to the Impact Assessment, 27 February 2008. http://ec.europa.eu/environment/climat/pdf/climate_package_ia_draft_annex.pdf

[37] In its impact assessment, the Commission has included all 'outbound' flights. This means all intra EU flights and external flights leaving from the EU (i.e. flights entering the EU from outside have been excluded).

[38] Here it appears that the distribution of effort between the (non-aviation) ETS sector and the aviation sector has also been calculated on a cost-effective basis. The percentages in this table suggest that in this cost-effective scenario, aviation emissions grow beyond 2005 levels – i.e. grow beyond the caps appearing in the proposed legislation on emissions trading for aviation (this conclusion is based on a comparison of the percentages in the table with estimated 2005 aviation emissions). This would imply that the 21% reduction for the traded sector is based on a looser cap on aviation emissions than that currently being proposed by the Commission or the Parliament.

carbon price associated with this (in the absence of the availability of JI/CDM credits) would be €(2005)39/tCO_2[39].

In the event that an international agreement is concluded, EU 2020 greenhouse gas reduction targets will be increased from 20% on 1990 to whatever target is established in the agreement (i.e. 30% if other industrialized countries agree to similar levels of effort). In this case the proposed directive states that the effort required in the EU ETS will be increased so that the overall greenhouse gas target will be achieved while retaining the distribution of effort between ETS and non-ETS sectors that would apply in the absence of an international agreement[40].

- ***The trajectory of ETS reduction targets over the period 2013-2020 and the ability to bank allowances***

Article 9 of the proposed ETS directive states that the "Community wide quantity of allowances issued each year starting in 2013 shall decrease in a linear manner from the mid point of the period 2008 to 2012". The same article states that this amounts to an annual decrease in emissions of 1.74% of the annual Phase II cap. This suggests that 2013 emissions must be reduced from the annual Phase II cap by three times 1.74%, 2014 emissions are reduced by four times 1.74% and so on (since the trajectory is a linear decrease starting at 2010). The 2020 cap would therefore be a reduction of ten times 1.74% on annual Phase II emissions, which appears to agree with the reduction of 21% on 2005 emissions.

If an international agreement is reached, the ETS reduction target for 2020 will be increased (as described above), and the annual decrease in the cap from 2013 to 2020 will be adjusted to maintain a linear trajectory.

Article 13 of the current EU ETS directive[41] implies that it is possible to bank Phase II allowances for use in future years within Phase II, and also for use in subsequent phases. The proposed revision of this directive implies that it will be possible to bank allowances for use in future years throughout the period 2013 to 2020. Effectively this would create a continuous period in which banking is allowed stretching from 2008 to 2020.

The ability to bank allowances means that the evolution of the ETS cap over the period 2013 to 2020 discussed above will not necessarily be directly reflected in the evolution of the carbon price over this period. Banking of allowances allows the redistribution of effort between years[42]. If abatement effort were to be distributed between years in an economically efficient way, then the growth in marginal abatement costs over time would reflect discount rates. Because banking of allowances is

[39] Here €(2005) denotes Euros in 2005 money – if the year is not indicated, prices are in 2008 money as in the rest of this document.
[40] We take this to mean that the distribution of effort between ETS and non-ETS sectors *when specified as a reduction on 2005 levels* would be maintained, so that an international agreement would lead to the scaling up of the percentages reported in Table 13, while retaining their relative sizes.
[41] Directive 2003/87/EC establishing a scheme for greenhouse gas emissions trading, 13 October 2003. http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2003:275:0032:0046:EN:PDF
[42] In fact banking only allows effort to be moved forward in time (borrowing of allowances from the future is not allowed). However, if the amount of effort required increases sufficiently rapidly in relation to discount rates, it does not make economic sense to delay effort anyway.

allowed throughout the period from 2008 to 2020, it might be expected that the carbon price would grow throughout this period at a rate reflecting discount rates, with the 2008 price being determined by the amount of effort required over the whole period (2008 to 2012).

A prerequisite for the carbon price to show this type of behaviour would be certainty about the shortfall of allowances in each year. At present, such certainty does not exist, not least because the post-2012 policy arrangements have not been finalised. Even with clarity about policy, there are other sources of uncertainty such as the supply of JI/CDM credits, 'business as usual' emissions, the willingness of ETS installations to trade surplus allowances and their propensity to invest in abatement measures. All these factors have the potential to shift the behaviour of the carbon price away from simple growth related to discount rates.

- ***The extent to which JI/CDM credits can be used***

Article 11a of the proposed ETS directive concerns the use of JI/CDM credits in the EU ETS in the absence of an international agreement. This article implies that no further JI/CDM credits can be imported into the EU ETS in the period 2013 to 2020 beyond the volume of credits already allowed in Phase II. In other words, JI/CDM credits would only be allowed to enter the ETS in 2013 to 2020 to the extent that the volume of these credits allowed in Phase II had not been used.

In addition to the above restriction on the use of JI/CDM credits in the period 2013 to 2020, it is proposed that only the following types of JI/CDM credits will be accepted in this period:

- Credits issued before 2013.
- Credits issued after Phase II from projects that were established before 2013.
- Credits from projects established after Phase II in Least Developed Countries.
- In the event that an international agreement is delayed, credits from projects or other emissions reduction schemes in a third country, if an agreement has been concluded with that country that specifies the level of use.
- These rules will apply up to the point where an international agreement is concluded. If such an agreement is concluded, only credits from third countries that have ratified the agreement will be accepted in the EU ETS.

The limit of JI/CDM credits to be allowed into the EU ETS has been subject to discussion in the Parliament committees and the Council of Ministers meetings/ COREPER. The direction has generally been towards a more flexible use of JI/CDM credits. Proposals by some member states have gone as high as allowing 50% of the effort on 2020 levels to be met by JI/CDM credits.

The Parliament and Council of Ministers are aware that limiting the use of JI/CDM credits in the period 2013 to 2020 to the volume that has already been allowed in Phase II could potentially put significant upward pressure on the carbon price (in Phase II and up to 2020). However, in its impact assessment, the Commission concludes this restriction would still allow one quarter of the effort required in the EU ETS in 2020 to be covered by JI/CDM credits, and could reduce the 2020 carbon price from €(2005)39/tCO_2 to €(2005)30/tCO_2[43] (these prices assume a 20% renewables target for 2020 – see the discussion below). It remains to be seen what the final outcome of the discussions between the Parliament and the Council will be, but an alleviation of the heavy limitation in the current proposal appears likely considering the discussions of the last few weeks.

In the case that an international agreement is reached involving greenhouse gas reduction targets for industrialized countries beyond the 20% to which the EU has already committed, the ETS caps in each year from 2013 to 2020 will be reduced accordingly (maintaining the given distribution of effort between the traded and non-traded sectors, and the linear decrease in the ETS cap). The proposed directive states that JI/CDM credits could then be used to cover up to half of the resulting additional effort (i.e. the use of JI/CDM credits would be allowed to cover up to half of the effort beyond that required in the absence of an international agreement). This would imply that even in the case that an international agreement were reached, the availability of JI/CDM credits to the EU ETS would be tightly restricted (with a higher carbon price than would be the case in the absence of an agreement).

- ***The interaction of renewable energy targets with the EU ETS***

The Commission has proposed that 20% of the EU's energy needs should come from renewable sources by 2020 (measured in terms of final energy consumption). This includes a 10% target for the use of biofuels in transport (although this has proved controversial and may be scrapped). The 20% target has been distributed between member states accounting for GDP and progress on renewable energy made so far. Linear trajectories have been specified for these targets over the period 2011 to 2020 (with intermediate targets being specified over two-year periods).

The effect of these targets on the carbon price will depend on the extent to which they are achieved using mechanisms other than the EU ETS that result in emissions reductions in EU ETS sectors. For example, support mechanisms for renewable electricity (such as quota obligations and feed-in tariffs) provide an incentive for reducing CO_2 emissions in the power sector that operates independently of the EU ETS. They therefore

[43] Annex to the Impact Assessment, Document Accompanying the Package of Implementation measures for the EU's objectives on climate change and renewable energy for 2020 (February 2008). http://ec.europa.eu/energy/climate_actions/doc/2008_res_ia_annex_en.pdf.
See in particular the discussion in section 5.3.6 and Table 15 in the above document. It should be noted that the calculations in the impact assessment assume an 'economically efficient' distribution of abatement effort, which would be unlikely to be realised in practice, meaning that the indicated carbon prices could potentially be on the low side.

have the potential to reduce demand for EU allowances and put downward pressure on the carbon price.

The European Commission's impact assessment[44] of the climate change proposals evaluates the effect of the renewables targets on the 2020 carbon price to be a reduction from 49 €(2005)/tCO_2 to 39 €(2005)/tCO_2 (these prices being based on the assumption that no JI/CDM credits are allowed into the EU ETS).

7.4. Analysis of PRIMES Baseline

The models used in PowerView for forecasting the carbon price are calibrated using modeled EU energy system projections published by the European Commission.

The 2007 baseline scenario for energy and transport trends to 2030[45] is calculated using the PRIMES energy system model (together with some auxiliary models). This modeling comprehensively covers energy consuming sectors in the EU member states under specific EU ETS carbon price assumptions (together with other assumptions on factors including policy and fuel prices). The outputs of the model include CO_2 emissions for various sectors of the economy. In light of the carbon price assumptions used, the CO_2 emissions calculated in the baseline can provide a reference point for the cost of abatement in the EU ETS (bearing in mind the assumptions used for other factors).

Baselines are calculated on the principle that only policies already adopted are included in the modelling (for example, the baseline will not reflect substantial changes in the working of the EU ETS beyond 2012). Scenarios are calculated on the basis of specific carbon price assumptions (rather than the carbon price itself being determined by the model).

Scenarios based on adjustments to the 2007 baseline to reflect various policy options related to the January climate change proposals appear in the Commission's impact assessment of these proposals. These provide an indication of the potential impact of various policies on the carbon price, and are also discussed below.

The previous baseline for 2005 is different to the 2007 baseline in a number of points.

For the latest (2007) baseline, it was assumed that the carbon price will be €(2005)20 /tCO_2 in 2010, and that will rise smoothly to €(2005)24 /tCO_2 in 2030. This contrasts with the previous (2005) baseline, in which it was assumed that the carbon price remained fixed at €(2005)5 /tCO_2 from 2010 onwards.

CO_2 in the power, energy and industry sectors in the 2007 baseline are higher than those for 2005 (Figure 36). This is despite the higher carbon price assumption, but will partially be as a result of higher oil price assumptions of the 2007 baseline[46]. This leads

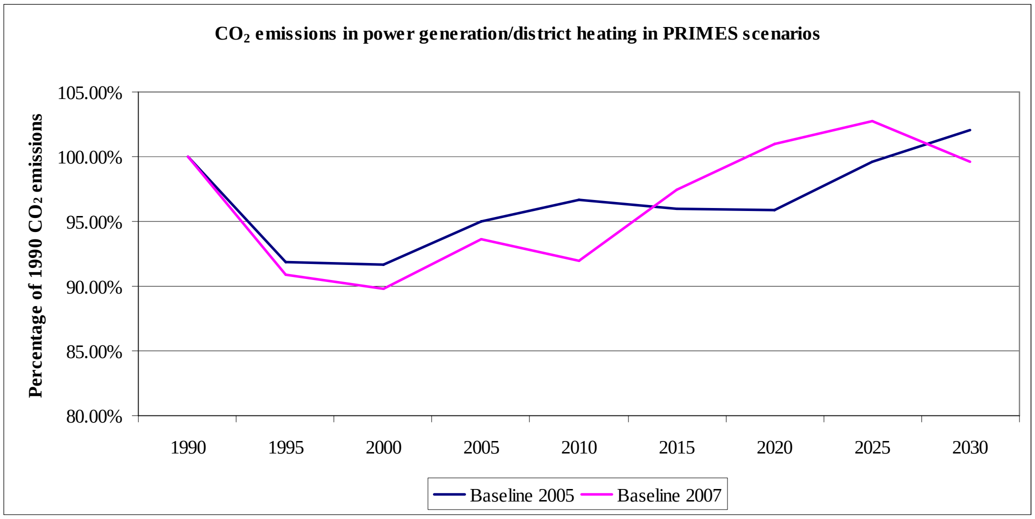
[44] Annex to the Impact Assessment, Document Accompanying the Package of Implementation measures for the EU's objectives on climate change and renewable energy for 2020 (February 2008). http://ec.europa.eu/energy/climate_actions/doc/2008_res_ia_annex_en.pdf

[45] European energy and transport – Trends to 2030 - Update 2007 (April 2008) http://ec.europa.eu/dgs/energy_transport/figures/trends_2030_update_2007/index_en.htm

[46] The 2005 baseline assumed an oil price of 48.1 $(2005)/boe in 2020 while 2007 baseline assumed an oil price of 61.1 $(2005)/boe. The increase in 2020 carbon emissions between the two scenarios (despite the higher carbon price assumption) suggests that higher oil prices may significantly increase the cost of abatement in the EU ETS.

to an increase in the gas price relative to the coal price, making higher-emitting coal generation more economical relative to gas generation. In using the Commission's published baseline scenarios as a reference point for the cost of abatement in the EU ETS, it should be borne in mind that current oil prices are much higher than those assumed in the 2007 baseline (historically high oil prices are reflected in the fact that carbon has recently been trading at a two-year high). The implications of the higher oil price are further discussed in Section 7.5 below.

Figure 36: Comparison of CO_2 emissions from power generation in the EU 27 from the 2005 and 2007 PRIMES baselines[47]



7.4.1. Variations in the baseline in the Commission's impact assessment

The Commission's impact assessment for the January climate change proposals provides an indication of how the baseline might vary as a result of the adoption of various policy options. Here we summarise the information on the likely effect on the carbon price of policy options contained in the impact assessment. Carbon prices in 2020 for various scenarios are shown in Table 14.

All the scenarios below assume an overall reduction in greenhouse gas emissions in the EU of 20% on 1990 levels (i.e. the EU's independent commitment), although one allows part of this to be covered by JI/CDM credits.

[47] Note that the 2005 baseline assumes a carbon price of €(2005)5 in 2020, while the 2007 baseline assumes a carbon price of €(2005)22 in 2020.

Table 14: Carbon prices resulting from various policy scenarios for a 20% reduction on 1990 GHG emissions by 2020[48]

Scenario[49]	**2020 Carbon price**[50]
1) Effort distributed between Member States and between ETS and non-ETS sectors on a cost efficient basis (i.e. which equalizes marginal abatement costs). Policies implemented to achieve renewables target. No access to JI/CDM credits.	€ 39/tCO_2
2) As in 1), but with GHG reduction effort modulated between member states on the basis of GDP per capita. No renewables policies.	€ 47/tCO_2
3) As in 2), but with renewables policies.	€ 43/tCO_2
4) As in 3) but with use of JI/CDM credits permitted	€ 30/tCO_2

In Scenario 4 it has been assumed that sufficient JI/CDM credits are allowed into the EU ETS to maintain the carbon price at € 30/tCO_2 (rather than the price being derived from a specific assumption about the volume of credits allowed in). The impact assessment states that the proposal to limit the use of JI/CDM credits beyond 2012 to those that have already been allowed in Phase II "resembles" this €30/tCO_2 scenario[51].

7.5. Potential Impact of High Oil Prices

Carbon price dynamics suggest that higher oil prices overall lead to higher carbon prices by improving the economics of coal generation relative to gas. However, the European Commission's climate change package impact assessment suggests that in the long term, high oil prices could have the opposite effect by promoting the development of renewable energy sources.

The impact assessment includes analysis of the sensitivity of greenhouse gas emissions to high oil prices[52], in which the 2020 oil price is increased to $(2005)100/bbl from the baseline value of $61/bbl. Two scenarios are considered, one in which the gas price remains linked to the oil price, and one in which it is decoupled. Commodity prices and the resulting reduction in CO_2 emissions on the baseline commodity price scenario are shown in Table 15, together with the baseline commodity prices.

For the scenario with gas linked to oil, the impact assessment states that the 2020 carbon price would reduce from €(2005)39/tCO_2 to €34.5/tCO_2 (note that these scenarios involve no import of JI/CDM credits).

[48] Impact assessment accompanying climate change and renewable energy package, 23 January 2008, page 15.
http://ec.europa.eu/energy/climate_actions/doc/2008_res_ia_en.pdf
[49] In the impact assessment it was assumed that aviation will be included in the EU ETS, although only flights within the EU, and outbound flights to countries outside the EU (inbound flights from countries outside the EU have been excluded).
[50] These prices are in 2005 euros (as is the case for prices appearing in the latest baseline projections).
[51] Impact assessment accompanying climate change and renewable energy package, 23 January 2008, page 15.
http://ec.europa.eu/energy/climate_actions/doc/2008_res_ia_en.pdf
[52] Commission Staff Working Document, Annex to the Impact Assessment, 27 February 2008, section 5.3.9.5.
http://ec.europa.eu/environment/climat/pdf/climate_package_ia_draft_annex.pdf

Table 15: Reduction in CO_2 emissions in 2020 resulting from high oil prices (in 2005 US$)[53]

Scenario	2020 oil price $/boe	2020 gas price $/boe	2020 coal price $/boe	Resulting reduction in CO_2 emissions
Baseline commodity price assumptions	61.1	46	14.7	0%
Gas linked to oil	100	77	24	7.1%
Gas and oil decoupled	100	59	23	7.6%

7.6. Supply of Kyoto credits

Over the past few months there have been various developments that could have a negative effect on the supply of CDM credits in Phase II:

- As discussed above, the European Commission's proposals for the EU ETS involve tight restrictions on the use of CDM credits after Phase II. While the member states and the Parliament are lobbying towards more flexible use of CDM credits, the original proposal creates uncertainty about the likely demand for CERs post-2012, which could limit project development in Phase II.
- The CDM Executive Board (the UN body responsible for supervising the CDM) has adopted new guidelines on determining whether a CDM project is 'additional' (i.e. that it would not happen without finance from the CDM – a necessary condition for a CDM project to be validated). The new guidelines make the test for additionality more rigorous, asking for a 6-month period for pre-registration of projects intending to apply for carbon credits, and developers believe that they will curtail the supply of CERs.
- Bottlenecks at the validation stage for CDM/ JI projects are worsening as it has emerged that there is a shortage of Designated Operational Entities (DOEs – organisations legally designated to verify CDM projects). This introduces delays in the validation process, which is estimated to take up to two years.

  August saw an "unprecedented" number of CDM projects submitted, due to specific project blueprints expiring mid-August which were extensively used for large and small scale renewable energy projects. Around 300 projects were submitted for completeness checks as a necessary step before registration.[54] This is the last step for projects before they are published on the UNFCCC website as "requesting registration" to produce carbon credits.

While forecasts had already been revised downwards in spring and summer this year, the past month has seen further revisions of the availability of CDM/ JI credits. In September, the UN revised down its forecast[55] of the likely total supply of CDM credits up to the end of 2012 to 1,478 million CERs. In June, the forecast was 1,568 million. Carbon analysts Point Carbon have also once more revised down their forecast at 19%

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[53] Scenarios calculated using PRIMES in the Commission's impact assessment.
[54] Once an updated version of a methodology has been approved under UN rules, project developers have 8 months to submit their projects for a final check to enter the registration process.
[55] See UNEP Risoe CDM pipeline analysis, http://cdmpipeline.org/.

compared to their previous forecast in August 2008. They expect 1,936 million CERs to be issued for the total period 2008 to 2012.

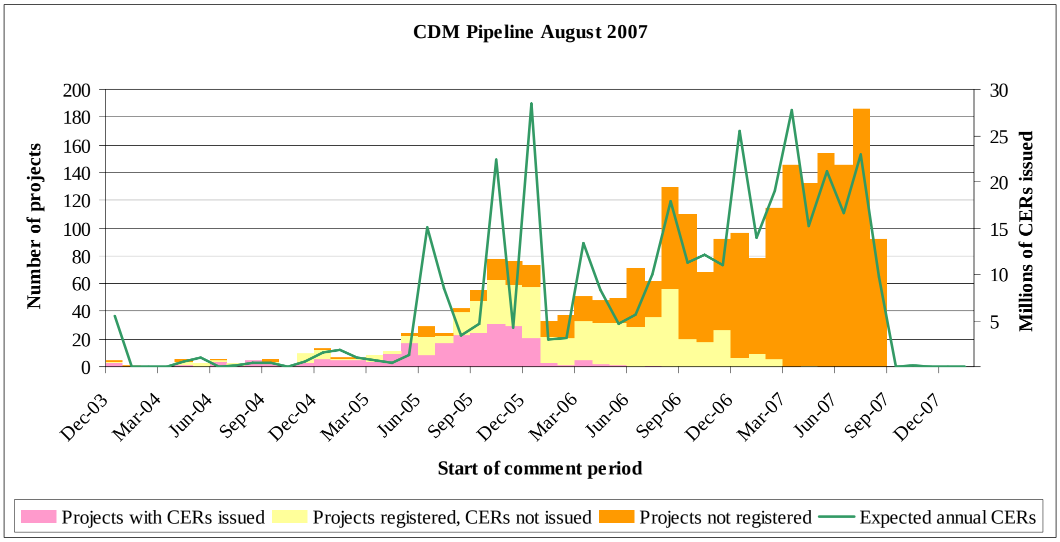
The current state of the CDM pipeline is shown in Figure 37, which also shows the state of the pipeline in August 2007 to give an indication of how the pipeline is evolving. A large number of projects has entered the pipeline over the last year (compared to the preceding few years). However, Figure 37 shows that the total expected annual volume of CERs is not increasing in line with the number of projects, indicating that recently a greater number of smaller projects has been entering the pipeline. Given the bottlenecks in the validation process, this could increase delays in the achievement of the expected issuance rates (expected annual issuance rates appear as the green line in Figure 37).

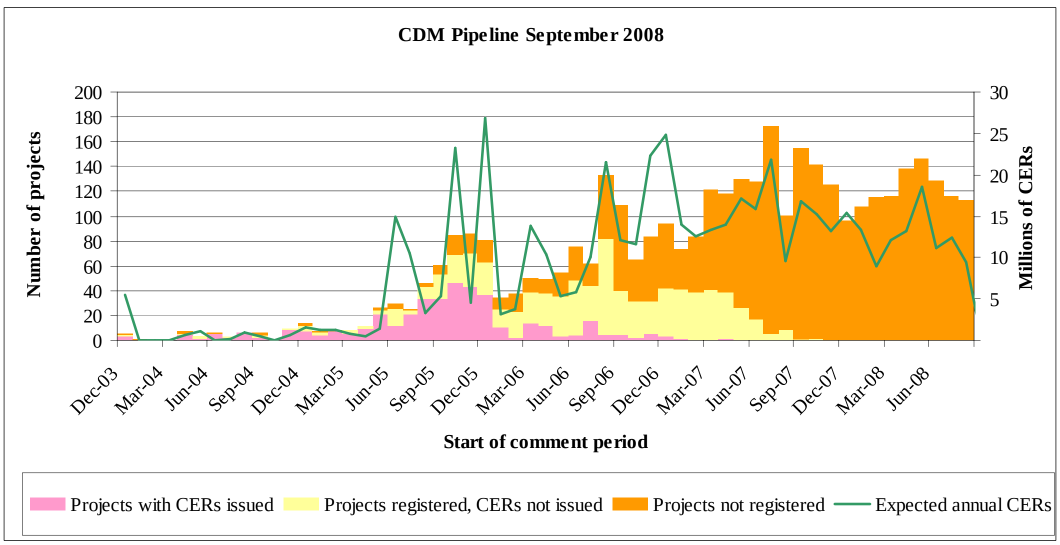
In total around 170 million JI/CDM credits have been issued so far (see Figure 38). Numbers of JI/CDM projects and credits currently at various stages of the pipeline are shown in Table 16. UN forecasts of the volume of JI/CDM credits issued by the end of 2012 are shown in Table 17.

On the basis of analysis of CDM pipeline data, we estimate that demand for CERs will be distributed globally as shown in Figure 39. If most of the volume marked ‘unknown’ in this figure is assumed to go to the EU ETS, this would imply that around 55% of CERs issued end up in the EU ETS. We calculate that around 76% of issued JI credits will enter the EU ETS.

Figure 37: Status of CDM pipeline in September 2008, and August 2007 for comparison

These graphs show numbers of projects and corresponding volumes of CERs arranged according to the date when the comment period for the project commenced. Projects are arranged throughout time according to the start of their comment periods[56].





[56] A new CDM project must produce a 'Project Design Document' which describes the design of the project and the methods for establishing the emissions savings that result from the project. This document is published on the UNFCCC web pages at the start of the project validation process, and thirty days are given for public comments. These thirty days are referred to as the 'comment period'. In these graphs, projects have been arranged according to the month of the start of their comment periods. The line 'Expected annual CERs' represents the total expected annual CERs for all projects (registered or awaiting registration) whose comment period started in the given month.

Figure 38: Cumulative number of JI/CDM credits issued

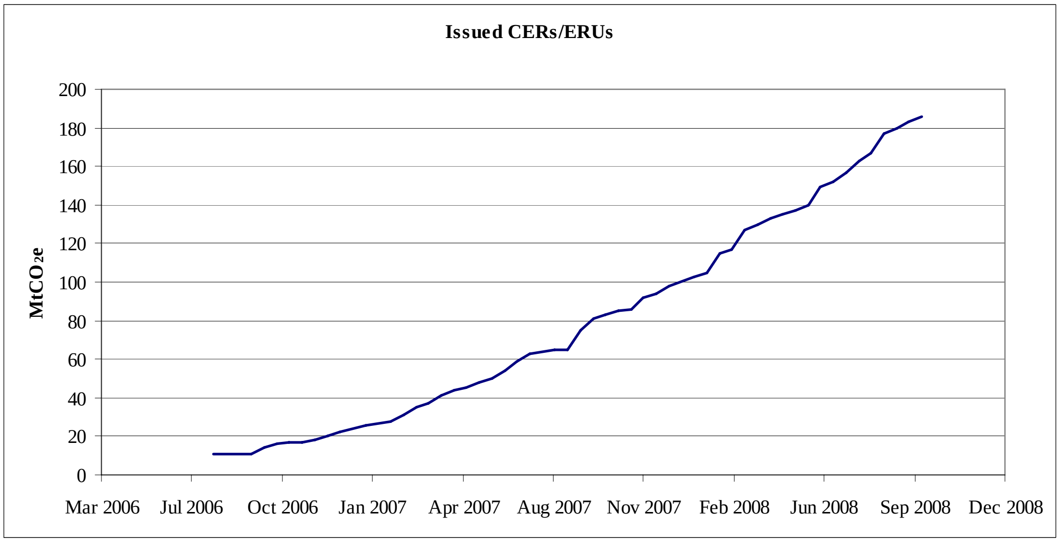


Table 16: CDM/JI Projects in Pipeline as of September 08 (May 08 figures shown in brackets)[57]

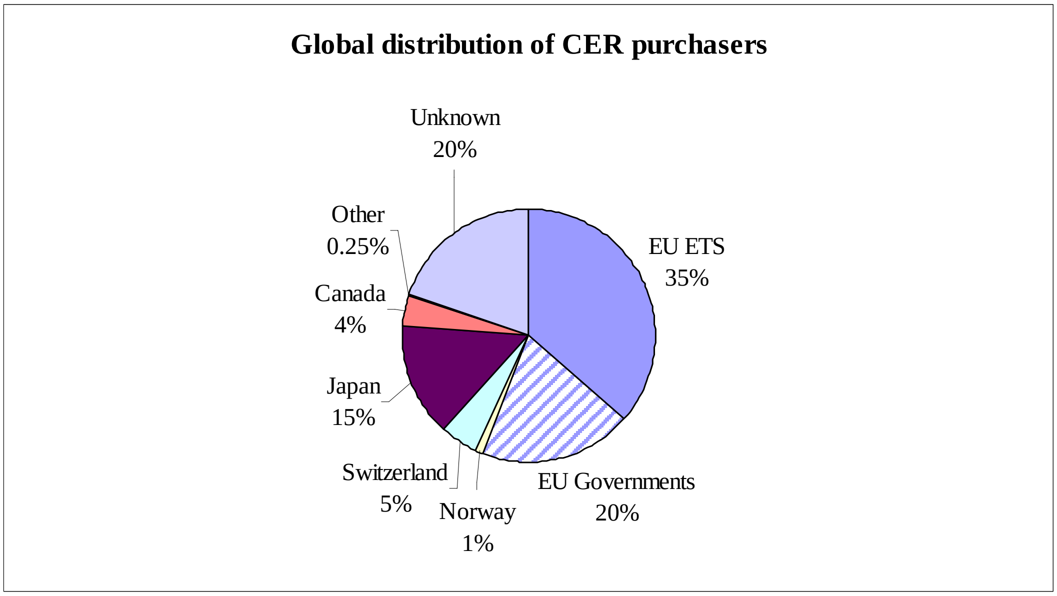
	Number of projects	Expected number of credits generated per year in Phase II
CDM projects in pipeline		
At validation stage	2467 (2122)	279M (245M)
In process of registration	200 (169)	29M (22M)
Registered	1152 (1033)	221M (211M)
Total	3819 (3324)	529M (477M)
JI projects in pipeline		
At validation stage	149 (132)	56M (52M)
In process of registration	0 (1)	0 (74k)
Registered	22 (1)	7M (0.8M)
Total	171 (134)	64M (53M)

Table 17: UNEP Risoe September 08 forecasts of CDM and JI credits issued by end 2012 (May 08 forecasts shown in brackets) [58]

Mechanism	Forecast of credits issued by end 2012
CDM (CERs)	1478M (1510M)
JI (ERUs)	206M (173M)

[57] Source: http://cdmpipeline.org/
[58] Source: http://cdmpipeline.org/

Figure 39: Global distribution of CERs purchased up to 2012[59]



UN discussions at Accra, Ghana, in August also tabled major revisions to the CDM/ JI mechanisms post-2012 but did not improve certainty over a post-2012 scheme. Among the proposals are plans to include sectoral targets into the mechanisms so that projects that cut emissions below an industry baseline could claim carbon credits. However, this has raised concerns from developing countries regarding the fair setting of such targets under differing economic development levels of participating countries. Remedies to this would include carbon intensity targets. Observers critiqued the potential complexity involved with carbon intensity targets which also differ within industries, e.g. cement. Discussions also covered eligibility of CCS, avoided deforestation and (controversially) nuclear plants for carbon credits.

7.7. Introduction of Aviation into the EU ETS

In May the European Parliament's Environment committee backed draft recommendations[60] on the inclusion of aviation in the EU ETS which were similar to the Parliament's original proposals, and considerably more ambitious than the Common Position agreed by the Council of Ministers earlier in the year. The main differences between the two positions are that the Parliament's proposals involve a tighter cap, earlier introduction of the scheme and an 'impact factor' to account for aviation's impact on global warming beyond CO_2 emissions[61].

[59] Calculated from UNEP Risoe CDM pipeline data for September 2008
[60] European Parliament Environment Committee, Draft Recommendation for Second Reading Council's common position on proposed amendment to the EU ETS directive to include aviation. http://www.europarl.europa.eu/meetdocs/2004_2009/documents/pr/718/718144/718144en.pdf
[61] There are also differences on levels of auctioning, but we do not anticipate that this will have much effect on the carbon price.

Subsequently, the European Parliament voted in favour of including aviation in the EU ETS in its second reading vote on the proposal in July[62]. All that remains for the directive to come into force is for the Council of Ministers to give it formal approval.

In adopting the proposal, the Parliament has made various concessions. In particular, there will be no ‘impact factor’ accounting for global warming effects from aviation beyond CO_2 emissions, all flights (intra-EU and external) will be introduced at the start of 2012 (as opposed to 2011 as originally proposed by the Parliament) and the cap will be set at 97% of average emissions in 2004 to 2006 (as opposed to 90% in the Parliament’s proposal).

With regard to the usage of CDM/ JI credits, the proposal states that their use should be reviewed alongside the percentage of allowances to be used in other sectors as part of the EU ETS review, to be published at least six months before each period.

The incorporation of external flights into the EU ETS is likely to prove controversial. The International Air Transport Association and the Director of the US Federal Aviation Administration have warned that legal action could be taken against the EU on this matter. Test cases are unlikely to arise before aviation is actually introduced into the scheme in 2012.

7.8. International Developments

7.8.1. Background to International Negotiations over Post-2012 Agreement

Negotiations under the UNFCCC aimed at producing a post-2012 international agreement have continued, with meetings taking place in Bangkok in March/April, Bonn in June and Accra in August.

These negotiations have proved to be complex, partly as a result of the diverse interests of the parties involved, and partly due to their twin-track nature. The roadmap agreed at the Bali conference in December 2007 (which aims to secure an international agreement at the UNFCCC conference in Copenhagen at the end of 2009) consists of two main tracks – one under the UNFCCC, and one under the Kyoto Protocol. The UNFCCC track (the ‘Convention track’) involves all parties to the UNFCCC (e.g. it includes the United States) and was initiated at the Bali conference. The Kyoto track only involves parties to the Kyoto Protocol, and was launched in 2005, so is at a more advanced stage.

Latest Meeting – Accra, August 2008

The main focus of this latest meeting was to continue to exchange ideas and clarify key elements of the Bali Action Plan, including on a “shared vision for long-term cooperative action,” as well as on mitigation, adaptation, technology and finance. Discussion topics included cooperative sectoral approaches and sector-specific actions and policy approaches; deforestation and sustainable forest management; and on the means for Annex I countries to reach emission reduction targets.

Conclusions on long-term cooperative action and on the 2009 work programme

[62] European Parliament Draft Recommendation for Second Reading http://www.europarl.europa.eu/sides/getDoc.do?type=TA&language=EN&reference=P6-TA-2008-0333

were adopted on a number of topics. While the talks in Accra were generally viewed as having moved discussions forward, one report suggested that progress had been somewhat limited, and some environmental groups urged a faster pace to future discussions. The next major round of talks will take place in December 2008, in Poznan, Poland.

The course of these negotiations involves a high degree of complexity, with the willingness of parties to modify their diverse positions depending on developments under both tracks. In terms of time, intensive effort will be required for a meaningful agreement to arise out of this complexity by the end of the Copenhagen conference.

An underlying source of disagreement in the discussions is the tension between industrialised countries and major developing countries (such as China, India and Brazil) over whether the latter should adopt binding targets. Some industrialised countries (such as the US) argue that an international agreement must involve binding targets for major developing countries. Japan has proposed a 'sectoral' approach to setting targets, which it hopes could overcome these differences. This would involve setting targets in developed and developing countries using a bottom-up approach for different sectors of industry based on best available techniques. It is intended that such an approach would maintain the principle of "common but differentiated responsibilities", which is enshrined in the current UNFCCC and is the basis for the different treatment of developed and developing countries under the Kyoto protocol. However, developing countries worry that sectoral approaches will favor industrialised countries with access to better technology, and this has been a point of contention at international meetings.

The EU has announced at a number of occasions that it will continue to pursue its climate change policy independent of the outcome of the international negotiations.

7.8.2. Further International Developments

This year's G8 Summit in Japan resulted in an agreement on the need for a long-term vision for reducing greenhouse gas emissions. The political leaders agreed on a declaration including a target of at least 50% reduction of global emissions by 2050 and calls for global action under the UNFCCC. The declaration highlights sectoral approaches, energy efficiency, clean energy, adaptation, technology, finance, market-based mechanisms, and tariff reduction. It also notes growing interest in nuclear power, research and development, and the World Bank's Clean Investment Funds. Some analysts welcomed the announcement and the apparent shift of the US position on a long-term goal. Other activists and some developing country politicians expressed disappointment with the outcome, arguing that it could have been stronger.

In a meeting held alongside the G8 Summit, political leaders from 16 countries and the EU issued a political declaration which focused on climate change and energy issues. The Meeting of the Major Economies on Energy Security and Climate Change process was part of a process initiated by the US Government in 2007. The meeting in Japan followed-up a previous meeting in Seoul, Korea, where a draft declaration had been adopted. The major economies' declaration underscores the UN Framework Convention on Climate Change (UNFCCC) as the global forum for climate negotiations, welcomes the outcomes from the 2007 Bali Climate Change Conference and highlights the December 2009 deadline to reach an agreement. The declaration also emphasizes the contribution of the Major Economies Meetings to the UNFCCC, stresses the importance of a long-term goal and mid-terms goals, commitments and actions, and underscores the role of carbon sinks, mitigation, adaptation, technology, and financial resources. The declaration did, however, not include an agreement on emissions targets for either the medium or long-term.

In the US, both presidential candidates have announced their intention of establishing a federal cap-and-trade scheme. However, they differ regarding the detail of the potential scheme with the democratic candidate, Barack Obama, favouring 100% auctioning of allowances and John McCain, the republican candidate, asking for partial auctioning while grandfathering the rest of the allowances. Analysts state that the cost to auctioning 100% of allowances would total $50 billion to emitters if the price of carbon reached $10/tCO_2$ under a federal cap-and-trade system.

7.9. Carbon Price Scenarios

7.9.1. Abatement curve calibration

The abatement curves used for the carbon price forecast have been calibrated using the 2007 PRIMES baseline and modeling results from the Commission's impact assessment for the climate change package (the scenarios appearing in the impact assessment are variations on the 2007 PRIMES baseline). The carbon price forecast presented here will therefore reflect the commodity price assumptions used in the 2007 PRIMES baseline. These are comparable with commodity price assumptions used elsewhere in PowerView, implying a level of consistency between the carbon price forecast and other forecasts.

The assumptions behind the scenarios are described in detail below. The carbon price scenarios are shown in Figure 40.

7.9.2. Base Case Scenario

- ***Phase II Base Case***

  For the Base Case, we assume that oil prices fall throughout the remaining years of Phase II, reaching 95$/bbl in 2012 (as has been assumed elsewhere in this forecast), putting downward pressure on the carbon price.

  We adopt the UN's forecast of the volume of JI and CDM credits that is issued in Phase II. The corresponding volumes of credits that become available to the EU ETS are shown in Table 18. We anticipate that the average annual shortfall in the EU ETS will be around 230 $MtCO_2$ making the total shortfall in Phase II around 1.1 billion tonnes of CO_2. Clearly, 970 million JI/CDM credits would cover most of this shortfall. However, a large proportion of these credits will not be issued until the final years of Phase II, meaning that it will not be possible to cover the majority of abatement effort with JI/CDM credits in the early years of Phase II. In addition, it is possible that some installations will not purchase their allowed volume of CERs, either due to perceived risk or disinclination to participate in carbon markets.

Table 18: Estimated volume of JI/CDM credits that become available to the EU ETS in Phase II

	Total volume issued by 2012 ($MtCO_2e$)	Percentage reaching EU ETS	Volume reaching EU ETS ($MtCO_2e$)
CDM credits (CERs)	1478	55%	813
JI credits (ERUs)	206	76%	157
Total	1684		970

The fact that secondary CERs currently trade at a discount to EUAs suggests that EU ETS participants consider that there is a risk that if EUAs are swapped for CERs, it may not be possible to surrender the acquired CERs for compliance in the EU ETS. However, once the EU and UN registries are linked, it can be assumed that more companies will swap EUAs for CERs in order to exploit the discount thereby closing the price gap.

Falling oil prices, together with greater use of JI/CDM credits in the EU ETS could lead to a drop in carbon prices over the next few years, but this is likely to be counteracted by anticipation of post-2012 arrangements. Given the pressure to finalise these arrangements in time for the UN climate change conference in Copenhagen at the end of 2009, it is likely that there will be greater clarity about the final form of these arrangements next year and that (given the ability to bank allowances) these will be increasingly factored into EU ETS participants' approach to trading. Even if post-2012 arrangements remain uncertain next year, installations with surplus allowances may hold on to them to reduce exposure to this uncertainty.

Aviation will be introduced into the EU ETS in 2012, with the baseline set at 97% of average emissions between 2004 and 2006. It is assumed that all flights departing from and coming in to EU airports are included in the scheme, reflecting the possibility of legal challenges if flights from outside the EU are included. Estimated demand for EUAs from the aviation sector is shown in Table 19. It is assumed that legislation incorporating aviation into the EU ETS is finalised by next year, and that demand for allowances from the aviation sector arises before 2010.

Table 19: Shortfall of allowances in aviation sector in Phase II

	Shortfall in Aviation sector ($MtCO_2$)
2011	30
2012	90

Our Base Case carbon price forecast for Phase II falls to a minimum of €22.70/tCO_2 in 2011.

- ***2020 Base Case***

We assume for the Base Case that an international climate change agreement is reached, with developed countries (and hence the EU) agreeing to a 25% reduction on greenhouse gas emissions on 1990 levels by 2020. We estimate that this would require a 29% reduction on 2005 emissions in the non-aviation traded sector (assuming that this proportional distribution of effort between the traded and non-traded sectors in the case of a 20% target is maintained).

We assume that 58% of the reduction on 2005 emissions in the non-aviation traded sector can be covered by JI/CDM credits (or 24% on the total 2020 emissions cap). This amounts to a more liberal use of these credits than would be allowed by the current proposals, with approximately 380 million JI/CDM credits being used in the non-aviation traded sector in 2020 (although we estimate that this amounts to less than half of the required reduction on business as usual emissions). In comparison, we estimate that the Commission's proposals would allow around 180 million JI/CDM credits to be used in 2020 if there is a 25% greenhouse gas target (assuming that a disproportionate quantity of JI/CDM credits is not used up in Phase II and that an international agreement is in place which allows the additional effort of 10% to be met by JI/CDM credits).

We assume that aviation is included in the EU ETS, and that all flights coming in to EU airports are included. We assume that the agreed baseline is maintained beyond 2012 (i.e. 97% of average emissions in 2004 to 2006). We assume that 50% of the reduction on business as usual emissions required in the aviation sector can be covered by JI/CDM credits.

Our Base Case forecast of the carbon price for 2020 is €35.20/tCO_2.

- ***2030 Base Case***

  We assume that a greenhouse gas reduction target of 35% on 1990 levels is adopted for 2030. We estimate that this would imply a reduction of 45% on 2005. Further, we assume that 60% of the reduction on 2005 levels can be covered by JI/CDM credits. We assume that the aviation cap remains the same and that 50% of aviation's reduction on business as usual can be covered by JI/CDM credits.

  Our Base Case forecast of the carbon price for 2030 is €45.60/tCO_2.

7.9.3. High Case Scenario

- ***Phase II High Case***

  In this scenario we assume that EU ETS participants' behavior in Phase II is dominated by anticipation of the required abatement up to 2020. We assume that clarity about post-2012 arrangements is achieved by the end of 2009, these being as for the 2020 high case scenario described below. We assume that all flights to and from EU airports are included in the EU ETS.

  Our High Case forecast for Phase II has the carbon price rising from current levels to €29.20/tCO_2 in 2012.

- ***2020 High Case***

  We assume that a firm international agreement for the post-2012 period is reached, leading the EU (and other developed countries) to adopt a target of a 30% reduction in greenhouse gas emissions on 1990 levels by 2020. We assume that the use of JI/CDM credits is only a bit lower than in the Base Case at 55% of the effort (or 33% of the total emissions cap in 2020). Aviation assumptions are as for Phase II and incoming and departing flights into and from EU airports are also included.

  Our High Case forecast of the carbon price for 2020 is €43.10/tCO_2.

- ***2030 High Case***

  We assume a 37% reduction target on 1990 levels for greenhouse gasses, estimating that this will require a 49% reduction on 2005 emissions in the EU ETS. We assume that 53% of the effort to reduce emissions on 2005 levels can be covered by CER/ERU credits.

  Our High Case forecast of the carbon price for 2020 is €54/tCO_2.

7.9.4. Low Case Scenario

- ***Phase II Low Case***

  In this scenario, we assume that finalisation of post-2012 EU ETS arrangements are delayed and that progress in international negotiations is slow, meaning that uncertainty about post-2012 arrangements persist well towards the end of Phase II. The consequent lack of clear signals means that anticipation of post-2012 arrangements does not have a strong influence on the behavior of EU ETS participants during Phase II.

  In addition, we assume that a significant volume of CDM credits becomes available to the EU traded sector towards the end of Phase II, and that greater confidence in the ability to use these credits for compliance in the EU ETS means that increased numbers of participants exploit the EUA-CER spread by exchanging EUAs for CERs.

  With the EUA-CER spread sending a stronger signal than anticipated post-2012, a greater volume of EUAs reaches the market during Phase II since installations with surplus free allowance allocations will be more inclined to trade them (being otherwise reluctant to do so, either out of a sense of the need to hedge against post-2012 uncertainty, or a more general lack of incentive to trade).

  We also assume that legal challenges prevent the inclusion of flights coming from third countries into EU airports in the EU ETS.

  The growing volume of EUAs reaching the market as the end of Phase-II approaches, together with declining oil prices causes the carbon price to fall towards 2011.

  Our Low Case carbon price forecast for Phase II drops from current levels to a minimum of €18/tCO_2 in 2011 and starts to recover slowly in 2012 at €19/tCO_2.

- ***2020 Low Case***

  In this scenario we assume that the EU adopts a 20% reduction target on 1990 levels for greenhouse gas emissions and hence a 21% reduction on 2005 levels for traded sector emissions. We assume that a large proportion (65%) of the required abatement can be covered by importing CDM credits. Again, we assume that flights from third countries are excluded from the EU ETS.

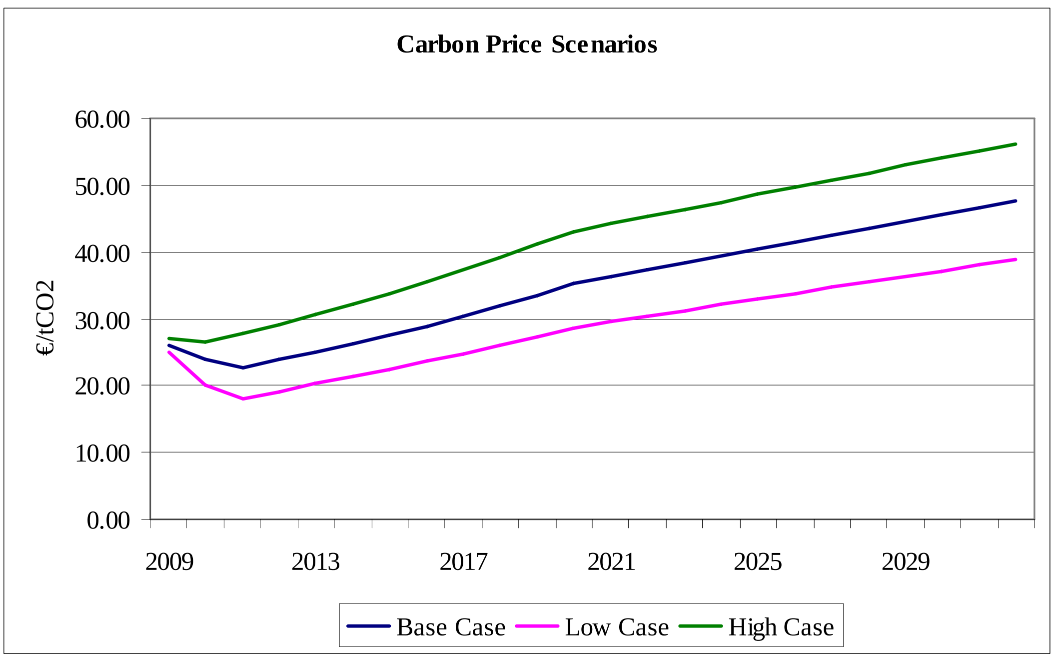
  Our Low Case carbon price forecast for 2020 is €28.70/tCO_2.

- ***2030 Low Case***

  We assume that a 33% reduction target on 1990 levels for greenhouse gas emissions, estimating that this corresponds to a reduction of approximately 42% on 2005 levels in the EU ETS. Again, we assume that much of the required abatement can be exported through the use of CDM credits (68% on reduction on 2005 levels). However, we assume that any potential international conflict over the aviation scheme will be resolved by then and all incoming flights will also be incorporated in the EU ETS.

  Our Low Case carbon price forecast for 2030 is €37.20/tCO_2.

Figure 40: Carbon Price Scenarios



7.10. UK Developments

7.10.1. Auctioning of EUAs in the UK in Phase II

The EU ETS Directive sets a limit of maximum 10% of allowances to be auctioned. The UK National Allocation Plan for Phase II sets aside 7% of the allowance cap for auctioning, amounting to approximately 85 million allowances over 2008 to 2012.

In September 2008, HM Treasury announced that the first auction will be held on November 19, 2008. The UK had refused to date to issue EUAs due to the missing link between the EU and UN credit registries. Secondary legislation and the design of the auction scheme have been developed following public consultation and came into force in August. The non-competitive element of the auctions is supposed to be in place early 2009, followed by publication of a revised scheme that will allow potential bidders access to up to 10 000 allowances.

- ***The auction scheme***

HM Treasury has appointed Defra to conduct the auctions and Defra has appointed the UK Debt Management Office (DMO) to act as its agent in running the auctions in Phase II.

Auction bids are made via primary participants (intermediaries) and organisations must apply with Defra and will be assessed against eligibility criteria.[63] Primary participants will collect and submit bids on behalf of participants (indirect bidders) who wish to acquire allowances at auctions. Any organisation with an EU ETS Registry account and an office base in an EEA state can apply. A list of primary participants will be published on the DMO website.

The application process will be open until the end of October. Defra is not willing to say how many applications it has received from potential primary participants but takes the view that the minimum viable number required for a competitive auction is 3 to 5.

The UK aims to coordinate auctions with other member states as much as possible.

- ***Auction volume***

Defra has said that the volume of allowances to be auctioned will be announced at least one month in advance of the auction date. The overall volume has been allocated across Phase II through front loading. The volume for the first auction in November will be less than 23 million.

Table 20: Estimated Front loading of the auctioning of EUAs over Phase II

Year	Date	No of allowances (million)
1	2008	23
2	2009	23

[63] These include having an office in an EEA state, having the ability to meet financial commitments supported by suitable credit ratings, the ability to effectively participate in an auction on behalf of others and systems to prevent the disclosure of confidential information (including having Chinese Walls within their organisation.) Once appointed, Primary Participants must abide by the "Terms" set out in the scheme. Further information on the application process for primary participants is available on the Defra website: http://www.defra.gov.uk/environment/climatechange/trading/eu/operators/primaryParticipants.htm

3	2010	23
4	2011	8
5	2012	8

- ***Reserve price mechanism***

  The auction scheme introduces a reserve price. HM Treasury may determine a price below which no allowances may be allocated before the close of the bidding window. The reserve price is to be paid if the auction clearing price is below the previously set reserve price.

  A reserve price was considered necessary to ensure that allowances are not sold at any price. The reserve price also mitigates against the risk of an unexpected event affecting the price during an auction. An exact reserve price mechanism is still to be developed.

7.10.2. Free allocation of EU Allowances in the UK in Phase III

The Commission's proposals for the EU ETS post-2012 state that as a consequence of its ability to pass through opportunity costs, the power sector should receive no free allocation of allowances from 2013 onwards.

In addition, the UK Chancellor announced in the 2008 budget[64] that in the UK, large electricity producers will face 100% auctioning of allowances post-2012.

In particular for Phase III, the UK government points out in its initial position that the post-2012 agreement for EUA allocation should:

- consider the benefits of a mandatory minimum level and flexibility for member states to go further if they choose, for example to capture windfall profits;
- create the right incentives for industry to price the cost of carbon into their investment decisions; and
- tend towards 100% auctioning, recognizing that a phased approach will be needed, particularly until there is a global carbon market.

Although it appears that many member states favor some free allocation to the power sector, this is not the case for the UK, and it is unlikely that UK power stations will receive any free allowances beyond 2012.

In calculating the power price forecast, we assume in all three scenarios that the UK power sector receives no free allocation of EU Allowances post-2012. This applies to both existing and new installations.

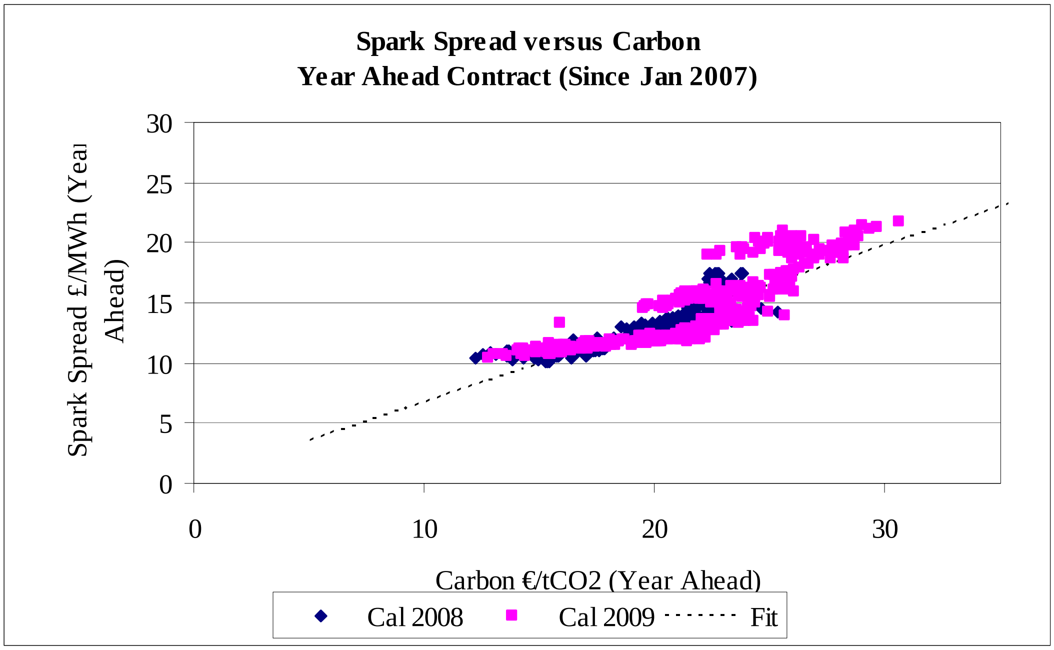
7.10.3. Carbon pass through in the UK

Economic theory suggests that carbon emissions in the power sector will be treated as an opportunity cost and passed through to power prices at the carbon intensity of marginal plant. If gas plant was always at the margin, this pass through would be manifested in a correlation between spark spreads and carbon prices.

[64] Budget 2008 http://budget2008.treasury.gov.uk/the_environment.htm

The relationship between the carbon price and the spark spread shown in Figure 41 shows higher spark spreads for higher carbon prices, suggesting significant pass-through of the cost of carbon. However, there is not a clear linear relationship, possibly reflecting complexity in the merit order.

Figure 41: Correlation between Spark Spreads and Carbon



8. EMISSIONS

This chapter discusses the sulphur emissions limits under the LCPD and IPPC and how these will impact upon the coal stations located across GB. There are corresponding limits on NOx and particulates that are not discussed in detail in this report, since broadly they are unlikely to place significant operational constraints on plant. However, these limits may require some plant to invest in emissions reduction technology. Limits on NOx emissions in the European Commission's proposed Industrial Emissions Directive could potentially pose a significant constraint from 2016 onwards, although this policy is at an early stage of development and could undergo significant modification. This is discussed in more detail in Section 8.4 below.

8.1. LCPD and IPPC

The Large Combustion Plants Directive (LCPD, 2001/80/EC) applies to combustion plants with a rated thermal input exceeding 50MW and aims to reduce acidification, ground level ozone and particles throughout Europe by controlling emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x) and dust (particular matter) from large combustion plants (LCP). LCPs include plants in power stations, petroleum refineries, steelworks and other industrial processes running on solid, liquid or gaseous fuel. LCPs must meet the emission limit values (ELVs) given in the Directive.

The UK Government implemented the LCPD through a combined ELV/NERP (National Emissions Reduction Plan)[65]. Operators had to choose by 3 February 2006 whether their plant would be regulated under the ELV or NERP approach.

After a significant amount of wrangling the final UK National Plan submitted to the Commission was based on the LCPD definition of plant=windshield, as defined by the EC rather than plant=boiler. Under the EC definition, plants whose waste gases are discharged through a common stack are considered a single plant.

In addition, plants subject to the LCPD must comply with Directive 96/61/EC (the Integrated Pollution Prevention and Control (IPPC) Directive) through the application of Best Available Techniques (BAT). In 2006, Pollution Prevention and Control Regulations 2000 (PPC) replaced IPC regulations. These regulations specified annual mass limits on the emissions of SO_2 at a station and company level for the period to December 2007, with statements on mass limits to 2015 released in January 2006[66]. In April 2008 in England and Wales, PPC regulations were replaced by the Environmental Permitting Regulations 2007. These bought together PPC and waste management regulations. This did not introduce any major changes to the PPC regulations.

[65] A framework for the Regulation for existing large coal and oil fired combustion plant at Power Stations in England and Wales 2008-15, Environment Agency, January 2006.
[66] Ibid.

8.2. Emissions Limits

The emissions limits for coal plant under different options are summarised in Table 21 below.

Table 21: Coal Plant Emission Limits

	Rate Limits	Mass Limits
Opted in ELV	$400mgSO_2/m^3$ Based on load weighted average over 48 hours over all boilers. Excludes start up and shut down.	9kt/year per GWe capacity Excludes start up and shut down. Transferable 'B' limits Limits FGD plant to 58% LF @ 1.75% sulphur coal with 90% sulphur removal.
Opted in NERP	$1.8tSO_2/GWh$ Equivalent to $400mgSO_2/m^3$, but this is an annual limit. Excludes start up and shut down.	Annual NERP mass limit = LCPD opted-in ELV × average annual waste gas flow for 1996-2000 (estimated using fuel net calorific values), resulting in limits/unit capacity of between 5.5 and 8.5 kt/year per GWe (implying load factors of between 35% and 55% @ 1.75% sulphur coal with 90% sulphur removal).
Opted Out 20,000 hours operation over station between 2008-2015. Plant must then close. Limit plant to average 28% LF over period	$7.5tSO_2/GWh$ Equivalent to $2000mgSO_2/m^3$, but this is an annual average. Excludes start up and shut down.	9kt/year per GWe capacity Excludes start up and shut down Transferable B limits Limits non-FGD plant to 22% LF @ 0.6% sulphur coal.

The controls define cap and trade limits on total emissions of SO_2 and NOx in the form of transferable operator 'B' limits for plant under LCPD and a parallel, but independent, arrangement for SO_2, NOx and particulates for plant under NERP.

The rate limits for plant Opted In under LCPD or NERP are low enough to effectively exclude non-FGD plant. This is because it would not be possible to achieve these rates without sourcing coal at below 0.2% sulphur, which is not widely available and likely to present problems for burning in existing boilers. Thus, to achieve these ELVs at least some of the plant will have to have been fitted with FGD equipment.

The LCPD definition of plant=windshield will significantly restrict the use of the limited hours for plant Opted Out of the LCPD, since operation of any of the units (including start up and shut down) will count toward the running hours of the station as a whole.

8.3. Market Response

The status of the UK coal and oil stations under the LCPD and in terms of FGD is summarised in Table 22 below. The Environment Agency has granted temporary low-load derogations under Article 5(1) of the LCPD for certain plants that have opted in to the LCPD but have yet to fit FGD equipment.

Table 22: UK Coal and Oil Stations

Installation	Operator	Fuel	Installed Capacity (MWe)	Number of boilers	Number of plant (Common Stack Definition)	Capacity Opted In (MW)	Capacity Opted In NERP (MW)	Capacity Opted In ELV (MW)	Capacity Opted out (MW)	FGD status
Drax	Drax Power	Coal	3,960	6	1	3,960	3,960	0	0	Fitted to all units
Eggborough	BE	Coal	2,000	4	1	2,000	2,000	0	0	Fitted to two out of four units
Cottam	EDF Energy	Coal	2,000	4	1	2,000	0	2,000	0	Fitted to all units
Ferrybridge	SSE	Coal	2,000	4	2	1,000	0	1,000	1,000	Limited hours derogation has been extended to Oct 15th 2008. FGD being fitted to two out four units.
Fiddlers Ferry	SSE	Coal	2,000	4	1	2,000	0	2,000	0	Limited hours derogation has been extended to Oct 15th 2008. FGD being fitted to all units.
Didcot A	RWE npower	Coal	2,000	4	1	0	0	0	2,000	Opted out (no FGD).
Tilbury	RWE npower	Coal	1,520	4	2	0	0	0	1,520	Opted out (no FGD).
Kingsnorth	E.ON UK	Coal	2,000	4	1	0	0	0	2,000	Opted out (no FGD).
Ratcliffe	E.ON UK	Coal	2,000	4	1	2,000	0	2,000	0	FGD fitted to all units
Ironbridge	E.ON UK	Coal	1,000	2	1	0	0	0	1,000	Opted out (no FGD).
Rugeley	IP	Coal	1,000	2	1	1,000	0	1,000	0	Rugeley has been granted limited hours derogation under the LCPD while FGD is being fitted. This will extend for an undefined period to be agreed with the Environment Agency.
West Burton	EDF Energy	Coal	2,000	4	2	2,000	0	2,000	0	FGD fitted to all units
Peterhead	SSE	CCGT	1,320	2	1	1,320	1,320	0	0	No FGD
Longannet	SP	Coal	2,304	4	1	2,304	2,304	0	0	FGD work will be completed in 2008.
Cockenzie	SP	Coal	1,152	4	2	0	0	0	1,152	Opted out (no FGD).
Aberthaw	RWE npower	Coal	1,500	3	1	1,500	0	1,500	0	Full abatement achieved on two units. Abatement on the remaining unit should be completed in October 2008.
Uskmouth	Uskmouth Power	Coal	393	3	1	393	0	393	0	Fitted to all units
Littlebrook	RWE npower	Oil	2,000	3	1	0	0	0	2,000	Opted out (no FGD).
Fawley	RWE npower	Oil	1,000	2	1	0	0	0	1,000	Opted out (no FGD).
Total			**33,669**	**69**	**24**	**21,997**	**9,584**	**12,413**	**11,672**	

As can be seen in the above table, there are a number of stations still in the process of fitting FGD. Most FGD installations use the limestone-gypsum method of FGD, but Aberthaw and Longannet are close to estuaries and are fitting the sea water scrubbing method of sulphur dioxide removal. The alkalinity of sea water restricts the amount of sulphur that can be removed by the scrubbing process, and so these stations will not have as much flexibility in terms of coal supplies, having to purchase slightly lower sulphur coal to maximise plant load factors and meet rate limits. Plant with the limestone gypsum method will have more flexibility and so will be able to burn coal with higher sulphur contents.

Opted Out Non-FGD plant SO_2 emission rate limits will allow burning coal up to 0.9% sulphur, but in practice they will target a lower content (around 0.6% has been achievable) to maximise load factors.

Ferrybridge has two stacks and so is defined as two plants, it has Opted In (ELV) half of the station and is fitting FGD to these units, and the other half of the station has been Opted Out and is to be left unabated.

Eggborough has a single stack but has FGD fitted to only half the units. It has chosen to Opt In (NERP), and as the NERP option provides flexibility through annual rate limits they will be able to run the non-abated units some of the time. To ensure that they remain below the emissions limits they will have to target relatively low sulphur coal burn, and limit the running of the non-FGD units. However they should be able to achieve around 30-40% of the total station running on the non-abated units, depending on the sulphur content of the coal used. Choosing to Opt In also leaves open the option of fitting FGD to the non-abated units at a later stage. However, running with some non-abated units could restrict the total level of station running, due to restriction under the NERP mass limit.

The controls place independent cap and trade limits for ELV and NERP. Most of the generators have opted under the ELV route and so will be able to trade emissions B limits. There are a smaller number of generators that have opted for the NERP route, but they will be able to trade with some of the 5 industrial plants that have also opted for the NERP route.

Following the consultation on the operation of the UK NERP, the Large Combustion Plants (National Emission Reduction Plan) Regulations 2007[67] came into force on 10 September 2007. In December the UK Government published revised NERP allocations[68] in the light of certain checks on plant details. The NERP limits for power stations are shown in Table 23.

Table 23: Contribution to UK NERP emissions limit bubbles for participating power stations (tpa).

Power Station	SO_2	NO_x from 2008 to 2015	NO_x from 2016 to 2017	NO_x from 2018	Dust
Drax	33,563	41,901	16,887	16,887	4,195
Eggborough	10,740	13,371	5,478	5,478	1,342
Peterhead	815	4,124	4,124	4,124	114
Longannet	13,845	17,533	7,328	7,328	1,732

8.4. Industrial Emissions Directive

The European Commission has published a draft Industrial Emissions Directive[69], which would come into effect in 2016, and has the aim of simplifying existing industrial emissions legislation. It recasts the IPPC directive, and six sectoral directives (including

[67] The Large Combustion Plants (National Emission Reduction Plan) Regulations 2007
http://www.opsi.gov.uk/si/si2007/uksi_20072325_en_1
[68] NERP Update No. 1, December 2007.
http://www.environment-agency.gov.uk/commondata/acrobat/finalplan_1913491.pdf
[69] Proposed Directive on Industrial Emissions (Integrated Pollution Prevention and Control), December 2007.
http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2007:0844:FIN:EN:PDF

the Large Combustion Plants Directive) into a single piece of legislation. It also seeks to address ambiguity in the requirement to comply with "Best Available Techniques" (BAT) as laid out in the current IPPC directive. Currently, national authorities responsible for implementing the IPPC directive are allowed significant flexibility in their interpretation of BAT, and the Commission considers that this leads to inconsistency in the implementation of the directive across the EU.

Key features of the directive include

- A single stack definition of plant (as in the current LCPD).
- An explicit requirement to comply with BAT, including stricter limits on NOx emissions than currently apply.
- No NERP option (as exists under the current LCPD), i.e. all combustion plants would have to comply with set ELVs.
- The threshold for inclusion of plants would be reduced from 50 MWth rated thermal input to 20 MWth (aggregated total capacity at plant level).
- The directive would cover gas turbines licensed before November 2002 (as well as those licensed after). The current LCPD does not cover gas turbines licensed before November 2002.

At present, the European Commission publishes BAT Reference Documents (BREFs) which provide information on BAT. The current IPPC directive does not impose a strict requirement to comply with BAT as outlined in the BREFs. The proposed Industrial Emissions Directive would introduce such a requirement.

In particular, coal plant would be required to comply with a NOx ELV of 200mg/m^3 from 2016 onwards. To achieve this, plants would be required to fit selective catalytic reduction (SCR) equipment. In addition, gas turbines (including CCGT) would have to comply with a NOx ELV of 50mg/m^3, and this could lead to early closure of old gas-fired power stations. Consequently, the proposals as they stand could create a "cliff edge" at the beginning of 2016. The sudden introduction of stringent NOx emissions requirements, without the flexibility of a mechanism such as the NERP, could make a significant amount of generation capacity uneconomical at the time when plant opted out of the current LCPD have agreed to cease running.

The UK government and Defra have stated that it generally welcomes the Directive, but has voiced its concern about the implications of these measures on security of electricity supply at EU level. Defra has consulted[70] on the proposed directive and responses closed on 31st July 2008.

Since this policy is still at an early stage of development, and its final form remains far from clear, possible effects of its introduction have not been incorporated into this forecast.

8.5. Forecast Assumptions

The assumptions on the sulphur content of coal burnt at the various coal generation plant are detailed in Table 24.

[70] http://www.defra.gov.uk/corporate/consult/emissions-other/index.htm

Table 24: Assumed Sulphur content of Coal

Plant	% Sulphur Coal
FGD (Lime-stone gypsum)	1.75%
FGD (Seawater Scrubbing)	1%
Non-FGD	0.6%

Plant opted out of the LCPD will have to close by 2016. However, it is considered that where plant is required to maintain security of supply, plant may be re-licensed as *peaking-plant*. This would allow their continued operation at low load factors, and allow plant margins to be maintained. The LCPD provides a derogation for peaking plant to run post 2016 for 1,500 hours per year with relaxed ELVs of 800mg/Nm^3 – which should be achievable on a low sulphur diet for non-FGD plant. Whilst not strictly under the terms of the original opt-out from the LCPD, this could perhaps yet provide an ongoing regulatory framework and a lifeline to keep these coal plants operating. It has been assumed that such plant would be limited to 1,500 hours running per year from 2016 onwards, but would have to close if they are no longer required for system security purposes. It is considered this is a reasonable assumption since there are likely to be a number of countries that may face security of supply issues with the sudden closure of coal plant, especially in a future where there is significant growth in intermittent generation from renewables.

It has been assumed that the ELV limits and mass limits for FGD plant remain the same post 2015, over the remainder of the forecast horizon.

8.6. Carbon Capture and Storage

The European Commission aims to provide a context that is favorable to the development of Carbon Capture and Storage (CCS). Although the Commission believes the primary incentives for the implementation of CCS should come from the EU ETS, it also believes that additional measures may be necessary to foster use of the technology. These measures would be implemented after 2020, but would be adopted sufficiently in advance to influence investment decisions[71].

As an option for providing incentives for the phasing in of CCS, the Commission has suggested legally binding measures to regulate emissions per kWh after 2020 with a timed phase-out of all non-CCS CO_2 emitting generation (by e.g. 2050). The Commission also believes that all new coal-fired plants should be fitted with CCS by 2020, although it has not yet reached a definite view on this[72].

As part of the January 2008 climate change package, the Commission published a proposed directive on the regulation of CCS. This covered criteria for the assessment of potential storage sites, Member States' permitting of storage and site exploration, regulation of CCS schemes during operation, closure and post-closure and access to transport networks and storage sites. The proposal did not include the mandating of CCS, which the Commission considers inappropriate given the current level of development of the technology. Article 32 of the proposed directive requires all new coal plant to be 'carbon capture ready', meaning that suitable space should be available for the necessary equipment, suitable storage sites should be available and that retrofitting of CCS should

[71] European Commission Communication. Sustainable Power Generation from Fossil Fuels: aiming for near-zero emissions from coal after 2020.
http://ec.europa.eu/energy/energy_policy/doc/16_communication_fossil_fuels_en.pdf
[72] European Commission Communication. An Energy Policy For Europe
http://ec.europa.eu/energy/energy_policy/doc/01_energy_policy_for_europe_en.pdf

be technically feasible. This definition of carbon capture readiness is addressed in the CCS consultation recently launched by the UK government (see below).

As part of the same climate change package, the Commission published a proposed directive on the operation of the EU ETS post-2012, which would include CCS activities in the EU ETS. The Commission will also consider intermediate options to account for CCS activities in the EU ETS during Phase II[73]. Under present plans, CCS with Enhanced Oil Recovery (EOR) will not be eligible under the EU ETS.

Members of the EU Parliament's Environment Committee have suggested that the proposed directive governing the operation of the EU ETS post-2012 be amended so that power stations with CCS are granted one extra EU Allowance for every tonne of CO_2 captured. This would effectively double the value of using CCS under the EU ETS. This proposal is designed to address the fact that current carbon prices are too low to incentivise the development of CCS. The extra allowances would come from the New Entrants Reserve.

In January 2007 the Commission announced its intention to launch a Strategic Energy Technology Plan[74] to promote R&D in low carbon technology for the energy sector. The results of the public consultation[75] on this plan were released in September 2007. Relatively few respondents saw CCS as the best technology for reducing CO_2 emissions.

In January 2008 the Commission published new guidelines on state aid for environmental protection[76]. This states that some means of support for CCS envisaged by member states could be considered state aid, but that given lack of experience, it is too early to lay down guidelines for authorizing such aid. The document states that given the strategic importance of CCS for the EU, the Commission will have a "generally positive" attitude towards state aid for CCS projects, provided they are environmentally safe and contribute towards environmental protection.

Last year significant regulatory obstacles to the implementation of seabed geological storage of CO_2 have been overcome, with revisions to the London Convention in February and the OSPAR Convention in June although it will take time for these to be incorporated into national legislation.

The Commission is aiming for the launch of up to 12 large scale demonstration projects for coal and gas plants by 2015, and has stated that it will design a mechanism to stimulate this. In this context, a competition to build the first CCS plant was launched by the Prime Minister in November 2007. BERR are running this competition and have announced the government will fund up to 100% of the "additional" costs of a demonstration plant. Currently, four bidders have pre-qualified for the competition. BP Alternative Energy International Limited, EON UK Plc, Peel Power Limited and Scottish Power Generation Limited were selected from nine contenders based on their responses to the pre-qualification questionnaire. A preferred bidder for the project is supposed to be

[73] European Commission Communication. Sustainable Power Generation from Fossil Fuels: aiming for near-zero emissions from coal after 2020.
http://ec.europa.eu/energy/energy_policy/doc/16_communication_fossil_fuels_en.pdf
[74] European Commission Communication. Towards a European Strategic Energy Technology Plan
http://eur-lex.europa.eu/LexUriServ/site/en/com/2006/com2006_0847en01.pdf
[75] Report of the Public Consultation on the European Strategic Energy Technology Plan
http://ec.europa.eu/energy/res/setplan/doc/2007_setplan_report_public_consultation_en.pdf
[76] New guidelines on State aid for environmental protection
http://ec.europa.eu/comm/competition/state_aid/reform/environmental_guidelines_en.pdf

announced by the end of summer 2009 with the aim of having an operational CCS power station by 2014.

Taxation implications for the offshore portions of the CCS chain (including pipeline and reservoir change of use) are currently being considered by a HMRC/Industry Working Group.

Separately, the UK government has consulted on CCS and what it means for a coal-fired power station to be 'capture ready'[77]. Details of the CCS capacity assumptions that are made within the model are provided in Section 9.

[77] BERR consultation: Towards Carbon Capture and Storage. http://www.berr.gov.uk/consultations/page46811.html

9. CAPACITY & COSTS

This section briefly describes some of the key capacity and cost assumptions used in constructing this forecast.

Generation capacities have been updated taking into account information from the NGT GB Seven Year Statement[78], Ofgem's list of ROC accredited generation stations[79], the Platts Power UK Power Station Tracker[80], as well as other Industry Sources.

There are a significant number of generation projects that are currently at various stages of development, predominantly CCGT and wind generation, with an increasing interest in investment in coal fired capacity. However, it is likely that many of these projects will not be commissioned within their currently projected timescales, and some projects may not be taken to completion.

Some of the recent capacity developments are discussed below.

9.1. Coal

A significant amount of investment has gone into enhancing existing coal units, predominantly in the area of emissions abatement, efficiency improvements and increased capacity to burn biomass. The investment has been predominantly in response to the LCPD (Large Combustion Plant Directive), the benchmark methodology for EUA allocations under the Phase II NAP, and incentives under the Renewable Obligation. The current status of FGD retrofitting projects is summarized in Chapter 8. Since most of this investment has been committed it has been assumed works will be completed under the modelling assumptions.

There is significant potential for retro-fitting the non-FGD coal plant (plant which have opted for a limited time derogation under the LCPD and will have to close by 2016) with supercritical coal units, which would provide significant efficiency improvements compared to the existing coal fleet (with efficiencies up to 45%), and significant savings on capital cost compared to new build, as existing infrastructure (such as rail facilities, coal handling and substations) can be reused. Estimates for capital costs vary significantly, and will be dependent upon the extent of reuse of infrastructure, SSE had estimated around £500/kW for Ferrybridge, E.ON had estimated £625/kW, and estimates provided to the DTI for the 2006 Energy Review[81] put costs around £720/kW. However, it appears that as FEED studies are developed some of the initial cost estimates appear optimistic, and actual costs could out-turn at the higher end of the range implied by the these studies. In the modelling it has been assumed that retro-fit supercritical build costs are around £720/kW, although in practice the costs are likely to vary significantly between sites, dependent upon the extent of the re-use of infrastructure.

Retrofit coal projects are likely to be carbon capture and storage (CCS) ready, and the addition of this technology is likely to cost at least £200/kW (although there are significant uncertainties associated with this estimate).

[78] NGT's Seven Year Statement 2008, http://www.nationalgrid.com/uk/library/documents
[79] Ofgem, http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/renewstat
[80] Platts Power UK Power Station Tracker, May 2008
[81] DTI 2006 Energy Review, Financial Models, Retrofit Coal Plant based on Pulverised Fuel with FGD and CCS

SSE is rethinking plans to extend the life of its Ferrybridge coal plant. They have announced that they are no longer looking at pursuing a retrofit plan on one of its subcritical 500MW units and that both subcritical units will close by 2016 as originally intended. However, SSE is looking to build an 800MW supercritical plant on the site re-using some of the infrastructure, but no application for consent has been made as yet and a decision is not expected before 2010.

There are several new build IGCC projects, with the intention that these projects could be developed with Carbon Capture and Storage systems (CCS). However, with capital costs likely to be in the £1,250/kW–£1,500/kW range it is unlikely that these projects will be pursued unless they receive significant support from Government. Whilst the Government are to fund a CCS demonstrator project they have restricted this to post-combustion technologies, effectively excluding these projects.

Details of proposed new and retrofit coal developments are provided in Table 25.

There are a number of risks associated with new coal build which increase the uncertainty over whether these coal developments get completed. These include:

- Obtaining planning consents for plant and associated infrastructure (including coal transportation and potentially CCS pipelines) can take a considerable amount of time. There are likely to be fewer issues for developments on the site of existing stations, but consents for new sites may be difficult and time consuming to obtain;
- There is limited industry capacity in terms of engineering, manufacturing and construction to build new plants in the UK, reflecting the fact that there has been relatively little coal build over the last 10 years across Europe (although there are currently lignite plant under construction in Germany). In addition, in the event that coal build is economic, the UK may have to compete for industry capacity with developments across Europe as well as significant new build in China and India;
- New coal plant developments are likely to use state-of-the-art super-critical technology, and retro-fit coal plant will combine the issues of super-critical technology with re-use of existing infrastructure. The lack of experience within Europe of developing these types of projects means that developers will be unlikely to obtain the type of fixed price turn-key contracts with performance guarantees that have become standard in CCGT development. This is likely to make developing coal projects significantly more risky than developing CCGT capacity.

The Government announced in the Budget, and within the Energy White Paper, that there will be a competition to build a CCS plant. To be eligible for the competition, project proposals must:

- Be situated in the UK;
- Cover end-to-end carbon processing (capture, transport and storage);
- Have a minimum of 300MW capacity;
- Demonstrate post-combustion CCS with CO_2 stored offshore (for coal-fired stations);
- Store at least 90% of carbon dioxide; and

- Start demonstrating the full chain of CCS at some point between 2011 and 2014.

BERR have announced four bidders that have pre-qualified for the competition. BP Alternative Energy International Limited, EON UK Plc, Peel Power Limited and Scottish Power Generation Limited were selected from nine contenders based on their responses to the pre-qualification questionnaire. A preferred bidder for the project is expected to be announced by the end of summer 2009 with the aim of having an operational CCS power station by 2014.

Alongside the UK competition, BERR will shortly announce a new call for expressions of interest under the Environmental Transformation Fund to support the development of component parts of CCS.

The Government has consulted[82] on CCS regulations and what it would mean for a new coal-fired power station to be 'capture ready', (i.e. to be in a position to retrofit CCS technology once it is proven at a commercial scale), and whether all new fossil fuel power stations should demonstrate that they are capture ready. The closing date for the consultation was the 22nd September 2008.

[82] BERR consultation: Towards Carbon Capture and Storage.
http://www.berr.gov.uk/consultations/page46811.html

Table 25: Coal Fired Generation Projects

Station Name	Developers	Size (MW)	Planned Date	Consent Status	Notes
Eston Grange	Centrica/ Progressive	800	2014	Not Applied	New IGCC plant (with capture). On hold due to the government announcement that pre-combustion CCS technologies are not to receive state funding.
High Marnham	E.ON	1,600	2015	Not Applied	Supercritical plant. E.ON looking to apply for a scoping study very soon.
Killingholme	E.ON	450	2012	Not Applied	On hold due to the government announcement that pre-combustion CCS technologies are not to receive state funding.
Kingsnorth	E.ON	1,600	2013	Applied – On Hold	E.ON have put this project on-hold whilst they await findings from the government on CCS. Local planners have voted to back the project.
Westfield	Global Energy	400	2010	Not Applied	New IGCC plant (with storage) is being considered at Global's Westfield site in Fife.
Hatfield	Powerfuel	900	2013	Approved as CCGT	Powerfuel have modified their original plans for an IGCC, having securing consent for a CCGT, which could be converted into an IGCC at some point in the future.
Wansbeck/ Blyth	Progressive Energy	800	2014	Not Applied	New IGCC plant. On hold as Progressive are focussing on the Teesside development.
Cambois/ Blyth	RWE	2,400	>2016	Not Applied	Supercritical plant. ES document has been submitted. Plant will be designed to be 'carbon capture ready'. RWE are looking to submit a planning application at the end of 2008.
Tilbury	RWE	1,600	2015	Not Applied	Replant of a supercritical plant. Project was not short-listed for the CCS competition, by may re-emerge as part of one of the consortia which does not yet include a power generation partner (with Peel and BP) using either Blyth or Tilbury sites.
Ferrybridge	SSE	800	>2016	Not Applied	SSE has scrapped plans to retrofit one of their 2 subcritical non-FGD units. However, they are considering an 800MW supercritical plant on the site.
Cockenzie	ScottishPower	1,200	2014	Not Applied	Supercritical plant. Designed to be 'carbon capture ready'
Longannet	ScottishPower	2,400	2014	Not Applied	Supercritical plant. Designed to be 'carbon capture ready'

9.1.1. Modelling Assumptions

It is assumed that all of the current investments being undertaken at existing coal plant to increase plant efficiency, reduce emissions, and increasing co-firing capacity are developed to completion.

Despite the significant growth in interest in coal generation projects, it is likely that many of the projects currently being investigated will not be developed. Future coal developments will be highly dependent upon new build economics over the forecast horizon, which also will be heavily influenced by decisions upon the future structure of the EU ETS. However, under any scenario the retrofit stations are the most likely to be developed due to their significantly lower capital costs.

PowerView modelling has the capability to construct retro-fit coal on the site of closed coal stations, where the modelling indicates that retro-fit coal capacity is economically viable (in terms of recovering financing, fixed and variable costs). The development of retro-fit coal capacity is therefore dependent upon project economics under each of the forecast scenarios. Modelling results are reported in Sections 11 and 12.

It is assumed that the CCS competition stimulates development of a CCS project. It is most likely that this will be developed as part of a supercritical retrofit at one of the coal plants providing the largest carbon saving at lowest capital cost. It is assumed in all scenarios that a 500MW retrofit coal CCS project is completed in 2013, and operates over the remainder of the forecast horizon.

Although the EU has announced an intention to require new coal plant to be fitted with CCS post 2020[83], CCS technology is relatively expensive and would need a significantly enhanced carbon price (with carbon trading at a premium to the PowerView carbon forecasts) to ensure long term economics. It is assumed that there are no other new CCS projects completed over the forecast horizon. It is accepted that further supported demonstrator projects could be constructed over the forecast horizon (and the EC has indicated potential support for this), and it is possible that CCS might approach economic viability approaching the end of the forecast horizon, especially under the high carbon price scenario.

[83] European Commission Communication *An Energy Policy for Europe*, 10/01/2007 http://eur-lex.europa.eu/LexUriServ/site/en/com/2007/com2007_0001en01.pdf, p17

9.2. CCGT Projects

There are seven CCGT / large CHP projects which are currently under construction:

- Centrica – Langage (900MW)
- ConocoPhillips – Immingham extension (450MW)
- E.ON UK – Grain (1,290MW CHP)
- ESBI/SSE – Marchwood (850MW)
- RWE – Staythorpe C (1,660MW)
- Welsh Power – Newport (850MW)

There are a number of other projects where the developers have made recent progress:

- Centrica has applied for Section 36 consent to a build a 1,020MW extension to its 340MW CCGT plant at Kings Lynn;
- BP Energy submitted a Section 36 consent application for an 870MW CCGT on a site adjacent to GE's existing Baglan Bay power station in South Wales;
- Bridestones Development have been awarded consent to build a 860MW CCGT at Carrington (called Partington); and
- Thor Cogeneration has been granted consent for their 1,020MW Seal Sands cogeneration plant.

There are a significant number of CCGT projects at various stages of development, with projects totalling nearly 19GW under development and are listed in Table 26. Projects are being pursued by a wide range of companies ranging from the major utilities and the oil majors, to independents.

Given the current status of these projects it seems unlikely that any will be commissioned before 2009, although there are several that could be commissioned shortly after that date. However, it is unlikely that all of these projects will be pursued in the timescales currently envisaged by developers.

The DTI's note on Guidance to Developers[84] places significantly more emphasis on developers to explore CHP options when applying for consent for CCGT development. The guidance is not rigid, and enables developers to pursue non-CHP developments. However, if the guidance is applied strictly it could make it more difficult to develop non-CHP projects, which could result in CCGT projects being delayed or cancelled, and could see developers much more focused on developments with the potential to supply large heat loads.

The modelling assumes that the CCGT projects where construction has commenced or there has been a firm commitment to develop the project are completed, these include Marchwood, Langage, Staythorpe C, Newport, Immingham extension and Grain. The Pembroke Phase I (800MW) development still has some uncertainty surrounding it, so it is only assumed to be constructed in the Low Case with capacity phased in from 2013.

[84] Guidance on Background Information to Accompany Notifications under Section 14(1) of the Energy Act 1976 and Applications under Section 36 of the Electricity Act 1989, DTI, December 2006

The proposed developments at Drakelow and Barking have enough uncertainty surrounding them to not be included as specific plant developments in the modelling.

The model also has the ability to build up to 1,000MW of generic CCGT capacity per year from 2011 onwards, where new CCGT capacity is economically viable (in terms of recovering financing, fixed and variable costs). This represents the construction of some of the projects identified in Table 26, but at this stage it is not possible to predict the specific projects that will be progressed to completion.

It is interesting to note that there is also some potential for the re-development of existing CCGT sites. For instance, RWE is upgrading two of the gas turbines at Didcot B and Teesside Power has signed a contract with MHI to upgrade their turbines, although SSE recently decided not to pursue a repowering of Peterhead on the grounds of onerous transmission charges. It seems likely that there could be additional upgrade/retrofit at other older CCGT plant over the forecast horizon. However, where there is significant plant and equipment upgrade these projects may not be significantly cheaper than some of the other CCGT developments, some of which may utilise some existing infrastructure.

Table 26: CCGT Projects under Development

Station Name	Developers	Size MW	Planned Date	Consent Status	Notes
Middleton	Acorn Power	1,320	2014	Not Applied	Acorn has secured a land option within Lancashire. An environmental scoping study has been completed.
North Bedford Power	Acorn Power	1,300	2012	Not Applied	Acorn has secured a land option within Bedfordshire. A scoping document has been submitted. An Environmental Impact Study has begun and an application for grid access has been made.
North East England	Acorn Power	1,300	2014	Not Applied	Acorn has secured a land option. Grid connection problems have now been resolved.
Stanford-le-Hope	Acorn Power	1,300	2014	Not Applied	Acorn has secured a land option near Tilbury. The EIA is now underway and an application for grid access has been made.
Barking extension	Barking Power	470	2013	Approved	Extension to current 1,000MW. Has Section 36 consent with the condition that CCS can be retrofiited. Planning application could be submitted by the end of the year. Connection agreement in place for end 2013.
Baglan Bay 2	BP Energy	870	2014	Applied	BP Energy looking to submit a planning application. Grid connection has been obtained.
Partington (formerly Carrington)	Bridestones Developments	860	2012	Approved	Section 36 consent granted. Transmission agreement has been granted starting in 2011. Could start commercial operation in 2012.
Amlwych	Canatxx	270	2012	Not Applied	Transmission agreement for 2012 signed.
King’s Lynn	Centrica	1,020	2014	Applied	Centrica have applied for Section 36 consent for the possible expansion of its existing King’s Lynn CCGT from 340MW to 1,020MW. However, no investment decision has been made and local grid constraints could result in a smaller plant.
Langage	Centrica	850	2008-09	Approved	Construction work has begun. Expected to be available for commercial operation by the start of 2009.
Immingham CHP extension	ConocoPhillips	450	2009	Approved	Under construction and expected to be operational for winter 2009.
Seal Sands CHP	ConocoPhillips	800	2012	Applied	Local authority approval granted for new plant on oil refinery site. To be developed in conjunction with proposed new LNG import terminal for operation in 2012.
Drakelow	E.ON	1,230	2011	Approved	3 unit CCGT. Section 36 consent and planning permission granted as long as CCS can be retrofitted to the plant. Has transmission agreement. Could start operating by 2011.
Grain CHP	E.ON	1,290	2010	Approved	E.ON has two transmission agreements, one for 860MW in 2010 and the other for 430 MW in 2011. Under construction and expected to be completed in 2010, despite difficulties experienced by EPC contractor Alstom.

Station Name	Developers	Size MW	Planned Date	Consent Status	Notes
Sutton Bridge	EDF Energy	1,280	2012	Applied	Transmission agreement secured for 2010.
West Burton	EDF Energy	1,300	2011	Applied	Transmission agreements secured for 435MW in 2009 and 870MW the following year. Section 36 consent granted. Project could start generating in 2011. Site preparation work has begun, and contracts signed with GE for equipment supply.
Marchwood	ESBI/SSE	850	2009	Approved	Construction has begun with commercial operation expected in winter 2009/2010.
Port Talbot	ESBI	1,300	2012	Applied	Lease option on the land agreed and electricity generation license granted. Section 36 applied for. Grid access applied for. Council has objected and project now faces public inquiry.
Hatfield	Powerfuel	900	2012	Approved	Originally a coal-fired IGCC project, but now intending to construct a CCGT with potential for a gasifier to be added at a later date. Transmission connection secured from Jan 2012.
Didcot B	RWE	110	2009	N/A	DTI have given RWE permission to replace blades in 2 turbines increasing capacity by 110MW. Scheduled to be completed by mid 2009.
Little Barford	RWE	475		Not Applied	RWE has withdrawn its transmission connection agreement and the project has effectively been scrapped.
Pembroke	RWE	2,100	2011	Applied	RWE have submitted an updated Environmental Statement. Awaiting Section 36 consent. Grid connection for 2010. Has unanimous council support, but strong objections from Countryside Council for Wales.
Staythorpe C	RWE	1,660	2010	Approved	RWE have secured transmission agreement for 1,700MW phased over 2009. Construction has begun and the plant could be operational by mid-2010.
Peterhead	SSE/BP/Conoco	475	2014	On hold	BP have dropped plans to build this demonstration CCS project.
Peterhead	SSE	340	2012	Not Applied	SSE is planning to repower the plant which would increase the capacity by 340MW and deliver a higher thermal efficiency.
Damhead Creek 2	ScottishPower	500	2016	Not Applied	Scottish Power are looking to extend the existing CCGT plant. Grid constraints could limit the size of any possible extension.
Teesside	Teesside Power	1,875	2012	N/A	Gaz de France and Suez (through its subsidiary Electrabel) have jointly acquired Teesside. Its previous owners were progressing plans to replace some of the turbines at the plant and a planning application was submitted to the local council in January and a contract signed with MHI for the supply of new gas and steam turbines.
Brine Field	Thor Cogeneration	1,020	2012	Approved	Section 36 recently granted for proposed CHP plant on Seal Sands. Transmission agreement for Nov 2011 signed, and plant could be operational

Station Name	Developers	Size MW	Planned Date	Consent Status	Notes
					by 2012.
Newport	Welsh Power (Carron Energy)	850	2010	Approved	Adjacent to Uskmouth Power FGD Plant. Transmission agreement, generating license and Section 36 granted and construction has recently started. Could be operational by winter 2010.
Wyre Power	Welsh Power	850	2012	Not applied	Land secured near Fleetwood, Lancashire, with intention of submitting consent application and EIA for gas pipeline in Oct 2009. Transmission agreement for 2012 applied for.

9.2.1. CCGT New Build Costs

The costs of building new CCGT have increased significantly over the last twelve months due to rising input costs and huge demand for components. Whilst capital costs were in the order of £400-£500/kW a year ago[85], the EPC contract for Welsh Power's Severn Power project is believed to be around £600/kW and some power developers are saying they are being quoted as much as £700/kW.

The annualised cost of plant will be highly dependent upon the financing arrangements as well as the location of the plant (which will impact on fixed costs - particularly TNUoS). The modelling has assumed an annualised financing and fixed cost for new entrant CCGT of just under £10/MWh based upon an 85% load factor.

9.2.2. CHP

All recent CCGT consents have included the requirement that developers must examine the possibility of including a CHP element in their plans, reflecting the Government's wishes to more than double the amount of CHP in the UK by 2010 and treble it by 2015. Four of the projects outlined above are indeed large-scale CHP:

- E.ON agreed a contract to supply up to 340MW of waste heat to the adjacent LNG terminal for regasification from their 1,290MW Grain project. Alstom has been awarded a turnkey contract for the project and the site is expected to be generating energy by 2010.
- ConocoPhillips have started work on increasing the capacity of the Immingham CHP plant from 760MW to 1,230MW. Commissioning is expected during 2009.
- ConocoPhillips has also been granted local authority approval to build an 800MW CHP at its Teesside oil terminal at Seal Sands, but must still gain

[85] Sources include the DTI's Energy Review 2006, CER's Best New Entrant Calculation and costs published in Power UK.

consent from BERR. The plant is likely to supply energy for their planned LNG terminal at the site, and could be operational by 2012.

- Thor Cogeneration have been granted Section 36 consent for their 1,020MW Seal Sands cogeneration plant with the developer planning construction to begin next year and the plant being operational by 2012.

There is still enough uncertainty surrounding these latter two developments that they have not been included as specific plant developments within the modelling.

There is relatively little other large CHP capacity currently under active development. It is possible that the clearer treatment of CHP under the Phase II NAP, with higher levels of free carbon allocations available than for power-only plants, and the new guidance to power station developers will serve to stimulate additional CHP development, although there continues to appear to be difficulties in finding large heat loads sufficiently close to proposed sites.

PowerView modelling has the flexibility to construct small and large CHP plant when economic, subject to certain build rate constraints, as described in Table 29, however, under all scenarios the build is limited by the 13GW of potential identified.

9.3. Nuclear

There is considerable uncertainty over nuclear capacity over the forecast horizon, deriving from both the uncertainty associated with the closure of existing capacity, as well as the potential for new nuclear build. We have used different assumptions on the closure dates for nuclear capacity in the different model scenarios.

British Energy has confirmed that both Hunterston B and Hinkley Point B will have 5 year life extensions through until 2016. BE has said that they will begin a study in 2013 to examine the potential for the plant to be extended beyond 2016.

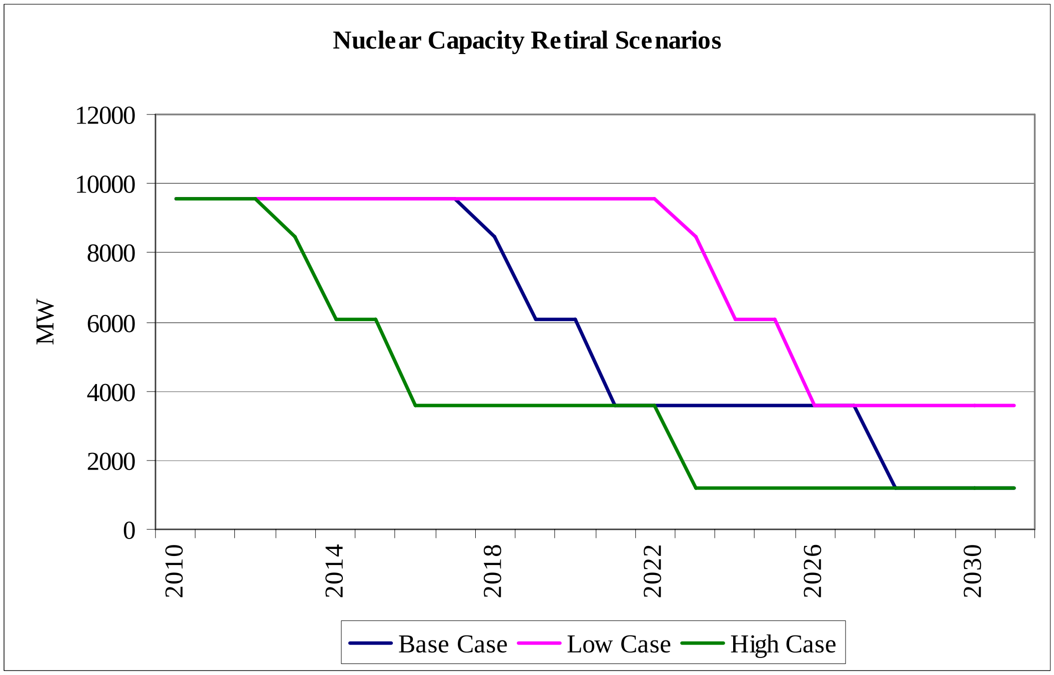
Both stations have had boiler problems for some time and have been running at a reduced load factors and have had outages since last October, but BE says that they are on track to restart the units by the end of this year.

The other stations in the nuclear fleet are likely to be assessed for life extensions as they approach their current planned closure dates. However, the economic case for life extensions would be made more difficult if there is any significant investment required on safety grounds by the Nuclear Installations Inspectorate.

The assumptions on nuclear lifetimes have a relatively significant impact upon the evolution of the generation mix over the medium term, and so different assumptions are used under the different power price scenarios. In the Base Case scenario it is assumed that all BE stations receive a five year life extension over BE's current estimated closure date, with Hunterston B and Hinkley Point B receiving an extension to 2021. It is assumed in the High Case scenario that there are no lifetime extensions except for the known 5 year extensions at Hunterston and Hinkley Point B and in the Low Case scenario, BE stations are assumed to be granted lifetime extensions of 10 years. The BE nuclear capacity scenarios are illustrated in Figure 42.

For the BNFL-Magnox plant any life extensions would be reliant upon sufficient supplies of fuel being maintained, as well as a requirement to explore different fuel disposal arrangements given the planned closure of the existing reprocessing facilities. It is assumed that under the Base and High Cases the remaining Magnox plant close according to their currently published timetables. However, under the Low Case it is assumed that Oldbury (2009-2014) and Wylfa (2011-2015) receive 5 year life extensions.

Figure 42: Existing BE Nuclear Station Capacity



The major discussion within the industry is whether new nuclear plant will be developed. In January 2008, the Government published its nuclear White Paper which included its decision to allow private companies to invest in new nuclear plant. The decision has been met with criticism from anti-nuclear groups, however further legal action such as that which was successfully levelled against the initial consultation process does not appear likely.

Any nuclear development would be undertaken by the private sector, who would meet the costs of decommissioning and waste management. However, the Government plans to provide assistance in identifying suitable sites, provide proposals for pre-licensing designs, provide a framework for planning enquiries with a high powered inspector, and a Government nuclear Tsar. It seems that the Government would expect the private sector to shoulder the risks associated with new nuclear build.

The Nuclear Decommissioning Authority has announced an increase in the cost estimate for decommissioning civil nuclear sites from £64 billion to £74 billion. Members of parliament have warned that the rising decommissioning costs should be considered by the government when it comes to new nuclear build in the UK.

The Scottish Government has rejected plans to build new nuclear power stations. Instead, additional investment in renewables and carbon storage is being recommended. However, there are some concerns within the Scottish Government that the UK government may try to remove the Scottish parliament's nuclear planning powers.

The appetite of investors for taking on the market risk on long term capital projects remains the largest question mark over a new nuclear build program. However, it should be noted that the European majors (EDF, E.ON, RWE, Iberdola, Vattenfall and Suez) all appear to be lining up to exploit any nuclear build opportunities within the UK with EDF and E.ON both announcing they would use Areva's EPR reactors in any new nuclear plant built in the UK. In addition four utilities have voiced their backing for GE-Hitachi's Economic Simplified Boiling Water Reactor (ESBWR).

It was announced in September 2008 that EDF has agreed to buy British Energy for £12.5bn. Centrica are in talks with EDF to take 25% of all power generated by British Energy once the deal is concluded and is also looking to get a 25% stake in any new nuclear plant built by EDF. As part of this purchase, EDF has agreed with the Government to sell sites to other parties for new nuclear development in order to ensure competition.

BE has signed transmission agreements for 4 new plant starting in 2016. Three are on the sites of existing plant (Sizewell, Dungeness and Hinkley) and the other plant, Bradwell, is on land adjacent to the previous Bradwell station which closed in 2003 (and is currently run by the Nuclear Decommissioning Authority). E.ON have signed a 1,600MW transmission agreement at Oldbury which it is believed may be for a new nuclear plant. Planning consents have yet to be applied for, with these only expected once generic design licensing has been completed.

9.3.1. Nuclear New Build Costs

Recent construction costs have shown increases in nuclear capital costs from the £1,000/kW – £2,000/kW range seen over the last year. Florida Power and Light puts the range of £2,500/kW - £2,760/kW (depending on which type of reactor is chosen) whereas E.ON, in May 2008, estimated the cost of a new nuclear plant in the UK would be around $6,000/kW (approx £3,000-£3,500/kW).

The reason for this price increase is likely to be a combination of the following factors:

- Surge in world commodity prices has seen steel and copper prices increasing by 20% and 70% a year respectively;
- Cost estimates by utilities appear more accurate as utilities realise they cannot pass costs of errors to consumers;
- The number of certified suppliers is much smaller resulting in greater bottlenecks in production facilities; and
- Global skills shortage in the nuclear engineering profession.

As all of these factors are medium to long term, they cannot easily be reversed.

The cost of new nuclear build will be dependent upon a large range of variables, including the costs of financing, and charges for waste disposal and commissioning. However, these capital cost assumptions are likely to give rise to a cost for nuclear power in the £50-60/MWh range.

A major factor in the economics of nuclear build will be whether there is any additional support for nuclear power reflecting its status as a low carbon generation technology. This could include providing some guarantee of future long term carbon price, granting nuclear power exemption from the Climate Change Levy, or other new taxation or support mechanisms that could serve to reduce risk and improve the economics of nuclear power.

9.3.2. Nuclear Modelling Assumptions

Despite the growing interest in nuclear power, it is very unlikely for there to be any new nuclear build prior to 2020, even with streamlined planning regimes and regulations for new construction. It is interesting to note that the Government's Nuclear Power Generation Cost Benefit Analysis has projections of 6GW of new nuclear before 2025[86], which seems extremely optimistic.

The inherent uncertainty associated with nuclear build, in terms of the regulatory framework, the underlying economics, the political differences between the devolved Governments and, most of all, the appetite of investors, means that the development and timing of any new nuclear plant is relatively uncertain. Different assumptions on new nuclear build are explored under the different modelling scenarios:

- In the Base Case it is likely that the economics of nuclear new build will be relatively marginal, and it is assumed that there is insufficient certainty over long term economics to stimulate significant new build. However, it is assumed that 1GW of plant is commissioned in 2025.
- In the High Case scenario it is likely that the nuclear new build will become economic. However, under the High Case it is assumed that there is insufficient public and political support to make nuclear new build a reality.
- Under the Low Case scenario, it is assumed that there is significant political focus on supporting the development of new nuclear plant by private companies. It is assumed that the Government grants nuclear plant additional support such as exemption from the climate change levy and guarantees for long term carbon values, which serve to improve the economics of nuclear and reduce development risk. Thus, despite the lower power price in this scenario it is assumed that 2GW of new nuclear plant is constructed over the period 2020-2025, as part of a larger nuclear build program.

9.4. Interconnectors

9.4.1. GB-Netherlands

The UK-Netherlands interconnector has been given the go ahead and site clearance work has begun. It is assumed in all three scenarios that 1GW of capacity will be available from 2010. It is assumed the spread between the GB-NL will be relatively small, and that there would be bi-directional flows over the interconnector. The interconnector has been modelled as having a 30% load factor net import of power into GB.

[86] Nuclear Power Generation Cost Benefit Analysis, DTI, Accompanying consultation document to the 2006 Energy Review

9.4.2. GB-Ireland

Imera Power have been awarded licenses for two 350MW underwater interconnectors between Wales and the Republic of Ireland. The first of these, EW1, could be operational in 2010. In July 2008, Imera held a conference that provided information on how the auction process would work and how interested parties could become qualified bidders.

Eirgrid has signed a transmission agreement with NGET for a 500MW link between the Republic of Ireland and North Wales for October 2011. However, even though the project does not have planning approval or an electricity interconnector license from Ofgem, Eirgrid plans to complete commissioning, testing and to start commercial operation in 2012.

In the Base Case it is assumed that the first Imera 350MW interconnector will be constructed and commissioning by 2010, followed by the Eirgrid 500MW interconnector in 2012. In the High Case, both 350MW Imera links are assumed to be completed in 2010 and 2013, with the Eirgrid interconnector being commissioned in 2012. In the Low Case, only the 500MW Eirgrid interconnector is assumed to be commissioned, with the capacity coming on-line by 2012.

In all cases it is anticipated that the flows on the interconnectors would be bidirectional reflecting short term price volatility in both markets, with the net flows to Ireland assumed at 30%.

9.4.3. GB-France/Belgium

Plans for four new transmission links to the continent have had recent progress. National Grid and Belgium's TSO Elia have signed a joint development to investigate the potential for a 700MW - 1,300MW interconnector.

Additionally, Imera Hydragrid has applied for a license to build two new electricity interconnectors between England and France and one between England and Belgium.

As all of these interconnectors are at a very early stage, none are assumed to to be built in the modelling.

9.5. Renewable Energy

Detailed assumptions on renewable capacity development are provided in the ROC forecast assumptions in Section 13. It should be noted that under all Power Price scenarios it has been assumed that the RO target continues to grow beyond 2015 and that the RO is extended to 2032, with a target of 30% of demand supplied by renewable generation. This provides a significant driver for growth in renewable generation across the forecast horizon.

9.6. Transmission Losses

As discussed in Section 3, there have been a number of BSC modification proposals (see Table 27) seeking to change the charging for transmission losses from the current postage stamp charge to a zonal charging methodology.

Table 27: Transmission Losses Modifications

Modification	Description
P198	Zonal Transmission Losses Scheme
P200	Zonal Transmission Losses Scheme with Transitional Scheme
P203	Seasonal Zonal Transmission Losses Scheme
P204	Scaled Zonal Transmission Losses

The BSC panel considered all of these modification proposals (and alternative proposals) and concluded that none of the modifications should be made. The proposals went to Ofgem who have published an impact assessment and consultation, and in June published a consultation on a 'minded to' decision to approve P203 with an implementation date of 1 October 2008, and reject the other proposals. However, on 14 September Ofgem published an open letter effectively delaying a decision on zonal losses. It stated that it had considered responses to the consultation, some of which considered Ofgem had placed too much weight on the quantitative analysis of the schemes in coming to a minded to decision. Ofgem is currently reviewing the analysis of the schemes and intends to consult on the findings of the review before it makes it final decisions on the proposals[87].

Teesside Power, Immingham CHP, Drax Power and British Energy have taken Ofgem to court over the proposed introduction of zonal transmission system losses. The judicial review is on a legal technicality – specifically whether the proposed rule change could be implemented other than in accordance with the proposed implementation date timetable set out in the Final Modification Report of the BSC panel. Judgement was handed down in June and found against Ofgem, although the judge granted the regular leave to appeal.

In July 2008[88], Ofgem announced that it would not be appealing in light of the resource implications and regulatory uncertainty that an appeal might cause. However, they state that it is possible that BSC parties may re-raise similar proposals in the future and as such Ofgem intent to publish the additional analysis that was commissioned from Oxera.

Although the implementation of a zonal losses scheme has clearly been delayed, Ofgem has been keen to implement this type of scheme for a long time. Thus, it is likely that the regulator will attempt to approve such a scheme in some form at some time in the future and that given the work and analysis that has already been undertaken, the time frame to consider any similar proposals would be much shorter than would otherwise be the case.

It has been assumed in the modelling that a zonal losses scheme based on P203 will be implemented in 2010 and will continue to apply for the remainder of the forecast period.

[87] Ofgem letter: 'The Authority's decisions on the Balancing and Settlement Code (BSC) modification proposals on zonal transmission losses', 28 March 2008.
[88] Ofgem letter: "Balancing and Settlement Code Modification Proposals on Zonal Transmission Losses", 17 July 2008

The loss factors assumed in the model have been taken from the Impact Assessment[89] (although it should be noted that the TLMs published in the document appear to only be the locational losses – fixed losses have been included within the modelling), and are summarised in Table 28 below.

Table 28: Zonal Transmission Loss Multipliers (2008 Annual Average)

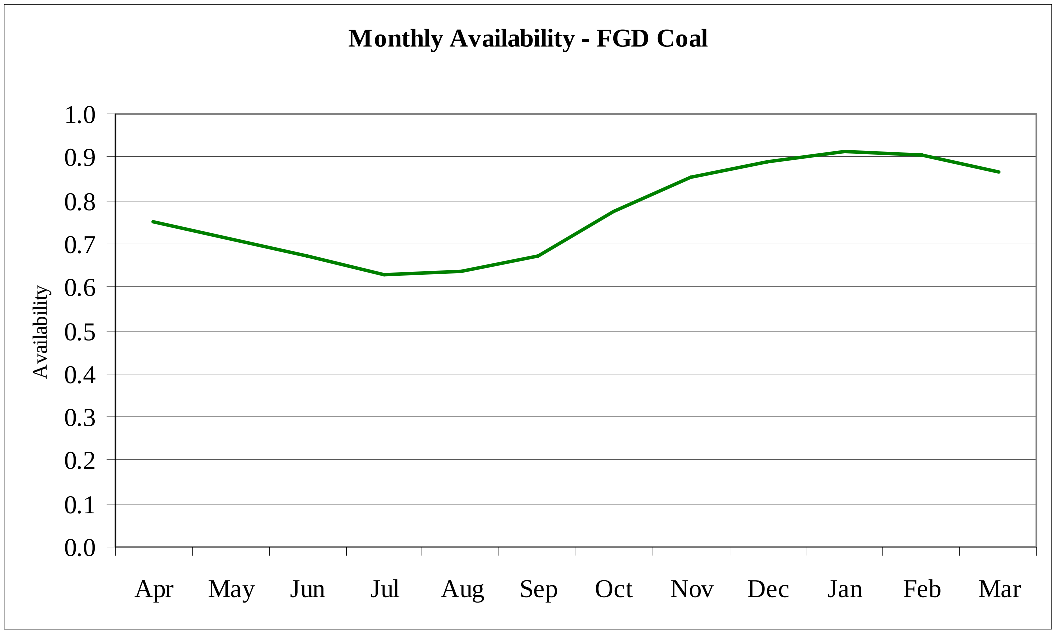
Zone	TLM
North Scotland	0.977
South Scotland	0.971
Northern	0.981
North Western	0.987
Yorkshire	0.982
Merseyside & North Wales	0.990
East Midlands	0.994
Midlands	1.001
Eastern	1.000
South Wales	1.000
South Eastern	1.002
London	1.008
Southern	1.007
South Western	1.009

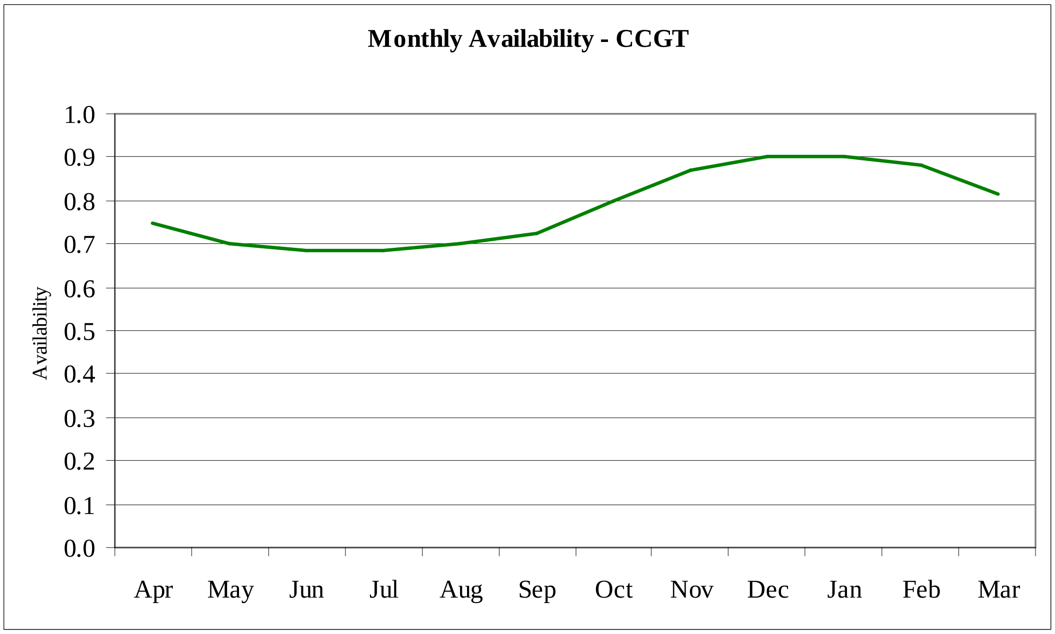
[89] Zonal transmission losses – assessment of proposals to modify the BSC, Ofgem 23 February 2007

9.7. Plant Availabilities

The availability of power stations (including both planned and unplanned outages) has a significant impact upon plant running and power prices. The monthly plant availabilities assumed within the modelling for FGD coal and CCGT plant are shown in Figure 43.

Figure 43: Example Monthly Station Availability





9.8. Summary

The key capacity assumptions for the three scenarios are detailed in Table 29.

Table 29: Scenario Capacity Assumptions

	Low Case	Base Case	High Case
BNFL Magnox Capacity	Wylfa & Oldbury Extension of 5 years	No Extension beyond published lifetimes	No Extension beyond published lifetimes
BE AGR Capacity	All stations 10 year extensions, with Hunterston and Hinkley Point to 2026.	All stations 5 year extensions, Hunterston & Hinkley Point extended to 2021.	No Extension beyond published lifetimes - Hunterston & Hinkley Point extended to 2016.
New Nuclear Capacity	New Nuclear capacity constructed 1,000MW in 2020 & 2025	New Nuclear capacity constructed 1,000MW in 2025.	No New Capacity
Netherlands Interconnector	Interconnector built, 1GW in 2010	Interconnector built, 1GW in 2010	Interconnector built, 1GW in 2010
Irish Interconnector	Eirgrid 500MW interconnector built in 2012.	First Imera Interconnector built, 350 MW, in 2010. Eirgrid 500MW link built in 2012	Both Imera Interconnectors built, 350 MW in 2010 and a further 350MW in 2013. Eirgrid 500MW link built in 2012.
Large CHP	Max Build rate 200MW/year	Max Build rate 200MW/year	Max Build rate 50MW/year
Small CHP	Govt subsidy reduces capital costs by 30%	No Subsidy	No Subsidy
Carbon Capture & Storage	500MW supercritical coal retrofit with CCS technology from 2013	500MW supercritical coal retrofit with CCS technology from 2013	500MW supercritical coal retrofit with CCS technology from 2013
Langage CCGT	900MW CCGT built in 2009	900MW CCGT built in 2009	900MW CCGT built in 2009
Marchwood CCGT	850MW CCGT/CHP built in 2009	850MW CCGT/CHP built in 2009	850MW CCGT/CHP built in 2009
Immingham CCGT/CHP	450MW CCGT/ CHP built in 2009	450MW CCGT/ CHP built in 2009	450MW CCGT/ CHP built in 2009
Staythorpe CCGT	1,660MW CCGT phased in from 2010	1,660MW CCGT phased in from 2010	1,660MW CCGT phased in from 2010
Newport CCGT	800MW CCGT phased in from 2012	800MW CCGT phased in from 2012	800MW CCGT phased in from 2012
New Grain CCGT/CHP	1,290MW CCGT/ CHP phased in from 2010	1,290MW CCGT/ CHP phased in from 2010	1,290MW CCGT/ CHP phased in from 2010
Pembroke CCGT	800 MW phased in from 2013	No specific capacity	No specific capacity

10. DEMAND

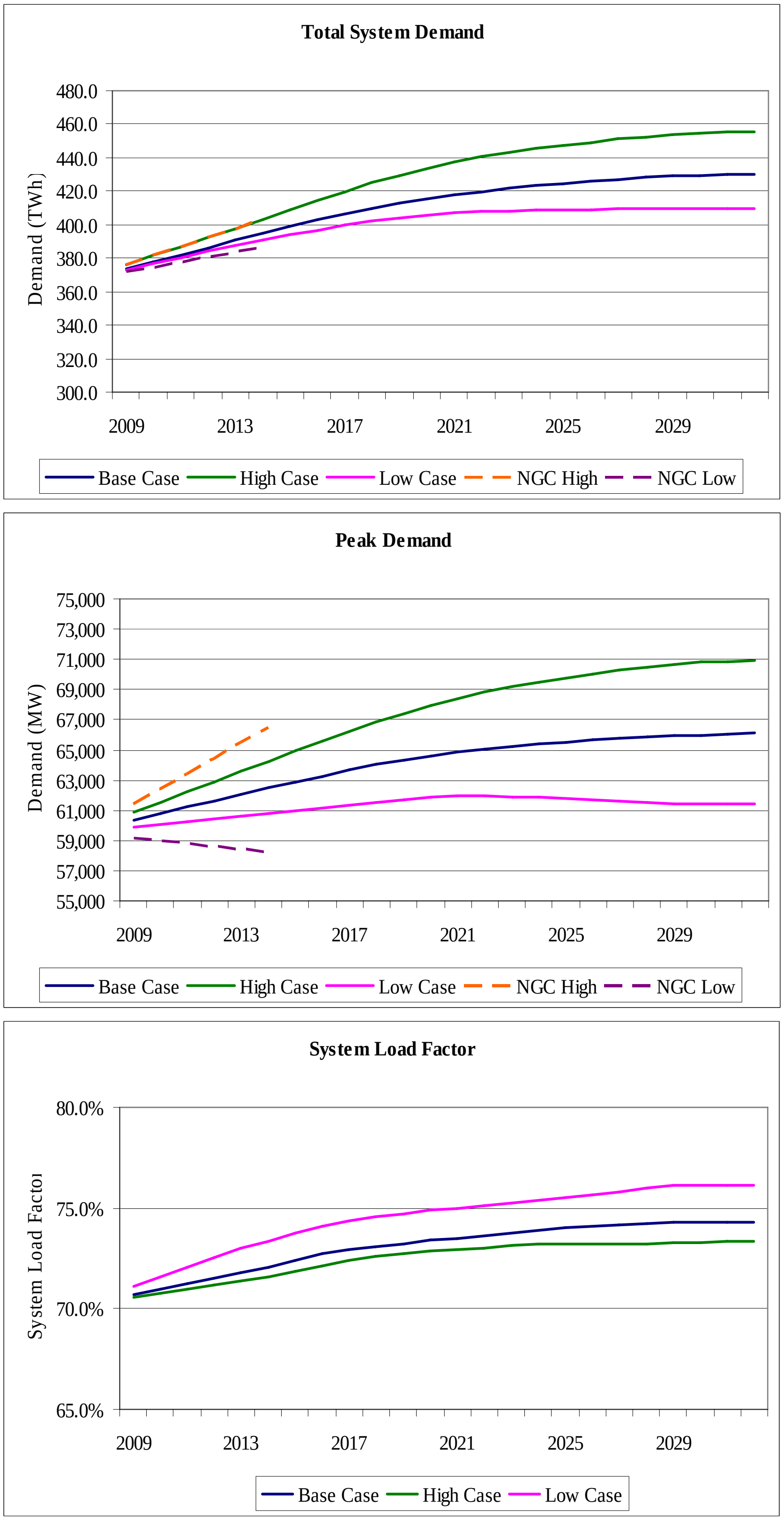
NGET have published demand forecasts in the seven year statement (May 2008). NGET's base case demand growth forecasts have growth in annual energy demand forecast at 1.1% and growth in peak demand forecast at 0.7% to 2014. These assumptions are used in the IPA Base Case scenario to 2013. Beyond then it has been assumed that growth in demand begins to soften with decreasing energy intensity over the economy as a whole.

The IPA demand scenarios are shown in Figure 44, which illustrates annual energy, peak demand and system load factors. It can be seen that under all scenarios the system load factor increases over the forecast horizon. This reflects the fact that there are a number of competing factors that will drive electricity demand in the longer term. There is likely to be some underlying growth in demand through growth in economic activity, increased demand from the domestic sector, and a general increase in processes and applications that use electricity. In addition, the introduction of carbon trading may encourage the use of electrical processes in some industrial sectors. However, these upward pressures are likely to be, in part, mitigated by increased energy efficiency, as well as increased focus on reducing energy usage. In particular, energy efficiency (Climate Change Program), load management and the development of micro-generation such as domestic CHP and renewables (Climate Change and Sustainable Energy Bill), are likely to lead to an increase in system load factor over the forecast horizon.

The NGET high and low scenarios are similar to those in the 2007 SYS for both annual energy and peak demand growth. However, the NGET assumptions, particularly on peak growth, still suggest a relatively rapid change in consumer behaviours.

The IPA annual demand and demand profiles reflect demand data for 2007/08.

Figure 44: Demand Scenarios



10.1.Demand Elasticity

In addition to the reductions in demand and demand shape over the longer term, as a result of investments in energy efficiency and on-site generation, consumers (particularly large industrial loads) have the potential to respond to short term market price signals by curtailing load at times of high market prices. The potential for large industrial demand to reduce load at specified price points has been built into the model, and is despatched economically. Assumptions on demand flexibility are detailed in Table 30 below.

Table 30: Industrial Demand Flexibility[90]

Demand (MW)	Price (£/MWh)
630	100
310	200

[90] Based on Data from Estimation of Industrial Buyers Potential Demand Response to Short Periods of Gas and Electricity Prices, Global Insight, May 2005

11. BASE CASE ANALYSIS

The Base Case power price forecast is presented in this section, and the key drivers of prices and structural change within the industry are discussed. The results are presented graphically in Figure 45 to Figure 49, which show:

- Base Case power price forecast, compared with new entrant CCGT costs and average system short run marginal costs;
- Comparison between converted coal and gas prices, including the impact of carbon;
- Generation capacity, generation output, and peak power margins, showing technology and fuel mix;
- Clean spark and dark spreads; and
- Average system carbon intensity.

The power price forecast, and the key drivers of prices and structural change with the industry are discussed below:

Period 2009 – 2012

- The markets have seen on-going firming in 2009 commodity prices in recent months particularly in coal and gas prices. However, carbon prices have softened slightly over the same period.
- In 2009, coal is competitive relative to gas and the competitiveness of coal fired generation strengthens over the period as a result of considerable softening to the coal prices and a slight reduction in carbon prices.
- Power prices soften over the period 2009-2012, reflecting some softening of commodity prices (particularly coal), as well as an increasing system margin (in terms of both peak power capacity and annual energy delivery) with changes to the capacity mix. In particular, the 6 GW of new CCGT currently under construction and assumed to be commissioned in 2009-2012 depresses the clean spark spreads to around £6/MWh.
- It is assumed that all FGD upgrades (approx 9GW of plant) are completed by the start of the forecast period, focusing coal running at FGD stations and increasing allowed annual energy output[91]. It is possible that some installations may not be fully commissioned and this could restrict coal running early in the forecast. The planned turbine work at some stations improves their efficiencies and helps maintain competitiveness.
- Coal running increases slightly over the period reflecting the softening of the coal price, although this is mitigated to some extent by increasing competition from new high efficiency CCGT plant and an increase in the carbon price over the second half of the period.
- Langage, Immingham and Marchwood are assumed to be commissioned in 2009, with Grain and Staythorpe also assumed to commission across the period along with the first units at Newport. This brings an additional 6GW of gas fired generation into the mix.

[91] Coal stations have sulphur emissions limits that restrict annual running levels, stations fitting FGD will be able to generate a higher level of energy over the year due to reduced sulphur emissions. In contrast non-FGD stations will have running further restricted under their limited running hours derogation from the LCPD.

- The modelling suggests an additional 1,600MW of large and small CHP plant could be constructed, with Grain also including some CHP capacity.
- Oldbury and Wylfa are assumed to close in 2009 and 2010 respectively, removing 1.4GW of Magnox plant from the generation mix.
- The Dutch interconnector (BritNed) is assumed to commission in 2010 making 1,000MW additional import capacity available. Although flows are likely to be bi-directional, the forecast has net import flows into the GB market.
- The new Imera Pentir 350MW Irish interconnector is also assumed to commission in 2010; again flows are likely to be bi-directional, but the forecast has net flows from GB to Ireland. Additionally, the 500MW Eirgrid interconnector is assumed to commission in 2012, with net flows from GB to Ireland.
- The RO and CCL serve to stimulate significant growth in renewable generation over the period. Onshore wind dominates the growth over the period, although there is increasing growth in offshore wind, and the introduction of ROC banding in 2009 helps stimulate some diversity in the mix of renewable generation, with some growth in biomass and marine technologies. However, renewable generation development lags behind Government targets with the number of ROCs generated equivalent to 8.6% of supplied energy - compared with the 10.4% target by 2010.
- It is assumed that co-firing with energy crops remains unrestricted, although availability of energy crops serves as a limiting factor. Energy crop co-firing increases significantly over the period, as crop availability increases. Non-energy crop co-firing is capped at 10% of surrendered ROCs, and this serves to restrict co-firing levels. Non-energy crop co-firing is assumed to be banded at 0.5 ROCs and the level of co-firing with non-energy crops increases slightly over the period.
- Relatively healthy plant margins (supported with over 3GW of new CCGT) put pressure on the more marginal plant, particularly non-FGD plant that have to generate revenue over a limited number of hours, and around 1.7GW of non-FGD coal plant is retired before they would be scheduled to close under the limited hours derogation under the LCPD. Additionally, around 2GW of CCGT closes over the period as the older, less efficient gas plant are displaced by the new stations in the merit order.

Period 2013-2022

- Carron Energy’s CCGT at Newport is assumed to be completed at the start of the period adding a further 400MW to the generation mix.
- Power prices continue to soften over the first half of the period, reflecting softening commodity prices mainly driven by downward pressure in the oil and coal markets and higher plant margins. However, these decreases are mitigated slightly by increasing carbon prices across the period due to tightening emissions targets.
- Power prices begin to firm slightly over the second half of the period, due in part to a flattening in gas prices (reflecting strengthening of oil markets, and increasing dependence on European and LNG imports allowing NBP to increasingly trade at a premium to BAFA levels). Strengthening carbon prices also continue to put upward pressure on power prices over the period.
- The competitiveness of coal is eroded throughout the period as carbon prices increase although in the first few years this is mitigated somewhat by decreasing coal prices.
- The more competitive position of coal plant over the first half of the period pushes older, less efficient gas plant down the merit order and 1GW of CCGT plant are retired over the

first half of the period. However, it should be noted that retrofitting these plant with new high efficiency turbines could provide an economic alternative to developing new (especially green field) CCGT plant.

- The running of non-FGD coal plant also reduces significantly over the period, putting pressure on plant economics and results in 2GW of non-FGD coal closures by 2016. It is assumed that the remaining non-FGD plant are not forced to close but are re-licensed to provide peaking and flexible generation services, with running hours limited to 1,500 per year, with around 6GW operating beyond 2016. A further 4GW is closed to the end of the period.
- One of the non-FGD coal closures provides potential for supercritical retrofit with carbon capture and storage under the competition run by BERR. It is assumed that a 500MW coal CCS plant is commissioned in 2013.
- The reduction in competitiveness of coal over the second half of the period also impacts on the running of FGD coal stations. Coal stations have to compete in the merit order with new high efficiency CCGT stations, as well as a growing contribution from renewable sources, although this is mitigated in part by closure of nuclear plant. Nevertheless, output of the FGD coal plant reduces by around 55% over the period, as coal is forced down the merit order.
- There is significant nuclear plant closure scheduled over the period with around 6GW of AGR plant retiring over the second half of the period, after assumed 5 year life extensions.
- Demand growth and plant closures over the period lead to tightening capacity margins over the second half of the period and this begins to allow the market to place upward pressure on power prices.
- Prices increase to a point where new build CCGT is economic in 2017, with around 6GW of CCGT constructed over the second half of the period. In addition to CCGT build, the higher efficiency of CHP ensures that their economics are also attractive, with around 2GW of large and small CHP constructed over the period.
- There is significant growth in renewable generation over the period. Renewable capacity growth is primarily in onshore and offshore wind, although there is also some growth in biomass generation and very limited development of marine generation technologies. Co-firing increases over the period, reflecting increased availability of energy crops and investment in co-firing equipment.
- The introduction of a headroom and price collapse mechanism allows capacity to build through the RO targets without collapsing ROC prices. Renewable generation rapidly approaches target levels in the first half of the period, reaching it in 2012 and exceeding it beyond 2015 with the number of ROCs generated exceeding the obligations target which is assumed to increase to 25% in 2021.
- Over the period as a whole, new gas fired generation capacity provides support to the capacity margin by serving to replace retiring nuclear plant. New CCGT capacity has higher efficiencies than the existing fleet, and so is more competitive relative to coal plant, and achieves high load factors.
- The significant growth in wind generation, which is high merit when running, serves to push coal plant down the merit order. However, the intermittent nature of wind generation means there is an increased requirement for capacity to provide flexibility, balancing services, and maintain system security, which could result in an increase in short term price volatility. There is an increasing requirement for generation capacity on the system relative to demand (as can be seen in Figure 47). It is assumed that the remaining non-FGD coal plant will increasingly be maintained to provide flexibility, and where these

coal plant are not able to extract sufficient revenues from the market, financial support will be available to maintain capacity (see discussion in Section 11.1).

Period 2023-2032

- Over the period 2023-2032 there is relatively steady upward pressure on power prices, driven in part by increases in oil, gas and coal prices as well as more significant increases in carbon prices.
- Changes in the generation mix, with increasing levels of renewables and new high efficiency CCGT capacity, means that old coal stations are increasingly pushed down the merit order with reductions in coal running of around 40% over the period.
- Non FGD Coal running reduces further over the period and this puts pressure on plant economics. All of the remaining non-FGD coal stations close, along with around 5GW of low merit-order FGD coal plant.
- All of the remaining nuclear plant (apart from Sizewell B) close, removing around 2.5GW of baseload plant from the generation mix. However, the assumed addition of 1GW of new nuclear in 2025 in part mitigates this loss of baseload generation.
- Although demand growth slows considerably over the period, the combination of limited demand growth, coal and nuclear closures, and slower renewable growth maintains pressure on plant margins and provides some upward pressure on power prices toward the end of the period.
- Power prices are sustained at a level to support the economics of new entrant CCGT, with steady build over the period resulting in an additional 8.5GW of new CCGT as well as 2GW new CHP being built.
- There is continued growth in renewables, with economics supported by the RO, or a similar support scheme beyond 2027. It is assumed that the maximum obligation level is increased to 25% for the period 2021-25 and to 30% between 2026 and 2032. The RO banding and the building-out of the wind resource means that there is increasing diversity in the renewable generation mix, with slight increases in biomass and marine generation capacity, although on and offshore wind still dominate the capacity mix. The volume of co-firing remains broadly constant over the period, as higher carbon prices improve the economics of co-firing and coal plant maximise co-fire running. The level of ROCs generated exceeds the 30% target at the end of the period.

25 Year Summary

- Power prices reduce over the first half of the forecast horizon, reflecting decreasing commodity prices, particularly coal, as well as relatively high plant margins with the commissioning of around 6GW of new CCGT plant. However, the second half of the forecast horizon sees some increases in commodity prices, particularly carbon prices, putting upward pressure on power prices. In addition, closure of nuclear plant and non-FGD coal puts pressure on plant margins, and power prices increase to a point where they provide economic incentives for new entry.
- Despite high prices in the coal forward market, coal generation is very competitive over the first few years of the forecast horizon. However, despite softening coal prices, increases in carbon prices start to erode coal's competitiveness from around 2010. Beyond that point gas becomes steadily more competitive with coal generation, primarily due to strengthening carbon prices over the second half of the forecast horizon. This, coupled with emissions restrictions, steadily erodes the competitiveness and economics of

coal plant, and coal running reduces significantly over the period. There is a significant volume of coal closures, with all of the non-FGD sets closing and around 5GW of the FGD sets closing over the period. Remaining coal stations increasingly provide power over peak periods, and provide flexible generation to the system.

- All of the existing nuclear fleet other than Sizewell B closes over the forecast horizon, removing approximately 10GW of baseload, zero-carbon intensity plant from the system. However, this is partly mitigated by the commissioning of 1GW of new nuclear capacity in 2025.
- There is significant demand growth of around 17% over the period, although peak growth is lower at around 11%, resulting in an increasing system load factor over the forecast.
- The closure of coal and nuclear plant, coupled with increasing demand growth, leads to tightening plant margins and a requirement for new generation, which is met over the period by new CCGT build, CHP and renewable generation capacity.
- Power prices exceed the cost of new entry for a CCGT plant in 2017, and remain around that level over the remainder of the forecast horizon. This stimulates steady growth in CCGT capacity, with approximately 13.5GW of new CCGT capacity combined with 6GW of CHP capacity constructed over the period (in addition to the 6GW of projects that are currently being developed for commissioning over the period 2009-2013).
- The competitiveness of coal as a fuel source improves over the first few years of the forecast, but is then steadily eroded over the remainder of the forecast horizon primarily due to increasing carbon prices. The higher capital costs and higher carbon intensity associated with new and retrofit coal plant relative to CCGT, mean that new coal plant is not competitive against CCGT as a new entrant, and current proposals for retro-fit supercritical coal plant are not further developed other than a 500MW supercritical coal CCS plant which receives support as part of the BERR competition.
- CCGTs comprise an increasing proportion of the plant mix, and increasing competition between CCGT plant tends to reduce the running of older less efficient CCGT plant, putting pressure on their economics. 3GW of older gas plant is assumed to close, and there is the possibility for further closures toward the end of the forecast horizon
- In addition to growth in CCGT capacity there is also strong growth in renewable capacity over the forecast horizon. Renewable growth is supported by the assumed continuation of growth in the RO target to beyond 20% from 2021. Renewable generation capacity growth is dominated by onshore and offshore wind although the introduction of ROC banding does encourage a wider mix of technologies, with biomass generation making a significant contribution, and a limited contribution from marine technologies.
- The level of banding for non-energy crop co-firing in 2009 serves to restrict running, with the level of energy crop co-firing increasing over the period as fuel availability increases, although there is some downwards pressure towards the end of the forecast period as carbon prices increase. Co-firing grows to around 12% of the coal burn, and serves to support the economics of remaining coal stations.
- The intermittent nature of wind leads to an increasing requirement for generation capacity (relative to demand) on the system. Although some capacity credit is given to wind, (greatly increased as a result of the effects of geographic diversity), this is relatively low compared to conventional plant. The impact of growing output from intermittent plant increases short-term volatility in power prices, and increases the requirement on the system for low load factor flexible generation. This effect is partly mitigated by the growth in the load factor of demand, making demand less peaky.
- There is a considerable change in the plant mix over the forecast horizon, with significant growth in renewable and gas fired generation, leading to a reduction in the carbon

intensity of the system from over 0.43 in 2009 to around 0.28 in 2018. There is a relatively steep reduction in the carbon intensity of the system between 2014 and 2018, reflecting fuel switching from coal to gas as well as increases in the level of renewable generation. This switching continues over the forecast horizon, but the closure of nuclear plant means that the system carbon intensity fluctuates over the period 2019-2022 (a period when there are a large number of nuclear retirals). However the growth in gas fired generation and renewables, along with some new nuclear capacity, reduces the system carbon intensity beyond 2022, with the intensity reducing to around 0.25 in 2032.

Figure 45: Base Case GB Power Forecast (Excluding BSUoS)

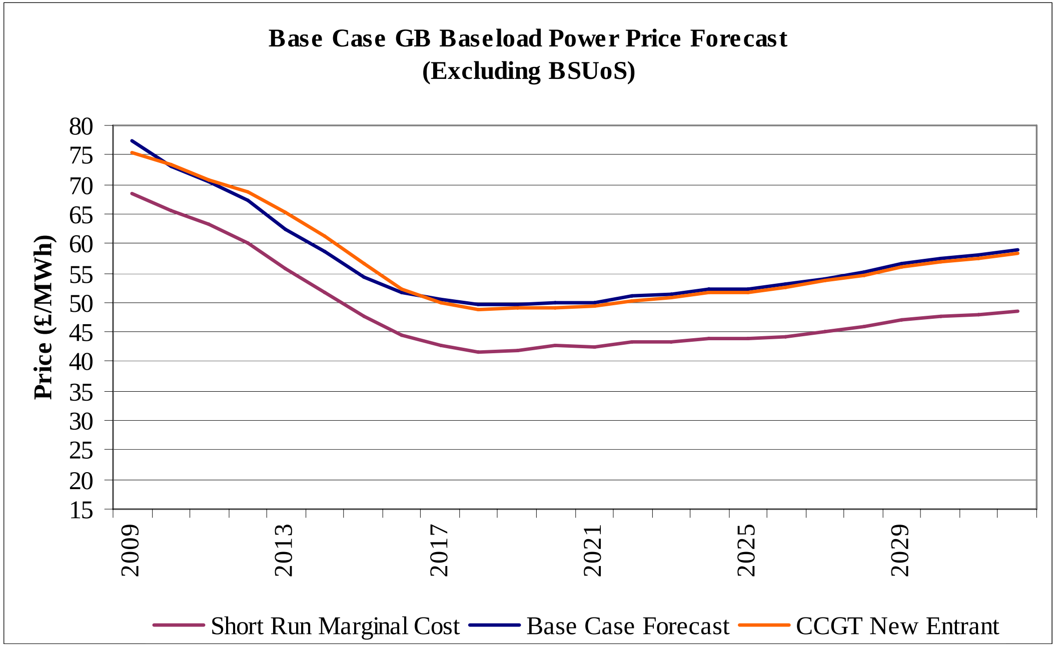


Figure 46: Base Case GB Converted Seasonal Commodity Prices (Including Carbon - Illustrative Plant Efficiencies)

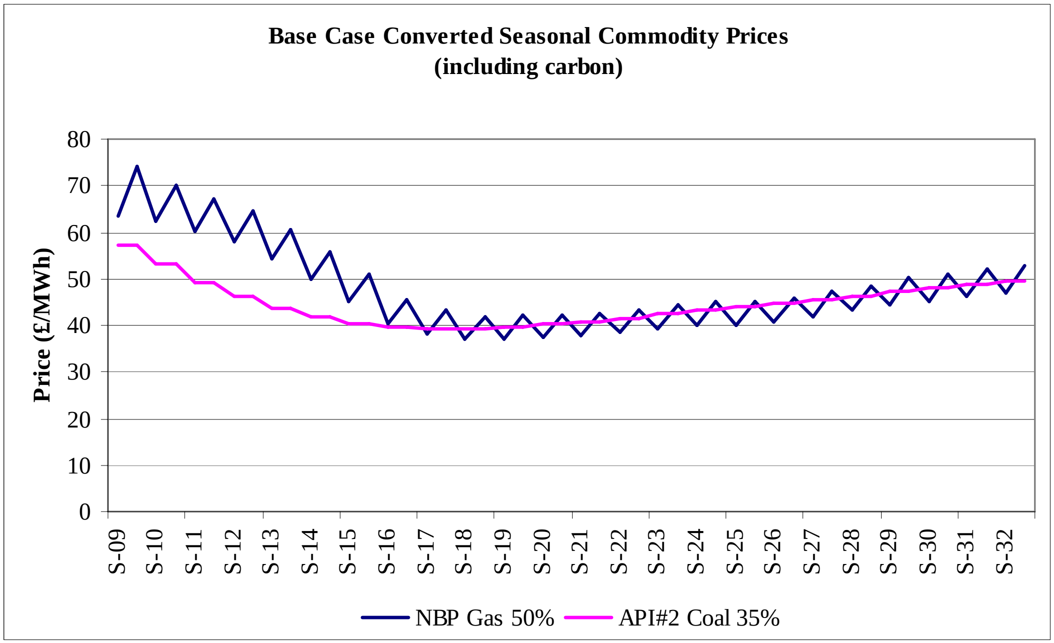


Figure 47: Generation Capacity, Output and Expected Peak Margin

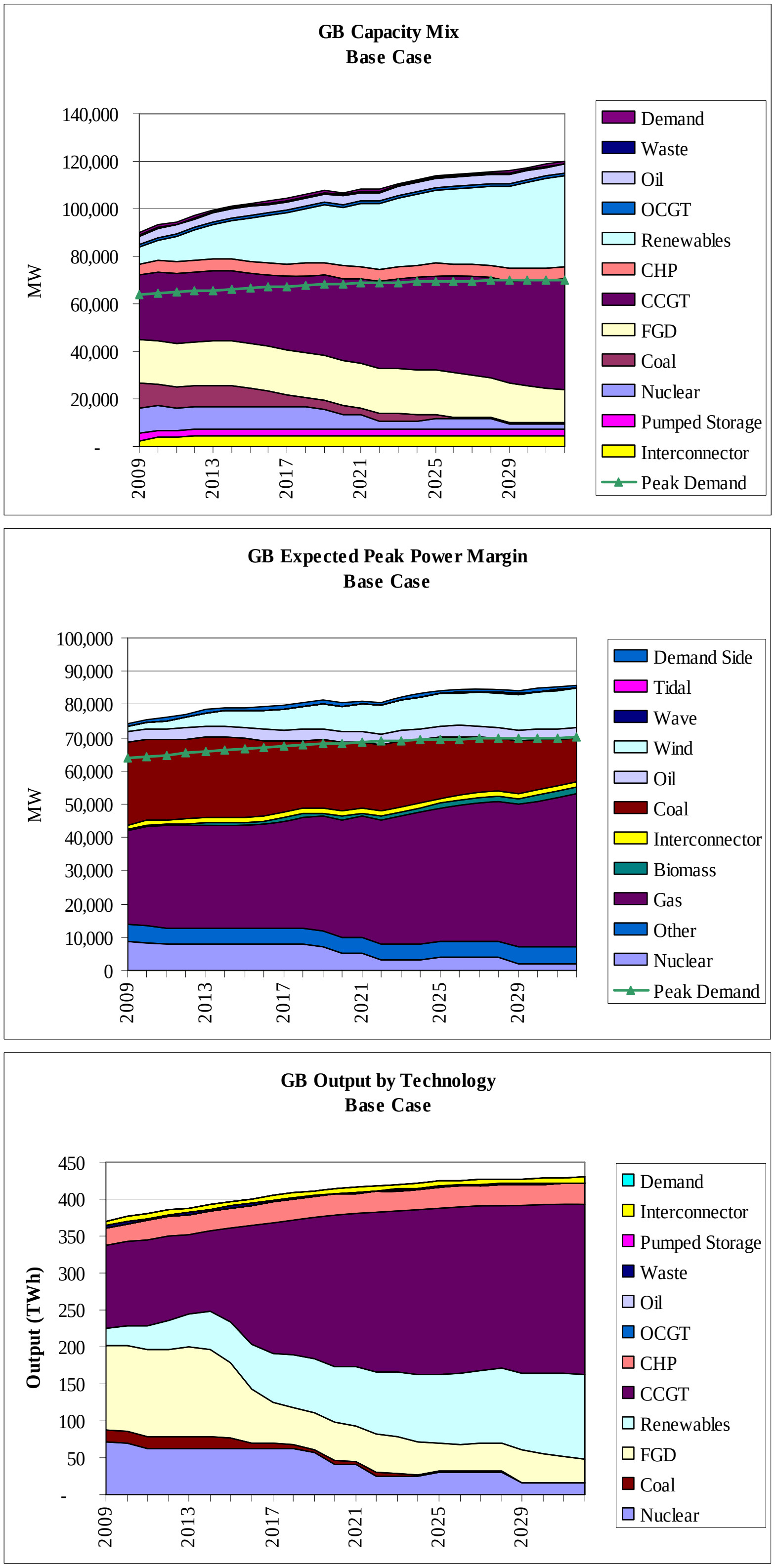


Figure 48: Clean Spark and Dark Spreads

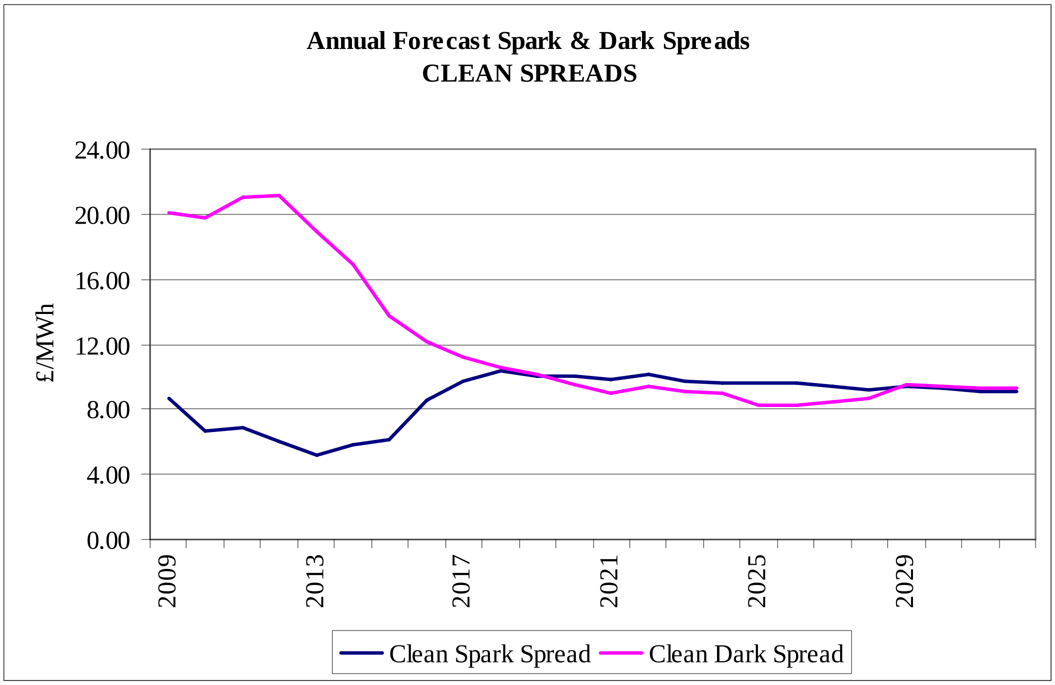
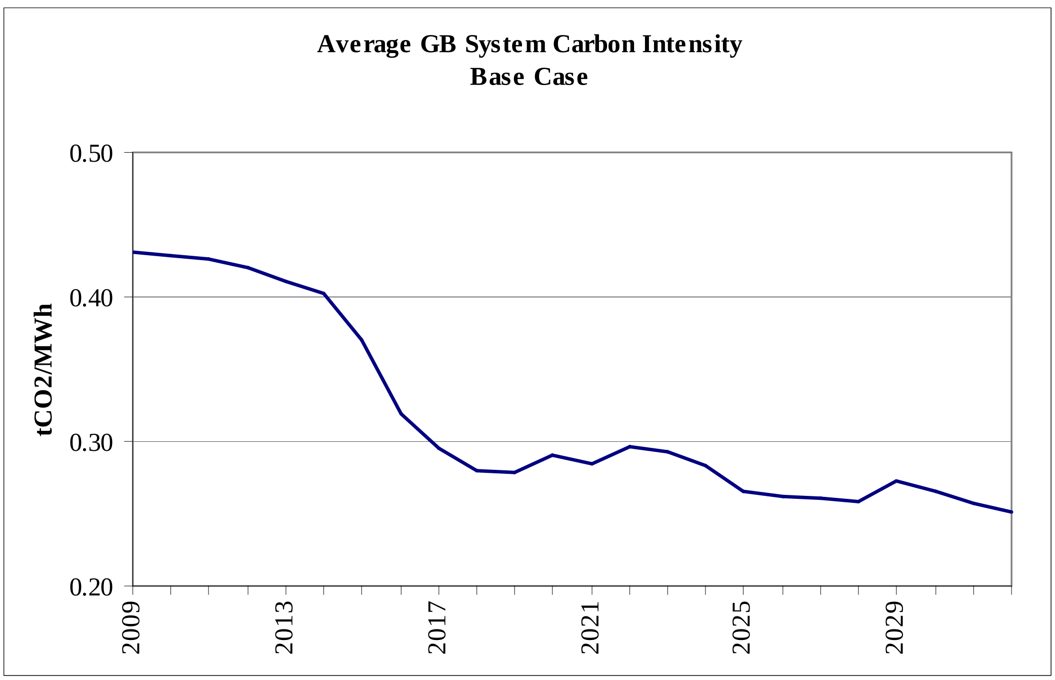


Figure 49: System Carbon Intensity



11.1.Maintaining Generation Capacity

The modelling has assumed that some uneconomic generation capacity would be maintained on the system to achieve the modelled level of security of supply (in terms of the probability of not meeting peak demand and a level of unserved energy). Generation margins could be supported either by maintaining uneconomic plant or assuming that new peaking (OCGT) plant were constructed. Plant required for maintaining security of supply would be required to be flexible plant, and 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 flexible plant to be maintained on the system:

- The trajectory of commodity and carbon prices increasingly reduces the competitiveness of coal plant, making it the marginal technology particularly over the second half of the forecast horizon;
- Increasing volumes of new high merit generation capacity (new CCGT and renewable generation) push existing coal plant down the merit order; and
- The increasing contribution of wind within the generation mix leads to an increase in the uncertainty associated with the level of generation capacity available at any time, although this effect is in part mitigated by locational diversity reducing the correlation in wind generation output. Nevertheless wind generation provides a lower contribution to system security than the same capacity of conventional plant. Thus, there is a requirement for an increasing volume of generation capacity to maintain a similar level of security of supply.

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 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:

- Increased peak power price volatility (in addition to volatility already captured in the model) over periods of low wind, allowing peaking plant to recover fixed costs over relatively few running hours. However, this would result in significant risks and volatility associated with the revenue of peaking plant;
- 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;
- The system operator (NGET) could purchase additional reserve, similar to their Short Term Operating reserve (STOR) tender, with costs most likely to be recovered through BSUoS; or
- Other reserve or capacity mechanisms, such as a supplier reserve obligation or a capacity payment mechanism.

It has been assumed here that the additional revenues will be provided predominantly through the purchase of reserve services by NGET, and so will be passed through to BSUoS, as discussed below.

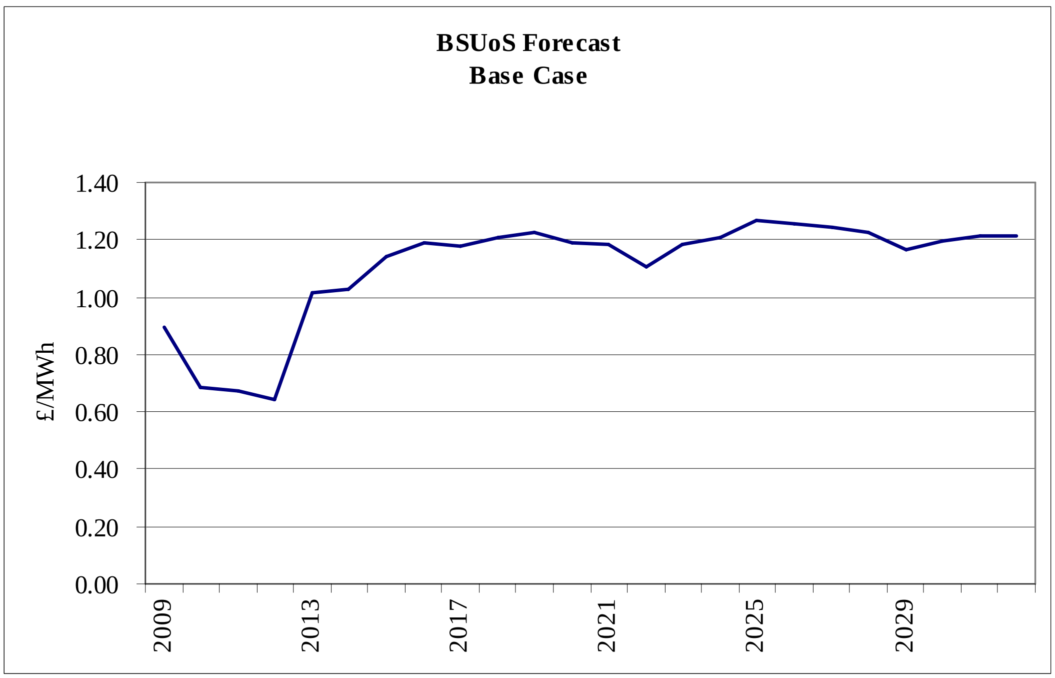
11.1.1. BSUoS

The system operator levies a variable (£/MWh) charge on power generation. This BSUoS (Balancing Services Use of System) charge is in effect an increased marginal cost for generators and so it is assumed that it would be passed through to the wholesale power price. BSUoS is an additional component that needs to be added to the price forecasts detailed above, to construct a wholesale price forecast. BSUoS averaged around £1.00/MWh over 2007/08.

As discussed above it is expected that generation margins will have to increase over the forecast horizon to maintain security of supply, and that a mechanism will be required to support this plant. Assuming that the system operator has responsibility for purchasing reserve capacity sufficient to maintain security, this would lead to an increase in BSUoS.

A Base Case forecast of BSUoS charges over the forecast horizon is given in Figure 50. It can be seen that BSUoS charges drop below the current levels in 2009. Post 2012, however, BSUoS costs begin to increase as there becomes a requirement to support generation capacity in the face of eroding competitiveness of coal plant and an increase in intermittent generation (requiring a growth in generation margins). A significant increase in BSUoS is evident at the beginning of Phase III (2013) of the EU ETS as the percentage of emissions targets that are distributed as free allocations are reduced to 0%.

Figure 50: Base Case BSUoS Forecast



12. POWER PRICE SCENARIO ANALYSIS

This section investigates the power price forecast under the Base, High and Low Case Scenarios. The key differences in terms of price drivers and the evolution of the power industry are identified and discussed. The results are presented graphically in Figure 51 to Figure 53, which show, for all three scenarios:

- Power price forecasts;
- Carbon intensity; and
- Expected peak power margin.

Period 2009-2012

- In all three scenarios, the current strength of the gas market means that coal is more competitive relative to gas, with coal being the cheaper generation fuel over the period.
- Under all scenarios, power prices soften over the period, reflecting the downward pressure across commodity prices, particularly coal, as well as increasing plant margins, with the commissioning of around 5GW of new CCGT generation capacity.
- The competitiveness of gas is further eroded over the period under all scenarios, driven by the softening of coal prices, as well as softening carbon prices in the Base and Low Cases. This helps to boost coal running to the end of the period, with coal generation increasing by between 1%-2% over the period for the Base and Low Cases, but decreasing 4% in the High Case due in part to increases in carbon prices across the period.
- The installation of FGD on around 9GW of plant is assumed to be completed at the start of the forecast period and ensures that coal running is increasingly focused on FGD units, with tighter emissions restrictions increasingly limiting running at non-FGD units. It is possible that some installations may not be fully commissioned and this could restrict coal running early in the forecast.
- Under all cases there is the completion of committed gas station build at Langage, Marchwood, Immingham, (New) Grain and Staythorpe, as well as assumed commissioning of the CCGT at Newport and the first phase of the RWE Pembroke project (Low Case Only). This leads to an increase in plant margins over the period, serving to provide increased competition and downward pressure on power prices.
- Under the Base and High Case Scenarios, the Oldbury (2009) and Wylfa (2010) Magnox plant close according to schedule, putting some pressure on capacity over the period. However, under the Low Case scenario, lifetime extensions for these stations ensure higher plant margins, serving to increase downward price pressures.
- The efficiency advantages associated with CHP plant, combined with their advantageous treatment under the EU ETS, sees some additional large and small CHP constructed over the period, with around 2.3-2.9GW (including the new Grain and Immingham plants) added, with lower build in the High Case.
- Relatively healthy plant margins in all scenarios puts pressure on the economics of marginal plant, this includes both non-FGD coal plant that have to generate revenue over a limited number of hours, as well as the older less efficient gas stations. Economic pressures see the closure of around 3-4GW of capacity, with fewer closures in the High Case due to tighter margins.

- Under all scenarios, the impact of the RO and CCL continue to stimulate significant growth in renewable generation. Onshore wind accounts for most of the renewable generation capacity, with increasing growth in offshore wind, some relatively small wave and tidal projects and some growth in biomass generation.
- Installed renewable capacity grows in all scenarios to around 11GW in 2012 from its current level of 4.5GW (excluding large hydro and co-firing). ROCs equivalent to around 8.6% are generated, with the Government failing to meet its 2010 target of 10.4%.
- The carbon intensity of the system remains relatively constant over the period under all scenarios, with similar levels of carbon emissions across scenarios due to the highly competitive position of coal in all cases.

Period 2013-2022

- The profile of power prices across the period is similar between the scenarios. All three scenarios generally show power prices softening to around 2017 and then increasing slightly thereafter. However, differences in levels of plant margin result in slightly different profiles with higher upward pressure in prices being seen in the High Case.
- It is assumed that a 500MW coal CCS plant is commissioned in 2013, supported through the carbon capture and storage competition run by BERR (it is assumed that this is a retro-fit coal project developed at one of the non-FGD coal sites closed over the period). In the Low Case, it is assumed that 1GW of new nuclear plant is commissioned in 2020.
- Under all scenarios the competitiveness of coal fired generation is eroded slightly over the first half of the period reflecting some increases in carbon prices beyond the end of Phase II of the EU ETS.
- Over the second half of the period, increases primarily in carbon price and changes in the relativity of coal and gas prices result in increasing erosion of coal's competitiveness. This effect is most prominent in the Low Case, where gas becomes more competitive especially in the summer months, and less prominent in the High Case where coal's competitiveness is eroded only slightly with coal plant remaining competitive over most of the year relative to older CCGT plant.
- The reducing competitiveness of coal, coupled with emissions restrictions for non-FGD units put pressure on the economics of coal stations. In the Low Case all of the remaining 8GW of non-FGD coal is closed over the period. In the High Case there are lower pressures on the economics of coal plant, but running restrictions on non-FGD plant still make economics challenging and 1.5GW of plant closes over the period. Under all scenarios it is assumed that the remaining non-FGD plant are not forced to close in 2016 but are re-licensed to provide peaking and flexible generation services, with running hours limited to 1,500 per year.
- 6GW of AGR capacity closes in the High Case between 2013 and 2022. In the Low Case the remaining Magnox capacity (1.5GW) closes, but life extensions of at least 10 years on all of the AGR fleet mean that these stations remain operational over the period.
- In the High Case, coal still provides a competitive fuel for electricity generation, and retro-fitting some of the closed non-FGD plant with super-critical units provides a relatively low capital route (although with significantly higher capital costs compared to greenfield CCGT) to developing new plant capacity utilising existing infrastructure. Power prices are sufficient to incentivise retro-fitting of around 1.5GW from 2015.

Additionally, new build CCGT becomes economic in 2016 and remains so over the remainder of the period. There is relatively steady build of gas plant over the period, with 6GW of CCGT constructed over the second half of the period, and 0.7GW of large and small CHP added to the generation mix, in addition to the 0.5GW of retro-fit CCS coal plant commissioned under the competition run by BERR.

- Under the Low Case, lower demand growth and higher nuclear capacity means that plant margins are more generous over the period, with margins only beginning to tighten toward the end of the period. Power prices begin to increase over the second half of the period, but only reach the level where new build CCGT is economic in 2022. However, there is steady build of higher efficiency CHP with around 2.2GW of small and large CHP added to the plant mix, as well as the assumed commissioning of 1GW of new nuclear in 2020 which is supported economically supported outside the market.
- The different power prices have an impact upon the economics of renewable build, although this is in part mitigated by the Government having the ability to manipulate the RO banding regime to ensure that the different renewable technologies remain economic over the period. However, the lower power price in the Low Case means that renewable capacity is much more focused upon the cheapest renewable technology - onshore wind - although banding ensures some diversity in the renewable generation mix, particularly in offshore wind. Under the High Case the higher power price serves to stimulate greater renewable build, with greater diversity in the generation mix, with significant contributions from onshore and offshore wind, slow but steady growth in biomass generation (~2.5GW constructed) and a limited contribution from marine generation (~250MW).
- In the Low Case the level of co-firing initially increases slightly across the period, although co-firing is increasingly focussed on energy crops. Banding levels support significant non-energy crop co-firing, particularly in the first half of the period. However, volumes drop significantly towards 2020. In the High Case co-firing utilises a mix of energy and non-energy crop fuel, with the volume of energy crop co-firing increasing over the period, again reflecting crop availability. The volume of co-firing under the High Case is higher, primarily reflecting the higher output from coal stations in this scenario.
- The RO headroom and assumed price collapse mechanisms maintain financial incentives to allow renewable projects to build through the RO target. In the Base Case, ROCs covering around 26% of supplied energy are generated in 2020, exceeding the assumed RO target of 20%. The level of renewable build will be dependent upon both power price and RO banding with higher power prices tending to increase renewable build rates, resulting in higher levels of renewable output under the High Case, and lower levels of renewables under the Low Case.
- The system carbon intensity in the High Case is maintained at a high level over the period, only beginning to reduce over the second half of the period. This reflects coal running remaining relatively flat with FGD plant running as high merit. This, coupled with nuclear station retirals, puts upward pressure on system carbon intensity. However, over the second half of the period the carbon intensity reduces slightly, with the introduction of new gas fired plant and significant increases in renewable generation.
- Under the Base and Low Case scenarios, the system carbon intensity reduces significantly over the period; reflecting reductions in coal generation (coal running reduces by 60% and 70% in the two cases respectively), increases in gas generation and increases in renewable output. The Low Case sees a significant reduction in carbon intensity at the start of the period, as gas prices soften and coal running reduces. Life

extensions to nuclear plant, and the assumed commissioning of a further 1GW of new nuclear in 2020, results in almost 5GW more nuclear capacity in 2020 under the Low Case, yielding significantly lower system carbon intensity at the end of the period.

Period 2023-2032

- Increases in oil, gas and coal prices, as well as significant movement in carbon prices, place upward pressure on power prices over the period under all scenarios.
- The relative competitiveness of gas and coal generation does not change significantly over the period for each individual scenario, although there are major differences associated with the competitiveness of coal generation across the three scenarios.
- In the Low Case, the economics of coal plant remain challenging, coal is increasingly pushed down the merit order by new baseload capacity (CCGT, renewable and nuclear plant) and coal running reduces further. Pressure on plant economics results in plant closures with around 3.5GW of FGD plant retired over the period.
- In the High Case, the running restrictions on non-FGD coal plant make plant economics challenging and most of the remaining capacity is retired. Although coal running is relatively flat over the period, it remains significantly higher than in the Low Case with coal running covering around 20% of generation output (compared to 10% in the Low Case). In addition, economics make retro-fit coal economic again towards the end of the forecast period with a further 1GW of coal being added to the system.
- In the High Case, toward the end of the period the costs of new build super-critical coal reduce to a level where they could be competitive with new build CCGT despite the significantly higher capital costs. However, the higher emissions levels from coal plant, coupled with the carbon price risks means that new coal is perhaps unlikely to be developed without carbon capture and storage. Indeed the EU has proposed that new coal plant would have to be fitted with CCS post 2020. It is assumed that CCS is unlikely to be economic under High Case conditions (although there is significant uncertainty associated with the costs of CCS), and no new coal plant is built. However, it is accepted that if there are successful CCS deployments and the costs of CCS reduces more quickly than expected, there could be new coal build over the period.
- In the High Case, the remaining 2.5GW of AGR nuclear plant retire, leaving Sizewell B as the only nuclear plant on the system. In the Low Case, there are also significant nuclear retirements, with 6GW closing. However, a new nuclear build program allows construction of a further 1GW of nuclear capacity in the middle of the period, with new units assumed to be constructed on the site of retired plant, reusing infrastructure, reducing capital costs and minimising planning issues.
- Despite slowing demand growth, plant margins are tight over the period under the High Case. This provides upward pressure on power prices and ensures that power prices are slightly above the cost of new build CCGT over the period. Around 7GW of CCGT and 0.5GW of CHP is constructed, and this, combined with retro-fit coal and renewables, is sufficient to replace nuclear and coal closures and maintain plant margins.
- In the Low Case, prices are sufficient to incentivise new CCGT build over the first half of the period, with around 3.5GW of new CCGT and 2GW of new CHP constructed. The new nuclear build (1GW in 2020 and 1GW in 2025) helps maintain plant margins as coal plant are retired. There is a high level of plant retirement over the period, but flat demand and increasing demand load factor, coupled with increasing renewable generation capacity, ensure that plant margins are only gradually eroded.

- In all scenarios there is significant growth in gas fired generation. In the Low Case, CCGTs comprise approximately 50% of generation output by the end of the forecast. Under the High Case, although the volume of installed CCGT plant is higher than under the Low Case, higher demand growth and slightly lower gas load factors mean that CCGTs comprise approximately 40% of generation output. The growth in CCGT capacity results in increasing competition between CCGTs and, in the High Case, where CCGT plant is also competing over some of the load curve with coal plant, this results in the profitability of older less efficient CCGT plant being squeezed, and could result in some plant closures.
- The assumed growth in the renewable obligation to 30% over the period 2026-2030 ensures continued development in renewable generation capacity. A relatively diverse renewable generation capacity mix is developed under all scenarios with onshore and offshore wind dominating renewable generation and biomass making a significant contribution particularly under the High Case. However, increases in capital costs for renewables have decreased the attractiveness of biomass and marine technologies in particular meaning that the government may be required to increase banding multipliers from their current levels to stimulate growth.
- Under the Low Case, the level of co-firing becomes restricted by the volume of coal burn and flattens off towards the end of the period. However, under the High Case the significantly greater coal burn allows greater levels of co-firing, and increasing utilisation of energy crops over most of the period.
- The level of renewable build will be dependent upon both power price and RO banding, with higher power prices tending to increase renewable build rates, resulting in higher levels of renewable output under the High Case, and lower levels of renewables under the Low Case. However, in all three scenarios, the government's targets are met by the end of the forecast period.
- The carbon intensity of the system reduces slightly in the High Case as coal running reduces and the contribution of gas and renewables in the generation mix increases. However, this is offset somewhat by the closure of the last remaining AGR nuclear units. In the Low Case the impact of reductions in coal running and increases in renewable generation capacity is mitigated by the closure of nuclear capacity, resulting in a slight increase in the carbon intensity in the middle of the period. There is some convergence in carbon intensity between the Base and Low Case scenarios approaching the end of the forecast horizon. However, in the High Case, higher coal burn ensures a higher carbon intensity compared with the higher levels of nuclear and gas generation in the Low Case scenario.

25 Year summary

- Coal generation is more competitive over the first few years of the forecast horizon under all scenarios, reflecting increased gas prices relative to coal. Increasing carbon prices from around 2010 erode coal's competitiveness slightly, although this is partly mitigated by falling coal prices. Over the second half of the forecast horizon gas becomes steadily more competitive relative to coal generation, primarily due to strengthening carbon prices. The relative competitiveness of gas and coal varies between scenarios, with coal being more competitive in the High Case and less competitive in the Low Case.
- The weakening of coal's competitiveness, especially against newer higher efficiency gas units, coupled with emissions restrictions, erodes the economics of coal plant. In the Low Case, coal running reduces significantly over the period, and there is around 14.5GW of coal closures, with all of the non-FGD sets and some of the FGD sets

closing over the period. Remaining coal stations increasingly provide power over peak periods, and provide flexible generation to the system.

- Under the High Case, coal maintains a place in the merit order, although competitiveness is eroded as newer higher efficiency gas units come on-line. There is a considerable level of coal closures with almost all of the non-FGD stations closing.
- However, supercritical retrofit coal is economic with 3GW added to the plant mix, (including the CCS unit) helping to maintain coal running at relatively high levels over the period.
- Most of the existing nuclear fleet closes over the forecast horizon, with between 1 and 3.5GW remaining in the different scenarios. However, in the Low Case, 2GW of new nuclear capacity is added over the period 2020-2025, maintaining a nuclear capacity contribution of around 5.5GW. 1GW of new nuclear capacity is also assumed to commission in 2025 in the Base Case. The differences in nuclear capacity assumptions have a significant impact on the evolution of the system, with the removal of between 5-10GW of baseload, zero-carbon intensity plant from the system.
- There is significant demand growth of between 11-23% under the different scenarios over the period, although peak growth is lower at around 3-17%, increasing the system load factor.
- The closure of coal and nuclear plant, coupled with demand growth, stimulates demand for new generation, which is met by a different mix of plant in each of the scenarios. However, under all scenarios there is significant growth in both CCGT and renewable generation capacity.
- The construction of Langage, Marchwood, Immingham, Staythorpe, New Grain, Immingham, Newport and Pembroke Phase I (Low Case) provides a higher level of plant margin over the initial forecast period, and means that upward pressures on power prices, due to reducing plant margins, are delayed. However, pressures on plant margins ensure that power prices increase to a point where new build CCGT becomes economic between 2016 and 2022 (High and Low Cases respectively), with continued (although sporadic – particularly in the Low Case) growth in CCGT capacity over the forecast horizon. There is significant growth in gas fired generation with around 16-21GW CCGT and CHP plant constructed over the forecast horizon in the Low and High Cases (including the named plant). In addition, new nuclear capacity contributes to capacity margins under the Base Case and the Low Case, while retro-fit coal contributes to plant margins in the High Case scenario.
- In addition to growth in CCGT capacity, there is strong growth in renewable capacity over the forecast horizon. Renewable growth is supported by the assumed continuation of growth in the RO target beyond 2015 to 2032. Renewable generation capacity growth is dominated by onshore and offshore wind, with biomass generation also making a relatively high contribution, particularly in the High Case. The introduction of banding serves to increase the diversity of renewable generation, while guaranteed headroom means that the RO target does not necessarily provide a cap on renewable generation development, and there are points over the forecast horizon where the RO targets are exceeded.
- Co-firing at coal plant with energy crops is restricted due to fuel availability, but increases over the forecast horizon with higher levels of cultivation. The lower level of ROC banding applying to non-energy crop co-firing means that, increasingly, only the cheaper biomass fuels are economic, restricting levels of burn – particularly towards the end of the forecast period. The reducing level of coal burn over the forecast horizon also serves to restrict co-firing volumes. However, in the High Case, high levels of co-firing are maintained due to higher levels of coal burn.

- The growth in intermittent wind generation capacity leads to an increasing requirement for generation capacity (relative to demand) on the system. Although some capacity credit is given to wind, due to the effects of geographic diversity, this is relatively low compared to conventional plant. The impact of growing output from intermittent plant increases short-term volatility in power prices, and increases the requirement on the system for low load factor flexible generation. Both these effects are in part mitigated by an increase in system demand load factor.
- In all scenarios, Summer-Winter spreads decline slightly over the initial forecast period, reflecting compression of gas seasonal spreads, but there is slight upward pressure on spreads over the second half of the forecast horizon.
- There is a substantial change in the plant mix over the forecast horizon, with significant growth in renewable and gas fired generation, retirement of nuclear plant and switching from coal to gas generation. The timing of these different drivers results in different trajectories for system carbon intensity under the scenarios. However, under all scenarios the system undergoes relatively significant levels of structural change. The scenarios converge on relatively similar levels of carbon intensity, although differences remain between the scenarios reflecting differing assumptions on the level of coal burn and nuclear build.

Figure 51: GB Power Price Forecast Scenarios (Excluding BSUoS)

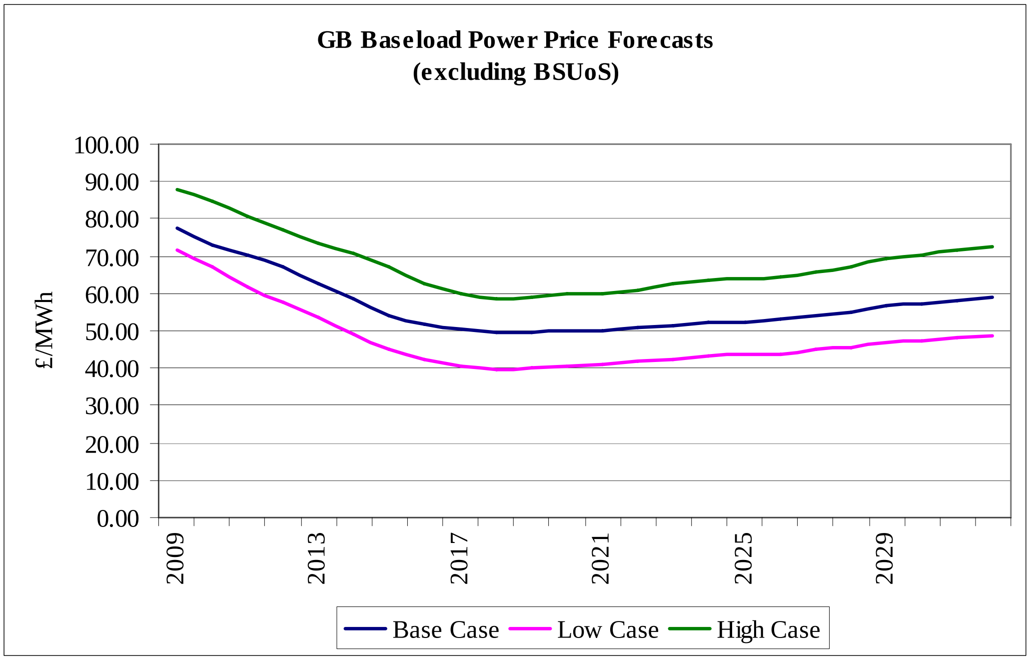


Figure 52: Average GB System Carbon Intensity

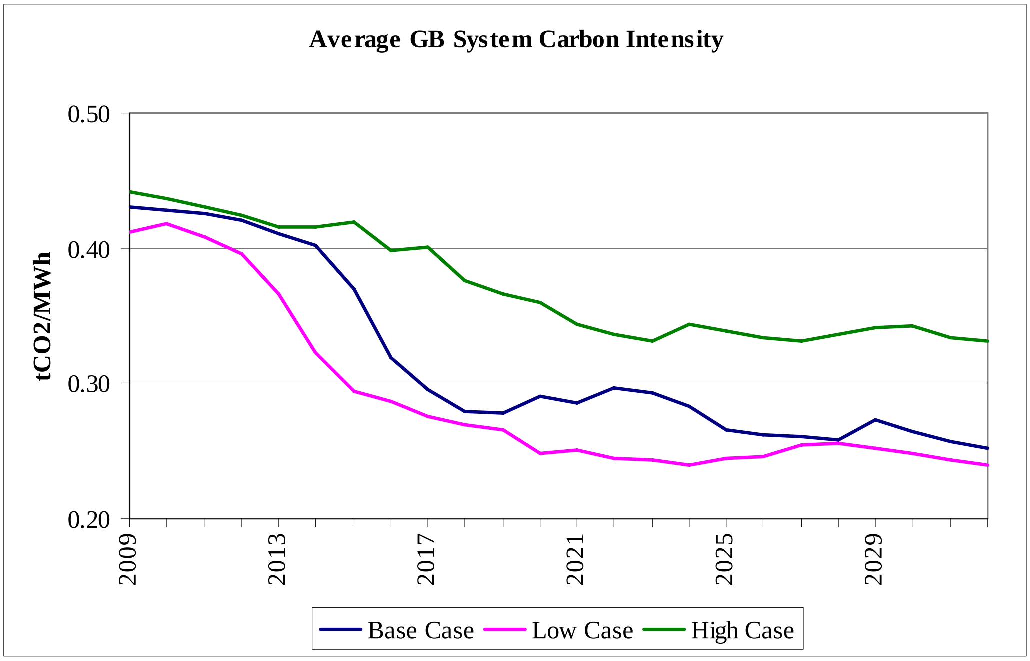
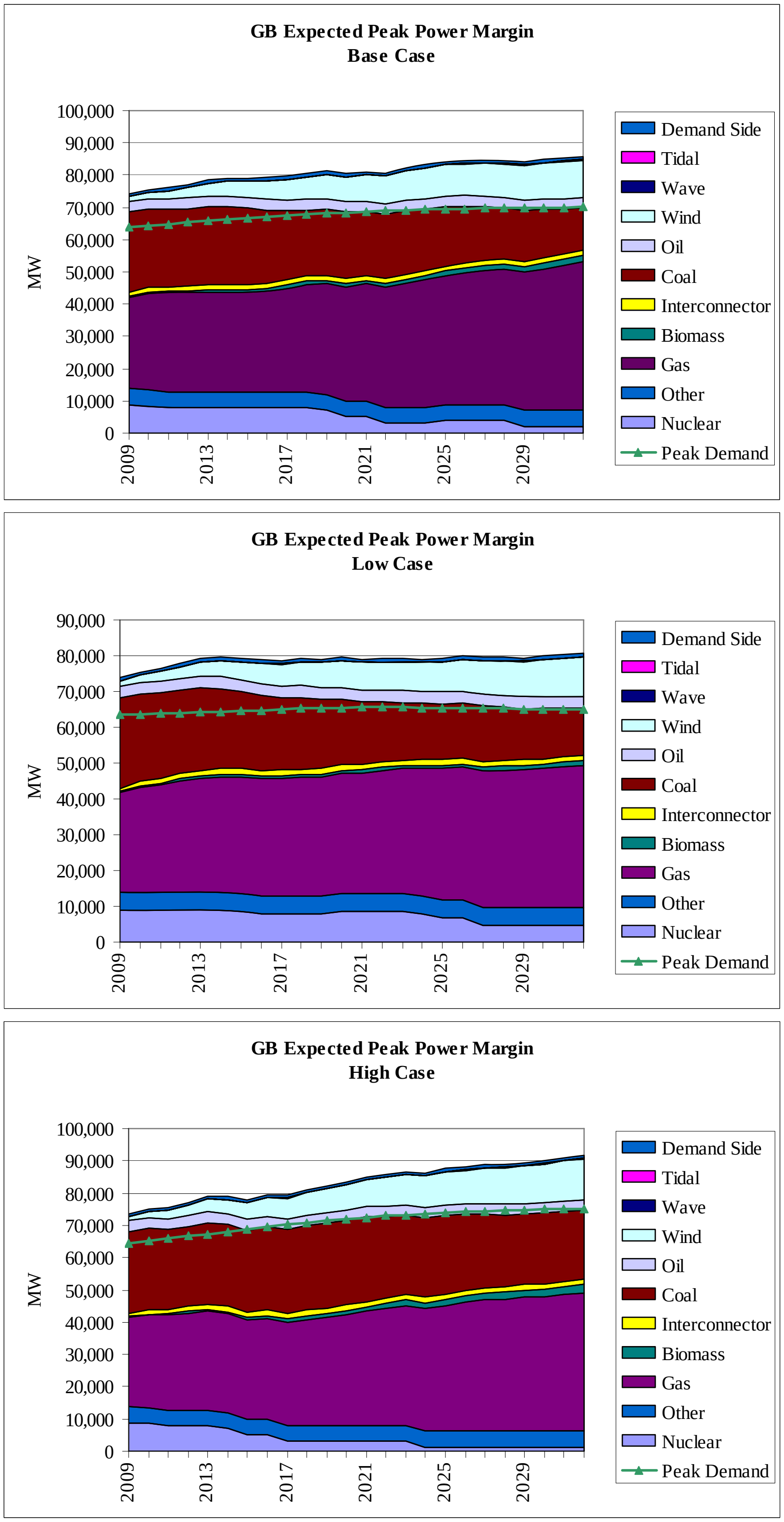


Figure 53: Expected Peak Power Margin Scenarios



13. RENEWABLE ASSUMPTIONS

This section provides a detailed analysis of the factors affecting the growth and economic viability of renewable capacity in GB, including the current legislation, consultations, resource base and connections, and explores potential future growth of the main renewable technologies.

13.1. The Renewables Obligation

The Renewables Obligation and Renewables Obligation (Scotland), which came into force in April 2002, require licensed electricity suppliers to source part of their electricity from renewable generation, or pay a penalty. The initial level of the Renewables Obligation was 3% of total electricity supplied to customers in Great Britain in 2002/03, and this grows to 15.4% in 2015/16, and remains at that level until the end of the Obligation in 2026/27.

In addition, the Northern Ireland Renewables Obligation came into effect on the 1st April 2005. This requires suppliers in Northern Ireland to source a proportion of their capacity from renewable generation (2.5% in 2005/06 increasing to 6.3% in 2012/13) or pay a penalty. Table 31 below shows the annual obligation targets.

Table 31: Supplier Renewables Obligation

Year	Total GB Obligation (as % of GB sales)	Total NI Obligation (as % of NI sales)
2002/03	3.0	
2003/04	4.3	
2004/05	4.9	
2005/06	5.5	2.5
2006/07	6.7	2.6
2007/08	7.9	2.8
2008/09	**9.1**	**3.0**
2009/10	9.7	3.5
2010/11	10.4	4.0
2011/12	11.4	5.0
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 – 2026/27	15.4	6.3

Renewable Obligation Certificates ("ROCs") are issued under the Renewables Obligations in the United Kingdom for each unit of output from generating stations accredited under the schemes.

A licensed supplier can meet its Renewables Obligation by producing ROCs to Ofgem or by making a buy-out payment, or a combination of both. Payments of "buy-out" are recycled and rebated to those suppliers who have surrendered ROCs, pro-rata to the number of certificates surrendered in that obligation period. The buy-out price was set at

£30/MWh in 2002/03, and is indexed to RPI. It is currently set at £35.76/MWh for the year 2008/09.

The value of ROCs should be equal across the three jurisdictions, reflecting the fact that ROCs, SROCs (Scottish ROCs) and NIROCs (Northern Irish ROCs) are fully fungible and the obligation of a supplier may be met in any of the jurisdictions by presenting any combination of the three.

13.2. The Energy White Paper and Reform of the Renewables Obligation

In May 2007 the Government published its Energy White Paper along with a number of consultations and supporting documents.

One of the significant changes discussed in the White Paper and an accompanying consultation was the reform of the Renewables Obligation (RO).

There are three stated aims to the reform:

1. Introduction of banding;
2. Increase the RO to a maximum of 20% by 2020 with guaranteed headroom; and
3. Maintain ROC prices in the event of oversupply.

The Government response to the consultation was published in January 08[92] and the Government is seeking through the Energy Bill to secure the necessary primary legislative powers to make the proposed changes. The detail will be implemented through a new Renewables Obligation Order. The government published in June 2008 a statutory consultation on the Renewables Obligation Order 2009[93].

The main points of the Government's response and consultation are set out below.

13.2.1. Banding

The proposed bands are linked to the state of development of the technologies and are as follows:

[92] BERR, Renewables Obligation Consultation, Government Response, January 2008.
[93] BERR, Statutory Consultation on the Renewables Obligation Order 2009, June 2008.

Stage	Technologies	ROCs
Established 1	Landfill gas	**0.25**
Established 2	Sewage Gas Co-firing on non energy crop (regular) biomass	**0.5**
Reference	Onshore wind Hydro Co-firing energy crops Energy from Waste with CHP Geopressure Co-firing of regular biomass with CHP Unspecified "others" – any new tech etc.	**1**
Post-Demonstration	Offshore wind Dedicated regular (non-energy crop) biomass Co-firing of energy crops with CHP	**1.5**
Emerging Technology	Wave Tidal Stream Advanced conversion tech (gasification, pyrolysis, anaerobic digest) Biomass with energy crops Regular biomass with CHP Energy crops with CHP Solar PV Geothermal Tidal Impoundment (tidal lagoons & tidal barrages (<1GW)) Microgeneration	**2**

The first banding period would run from 2009-2012 and from then onwards the Government proposes that the banding process will be linked to the phases of the EU ETS. For example, the government intends that any changes in bands should come into force on 1st April 2013 to take into account the expected impact of Phase 3 of the EU ETS. There would be consultation prior to changes, and recommendations would be made by an Independent Advisory Commission.

- ***Grandfathering***

  A grandfathering system has been proposed that will apply to all technologies apart from co-firing. The approach outlined is:

  - Generators operational on 11 July 2006 will continue to get 1 ROC per MWh (independent of whether their technology is banded up or down).

- Generators over 50kW which are not operational by 11 July 2006 but get planning consent and preliminary accreditation before 1 April 2009 and are operational before 31 March 2011:
    - If their band moves down they continue to get 1 ROC per MWh.
    - If their band moves up they get multiple ROCs from 1 April 2009.
- All other generators operational after April 2009 receive ROCs according to the banding system.
- Generators who receive grants based on a 1 ROC system can't move up (although they may be able to if they give back the grant). The detail of this will be worked out on a case by case basis.
- Additional capacity added to an existing station will be left to the generator's discretion as to whether it will be treated as a separate generating station – so it could get a different number of ROCs per MWh to the rest of the generating station - or whether their ROC entitlement will be pro-rata to the installed capacities.

Subsequent changes to the RO bands would have the same process of grandfathering depending on the date of the consultation and the date of the change. The ROC entitlement of a site will be dependant on the dates of planning consent, preliminary accreditation, commissioning, whether they had grant support and the capacity, as well as the technology.

- ***Time limit on grandfathering***

The May 07 consultation document had proposed a time limit on grandfathering, with stations that had been generating for over 20 years dropping to 0.25ROCs per MWh. However, the Government recognises concerns over this and the June 2008 consultation document now states that the Government has no intention of curtailing before 2027 the ROC entitlement of capacity which is operational.

- ***Co-firing***

The Government consultation states that co-firing of regular biomass will be eligible for 0.5ROCs per MWh but that the cap on the proportion of a supplier's obligation that can be fulfilled by co-fired ROCs will be retained at a level of 10% of the number of ROCs. Energy crops will not form part of any cap.

- ***Biomass***

The June 2008 consultation document states that the government no longer proposes to "deem" all waste as having a renewable energy content of 50% without further evidence. Instead, the proposed changes allow Ofgem to award ROCs on up to 50% of the total energy content to operators who satisfy evidential requirements without necessarily requiring those operators to directly measure the renewable energy content of the waste. If an operator wishes to claim more than 50%, they will be required to directly measure the renewable content of the waste.

The consultation outlines the government's plan to also to allow ROCs to be claimed on eligible biomass co-fired in a fossil fuel power station alongside solid recovered fuel.

- ***Impact of the Proposed Changes***

  According to analysis commissioned by BERR, there will be 13.4% renewables by 2015 under the proposed banding regime, opposed to 11.4% renewables under a base case.

  The Government's May 07 consultation document suggested that the proposed system would result in an average of 1.12ROCs per MWh.

13.2.2. Increase RO to maximum 20% with headroom

The Government's June 2008 consultation continues to keep the RPI link for the buyout fund for the duration of the RO which was been largely supported by respondents in the earlier consultation.

A "guaranteed headroom", based on the estimated amount of ROCs produced, was proposed in the May 07 consultation and supported by respondents. The level of the obligation will be a minimum of 108% of forecasted ROC production for a given year.

Guaranteed headroom will apply from the introduction of banding in 2009, however the obligation will be at least the level previously committed to – in other words the obligation in 2015/16 will be at least 15.4% but could theoretically be higher if there was higher anticipated ROC production.

They have decided that a six month notice period for announcing the level of the Obligation for a given obligation period is sufficient.

This change would apply to England and Wales only, although in the response document it states that Scotland and Northern Ireland will carry out further consultation with stakeholders before determining its own policy, whilst understanding the benefits of a consistent approach across the UK.

We assume that, for each five year period from 2015, the total obligation is capped at 108% of the target at the end of the period.

In the June 2008 consultation, the government sets out that the maximum upper limit of the obligation be set at 20%, but this should come into force in 2009 and not 2020 which had been set in the earlier consultation.

13.2.3. Maintain ROC Prices in the Event of Oversupply

In the June 2008 consultation, the government stated that they do not propose to bring forward provision to introduce a "ski-slope" mechanism to prevent a crash in the ROC market. This is because they consider the 20% maximum obligation limit to be sufficient in the immediate future to mean that the final level of the obligation is unlikely to be exceeded. However, they do consider that such a mechanism could be put in place in a subsequent reform depending on circumstances.

13.3. The Renewables Obligation Scotland (ROS)

Current targets for the ROS are the same as for the E&W RO. However, in 2006 the Scottish Executive consulted on developing separate Renewable Obligations for wave and tidal generation, which received support through the consultation process. Subsequently, the Renewables Obligation (Scotland) Order 2007 contained separate Obligations on Wave and Tidal generation from 2008 with different buy-out prices. The percentage of these Obligations rose from 0.05% of total supplies in 2008/09 to 0.35% of total supplies in 2015/16, for each of wave and tidal, remaining at that level to the end of the Obligation in March 2027.

However, in September 2007, the Scottish Government launched a consultation on changes to the Renewables Obligation (Scotland) Order 2008, which solely addressed the Marine Supply Obligation (MSO).

As no eligible projects or generating capacity have come forward, or been declared, the MSO level for 2008/09 is proposed to be set to zero. As before, the remaining periods have been recalculated to map out an **illustrative** path towards the proposed 75 MW cap from 2009/10 to 2015/16.

The Buy-Out prices for wave and tidal projects in the MSO are not linked to RPI and are shown in the following table.

Table 32: Buy-Out Prices for Wave and Tidal Technologies

Technology	Buy-Out Price, £/MWh
Wave	175
Tidal	105

The closing date for responses to the consultation was the 13th December 2007 and responses have been published. The Scottish Government has also decided that banding should be introduced to the ROS, and that this mechanism is capable of replacing the MSO. However, in the absence of further detail regarding the availability of additional grant support, they do not believe that the band level proposed by BERR for wave and tidal is sufficient.

In September 2008, the Scottish Government launched its statutory consultation on the Introduction of Banding to the Renewables Obligation (Scotland) with responses due by the 12th of December 2008.

In this document, the Scottish Government plans to adopt the same changes to the statutory obligation as those outlined in the main BERR consultation outlined above but with the following proposed differences:

- The MSO will be disbanded and replaced with an equivalent ROC multiple. Wave will receive 5 ROCs and tidal stream will receive 3 ROCs;
- Advanced Conversion Technologies in Scotland will have their eligibility for double ROCs linked to regard for SEPA's Thermal Treatment guidelines for waste; and

- Island wind will not be granted the 1.5ROC/MWh support BERR has proposed for wind. Instead the Scottish Government will continue to work to amend the current transmission charging models.

13.4.The Climate Change Levy

In April 2001, the Climate Change Levy (CCL) was introduced in the UK. This is a tax on the consumption of electricity and gas by non-domestic customers. The tax on electricity consumption for 2008/09 is 0.456p/kWh (or £4.56/MWh) and is linked to RPI, but electricity produced from renewable sources and good quality CHP is levy exempt. Consumers are therefore prepared to pay a premium for Climate Change Levy Exemption Certificates (LECs) in order to avoid paying the levy. This premium is an extra source of income for the renewable projects, and also for Good Quality Combined Heat and Power.

13.5.NFFO

Before the introduction of the Renewables Obligation, the Non-Fossil Fuel Obligation (NFFO) was the Government's major instrument for encouraging growth within the renewable energy industry. The NFFO applied in England and Wales. In Scotland and Northern Ireland, the Scottish Renewables Obligation (SRO) and the Northern Ireland NFFO (NI-NFFO) applied respectively.

These instruments assisted the industry by providing fixed price offtake contracts for electricity generated from renewable sources over a fixed period, with contracts being awarded to individual generators. In addition to electricity generated by renewable fuels, electricity from Municipal & Industrial Waste technology was also included in these schemes. This is, however, not RO eligible.

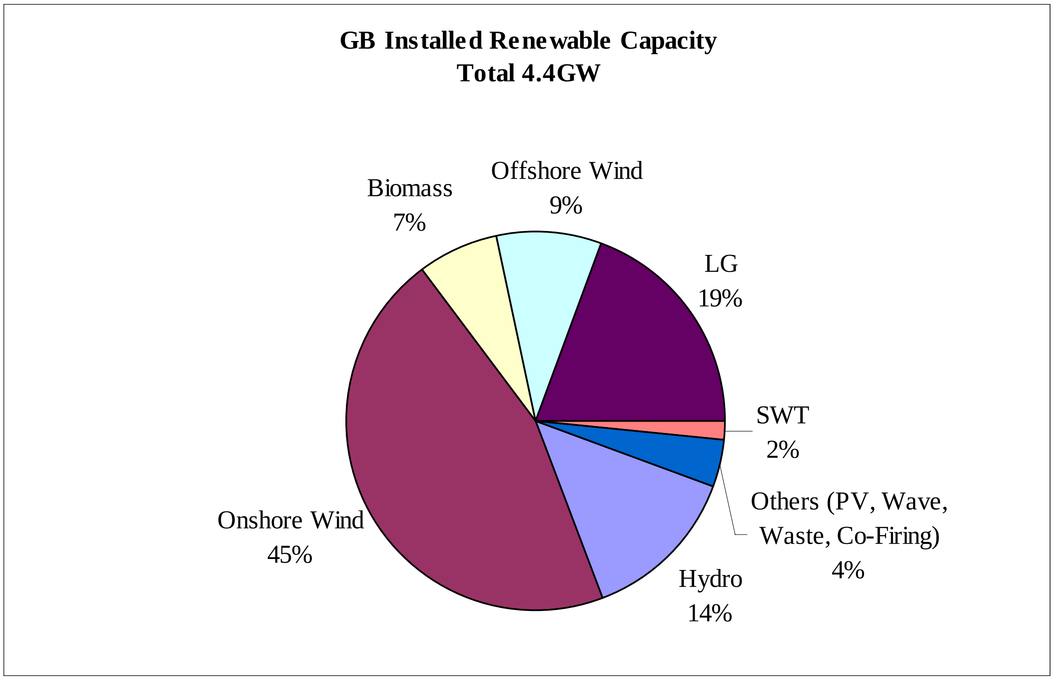
There are more than 400 NFFO projects currently operational but, with the introduction of the Renewables Obligation, no new NFFO contracts will be awarded.

The NFFO and SRO projects are eligible for ROCs, but since the projects are on fixed price contracts the ROCs are awarded to the Non-Fossil Purchasing Agency (NFPA) who then release them to the market via an auction.

13.6.Renewable Capacity

There is currently 4.4GW of installed renewable capacity in GB. The breakdown between the technology types is shown in the following figure.

Figure 54: Installed Renewable Capacity



13.6.1. Wind

There is currently just over 2.5GW[94] of operating windfarms in the United Kingdom (both onshore and offshore). These are shown in Table 33 below, and graphically in Appendix A.

Table 33: Distribution of Operational Wind Farms

Region	Onshore Installed Capacity MW	Offshore Installed Capacity MW
England	421	334
Wales	305	60
Scotland	1,208	10
Northern Ireland	209	
Total	**2,143**	**404**

In addition to the installed wind capacity, detailed above, there is currently a further 1,650MW of wind capacity under construction throughout the UK, around 60% of which is situated in Scotland. In addition to those under construction, a further 6.8GW of capacity have received consents but construction has not yet started.

[94] BWEA webpages, Sep 2008, www.bwea.com/ukwed/

Table 34: Distribution of Wind Farms Under Construction

Region	Onshore Capacity MW	Offshore Capacity MW
England	206	359
Wales	16	90
Scotland	759	180
Northern Ireland	63	
Total	**1,044**	**629**

The data above includes some of the offshore windfarms consented under the 'Round One' and 'Round Two' tender processes, the results of which are summarised in the following table. These projects are at various stages of development and, of this capacity, only 180MW is located in Scotland. The rest are located around the coast of England & Wales.

Table 35: Offshore Rounds

Lease Round	Capacity Awarded, MW
Round 1	1,000
Round 2	7,169

The development of Offshore windfarms was slower than initially expected although several of the Round 1 projects are either now operational or have started construction. In addition, several of the Round 2 projects have also received consents, with construction due to commence this year.

13.6.2. Landfill Gas

The amount of landfill gas capacity in GB accredited for ROCs with Ofgem is currently 853MW[95], of which only 81MW are installed in Scotland.

Although the growth in landfill gas capacity has been relatively high over the last few years, indications are that the Landfill Gas industry is gradually approaching saturation in the development of new low cost sites[96].

The EU Landfill Directive[97], which restricts the amount of biodegradeable municipal waste that local authorities can send to landfill, will limit the quality and quantity of methane produced by the sites, reducing the feasibility of electricity generation from landfill gas in the future.

13.6.3. Hydro

The capacity of ROC eligible hydro plant in GB is 607MW, 508MW of which are situated in Scotland.

[95] Ofgem List of RO and CCL accredited generating stations, May 2008.
[96] DTI, The Costs of Supplying Renewable Energy, A Report by Enviros Consulting Limited, September 2005.
[97] Council Directive 1999/31/EC of 26th April 1999 on the landfill of waste.

In 2005 the Scottish Executive gave permission for the first major hydro scheme in years, the 100MW Glendoe scheme, at the southern end of Loch Ness. This is well underway and is expected to be commissioned and operating in 2009.

Apart from this development it is not expected that significant volumes of hydro capacity will be developed over the forecast horizon.

13.6.4. Biomass

The capacity of ROC eligible biomass plant in GB is reported to be 316MW, with a further 5.4MW accredited under the category of 'Biomass and Waste using Advanced Conversion Technology'. Of this total, 82% is situated in England & Wales.

Over the past year there have been several announcements of new dedicated biomass projects to be built in GB and there are currently 1.9GW of biomass projects at various stages of planning/approval. As at May 2008, only around 12% of this had received approval.

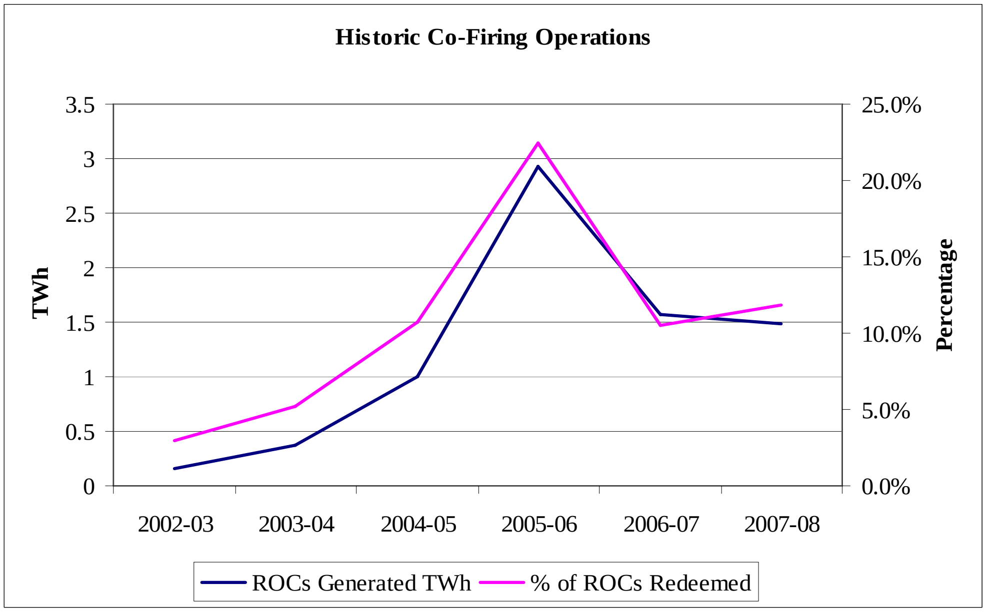
The European Commission's 'Biomass Action Plan'[98] encourages Member States to develop national biomass action plans. Defra published a Biomass Action Plan for England in April 2006[99] and the Scottish Executive published their Biomass Action Plan last year[100], which provides a comprehensive picture of the activity being undertaken in Scotland to develop the sector and sets out a framework for future policy and support.

13.6.5. Co-Firing

The following figure shows the co-firing volumes and percentages for the years 2002-03 to 2007-08 inclusive. From 2006 a maximum of 10% of ROCs surrendered by suppliers should originate from co-firing.

[98] The European Commission, COM(2005)628, December 2005
[99] Defra, The Government's Response to the Biomass Task Force Report, April 2006
[100] The Scottish Executive, A Biomass Action Plan for Scotland, March 2007

Figure 55: Historic Co-Firing Volumes and Percentage of total ROCs Surrendered



It is proposed retain the cap on non-energy crop co-firing at 10% of a supplier's obligation but to set the banding at 0.5 ROCs per MWh generated.

In comparison, it is proposed that energy crop co-firing receives 1 ROC per MWh generated. This could be sufficient to stimulate higher volumes of energy crop co-firing, which is currently constrained by energy crop supply. We assume that this proposed level of banding incentivises the energy crop market, and available volumes increase steadily throughout the forecast period. Indeed, Scottish Power has announced plans to use 35,000ha of Scottish agricultural land to grow energy crops for its Longannet and Cockenzie power stations. This equates to around 4%[101] of the 2006-07 output from these stations.

13.6.6. Wave & Tidal

The current UK wave and tidal capacity in GB remains small, with 0.5MW of shoreline wave, 0.75MW of wave and 0.55MW of tidal turbines installed and operating in GB waters.

Scotland's first tidal power driven electricity was connected to the National Grid in May 08, with the connection of OpenHydro's 250kW turbine, situated at the European Marine Energy Centre in Orkney.

There are also several other projects under development, such as Scottish Power's 3MW wave scheme in Orkney (scheduled to be operational this year) and EON's 8MW tidal stream project off the UK's West Coast (scheduled to be online by 2010).

[101] Assuming 11 tonnes of crop per ha and a calorific value of 17MJ/kg.

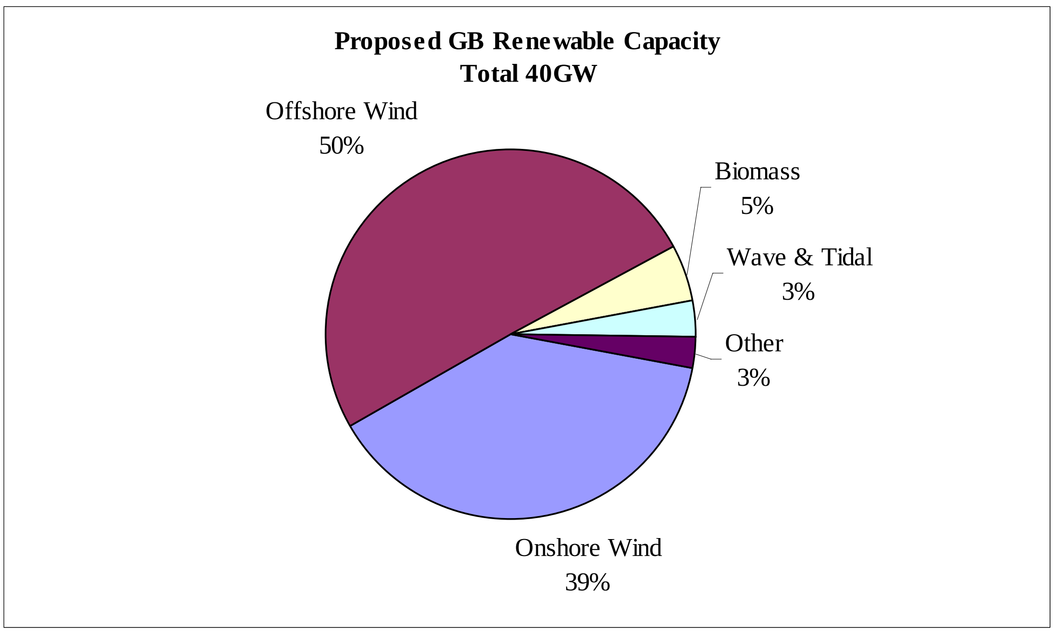
13.7.Renewable Build Rates

There is a significant renewable resource in GB, and there is considerable interest in developing renewable generation projects. However, there are barriers to development including difficulties obtaining planning permission, manufacturing resource limitations and transmission constraints.

A breakdown of renewable projects currently at some point in the development phase, including embedded and transmission connected projects, is given in Figure 56. However, many of the projects are not well advanced, and it is likely that a number of these projects will not get built as some will not obtain planning, and some of the projects will conflict. This excludes speculative plans for a North Sea Supergrid, totalling 10GW, which has recently been mooted, and the 8.6GW Severn Barrage, for which the Government is currently carrying out a 2-year feasibility study. Of this 39GW, around 5.5GW have received approval.

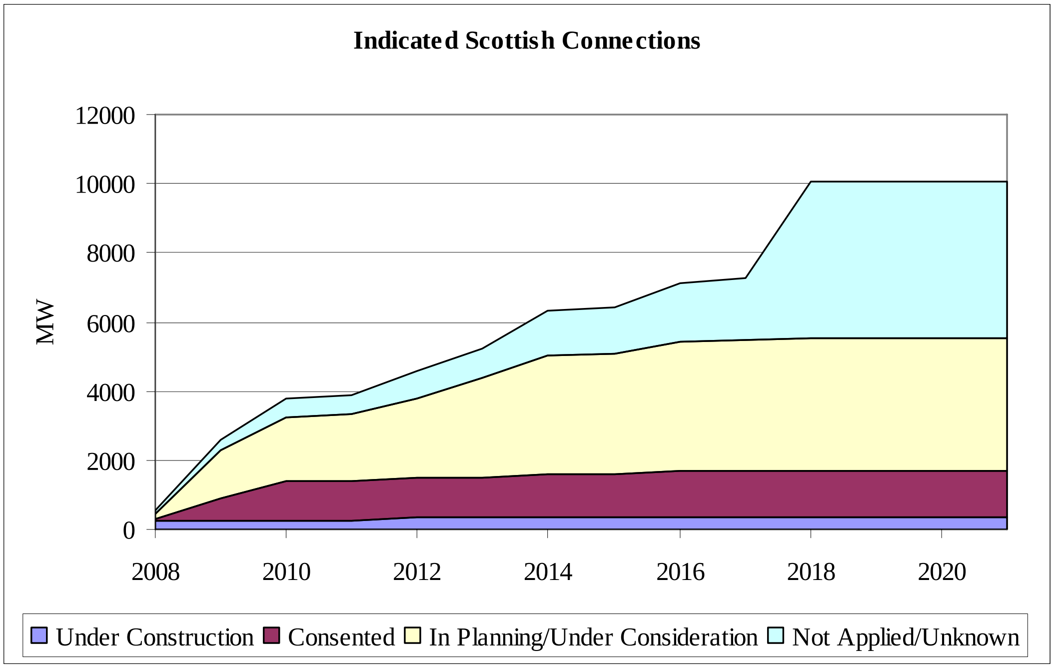
About 13GW of this capacity is located in Scotland and recent information published by National Grid[102] indicates that approximately 1.7GW of this has consents over the period to 2021, with a further 8.3GW either in planning or under consideration. This is illustrated in Figure 57.

Figure 56: GB Renewable projects



[102] "GB Queue Management – 25 February 2008", February 2008.

Figure 57: Scotland Generation Connections



13.7.1. Transmission Constraints

Transmission constraints provide a significant restriction on the development of the renewable resource, particularly in Scotland where many of the best renewable resources are located, but where, paradoxically, the transmission system is weakest.

Transmission constraints are being addressed by Ofgem through the 'Transmission investment for renewable generation'[103] proposals. The transmission licencees, SPTL, SHETL and NGT proposed several system upgrades which were then assessed and categorised by Ofgem[104 105]. Four projects were highlighted as 'Baseline' projects, which appeared to be clearly justifiable in terms of savings and constraint and other costs and were approved by Ofgem. Lead times for the construction for these upgrades have been indicated to range between 3 years for the Sloy proposal to 6 years for the Scotland – England interconnector proposal.

In addition to the 'Baseline' projects, further transmission upgrades for Scotland have also been proposed. These are shown in the following table.

[103] Ofgem, Transmission Investment for Renewable Generation – Final Proposals, December 2004
[104] Sinclair Knight Merz, Technical Evaluation of Transmission Network Reinforcement Expenditure, Proposals by Licensees in Great Britain, August 2004
[105] Ofgem, Transmission Investment for Renewable Generation – Final Proposals, December 2004

Table 36: Transmission Upgrades

Proposal		Earliest Connection Date
Beauly-Denny	Baseline	2011
Sloy	Baseline	
Kendoon	Baseline	
Scotland-England Interconnector[106]	Baseline	2011
Beauly-Blackhillock	Additional	
Beauly-Keith	Additional	
South West Scotland	Additional	
North Ayrshire	Additional	

The Beauly - Denny Public Inquiry has completed its final session and the Scottish Government have indicated that its decision on the issue is unlikely to be announced before the Spring of 2009. This will delay the connection of a significant amount of renewable capacity until 2012 at the earliest, or could potentially lead to cancellation of this project.

In addition to these, several other transmission upgrades are being considered:

The Kintyre-Hunterston Connection. In January 2007, SSE published a Consultation Document on the possible development of a new high voltage electricity transmission line capable of accommodating output from renewable energy schemes which may be developed on the Kintyre peninsula and to connect this to the existing mainland transmission network at Hunterston in Ayrshire. The need to upgrade the existing infrastructure is driven by requests to connect over 100MW more renewable generation capacity to the current system in this area, which already connects 60MW of renewables.

Connection of the Scottish Islands. In early June 2007, Ofgem published a consultation on "Connecting the Islands of Scotland" inviting views on proposed ways forward for regulating the connections to the Scottish islands. However, these connections are currently being developed by SSE under normal connection procedures.

Wales. Transmission development is also being considered for Wales where there is the potential for around 1.1GW of onshore wind connections[107].

13.8. Renewable Costs

Recent information regarding the costs of developing the different kinds of renewable projects indicates that costs for all the technologies considered in this study have increased significantly since the last major review. This has been due to a number of reasons, including:-

[106] Originally this upgrade was dependent on the Beauly-Denny upgrade or additional connection activity in western Scotland. However, Scottish Power showed there was 4.4GW of wind generation that could connect without the Beauly-Denny upgrade, and Ofgem approved the Scotland-England interconnector upgrade, independent of the Beauly-Denny upgrade, in December 2005. SP suggest that the full upgrade could be complete around 2010.

[107] National Grid Seminar "Mid Wales User Workshop Slides 21st June 2007", June 2007

- Increased raw material costs for capital items;
- Increased competition for key components; and
- Increased competition for fuel (in the case of biomass).

The costs of developing renewable projects differ between specific projects and typically, as the installed capacity increases, the cost of capacity reduces.

Differences in costs reflect differences in the following parameters:-

- Capital costs, accounting for changes in manufacturing costs, raw material costs, installation costs and infrastructure costs, typically reducing as technology becomes more mature;
- Experience of operating the technology and experience of EPC contracts;
- Investor Confidence and Cost of Financing; and
- The maturity of the technology.

For the Base Case, estimates of costs have been sourced from DTI's 'Impact of banding the Renewables Obligation – Costs of electricity production' report[108] using their Medium Case as the basis.

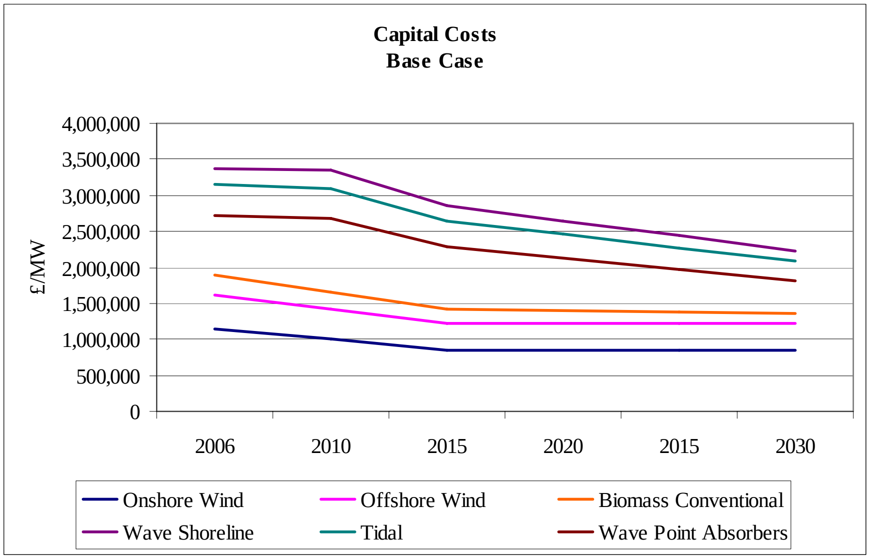
For the ROC price scenarios we have constructed ranges of current costs around our Base Case, reflecting different technology installation and possible expenditure ranges. Cost reductions over the forecast period are varied between the scenarios, reflecting different learning rates over the forecast period and assumed cost reductions in the different parameters.

13.8.1. Cost Comparison

The capital costs for the technologies under the Base Case are illustrated in the following graph, which shows the assumed reductions over the forecast period.

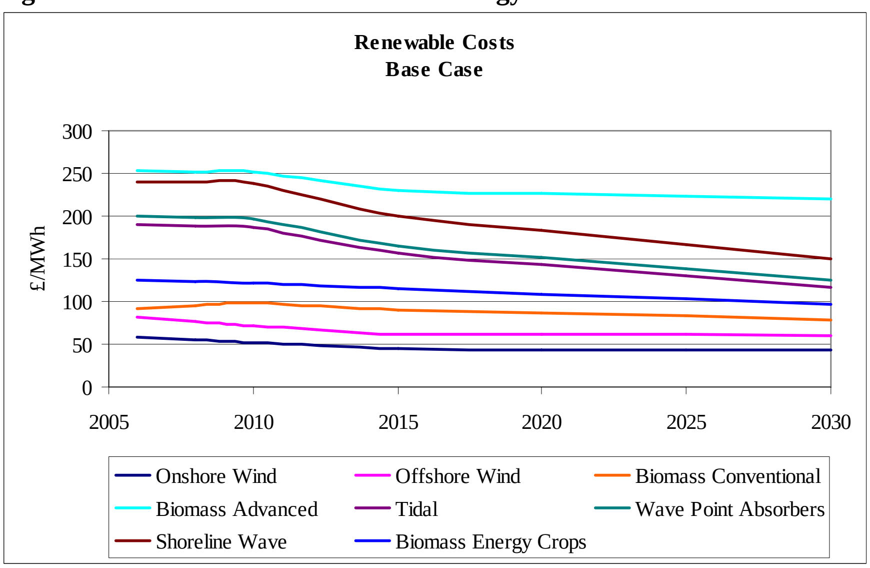
[108] DTI, 'Impact of banding the Renewables Obligation – Costs of electricity production', April 2007, URN 07/948

Figure 58: Base Case Renewable Technologies Capital Costs



The total costs of the different technologies, including capex financing, fixed and variable costs are shown in the following figure.

Figure 59: Base Case Renewable Technology Costs



13.9.Scenario Assumptions

We have constructed three scenarios: a Base ROC Price Case, a High ROC Price Case and a Low ROC Price Case. These scenarios are based around proposed changes to the Renewables Obligation and also explore different transmission development assumptions, as well as different cost assumptions and success rates through the planning process.

It is assumed under all scenarios that the proposed changes to the RO are enacted in some form. The main assumptions associated with modelling of the RO are summarised below:

- For the Base and High ROC Price Cases the renewable target is extended to a maximum of 20% over the period 2016-2020, 25% over the period 2021-25, and 30% over the period 2026-2032.
- For the Low ROC Price Case the renewable target remains at a maximum of 20% from 2016/17 to the end of the current Obligation period in March 2027.
- Post 2009 the RO target is set at 8% above the actual level of renewable generation (the guaranteed headroom model), up to the maximum target for generation from renewable sources over the period.
- In the event that generation from renewable sources exceeds the target level in a period, the contribution of ROCs to the target is scaled downward so that the target is exactly met. This removes the risk of a ROC price collapse, by providing a mechanism where, in the event of over-supply, prices will taper gradually downwards.
- The RO is banded to provide greater support for emerging technologies (and less support for developed technologies), with banding introduced in 2009.
- It is assumed that, to 2020, the banding phases are aligned to the EU ETS phases. Thereafter the banding periods are extended to 10 years. Between the periods the banding levels can be adjusted, especially in the case of the nascent technologies where technology costs reduce rapidly as installed capacity is developed.
- The existing rights of projects to ROCs are grandfathered, other than for co-firing.
- The cap on non-energy crop co-firing of 10% of suppliers' ROC obligation remains in place.
- The RO buyout price will remain indexed to RPI.
- In 2009 the separate marine obligations under the SRO are dropped, in favour of maintaining consistency across the Renewable Obligations. However, Scottish marine technologies are allocated more ROCs than the England & Wales and Northern Irish marine technologies.
- The initial banding of the different technologies is that outlined in the Government's June 2008 consultation on the Renewables Obligation Order 2009.
- Due to the high renewable build costs, the banding multipliers are maintained at the 2009-2012 levels across the forecast period to support growth except for offshore wind which drop slightly from 2021.
- It is assumed that the Scottish Marine Supply Obligation is superseded by banding from 2009 but that the Scottish banding levels remain around those indicated in the MSO, which, if wave and tidal technologies were to receive banding ROCs then, at the 2008/09 Buy-Out price of £35.76/MWh, 1MWh generated from wave technology would require approximately 5 ROCs to get a similar level of support and 1MWh generated from tidal technology would require approximately 3 ROCs.
- It is assumed that Scottish shoreline wave projects receive 5 ROCs per MWh, Scottish offshore wave projects receive 3.9 ROCs per MWh and Scottish tidal projects receive 2.9 ROCs per MWh.

The banding assumed under all scenarios is detailed below.

Table 37: Renewables Banding Assumptions

	Existing	2009 - 2012	2013 - 2020	2021 – 2032
Conventional Biomass	1.5	1.5	1.5	1.5
Advanced Biomass	N/A	2	2	2
Non Energy Crop Co-Firing	0.5	0.5	0.5	0.5
Energy Crop Co-Firing	1	1	1	1
Hydro	1	1	1	1
Landfill Gas	1	0.25	0.25	0.25
Onshore Wind	1	1	1	1
Offshore Wind	1.5	1.5	1.5	1.25
Sewage	1	0.5	0.5	0.5
E&W Tidal	2	2	2	2
Scottish Tidal	2.9	2.9	2.9	2.9
E&W Wave	2	2	2	2
Scottish Shoreline Wave	5	5	5	5
Scottish Offshore Wave	3.9	3.9	3.9	3.9

For all scenarios we use the Power Price Base Case assumptions of fuel prices, demand growth and non-renewable capacity closures/build.

13.9.1. Base Case Assumptions

This section summarises some of the key assumptions that are used within the Base Case forecast. It is assumed that:

- All renewable projects under construction proceed to completion.
- ‘Baseline’ transmission upgrades go ahead as planned and are completed by the end of 2010, apart from the Beauly-Denny upgrade which is delayed and not completed before 2012. These upgrades allow the connection of additional Onshore Wind capacity, which connects incrementally during the upgrade period. The four additional proposed Scottish transmission upgrade projects also go ahead, but later in the forecast horizon.
- In addition to the 2GW of currently connected Onshore Wind we assume a further 2GW of onshore wind capacity is connected to the GB system by the end of 2010.
- The higher proposed banding for Offshore windfarms is assumed to stimulate the progress of the Offshore projects and capacity roughly equivalent to 85% of the total capacity of the Offshore Round One leases is assumed to be completed by the end of 2010.
- In addition to the Round One and Round Two offshore wind leases, which are predominately located in England & Wales, we assume that further offshore wind projects are also developed in Scottish waters, although these are later in the forecast horizon.

- The long term build rates for both onshore and offshore wind reflect industry opinion on timescales for the planning process and the availability of the turbines from manufacturers. In addition, high demand for wind turbines maintains prices at a relatively high level, leading to delays and cancellations for some projects on economic grounds.

13.9.2. High ROC Price Case

This section details the assumptions used in the High ROC Price Case. It is assumed that:

- As in the Base Case, we assume that all projects under construction proceed to completion, but that the Beauly–Denny 'Baseline' transmission upgrade is further delayed, restricting access to the system from the North of Scotland. The other baseline projects, although started on time progress more slowly than expected and, by 2010 only 1.6GW of Onshore Wind capacity can connect to the system, 0.4GW less than in the Base Case.
- Build costs for all technologies are assumed to be higher than in the Base Case, and cost reductions over the forecast period are lower.
- Development of the Offshore projects is also delayed and only around 60% of the Round One capacity is assumed to be installed by the end of 2010.
- Round Two projects and Scottish Offshore developments are also delayed due to planning restrictions and availability of materials and services. The net effect of continuing difficulties in connection and planning mean that maximum build rates are generally lower than in the Base Case.
- The development of Wave and Tidal generation is assumed to be slower than under the Base Case, reflecting slower commercialisation of the technologies, and difficulties in developing larger machines for more hostile environments.

13.9.3. Low ROC Price Case

This section details the assumptions used in the Low ROC Price Case. It is assumed that:

- In the Low ROC Price Case we again assume that all projects under construction proceed to completion.
- 'Baseline' transmission upgrades go ahead as planned and are completed by the end of 2010, apart from the Beauly-Denny upgrade which is delayed and not completed before 2012. These upgrades allow the connection of additional Onshore Wind capacity, which connects incrementally during the upgrade period. The four additional proposed Scottish transmission upgrade projects also go ahead, and are completed earlier than in the Base Case.
- Build costs are assumed to be lower than in the Base Case, and cost reductions over the forecast period are higher.
- In this scenario, planning delays are reduced compared to the Base Case, and manufacturing capacity for turbines and the structures increases, allowing higher build rates than the Base Case. This allows more rapid

development of many existing projects, and so slightly higher capacities relatively early in the forecast horizon.

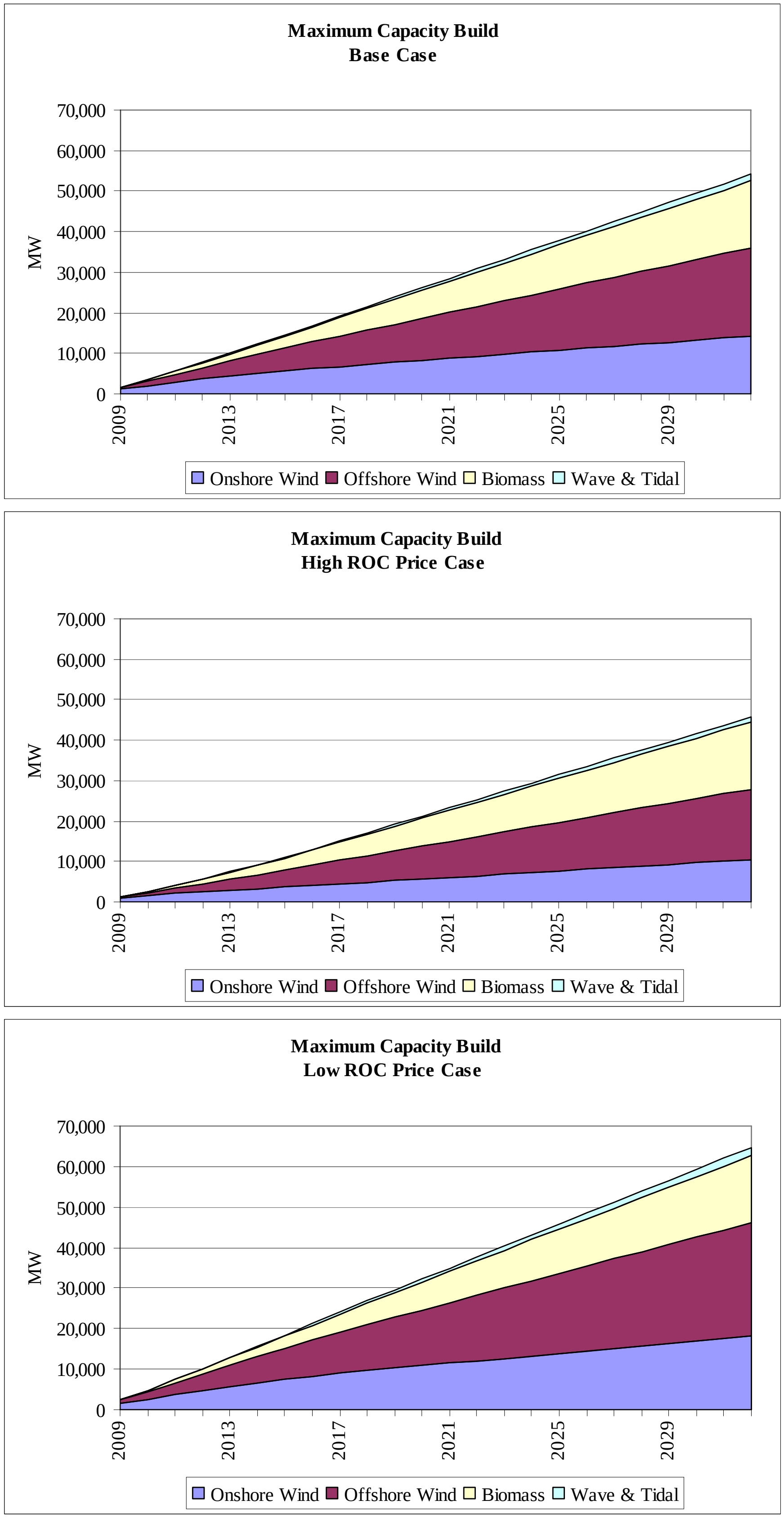
- The offshore transmission regime is resolved and in place for 2009, stimulating the progress of the Offshore projects. Capacity equivalent to the total capacity of the Offshore Round One leases is assumed to be completed by the end of 2010, but there is more rapid development of the Round Two projects as well as further offshore developments including some in Scottish waters.
- More rapid commercialisation of wave and tidal projects allows the marine generation industry to expand more rapidly and the capacity of marine generation projects increases more rapidly than under the Base Case.

13.9.4. Maximum Potential Build Rates

The modeling constrains the maximum annual build rate for each technology. This reflects the differing assumptions under each of the scenarios about planning restrictions, transmission constraints, and the ability of the industry to develop, install and finance projects. The actual rate of renewable development is then optimized by the model, dependent upon the relative economics taking into account power prices and the effect that increasing renewable capacity has on the value of ROCs.

It should be noted that these represent maximum potential build rates. Renewable build rates are an output from the modelling process, based upon the interaction between plant economics, forecast market power and ROC prices and are less than or equal to the capacities shown in the following figures.

Figure 60: Maximum Potential Capacity Build



14. ROC PRICE FORECASTS

The ROC price forecasts have been constructed using IPA's proprietary model ECLIPSE (Emissions Constraints and Policy Interaction in Power System Economics). ECLIPSE provides forecasts of both power and ROC prices within a single consistent framework. It represents the non-linear ROC (Renewable Obligation Certificate) value function defined by the supplier obligation and buy-out price, encompassing all the proposed changes to the Obligation, including banding, headroom, grandfathering and a price collapse mechanism. It simulates the optimal economic despatch and construction of renewable plant, allowing for their impact on ROC prices. This allows simulation of the optimal despatch for co-firing coal plant, and simulation of the interaction between ROC prices and renewable project economics which governs the penetration of different technologies.

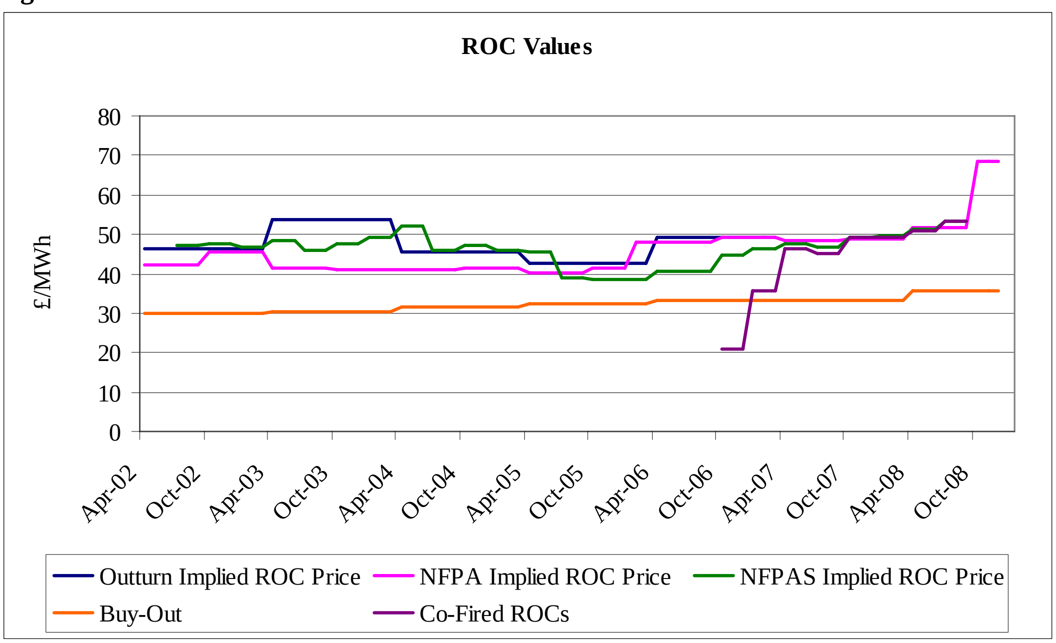
14.1.Current ROC Market

Data from the latest NFPAS auction indicate ROC prices of £53.27/MWh for Scotland for the period Jul – Sep 2008. This is a slight increase over the prices achieved in the previous auction (£51.39/MWh), but is lower than £68.60/MWh, which is the price for England & Wales for the period Oct 08 – Mar 09 from the latest NFPA auction.

The co-fired ROC price is around £53.5/MWh based on the sale of just over 4,000 co-fired ROCs in the latest auction.

The following figure shows the historic out-turn ROC prices from the beginning of the Obligation in April 2002.

Figure 61: Historic ROC Prices



14.2.Base Case

Figure 62 shows the forecast ROC price compared to the buy-out price, the renewable capacity constructed over the forecast period and the number of ROCs produced along with the renewable energy (MWh) produced.

Note that once banding is introduced in 2009, the number of ROCs produced from co-firing with non energy crops is forecast to be less than the 10% limit and so ROCs produced from co-firing are expected to trade at parity with normal ROCs.

2009-2012

- Over this period the current rules surrounding the Renewables Obligation are maintained and known projects are built.
- The introduction of banding in 2009 begins to incentivise the development of a range of technologies, with onshore wind and offshore wind (mainly England & Wales Round 1 projects) beginning to make a significant contribution. There is a significant increase in the installation rate for offshore wind projects and, towards the end of the period, this exceed the growth rate for onshore wind projects.
- The banding assumed for energy crops makes them economic which helps stimulate energy crop cultivation, increasing fuel availability, and energy crop co-firing volumes start to increase. By 2012, approximately 40% of co-firing volumes are from Energy Crop burn.
- ROCs covering around 8.6% of supplied energy are generated in 2010, but falling Renewable generation is forecast to exceed the obligation (of 12.4%) by 2012, and hence guaranteed headroom is triggered. As a result, prices fall from around £51/MWh in 2009 to £38.60/MWh by the end of the period (equal to 108% of the buy-out since the 20% maximum level is not reached).
- In 2012, the ratio of the number of ROCs generated to the amount of renewable energy generated is 1.08.

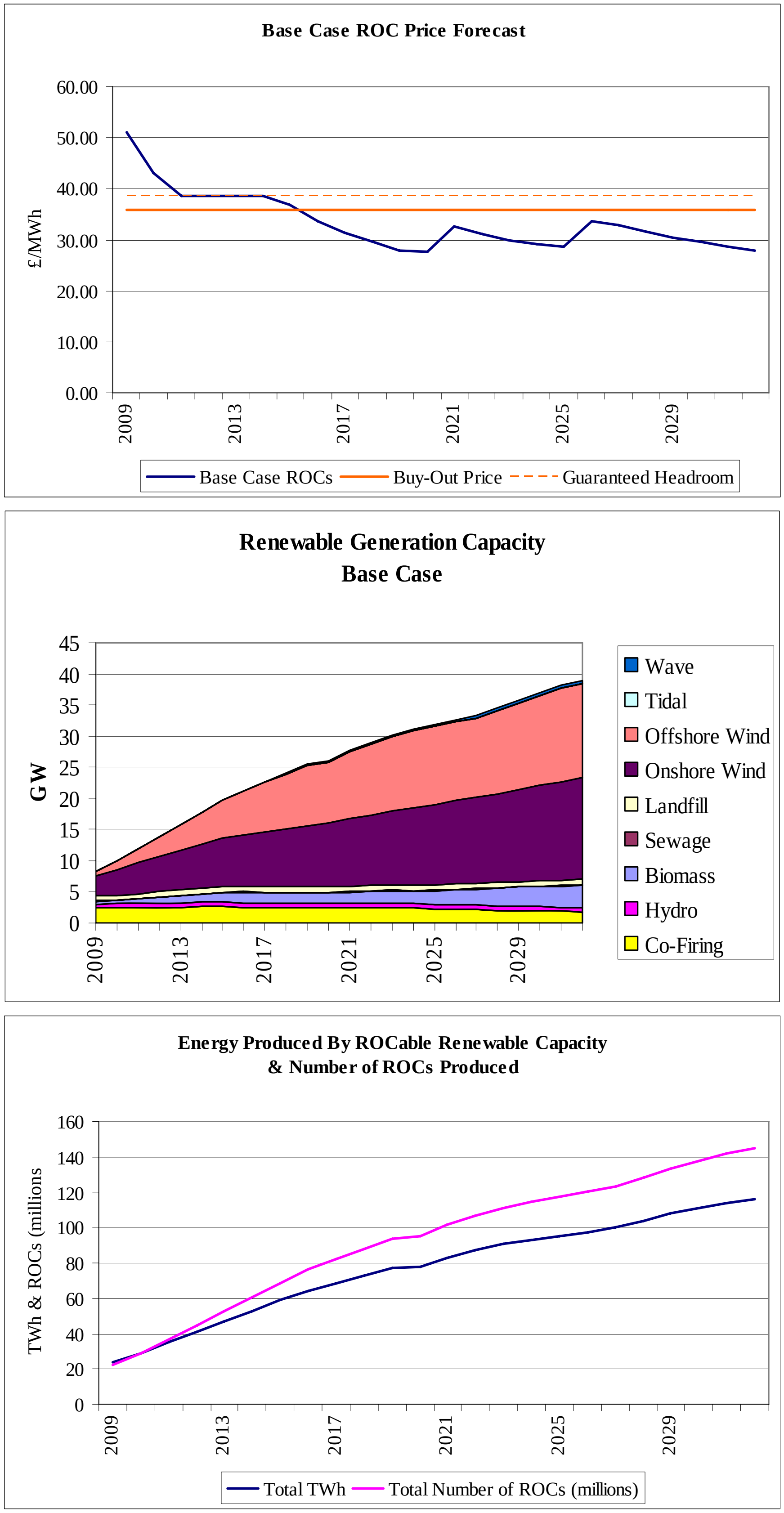
2013-2022

- Streamlining of planning with the Energy Review and the implementation of Scottish Planning Policy 6 begin to increase renewable build rates.
- Completion of the Beauly-Denny transmission upgrade in 2012, and the assumed completion of the additional transmission capacity upgrades, allows more Scottish renewable projects to be built.
- There is continued growth in both onshore and offshore wind generation (with maximum build rates of approximately 700MW and 950MW per annum respectively), although capacity growth begins to stabilise as new sites become more costly to develop, particularly for onshore wind as the best (in terms of access and yield) sites will have already been developed.
- The proposed banding for wave and tidal projects is sufficient to stimulate only a small amount of capacity growth and, by the end of the period, only relatively limited volumes of marine technologies are built (~200MW).
- Energy crop projects continue to be developed and the higher volume of energy crop cultivation leads to higher fuel availability. This results in the level of co-firing increasing by 45% over the period.
- There is some growth in biomass generation across the period, in part reflecting increased availability of biomass, but also reflecting higher banding levels which are required to offset high capital costs.
- ROC prices reduce rapidly beyond 2015 as growth in renewable generation capacity, and ROC production, is more rapid than growth in the RO targets and generation exceeds the 20% maximum obligation level.
- The presumed implementation of a mechanism to prevent a collapse in the ROC price (so called “ski-slope”) enables renewable development in excess of the RO target, resulting in ROC prices falling below the buy-out price for the remainder of the period, although fluctuations are observed as the maximum obligation is assumed to increase in 2021.
- In 2020, ROCs accounting for approximately 25% of supplied energy are generated, slightly above the 20% target.
- The assumed banding levels from 2013 (equivalent to those proposed for 2009 – 2012) impact on the ratio of the number of ROCs generated to the amount of renewable energy generated and, in 2020 this rises to 1.2 as offshore wind (with 1.5 ROCs) become increasingly significant in the generation mix.

2023-2032

- The assumed growth in the Obligation to 25% between 2021 and 2025, and to 30% between 2026 and 2032 continues to stimulate renewable growth of most technologies.
- The wasting nature of the onshore wind resource base means that there are a limited number of economic onshore wind sites that can be developed, and the onshore build rate therefore remains relatively low.
- Despite the higher costs of developing offshore wind, the higher banding levels support the development of further offshore wind sites, although the build rates decrease slightly towards the end of the period as offshore wind also suffers from being a wasting resource.
- Towards the end of the period, biomass becomes more competitive with offshore wind, as remaining offshore wind sites are more costly to develop, and biomass makes a more significant contribution to the level of renewable generation output. However, the high capital costs for biomass suggest the Government may need to increase the banding for biomass above the currently assumed levels to stimulate significant capacity growth.
- In this period, build costs for wave and tidal reduce due to global technology advancements, and the assumed continued availability of multiple ROCs for these technologies means that a small amount of capacity is built with relatively constant build over the period. At the end of the period approximately 450MW of wave and tidal capacity is installed. As with biomass, the high capital costs for these technologies suggest that the Government may need to raise the banding multipliers for these technologies above the currently assumed levels to stimulate significant capacity growth.
- The number of co-firing stations reduces over the period due to coal capacity retirement. However, the increasing volumes of available energy crops maintains co-firing levels and ensures that the volume of co-fired energy remains fairly stable (at around 5% of total ROCs) over the period, only tailing off towards the end of the period.
- As renewable technologies are not economic without the support of ROCs, build does not significantly exceed the ROC target and so ROC prices remain around the buy-out price for the remainder of the period.
- The continued maintenance of the banding multipliers from their 2009-2013 levels impacts slightly on the ratio of the number of ROCs to the amount of renewable energy generated and, in 2032, this ratio increases to 1.25.

Figure 62: Base Case ROC Price Forecast and Capacity Growth



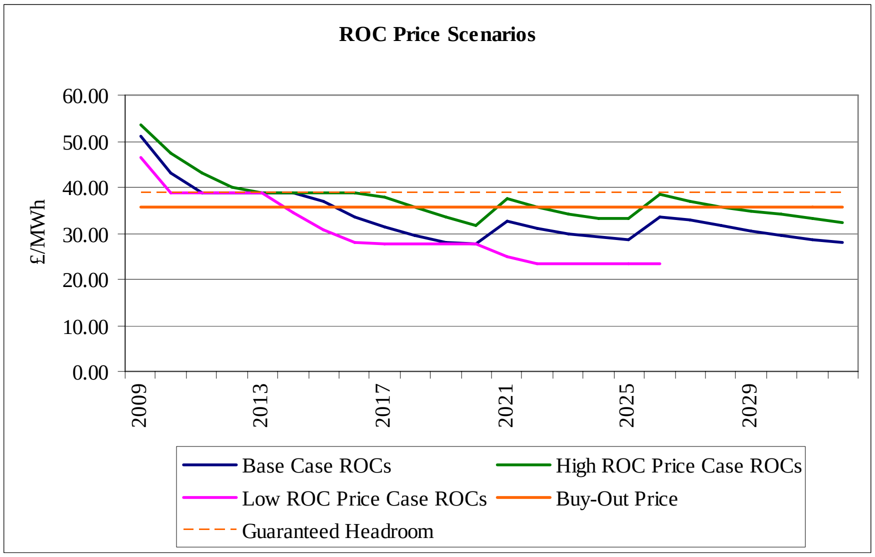
14.3.ROC Price Scenarios

In this section the ROC price scenarios are compared and the key differences between the scenarios discussed.

Note that the banding of non-energy crops means that, even with sustained levels of high non-energy crop co-firing, this cap is not a constraint on co-firing burn throughout the forecast horizon and non energy crop co-firing ROCs are expected to trade at parity with normal ROCs.

Forecast ROC prices for all three scenarios are shown in Figure 63 below and tabulated in the appendix. Figure 64 shows the number of ROCs generated by technology compared to the maximum RO obligation level for each of the three scenarios.

Figure 63: ROC Price Scenarios



2009-2012

- Over the period there is an increasing convergence between the ROC price scenarios, primarily reflecting renewable growth rates exceeding targets and downward pressure on prices being limited by the 8% headroom on the buy-out price. The rate at which the scenarios hit this floor price is different based on the assumptions on how quickly projects are completed and commissioned. In addition, differences in assumptions on the completion of major transmission reinforcements and the rate of progress of offshore developments begin to have an impact on capacity growth toward the end of the period.
- Under all cases, ROC prices reduce over the period, reflecting more rapid renewable development than the annual incremental increases in the RO targets.
- Under all scenarios, renewable generation capacity growth is driven by onshore wind, with offshore wind development beginning to increase significantly toward the end of the period, particularly in the Low ROC Price Case.
- Non-Energy Crop co-firing remains capped at 10% of all ROCs redeemed throughout the forecast period. Despite the lower banding for non energy crops, the volume of non-energy crop co-firing remains high.

- The higher banding for energy crop co-firing means that this type of generation is more economic. However, the volumes of energy generated are limited by the availability of energy crops. By 2010, the volumes of non Energy Crop and Energy Crop burn are around 0.8% and 0.5% of supplied energy respectively.
- There is very limited development in marine energy in all three scenarios; although banding, and the assumed Marine Feed-In tariff which is available to 2010, begins to stimulate development in this sector, resulting in around 20MW capacity built in each of the scenarios.
- Renewable generation reaches 15.3%, 13%, and 11% of supplied energy in 2012 under the Low, Base and High ROC Price Cases respectively, with the Base and Low Cases exceeding the Government's 12.4% target.
- In 2012, the ratio of the number of ROCs generated to the amount of renewable energy generated differs slightly between the scenarios (1.07 in the High ROC Price Case, 1.08 in the Base Case and 1.10 in the Low ROC Price Case) reflecting differences in the technology built.

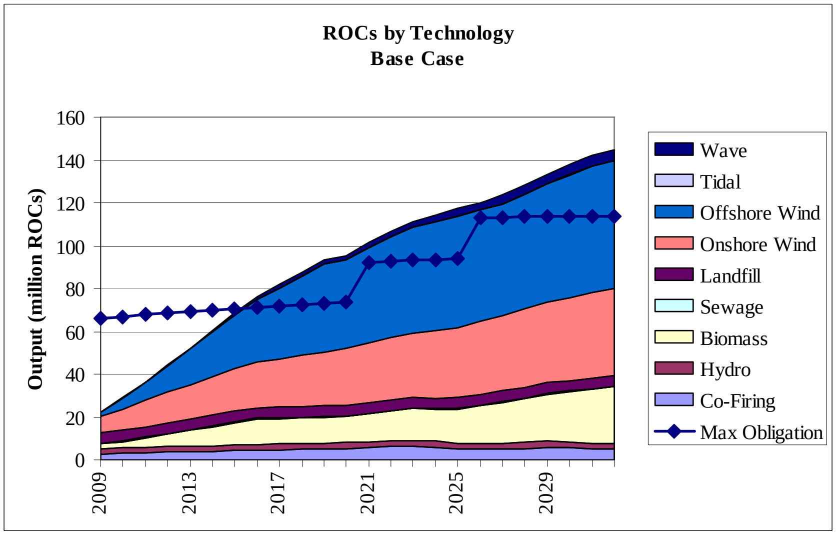
2013-2022

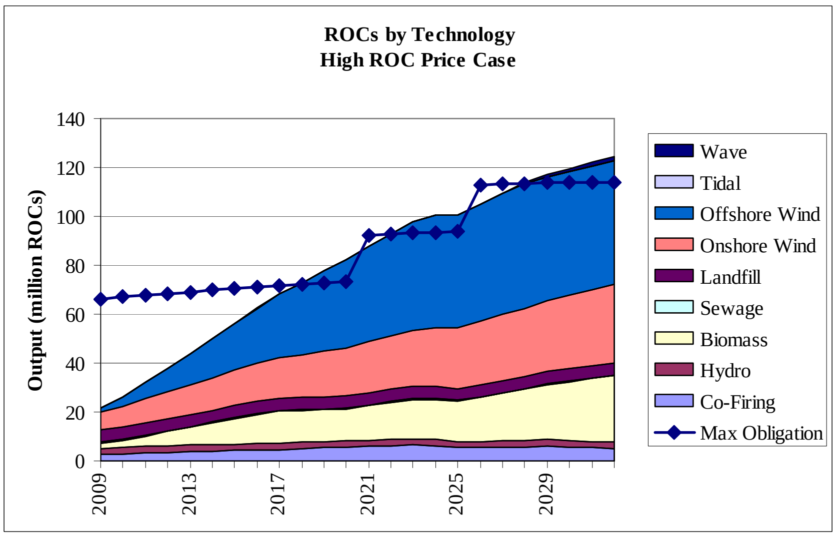
- In the High ROC Price Case, higher technology costs mean that projects are only economic at higher ROC prices. Consequently, limited build rates maintain the ROC price above the buy-out over much of the period, with the price reducing to just below the buy-out price in 2018, but increasing again when the maximum obligation target is increased to 25% in 2021.
- In the High ROC Price Case, growth is predominantly in onshore and offshore wind, with offshore capacity growing at a faster rate due to the typically larger size of projects. There is also some growth in Biomass generation capacity, although this is limited by the relatively high construction costs.
- Under the Low ROC Price Case, the ROC price drops below the buy-out price in 2014 (slightly earlier than in the Base Case) and remains that way for the remainder of the period, reflecting higher capacities, improved transmission access and a more streamlined planning process. In addition, assumed cheaper technology costs enable more capacity to be built at lower ROC prices and allow build through the ROC target.
- Differences in transmission capacity, and slower development of offshore projects, limit the growth in renewable capacity in the High ROC Price Case. However, under the Low ROC Price Case completion of major transmission works allows significant growth in capacity, particularly in Scotland.
- Under the Low ROC Price Case, the lower ROC price affects the build of marginal renewable stations and only limited further biomass capacity is built.
- Co-firing continues in all cases over the period, with increasing levels of co-firing volumes driven by increasing availability of energy crops.
- In the Low ROC Price Case, the amount of ROCs generated comprise around 30% of supplied electricity in 2022, ahead of the 20% intended RO target. Under the High ROC Price Case, ROCs generated account for approximately 25% of supplied electricity, meeting the assumed 25% RO target.
- By the end of the period, the ratio of the number of ROCs generated to the amount of renewable energy generated is very similar across all the scenarios at around 1.2.

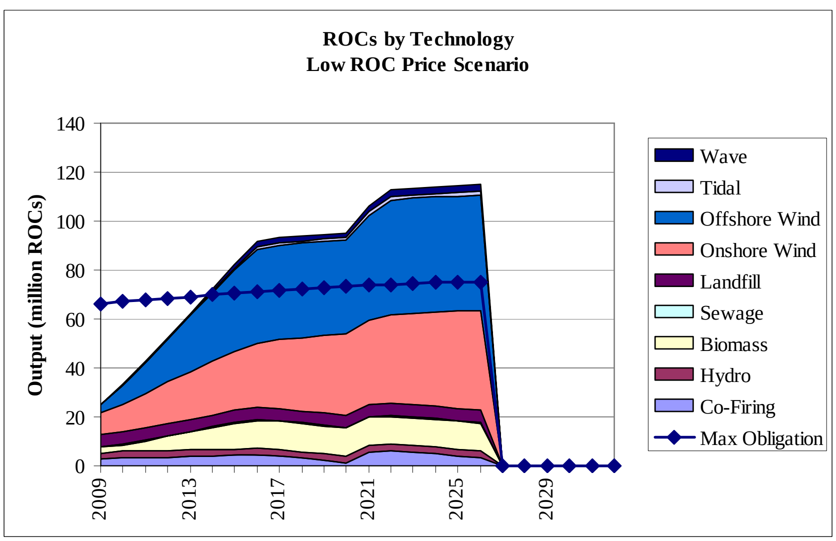
2023-2032

- Differences in build rates, ROC prices and banding result in a slightly different renewable generation capacity mix evolving in each scenario.
- In the High ROC Price Case, growth is focused on onshore and offshore wind, as well as biomass, which is less location-specific than wind developments and less dependent on transmission upgrades. Growth in offshore wind is limited by the more expensive capacity cost assumptions, and the ROC price generally fluctuates around the buy-out price depending on the evolution of the obligation target level. Growth remains relatively constant over the forecast horizon reflecting lower maximum growth rates and leads to corresponding higher ROC price, which continues to stimulate investment in capacity.
- In the Low ROC Price Case the RO target does not increase above 20% and so does not provide an incentive for additional capacity build. All renewables still need some support from the RO and so growth is effectively restricted by the target level. Growth is very limited over the period and only the most economic renewable projects are built. From 2027, after the cessation of the RO, almost no further renewable capacity is built, as most of the renewable technologies are not viable without some support from the RO mechanism.
- Even with the wave and tidal ROC bandings being maintained at their current levels across the forecast, very little additional capacity is constructed for these technologies in any scenario. This suggests the Government may need to increase the banding multipliers for these technologies to stimulate growth.
- Under the High ROC Price Case, higher build costs restrict the amount of build achieved throughout the forecast period.
- In the Base Case, the amount of ROCs generated comprises around 38% of supplied electricity in 2032, exceeding the assumed 30% obligation. Under the High ROC Price Case ROCs generated account for approximately 33% of supplied electricity which is slightly higher than the assumed 30% RO target. In the Low ROC Price Case the amount of ROCs generated comprise around 31% of supplied electricity in 2026, well above the assumed 20% RO target.
- In 2032, the ratio of the number of ROCs generated to the amount of renewable energy generated remains reasonably similar between the Base and High Case scenarios at around 1.25, reflecting the dominance of offshore wind (receiving 1.5 – 1.25 ROCs/MWh) in all scenarios.

Figure 64: ROCs and Maximum RO Targets







ANNEX A: DATA

Table 38: Brent Crude Oil Price Forecasts, $/barrel (April 2008 money)

	Base Case	Low Case	High Case
2009	111.84	105.00	126.75
2010	109.91	100.50	122.00
2011	104.50	93.75	114.25
2012	94.50	83.75	104.75
2013	85.00	73.25	96.50
2014	77.00	64.50	89.25
2015	70.00	57.50	83.25
2016	65.00	52.00	78.00
2017	61.50	48.00	74.25
2018	59.75	46.00	73.00
2019	59.00	45.25	72.50
2020	58.50	44.75	72.00
2021	58.50	44.75	72.00
2022	58.75	44.91	72.38
2023	59.00	44.95	73.05
2024	59.16	44.91	73.41
2025	60.00	45.54	74.46
2026	60.91	46.25	75.58
2027	61.94	47.06	76.81
2028	62.99	47.91	78.07
2029	64.24	48.96	79.53
2030	65.21	49.72	80.70
2031	66.20	50.50	81.90
2032	67.15	51.25	83.00

Table 39: Oil Product Price Forecasts, $/MT (April 2008 money)

	HFO			GasOil		
	Base Case	**Low Case**	**High Case**	**Base Case**	**Low Case**	**High Case**
2009	475.20	448.31	533.76	993.17	932.39	1125.53
2010	467.58	430.63	515.10	975.95	892.43	1083.35
2011	446.35	404.11	484.65	927.95	832.49	1014.53
2012	407.06	364.83	447.33	839.15	743.69	930.17
2013	369.74	323.58	414.92	754.79	650.45	856.91
2014	338.31	289.20	386.43	683.75	572.76	792.53
2015	310.81	261.70	362.86	621.59	510.60	739.25
2016	291.17	240.09	342.24	577.20	461.76	692.63
2017	277.41	224.38	327.51	546.12	426.24	659.33
2018	270.54	216.52	322.59	530.58	408.48	648.23
2019	267.59	213.57	320.63	523.92	401.82	643.79
2020	265.63	211.61	318.67	519.48	397.38	639.35
2021	265.63	211.61	318.67	519.48	397.38	639.35
2022	266.61	212.24	320.15	521.70	398.80	642.72
2023	267.59	212.41	322.78	523.92	399.19	648.64
2024	268.23	212.23	324.22	525.34	398.78	651.91
2025	271.51	214.71	328.32	532.78	404.38	661.17
2026	275.11	217.49	332.73	540.90	410.67	671.13
2027	279.13	220.70	337.56	550.00	417.93	682.06
2028	283.27	224.03	342.51	559.36	425.46	693.26
2029	288.19	228.14	348.24	570.46	434.73	706.20
2030	292.00	231.14	352.86	579.09	441.52	716.65
2031	295.87	234.20	357.55	587.84	448.44	727.24
2032	299.61	237.15	361.88	596.29	455.10	737.03

Table 40: NBP Gas Price Forecasts, p/th (April 2008 money)

	Base Case		Low Case		High Case	
	Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
2009	81.10	96.41	73.86	84.26	98.20	116.75
2010	80.51	91.83	71.92	81.37	96.69	110.29
2011	77.49	87.67	65.91	74.70	89.80	101.56
2012	73.74	83.59	59.80	67.68	84.68	95.95
2013	67.98	76.94	53.46	61.05	78.39	88.91
2014	61.10	69.78	46.48	53.56	74.00	84.61
2015	53.69	61.87	39.91	46.42	67.06	77.32
2016	46.11	53.61	34.66	40.68	57.86	67.81
2017	42.09	49.38	31.18	36.81	52.83	62.53
2018	39.45	46.72	29.26	34.47	49.62	59.15
2019	39.24	46.47	29.02	34.11	49.79	59.42
2020	38.73	45.86	28.87	33.85	50.49	60.30
2021	38.62	45.73	28.75	33.66	49.50	59.18
2022	39.32	46.56	29.36	34.31	50.81	60.81
2023	40.06	47.43	29.93	34.92	52.64	63.07
2024	40.77	48.28	30.40	35.47	53.49	64.16
2025	40.47	47.92	30.48	35.57	53.83	64.63
2026	41.06	48.62	31.02	36.19	53.62	64.45
2027	42.27	50.05	32.02	37.36	55.36	66.61
2028	43.50	51.51	33.08	38.60	57.23	68.94
2029	45.05	53.35	34.33	40.06	60.00	72.36
2030	45.74	54.16	35.00	40.84	61.11	73.78
2031	46.49	55.05	35.76	41.73	61.97	74.90
2032	47.14	55.82	36.27	42.33	62.94	76.07

Table 41: CIF ARA API#2 Coal Price Forecasts, $/tonne (April 2008 money)

	Base Case	Low Case	High Case
2009	173.32	164.32	181.82
2010	162.36	153.36	171.36
2011	148.50	139.00	157.50
2012	130.00	120.25	139.75
2013	114.25	104.75	123.75
2014	102.25	92.50	111.50
2015	91.75	82.00	101.00
2016	83.00	73.51	92.18
2017	76.50	66.96	85.72
2018	71.25	61.67	80.51
2019	67.50	57.88	76.79
2020	65.25	55.58	74.58
2021	64.29	54.58	73.65
2022	64.42	54.69	73.81
2023	64.56	54.79	73.97
2024	64.69	54.89	74.14
2025	64.83	54.99	74.30
2026	64.96	55.09	74.47
2027	65.10	55.18	74.64
2028	65.23	55.28	74.81
2029	65.37	55.37	74.98
2030	65.50	55.47	75.15
2031	65.65	55.58	75.33
2032	65.75	55.68	75.43

Table 42: Annual Carbon Price Forecasts, Euro/tCO_2 (April 2008 money)

	Base Case	Low Case	High Case
2009	26.00	25.00	27.00
2010	23.90	20.00	26.48
2011	22.69	18.00	27.80
2012	23.82	19.00	29.19
2013	25.01	20.40	30.65
2014	26.27	21.42	32.18
2015	27.58	22.49	33.79
2016	28.96	23.62	35.48
2017	30.41	24.80	37.26
2018	31.93	26.04	39.12
2019	33.52	27.34	41.07
2020	35.20	28.71	43.13
2021	36.24	29.56	44.22
2022	37.28	30.41	45.31
2023	38.32	31.26	46.39
2024	39.36	32.10	47.48
2025	40.40	32.95	48.57
2026	41.44	33.80	49.66
2027	42.48	34.65	50.75
2028	43.52	35.50	51.84
2029	44.56	36.35	52.92
2030	45.60	37.20	54.01
2031	46.65	38.05	55.10
2032	47.69	38.89	56.19

Table 43: GB Baseload Forecast Power Prices - Seasonal Prices Apr 09 – Mar 32, £/MWh (April 2008 money)

	Base Case		Low Case		High Case	
	Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
2009	73.21	81.52	67.50	75.77	83.77	91.74
2010	69.53	76.53	63.34	71.32	81.12	88.37
2011	66.96	73.88	58.34	65.53	76.81	84.43
2012	63.81	70.72	54.50	61.04	73.31	80.92
2013	59.21	65.75	50.38	56.46	69.75	77.37
2014	55.70	61.81	46.30	51.96	67.37	74.21
2015	50.97	57.49	42.39	47.71	64.31	70.08
2016	48.79	54.62	39.79	44.82	59.88	65.23
2017	47.67	53.20	38.08	42.67	57.87	61.87
2018	47.23	52.25	37.39	41.80	56.56	60.79
2019	47.29	52.12	37.90	41.85	56.54	61.40
2020	47.53	52.09	38.72	42.33	57.76	62.33
2021	47.58	52.13	38.95	42.99	57.25	62.66
2022	49.22	52.90	39.66	43.91	57.89	63.91
2023	49.30	53.63	40.56	44.25	60.03	65.00
2024	50.21	54.25	41.38	45.14	61.21	65.61
2025	50.32	54.28	41.58	45.63	61.28	66.67
2026	51.07	54.93	41.80	45.50	61.08	67.39
2027	51.86	56.32	43.41	46.74	62.28	68.96
2028	52.54	57.55	43.55	47.40	64.31	70.14
2029	54.26	59.15	44.68	48.58	67.27	71.79
2030	55.10	59.75	45.16	49.45	67.71	72.77
2031	55.72	60.49	46.00	50.41	68.97	74.08
2032	56.70	61.14	46.55	50.51	69.57	75.36

Table 44: Forecast BSUoS, £/MWh (April 2008 money)

	Base Case	Low Case	High Case
2009	0.89	0.93	0.85
2010	0.69	0.72	0.65
2011	0.68	0.75	0.63
2012	0.64	0.75	0.63
2013	1.02	1.27	0.94
2014	1.03	1.31	0.91
2015	1.14	1.36	0.91
2016	1.19	1.34	0.94
2017	1.18	1.32	0.96
2018	1.21	1.35	1.03
2019	1.22	1.32	1.08
2020	1.19	1.30	1.07
2021	1.19	1.26	1.14
2022	1.11	1.23	1.10
2023	1.18	1.20	1.06
2024	1.21	1.20	1.00
2025	1.27	1.21	1.08
2026	1.25	1.20	1.12
2027	1.24	1.19	1.14
2028	1.23	1.18	1.12
2029	1.17	1.13	1.04
2030	1.20	1.14	1.06
2031	1.21	1.12	1.09
2032	1.21	1.18	1.11

Table 45: Base & High ROC Price Cases RO Co-Fire Constraints

Year	GB Demand TWh	Maximum Obligation (as % of GB sales)	Maximum Obligation TWh	Non-Energy Crop Co-fire Limit %	Max Non-Energy Crop Co-fire TWh
2009/10	374	20	66.25	10%	6.62
2010/11	378	20	66.95	10%	6.70
2011/12	382	20	67.66	10%	6.77
2012/13	386	20	68.38	10%	6.84
2013/14	390	20	69.11	10%	6.91
2014/15	395	20	69.84	10%	6.98
2015/16	399	20	70.58	10%	7.06
2016/17	403	20	71.28	10%	7.13
2017/18	407	20	71.91	10%	7.19
2018/19	410	20	72.47	10%	7.25
2019/20	413	20	72.97	10%	7.30
2020/21	415	20	73.40	10%	7.34
2021/22	418	25	92.25	10%	9.22
2022/23	420	25	92.70	10%	9.27
2023/24	422	25	93.10	10%	9.31
2024/25	423	25	93.46	10%	9.35
2025/26	425	25	93.77	10%	9.38
2026/27	426	30	112.86	10%	11.29
2027/28	427	30	113.18	10%	11.32
2028/29	428	30	113.41	10%	11.34
2029/30	429	30	113.63	10%	11.36
2030/31	429	30	113.75	10%	11.37
2031/32	430	30	113.86	10%	11.39
2032/33	430	30	113.86	10%	11.39

Table 46: Low ROC Price Case RO Co-Fire Constraints

Year	GB Demand TWh	Maximum Obligation (as % of GB sales)	Maximum Obligation TWh	Non-Energy Crop Co-fire Limit %	Max Non-Energy Crop Co-fire TWh
2009/10	374	20	66.25	10%	6.62
2010/11	378	20	66.95	10%	6.70
2011/12	382	20	67.66	10%	6.77
2012/13	386	20	68.38	10%	6.84
2013/14	390	20	69.11	10%	6.91
2014/15	395	20	69.84	10%	6.98
2015/16	399	20	70.58	10%	7.06
2016/17	403	20	71.28	10%	7.13
2017/18	407	20	71.91	10%	7.19
2018/19	410	20	72.47	10%	7.25
2019/20	413	20	72.97	10%	7.30
2020/21	415	20	73.40	10%	7.34
2021/22	418	20	73.80	10%	7.38
2022/23	420	20	74.16	10%	7.42
2023/24	422	20	74.48	10%	7.45
2024/25	423	20	74.77	10%	7.48
2025/26	425	20	75.02	10%	7.50
2026/27	426	20	75.24	10%	7.52
2027/28	427				
2028/29	428				
2029/30	429				
2030/31	429				
2031/32	430				
2032/33	430				

Table 47: ROC Price Forecasts, £/MWh (April 2008 money)

	Base Case	**Low ROC Price Case**	**High ROC Price Case**
2009	51.03	46.33	53.50
2010	43.09	38.62	47.51
2011	38.62	38.62	43.09
2012	38.62	38.62	40.15
2013	38.62	38.62	38.62
2014	38.62	34.47	38.62
2015	36.85	30.65	38.62
2016	33.51	27.85	38.62
2017	31.38	27.61	37.75
2018	29.52	27.61	35.59
2019	27.89	27.61	33.63
2020	27.61	27.61	31.83
2021	32.55	24.89	37.64
2022	31.15	23.51	35.66
2023	29.97	23.45	34.06
2024	29.19	23.45	33.27
2025	28.62	23.45	33.27
2026	33.56	23.45	38.39
2027	32.78	0.00	36.95
2028	31.61	0.00	35.67
2029	30.42	0.00	34.70
2030	29.50	0.00	34.01
2031	28.65	0.00	33.34
2032	27.86	0.00	32.41

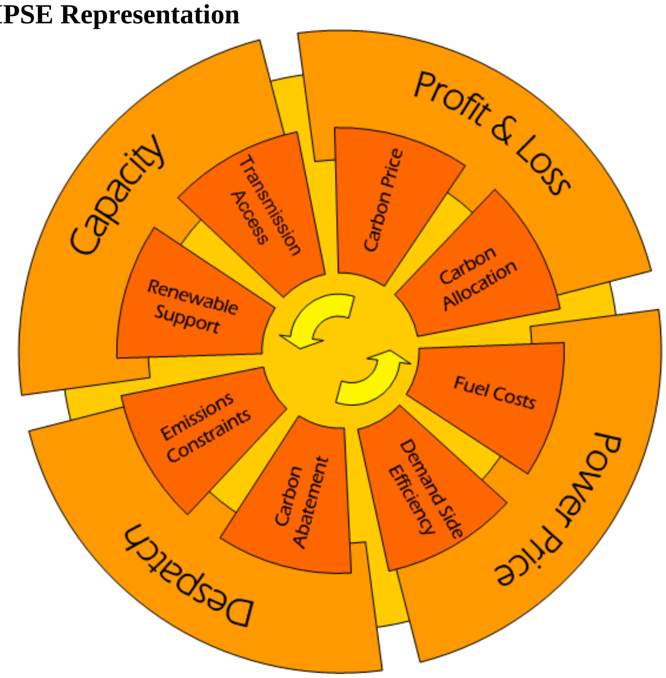
ANNEX B: ECLIPSE

The power industry is driven both by the details of plant operation, but also by wider macro-economics, market and regulatory developments and governmental policy all of which have a key role in shaping the future of the industry.

ECLIPSE (Emissions Constraints and Policy Interactions in Power System Economics) is a proprietary model that uses a Mathematical Programming approach to model the fundamental economics of power markets, allowing for the interaction with political, environmental and regulatory developments.

ECLIPSE captures the complexitiy of the power markets in terms of contracts, carbon pricing, emissions constraints, renewable obligation certificates, security of supply and the evolution of generation capacity within a single consistent framework.

Figure 65: ECLIPSE Representation



Despatch: Despatch of all major power stations down to an hourly granularity. Accurate modeling of different generation technologies, including thermal plant, plant co-fired with biomass, hydro and other renewable schemes, and modeling of commercial constraints associated with off-take and fuel contracts. ECLIPSE utilizes detailed information on fixed and variable costs, technical constraints and efficiencies for each power station.

Carbon Pricing: The European Carbon Trading Scheme (EU ETS) has a significant effect on generator economics. ECLIPSE models both the impact of carbon pricing on station running and power prices as well as the impact of free allocations on station profitability. ECLIPSE utilizes IPA's carbon price modeling to inform assumptions about future carbon market prices and free allocations at installation level.

Emission Limits: Power plants are subject to emissions restrictions under the LCPD and IPPC which limit the volume and rate of emission of certain pollutants. ECLIPSE represents these emissions limits, and can simulate their impact on plant economics and power pricing. The dispatch of coal is optimized over the year to ensure maximized profitability over restricted running hours.

Renewables Obligation (RO): The Renewables Obligation is the main renewables support mechanism in Great Britain. ECLIPSE provides detailed forecasts of ROC prices and represents the complexities of the ROC price mechanism. ECLIPSE models the non-linear price curve and the interaction with the dispatch of controllable renewables such as biomass and co-fired coal. ECLIPSE captures RO restrictions (such as applied to co-firing), technology banding, headroom, and the proposed ROC over-supply price mechanism.

Capacity: ECLIPSE models the economically optimal development of capacity over the forecast horizon. It calculates optimal capacity build rates over the range of generation technologies dependent upon capital and operating costs, fuel, carbon and ROC prices. Build rates are constrained by assumptions on the ability of the industry to develop, finance, build and connect generation. Renewable technologies are also subject to economic resource constraints. Capacity costs are subject to cost curves, reflecting reducing capacity costs for nascent technologies, as well as the quality of the available resource for renewable generation.

ANNEX C: GLOSSARY

AGR	Advanced Gas Cooled Reactor
ARA	Amsterdam Rotterdam Antwerp
BE	British Energy
BERR	Department for Business, Enterprise and Regulatory Reform
BETTA	British Electricity Trading and Transmission Arrangements
BSUoS	Balancing Services Use of System (charges)
CCGT	Combined Cycle Gas Turbine
CCL	Climate Change Levy
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CHP	Combined Heat and Power
CIF	Carriage Insurance and Freight
CO_2	Carbon Dioxide
DEFRA	Department for Environment, Food and Rural Affairs
ECLIPSE	Emissions Constraints and Policy Interactions in Power System Economics
ELV	Emission Limit Values
ETS	Emissions Trading Scheme
EU	European Union
FGD	Flue Gas Desulphurisation
GB	Great Britain
GHG	Green House Gas
IPPC	Integrated Pollution Prevention and Control
JI	Joint Implementation
LCPD	Large Combustion Plants Directive
LNG	Liquefied Natural Gas
NAP	National Allocation Plan
NBP	National Balancing Point
NGC	National Grid Company, (National Grid Transco)
Ofgem	Office of Gas and Electricity Markets
RO	Renewable Obligation
ROC	Renewable Obligation Certificate
SO_2	Sulphur Dioxide
SSE	Scottish and Southern Energy
TNUoS	Transmission Network Use of System (charges)