CHAPTER 5:

DECARBONISING ELECTRICITY GENERATION

Electricity generation accounts for about 37% of all UK CO_2 emissions. Reductions in these emissions are possible at relatively low cost when compared with other sectors; and radical reductions in emissions in this sector are essential if overall greenhouse gas targets are to be achieved. Our analysis in Chapter 2: *Meeting the 2050 target* illustrated that any path to an 80% reduction by 2050 requires that electricity generation is almost entirely decarbonised by 2030; but it also illustrated that as electricity is decarbonised it is highly likely that the relative importance of electricity within overall energy end use should grow, with increasing substitution of low-carbon electricity for fossil fuels in surface transport and heating. Achieving a decarbonised electricity generation system is therefore even more important than its current share of CO_2 emissions suggests.

This chapter focuses on the prospects for reducing emissions from electricity generation in the first three budget periods. While emissions from the power sector are capped under the EU ETS, it is important that the foundations for radical decarbonisation in the 2020s are laid during this period. The fact that much of the UK's existing electricity generation capacity will need to be replaced in the next ten to fifteen years creates a major opportunity to invest in low-carbon technology. There is also a danger that failure to grasp this opportunity will result in lock-in to high carbon generation, increasing the cost of subsequently meeting long-term targets.

The overall conclusions of this chapter are that:

- There exist a set of technological options which will make it possible to reduce CO_2 emissions from the electricity generation sector by around 40% on 1990 levels by 2020.[1] The carbon intensity of generation could fall from around 560 gCO_2/kWh to around 310 gCO_2/kWh by 2020.

- While this report does not propose any one specific portfolio of generation capacity, it is likely that in the period to 2022, decarbonisation will be primarily achieved through deployment of renewable energy as part of the UK's contribution to the EU renewable energy target. There may also be an important role for new nuclear in the period to 2022, depending on the realistic potential for renewables deployment. Renewables, new nuclear and carbon capture and storage (CCS) will all have a potentially important role in the 2020s.

- The creation of a clear carbon price signal within the EU ETS is a vital tool in driving electricity sector emission reductions, but additional policy levers will be required:
  - The financial support and non-financial policy measures of the draft Renewable Energy Strategy are vital
  - The extension of the EU ETS beyond 2020 is essential
  - Expenditure on CCS demonstration projects is a priority
  - New conventional coal-fired power stations should only be built on the clear expectation that they will be retrofitted with CCS capability by the early 2020s.

- The cost of reducing CO_2 emissions from electricity generation by 40% within the next 15 years is about 0.2% of GDP in 2020. Achieving this reduction will add significantly to electricity bills, with resulting fuel poverty implications; we address issues relating to fuel poverty impact and mitigation in Chapter 12: *Fuel poverty implications*.

1 In the DECC Energy Model, this rises to up to 55% taking into account the electricity demand savings in end-use sectors in the Extended Ambition scenario, which we look at in Chapter 6: *Energy use in buildings and industry.* See Figure 5.22.

The analysis which underpins these conclusions is set out in six sections:

1. The starting point and reference emissions projections

2. Economics of low-carbon generation technologies

3. Policy issues in driving low-carbon investment: is a carbon price sufficient?

4. Scenarios for generation mix and implications for emissions

5. Aggregate costs to GDP and to the consumer

6. Power generation scenarios in the economy-wide abatement scenarios.

The analysis in this chapter covers centralised generation from major power producers and renewable generators[2] – micro-generation and CHP are covered in Chapter 6: *Energy use in buildings and industry*.

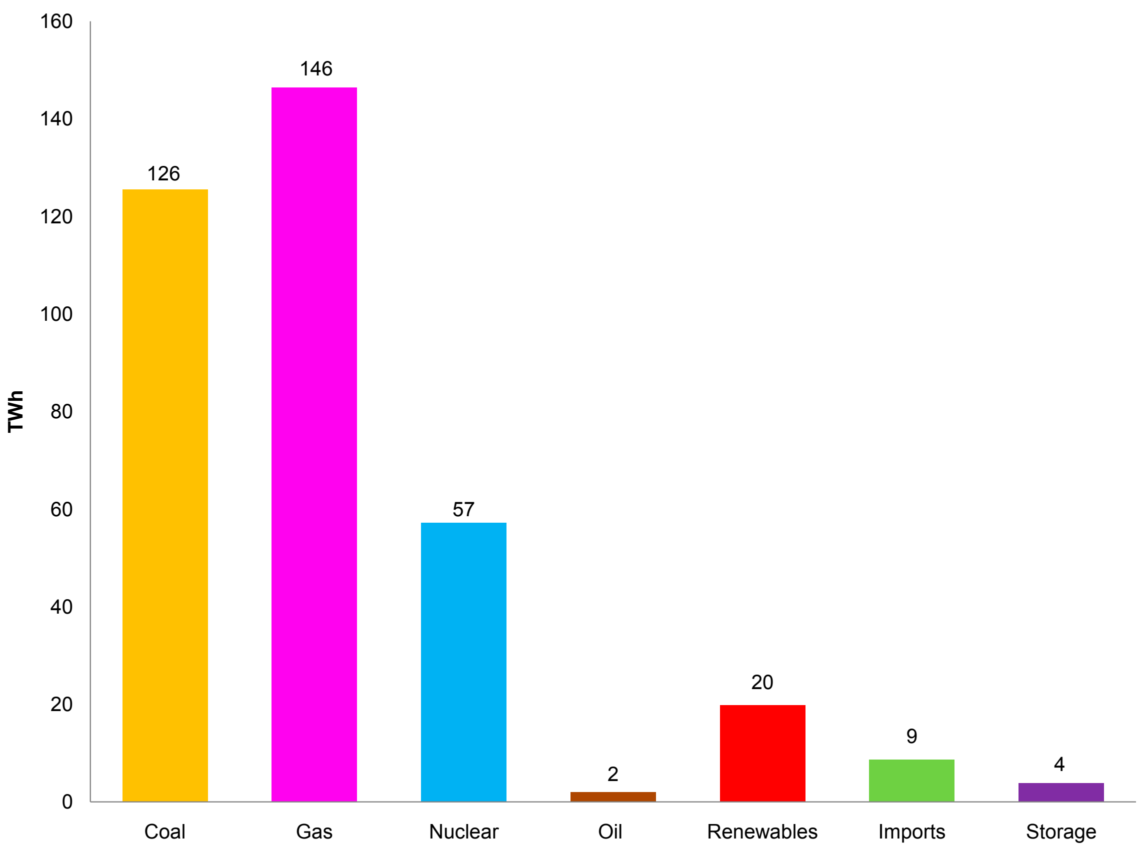
2 Major power producers are separated from 'other generators' and are defined in DUKES as companies whose sole purpose is the generation of electricity. However, most renewable generators are defined as 'other generators' due to their comparatively small size. We also include other renewable generators in our analysis.

1. THE STARTING POINT AND REFERENCE EMISSIONS PROJECTIONS

Emissions from UK electricity generation are to a significant extent driven by the relative importance of coal within the fuel mix. Looking forward, most existing coal generation capacity will cease operation over the next 15 years, but without a carbon price it is likely that some new coal investment would replace it. Given the EU ETS and carbon prices in line with the estimates in Chapter 4: *Carbon markets and carbon prices*, investment in new gas-fired generation would be likely to dominate, but with the possibility of portfolio investment in coal:

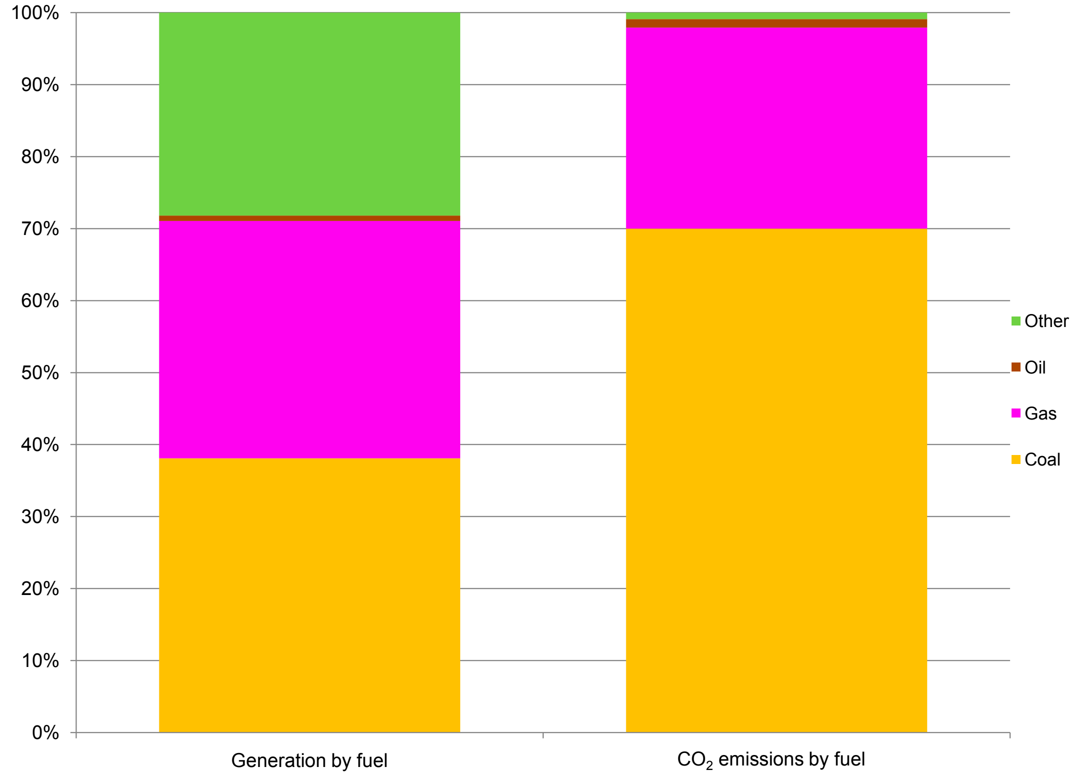
- The UK's current (2007) electricity generation mix is shown in Figure 5.1, with fossil fuels (gas and coal) accounting for over 75% of the electricity supplied, nuclear 16%, and renewables (including long-established hydropower) about 5%.
- The emissions produced are dominated by coal generation, reflecting the high-carbon intensity of coal generation per kWh generated (Figures 5.2 and 5.3).
- Electricity demand increased at about 1.6% per annum over the period 1990 to 2005, but since then demand has declined, and in 2007, demand was 1.3% lower than in 2005 (Figure 5.4).
- Meanwhile, emissions have fallen as a result of the shift during the 1990s from coal to gas generation. Since around 2000, however, this reduction has halted and indeed slightly reversed, as high gas prices have induced a shift back to coal generation (Figure 5.5).

Figure 5.1 Electricity generation by fuel, 2007



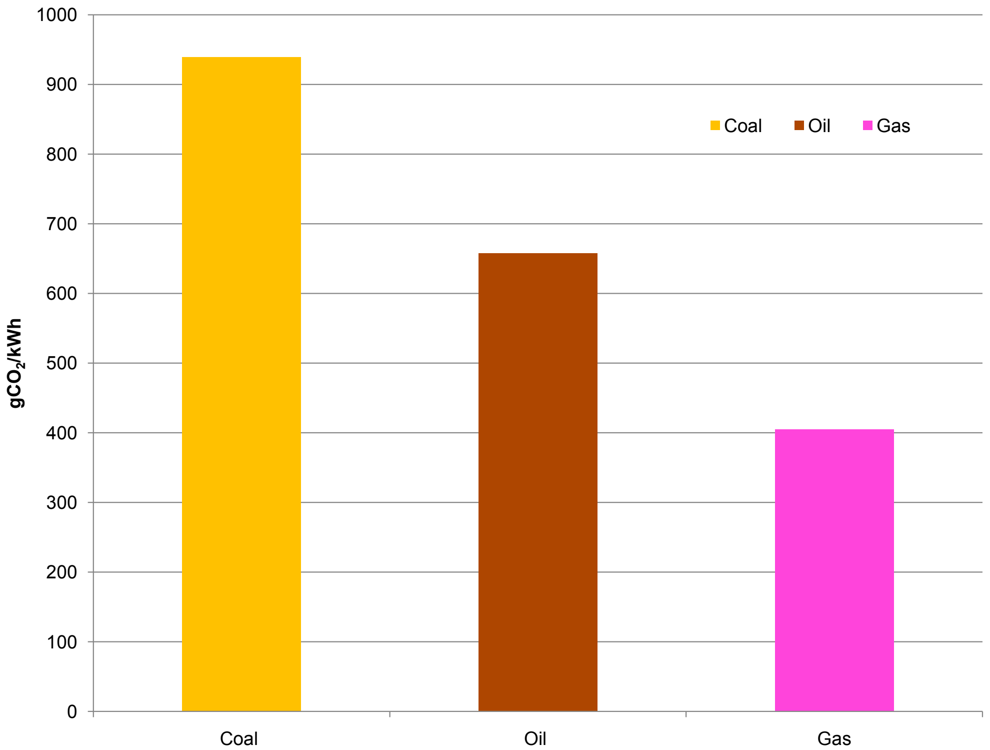
Source: DUKES (2008), Table 5.6.
Note: Covers electricity generated from all major power producers (MPPs) only; and renewable generation. Excludes electricity used in generation process ('own use').

Figure 5.2 Share of generation and CO_2 emissions by fuel for power stations, 2006



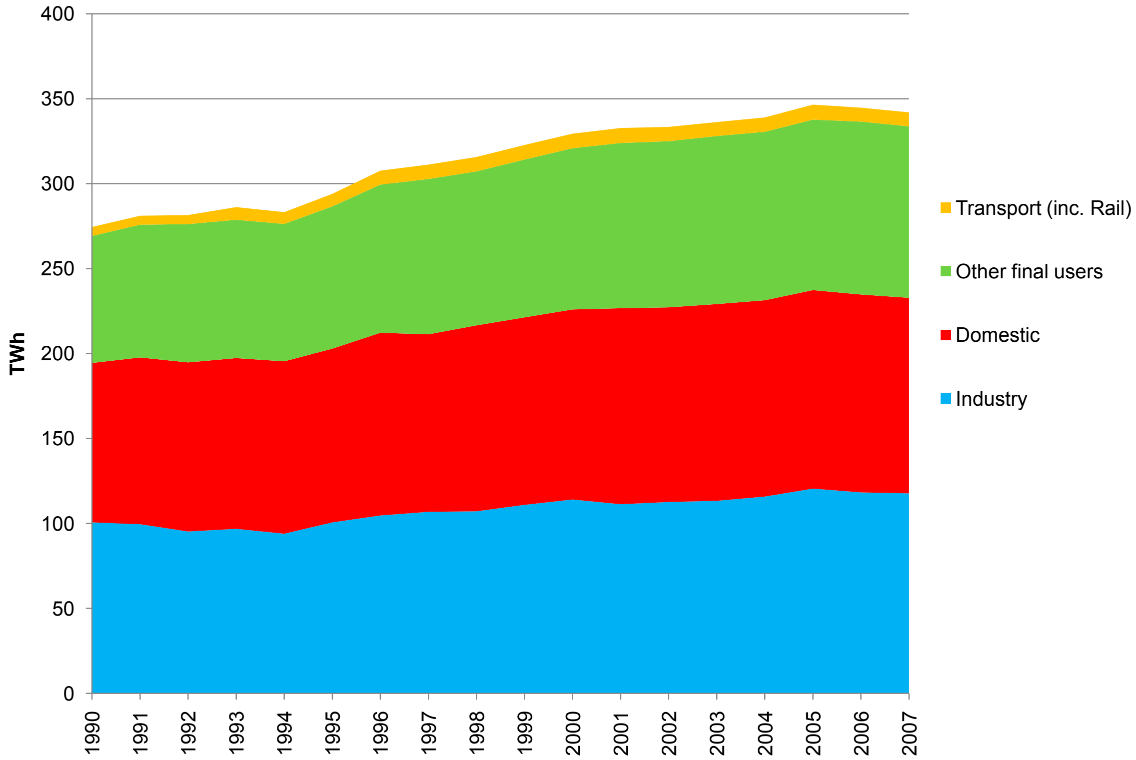
Source: DUKES (2008), NAEI (2008)
Note: Generation from MPPs only and renewable non-MPP and excluding 'own use'. CO_2 emissions from NAEI (2008) (including own use generation).

Figure 5.3 Estimated CO_2 content of electricity by fuel, 2007 (gCO_2/kWh of electricity supplied)



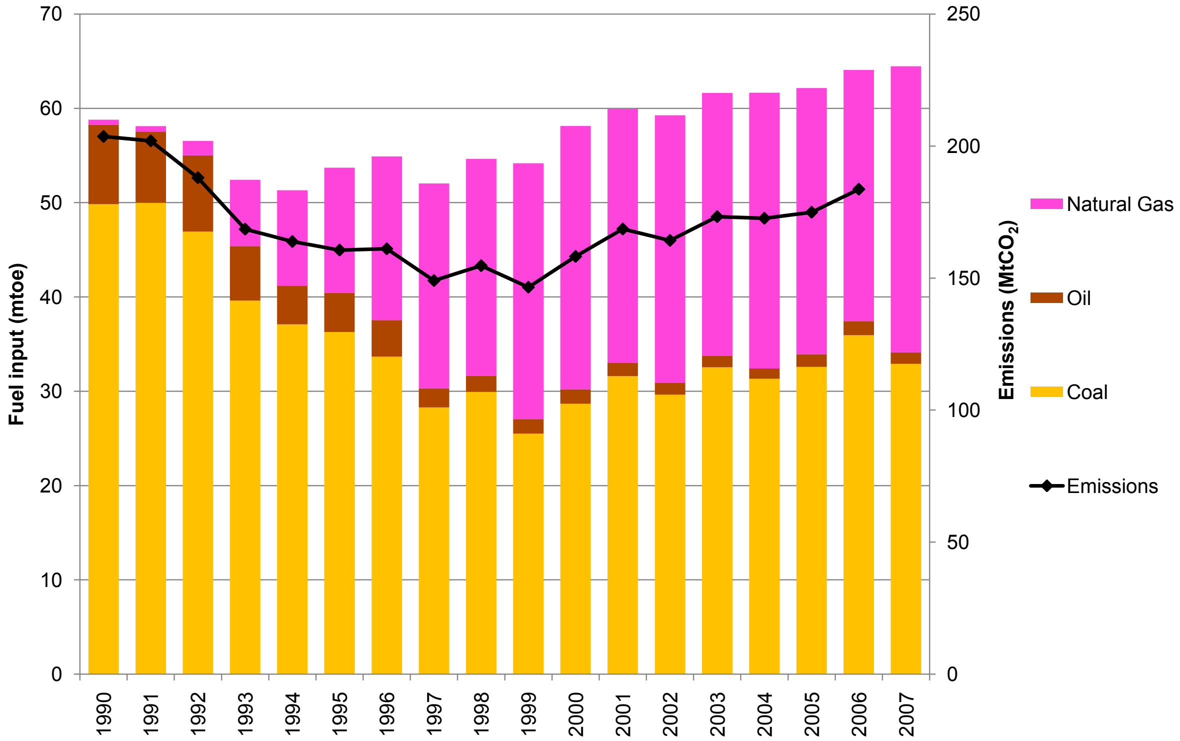
Source: DUKES (2008), Table 5C.
Note: Not adjusted for losses in transmission and distribution. Includes MPPs and all other generators.

Figure 5.4 Electricity demand since 1990, final users



Source: DUKES (2008) *Long Term Trends*, Table 1.1.5.
Note: Final users excludes fuel industries. Other final users: agriculture, commercial and public sectors.

Figure 5.5 Fuel input for electricity generation and CO_2 emissions since 1990



Source: DUKES (2008) *Long Term Trends*, NAEI (2008).

- A significant amount of existing generation capacity is scheduled to retire within the next 15 years, as shown in Figure 5.6. This is due to the closures of coal plants which cannot meet the requirements of the Large Combustion Plant Directive and from nuclear plants reaching the end of their scheduled lives. Electricity demand should ideally fall slightly over this period, given the potential and the need to achieve the energy efficiency improvements discussed in Chapter 6: *Energy use in buildings and industry*, but a major gap will still emerge between capacity and demand, as shown in Figure 5.6.

- As a result major new investments in generation capacity will be required. This creates an opportunity for the UK to start building a decarbonised electricity generation system. Seizing this opportunity is vital, especially given the likelihood (discussed in Chapter 2: *Meeting a 2050 target)* that electricity will play an increasing role in energy use beyond 2020, particularly in surface transport and heating, as Figure 5.7 illustrates.

- Forecasts for new generation investment, however, suggest that a mix of new coal and gas plant capacity would dominate if additional climate change policies were not in place.[3] Without the carbon price established by the EU ETS, the run off of existing coal capacity would probably be largely matched by new coal investments, and emissions would be unlikely to fall (Figure 5.8).

- With a carbon price in line with our estimates in Chapter 4, and with fossil fuel prices in line with the central projection, as shown in Figure 5.9, investment in new gas generation would be likely to dominate.[4]

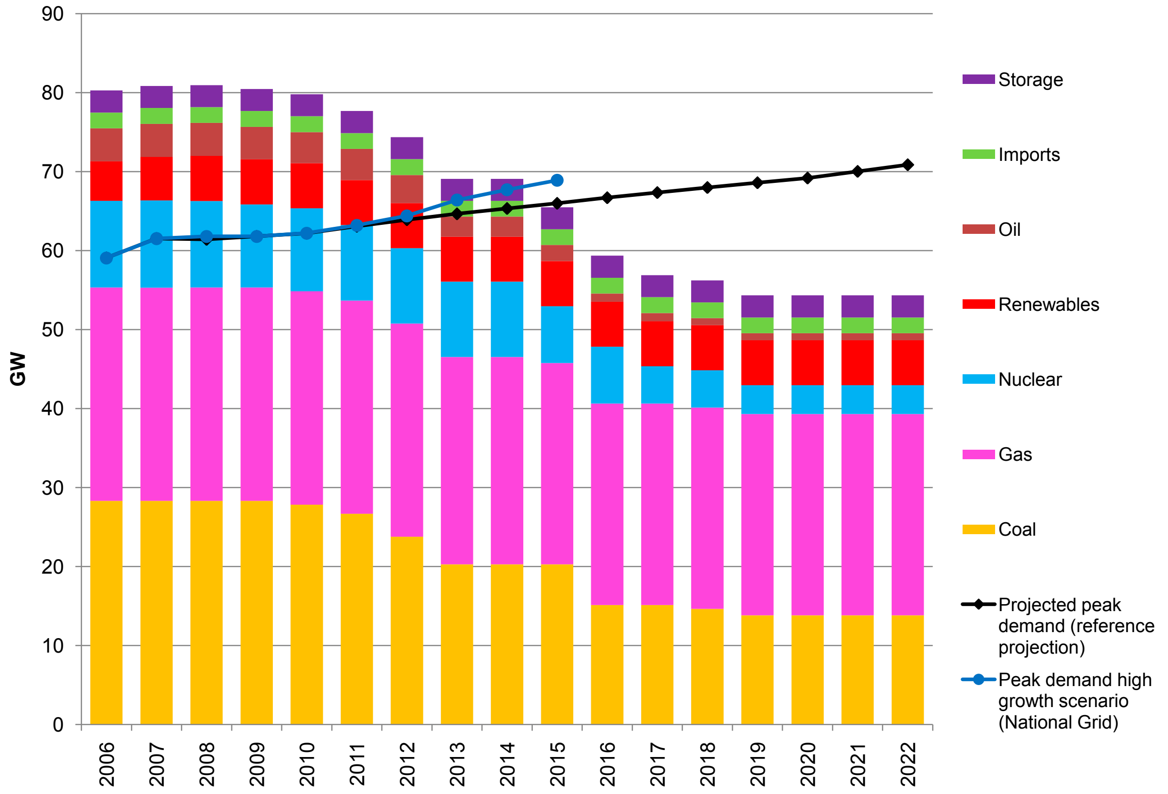
- Expectations of future gas and coal prices and of carbon prices will play a crucial role in determining the precise mix of coal and gas new investment, while current coal, gas and carbon prices will determine which capacity (coal or gas) is most intensively used. For example Figure 5.10 shows generation under alternative coal and gas price assumptions.

This generation mix will in turn be a crucial driver of year by year emissions (Figure 5.11). These scenarios do not, however, reflect full potential for decarbonisation through aggressive deployment of renewable electricity, nuclear new build and CCS; we now consider these technologies.

3 The reference projections include the impact of the non-banded Renewables Obligation, but not the EU ETS.

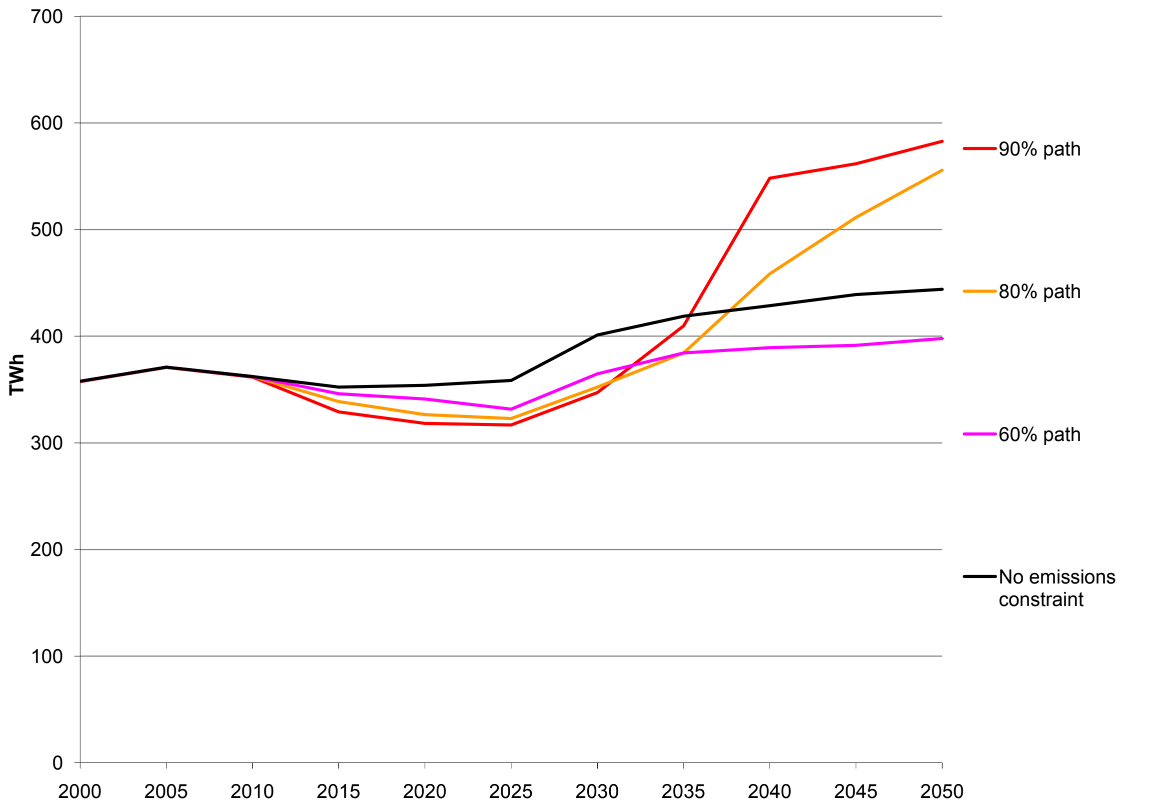
4 The DECC Energy Model is a least-cost optimisation model, therefore does not formally capture investment that might occur on a portfolio basis, such as new coal build.

Figure 5.6 Capacity of existing generation and projected peak demand, 2006-2022



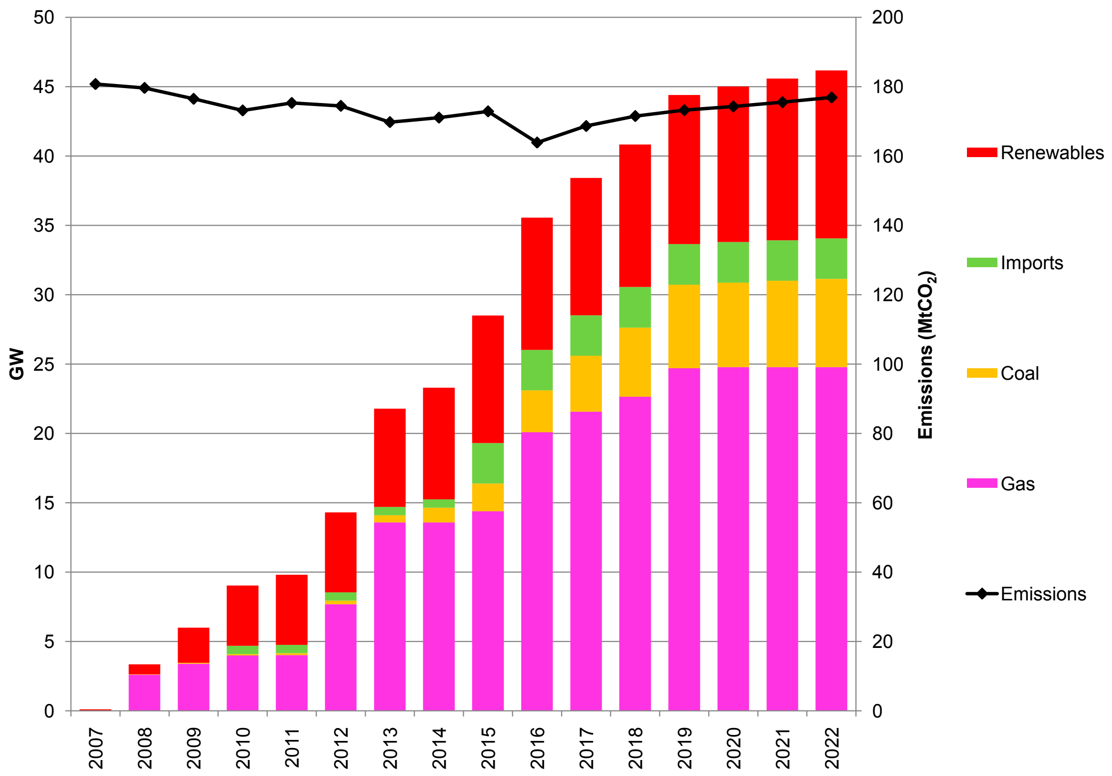
Source: DECC Energy Model, National Grid (2008) *Seven Year Statement*.
Note: Assumes peak demand grows in line with demand in our central case reference emission projection.

Figure 5.7 Long-term electricity generation, 2000–2050



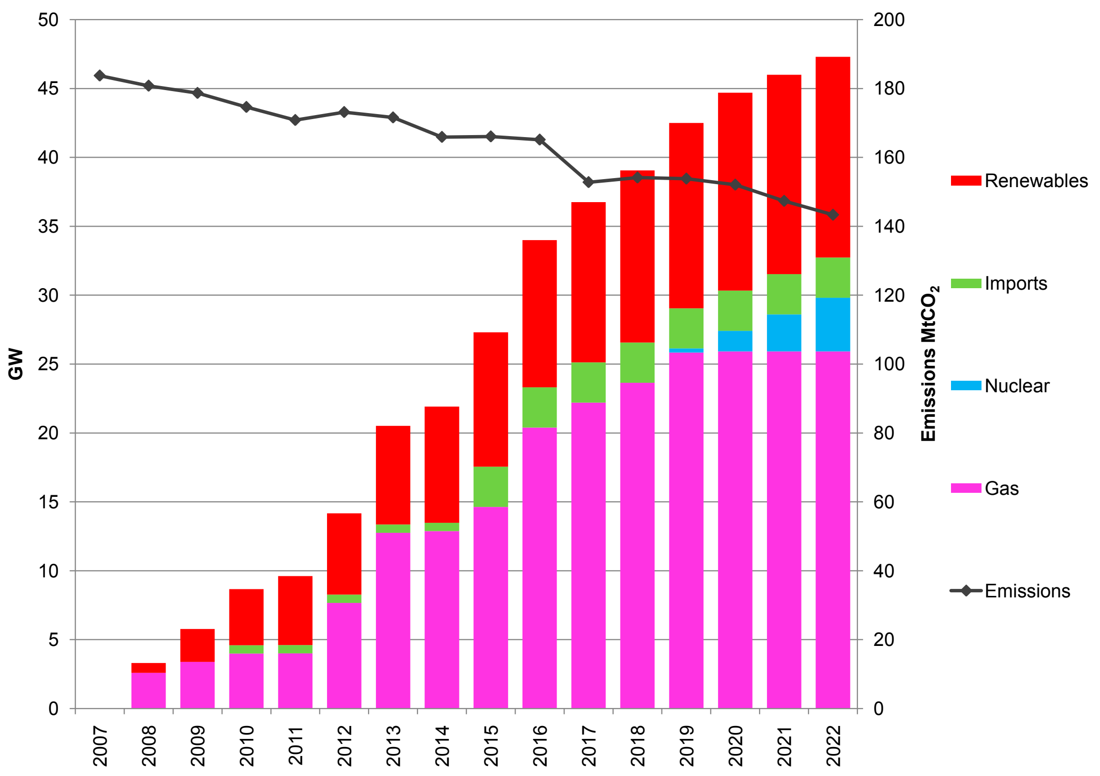
Source: MARKAL model based on CCC assumptions.

Figure 5.8 Projected cumulative new build and CO_2 emissions in the reference emissions projection without a carbon price (central fossil fuel prices)



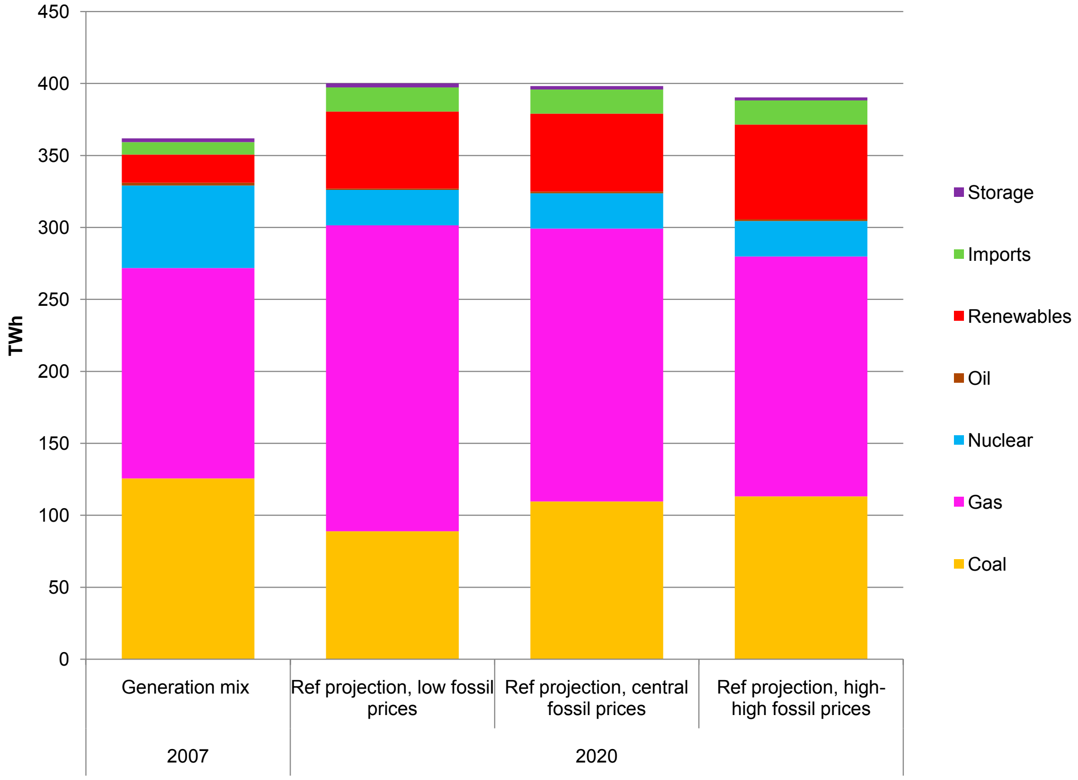
Source: DECC Energy Model based on CCC assumptions.

Figure 5.9 Projected cumulative new build and CO_2 emissions in the reference emissions projection with a carbon price (central fossil fuel prices)



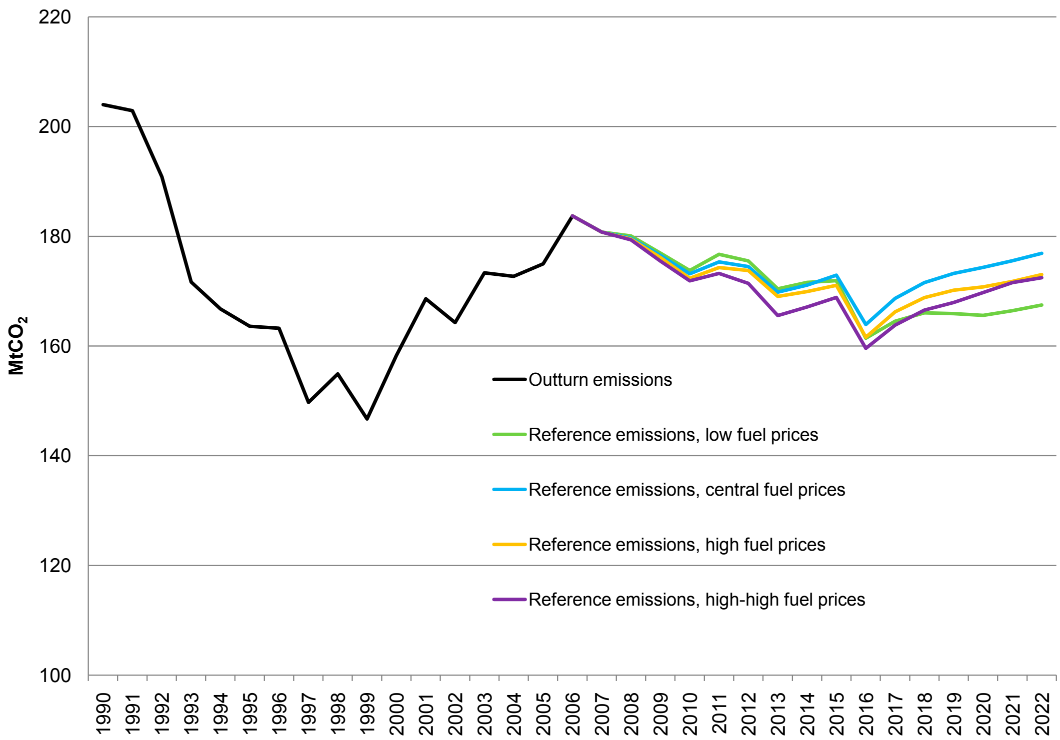
Source: DECC Energy Model based on CCC assumptions.

Figure 5.10 Historic and projected generation mix in the reference emissions projection under a range of fossil fuel prices, 2007 and 2020



Source: DECC Energy Model based on CCC assumptions.

Figure 5.11 Historic and projected CO_2 emissions from the power sector under range of fossil fuel prices (reference emissions projection), 1990 to 2022



Source: DECC Energy Model based on CCC assumptions.

2. ECONOMICS OF LOW-CARBON GENERATION TECHNOLOGIES

The economic cost of decarbonising electricity generation depends on the cost of low-carbon electricity relative to that of coal or gas based electricity generated without CCS. Making this comparison is complex for four reasons:

- **Fossil fuel price volatility and uncertainty:** Wholesale electricity prices are determined by the price of fossil fuels (i.e. gas and coal). When the current set of regulatory arrangements were introduced (see Box 5.1), the costs of coal or gas based generation in the UK were typically estimated at about 1.5-2p/kWh, and wholesale electricity prices reflected these costs. But in recent years, fuel prices and particularly gas prices have increased markedly. The average wholesale electricity price in the year to October 2008 was around 6-7p/kWh, compared with 2-3p/kWh in the same period a year earlier (Figure 5.12). When fossil fuel prices are low, all low-carbon alternatives face a significant cost penalty; but at recent prices, some are cost-effective without any policy intervention. Looking forward, fossil fuel price uncertainty is at least as great as the variation over the last three years.[5]

- **Different stages of technological development:** Some low-carbon technologies (e.g. wind and nuclear) are proven and are already installed on a significant scale and in normal commercial generation across the world. Some (e.g. wave power and CCS) have yet to be deployed on a significant scale. Relative cost figures therefore often depend on comparisons between the actual costs of one technology and the estimated future costs of another.

- **Long-term cost trends:** The cost of deploying new technologies typically falls significantly as volumes of production increase, cumulative research and development commitments rise, and manufacturing scale is achieved. Estimates of the future cost of renewables, of new generation nuclear plants, and of CCS, therefore depend crucially on assumptions about the potential for future cost reduction: apparently minor changes in assumptions can dramatically shift the relative cost of different technologies.

- **Short-term cost trends and supply bottlenecks:** Over the last few years, however, the investment costs of all electricity generation options have increased as a result of rising energy and steel prices and of supply bottlenecks which have driven up the price of wind turbines and solar photovoltaic panels, but also the costs of nuclear new build and of conventional power station construction. Some of these supply bottlenecks may diminish in a few years, some may last many years. Estimates of the relative cost of different technologies in the future are therefore highly sensitive to the date at which each individual cost was calculated, and to the extent to which future supply bottlenecks (or their disappearance) have been anticipated. In particular there is a danger that the relative cost of the already deployed technologies (e.g. wind or nuclear) can be overstated relative to speculative technologies (e.g. CCS) simply because the impact of supply bottlenecks on the former is already apparent, while desktop calculations of the latter's cost do not allow for the bottlenecks which might emerge if CCS were deployed on large scale.

The impact of these factors on the economics of alternative technologies is considered in detail in a separate technical paper.[6] This section summarises our key conclusions in respect to renewables, nuclear, and CCS, and identifies the implications for the relative cost likely to pertain over the first three budget periods.

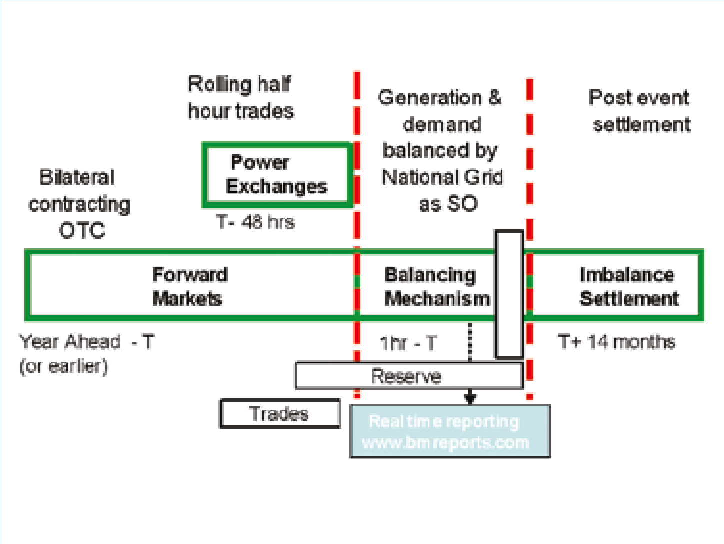
5 The projections of fossil fuel prices used in our analysis is presented and disscussed in Chapter 3, Section 1.
6 Forthcoming on the CCC website.

Box 5.1 The UK market for electricity

The market for electricity is governed by a complex set of regulatory arrangements known as BETTA (British Electricity Trading and Transmission Arrangements). Within BETTA, electricity is bought and sold on a bilateral basis between generators and suppliers.

Forward markets allow contracts for electricity to be struck up to years in advance. Closer to real time (i.e. within an hour of delivery) power is exchanged within the ‘balancing mechanism’ (see Figure, below). Within this mechanism, the System Operator (i.e. National Grid) is able to fine tune contract positions to ensure that supply and demand for electricity is matched in real time and that the system remains within safe technical limits.

Figure: Key features of BETTA

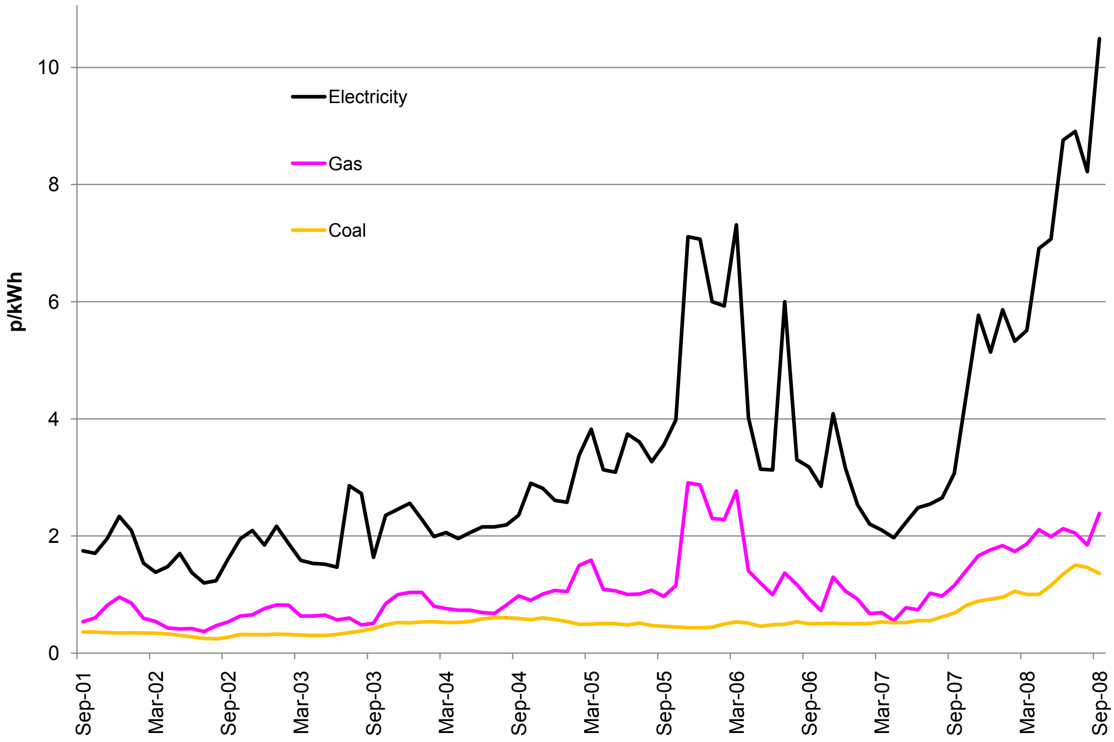


Source: National Grid

Price formation for electricity occurs in a similar way to other commodity markets. Within the balancing mechanism generators offer to dispatch electricity and the spot price is set by the market’s view of the short-run marginal cost of the last plant dispatched to meet demand. Forward prices for electricity are typically much less volatile than the spot price, which will oscillate widely depending on the time of day (i.e. very high during peak periods when more expensive plants are dispatched in order to meet high levels of demand). Conversely, during periods of low demand (i.e. in the middle of the night) prices are low.

Very few consumers are exposed to the spot price and the majority of electricity is exchanged on forward contracts that have been struck on a quarterly or annual basis. In the short to medium-term the wholesale electricity price in the UK remains closely linked to the price of gas (as the marginal source of generation) as Figure 5.12 illustrates.

Figure 5.12 Average monthly wholesale electricity, gas and coal prices, September 2001 – September 2008



Source: Platts.
Note: Electricity – Day-ahead baseload; Gas – Day-ahead NBP; Coal – 90 day forward CIF ARA. Nominal prices .

Renewables

Chapter 2: *Meeting a 2050 target* considered a range of renewable technologies which could play a role in decarbonising electricity generation. Of these, two groups of technology are unlikely to play a significant role in the UK within the first three budget periods. These are:

- **Wave and tidal stream power:** which are currently at a much earlier stage of technological development than wind, and which if deployed commercially today would face a very significant cost penalty. Given the UK's inherent natural resource, these technologies may become important in the long-term, but over the first three budget periods, their contribution to UK emission reductions is likely to be marginal.

- **Solar photovoltaic (PV):** At present solar PV electricity generation costs are much higher than those for wind, and indeed have increased in the last few years as a result of bottlenecks in supply in the face of unanticipated and rapid increases in demand. Over the medium to long-term, it is quite possible that solar PV costs will fall dramatically due to learning curve effects, manufacturing scale and research breakthroughs, and that solar PV will play a major role in electricity generation in many naturally sunny countries. But the more limited sunshine resource of the UK makes large-scale deployment in the UK less likely even in the longer-term, and within the first three budget periods the emissions reduction potential of solar PV deployment is very small.

Conversely there are three renewable technologies which could play a significant role in emission reduction in the next three budget periods. The most important of these is wind; but the role of biomass merits careful consideration; and tidal range could play a significant role by the end of the third budget.

Wind power: Various estimates of the cost of wind generated electricity in 2010 are shown in Figure 5.13[7]. These range widely, from as low as 3p/kWh for the lowest estimates for onshore wind, to as high as 10p/kWh or higher for offshore. Three key points should be noted in assessing the implications of these estimates.

- **Long-term versus short-term cost trends**
  - The long-term cost trend has been downwards, with the cost of wind generation falling by over 75% in the last 20 years (see Chapter 2: *Meeting a 2050 target*). But over the last two years costs of turbines and switchgear have increased significantly, due to steel price increases and supply bottlenecks. Typical estimated costs for onshore generation in the UK have therefore increased to about 7p/kWh.
  - In the medium term, however, supply bottlenecks may well ease (given few inherent barriers to entry for new production capacity) and the long-term trend decline may be resumed. There is therefore a danger that current estimates are overstating the long-term cost of wind power deployment. The fact that German onshore feed-in-tariffs (a market measure of the price at which operators are willing to invest) are significantly below typical UK cost estimates provides some support for this hypothesis[8].
  - Conversely it is possible that the UK may face a significant cost penalty as it drives wind deployment over the next several years with wind deployment more expensive than in, for instance, Germany or Spain, which have achieved rapid progress over the last ten years when costs have been lower. This may be particularly the case in offshore deployment given supply chain bottlenecks (e.g. there are only a limited number of appropriately equipped supply vessels currently available to support offshore construction activity).
- **Costs of intermittency, back-up, connection and transmission.**[9] Since wind power is inherently intermittent, it is important that estimates of the cost of wind generated electricity allows for the back-up generation capacity (usually gas based) needed to meet demand when the wind is not blowing.[10] These estimates are considered in more detail in a separate technical paper but essential points to note are:[11]
  - As discussed in Chapter 13: *Energy security of supply*, there is no inherent 'security of supply' problem created by intermittency, but simply one of cost: how much back-up capacity is required and how much does it cost to keep it available. Estimates by Redpoint for the draft Renewable Energy Strategy consultation published in June this year suggest that around 1.3p/kWh should be added to the cost of renewable electricity if intermittent renewables, primarily wind, reach around 25% of UK electricity supply. Estimates by SKM for the draft Renewable Energy Strategy consultation put these costs at around 1.7p/kWh of intermittent renewable electricity, while recent estimates from the Carbon Trust put them at around 1.2p/kWh (Figure 5.14). While there is much uncertainty around these cost estimates, it is likely that they are within the range of 1–2p/kWh of intermittent electricity, at the levels of wind penetration likely to be required to meet the renewables target[12].

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7 Except where stated to the contrary, levelised cost estimates in this document come from the following sources: Carbon Trust (2008), *Offshore wind power: big challenge, big opportunity;* Ernst & Young (2007) *Impact of Banding the Renewables Obligation – Costs of electricity production*; IPPC (2005) *Special report on carbon dioxide capture and storage*; Pöyry (2008) *Compliance costs for meeting the 20% renewable energy target in 2020*; Redpoint et al (2008) *Implementation of the EU 2020 renewable target in the UK electricity sector: Renewable support schemes*; SKM(2008), *Growth scenarios for UK renewables generation and implications for future developments and operation of electricity networks*, UKERC (2006), *An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network.*

8 Although part of the difference is likely to be explained by the fact that unlike the levelised cost estimates, the German feed-in-tariffs do not cover grid connection and extension costs. Pöyry (2008) estimate that grid related costs make up around 14% of the capital cost of onshore wind.

9 System balancing and back-up costs are not included in the levelised cost estimates presented in Figure 5.13, but are included in our assessment of total costs in Section 5 below, and in Figure 5.17.

10 The back-up generation capacity referred to here is the capacity needed to cover the difference between the proportion of wind generation which will be reliably available to meet demand any time it is needed (the capacity credit, assumed to be around 20%) and the average annual availability of wind plant (between 21% and 39%, depending on the site),

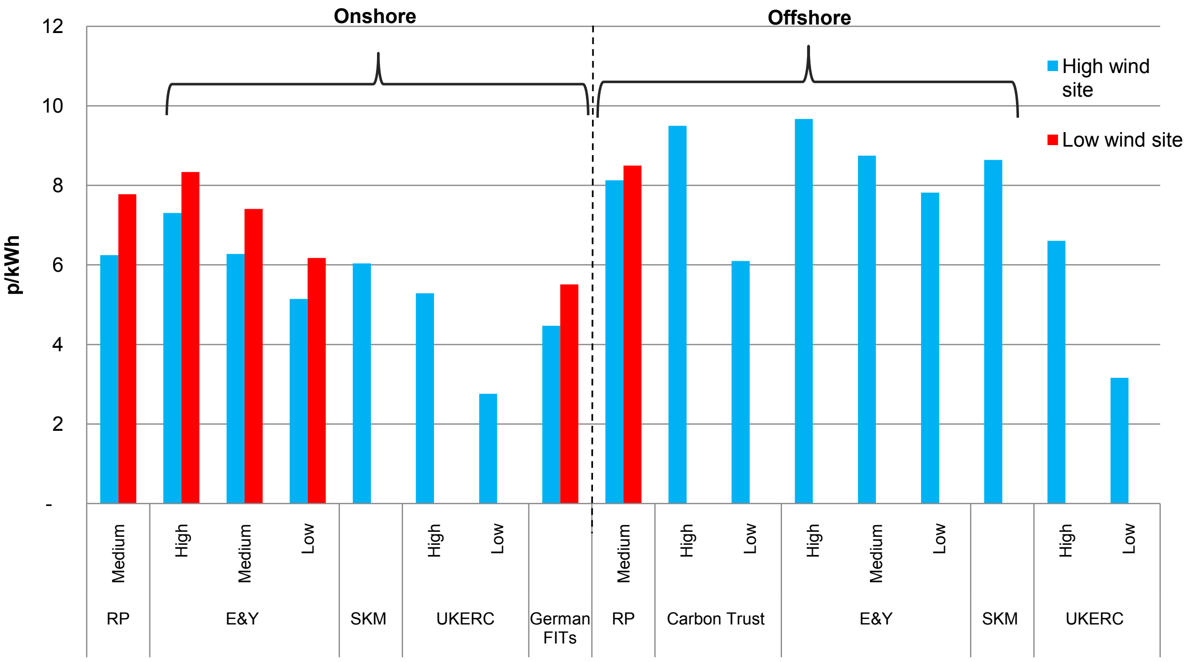
11 Forthcoming on the CCC website.

12 Other studies have come up with lower estimates, for example, a systematic review by UKERC (2006) estimated that the costs would be 0.8p/kWh at 20% penetration of intermittent renewables.

– Over the long-term, and in the context of the technological vision presented in Chapter 2, the cost penalty incurred as a result of intermittency can be reduced if more electricity is stored in car and other batteries, and if smart metering allows non time-critical demand for electricity to be switched off in the face of supply shortage. Costs can also be reduced by increasing the degree of interconnect with other national grids.

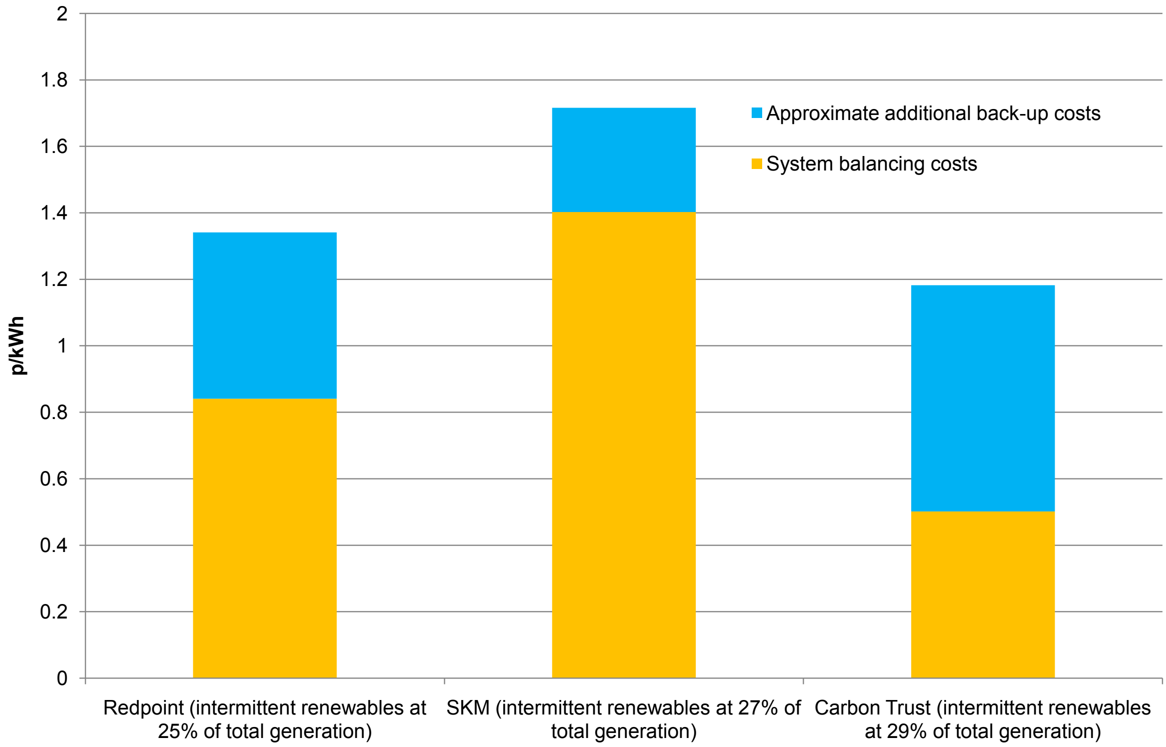
- **Offshore wind is significantly more expensive than onshore:** Whatever the uncertainties about the absolute cost of wind power, or of wind power relative to fossil fuel power, it is clear that offshore wind will be significantly more expensive than onshore, with typical estimates placing the additional cost penalty at 2p/kWh. In addition it appears likely that supply bottlenecks may be more severe and longer lasting in offshore deployment than in onshore. High reliance on offshore wind would therefore increase the danger that renewables targets cannot be met as a result of supply bottlenecks and will result in significant additional costs over and above those strictly necessary to achieve emissions reduction targets.

Figure 5.13 Estimates of levelised costs for wind



Source: SKM (2008), Ernst & Young (2006), UKERC (2006), Redpoint et al (2008), Carbon Trust (2008). Calculations of German feed-in-tariffs (FITs) based on www.wind-energie.de.and www.windworks.org
Note: £2008. All costs relate to 2020 except for UKERC costs which are based on a systematic review of costs from a range of years, and German FITs which are based on current levels. Top of Carbon Trust range relates to best site. Bottom of range relates to worst site.

Figure 5.14 Additional costs at different penetrations of intermittent renewable generation (e.g. wind generation)



Source: CCC Calculations based on SKM (2008), Redpoint et al (2008) and Carbon Trust (2008).

Biomass: The UK currently generates around 2 TWh annually from biomass which is co-fired with coal. The cost per tonne of emissions saved from co-firing is comparable with other forms of renewable electricity generation, and so there may be a role for co-firing alonside onshore and offshore wind.

This may be true for the first three budget periods. Further into the future, however, it is our view that there is no role for conventional coal-fired generation without CCS; we discuss this in Section 3 below. Any role for co-firing would then have to be in the context of CCS technology; this could potentially be an attractive means for reducing residual CCS emissions as the carbon price increases through the 2020s and beyond.

One alternative to co-firing is dedicated biomass generation (i.e. where biomass is the only fuel used). This may be regarded as a low-carbon source of electricity, and could in principle be an attractive option for power sector decarbonisation. In practice, however, Defra's Biomass Strategy (2007) and the draft Renewable Energy Strategy concluded that dedicated biomass generation is relatively expensive, both in comparison with other forms of renewable electricity generation, and in comparison with alternative uses for biomass. In particular, Defra's Biomass Strategy suggested that biomass should be used for generation of renewable heat rather than renewable electricity.

In addition, there may be questions over the sustainability of biomass production and the associated life-cycle emissions. These are discussed in the Gallagher Review.[13]

Tidal range: This is a potentially large source of renewable energy generation that could make a significant contribution to power sector decarbonisation. The proposed Severn Barrage project, for example, could contribute up to 4% of total UK power generation.[14] It may be attractive for this

13 RFA (2008) *The Gallagher review of the indirect effects of biofuel production.*
14 Sustainable Development Commission (2007), *Turning the Tide: Tidal power in the UK.*

reason, and because it would generate on a predictable basis, in contrast to the unpredictably variable nature of wind generation.

Questions remain, however, over the economics of this technology. Cost estimates provided by the Sustainable Development Commission (SDC) for the Severn Barrage range from 4p/kWh to 12p/kWh and are highly sensitive to assumptions on construction and financing costs (with the higher end of this range corresponding to the risk adjusted discount rates assumed elsewhere in this chapter).[15] Clearly at the lower end of the range, the economics of the Severn Barrage are favourable, whereas at the higher end of the range it is relatively expensive in comparison even with offshore wind. Going beyond narrow economic considerations, there are a number of possible impacts of the project which would have to be considered as part of any investment decision. These could include flood protection benefits, changes in water quality, and impacts on biodiversity.

Our view is that the Severn Barrage and other potential tidal range projects certainly warrant further assessment and could be an important contributor to power sector decarbonisation. For the purposes of this chapter, however, which focuses on the first three carbon budgets, we recognise that tidal range is likely to have very limited impact during this period, given long lead times for project development and implementation.

Nuclear

Current estimates of the likely cost of generating electricity from new nuclear are in the range 4-5p/kWh (Figure 5.15). These cost estimates are higher than typically produced two to three years ago, as a result of the significant increases in steel and other component prices, and of significant supply bottlenecks which have emerged as demand for new nuclear power station construction has come up against a limited capacity supply industry.

But fossil fuel price increases over that period have produced an even greater increase in the cost of fossil fuel based electricity, and the relative cost position of nuclear has therefore improved (Figure 5.16).

The future path of fossil fuel prices is inherently uncertain, but under the central, high and high-high fuel price projection, it is likely that nuclear power could be fully economic compared to coal and gas generation even before the impact of a significant carbon price, and even more so given the possible range of future carbon prices discussed in Chapter 4: *Carbon markets and carbon prices* (Figure 5.15)[16].

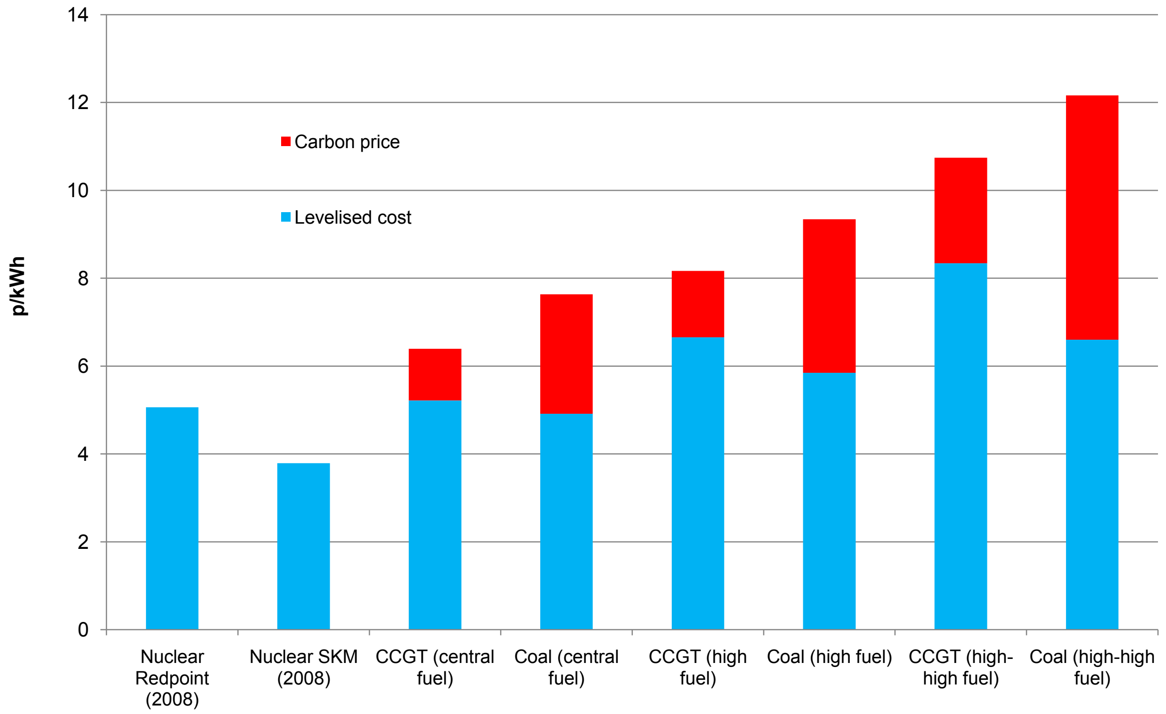
There is therefore a strong economic case for nuclear power to play a role in the future UK electricity generation mix. And our analysis suggests that some of the standard arguments made against the costs of nuclear power are not valid.

- The £80 billion of decommissioning and waste disposal costs which the UK may face from previous nuclear deployment are often cited. But the vast majority of these relate to military-linked research programmes in the 1940s to 1960s and to the Magnox reactors, and are not relevant to the estimation of future costs. The £3.4 billion of decommissioning costs estimated for the ten advanced gas-cooled reactors built in the 1970s are more relevant and costs for latest generation stations may be lower still. Estimates for both decommissioning and waste handling costs are included in the total cost figures presented in Figures 5.15 and 5.16.

- Potential limits to the availability of uranium fuel supplies are also sometimes cited, but the 2006 SDC report on nuclear power (despite concluding on balance against its deployment), argued that concerns about the availability and cost of uranium supplies were not a valid basis for rejecting the nuclear option.[17]

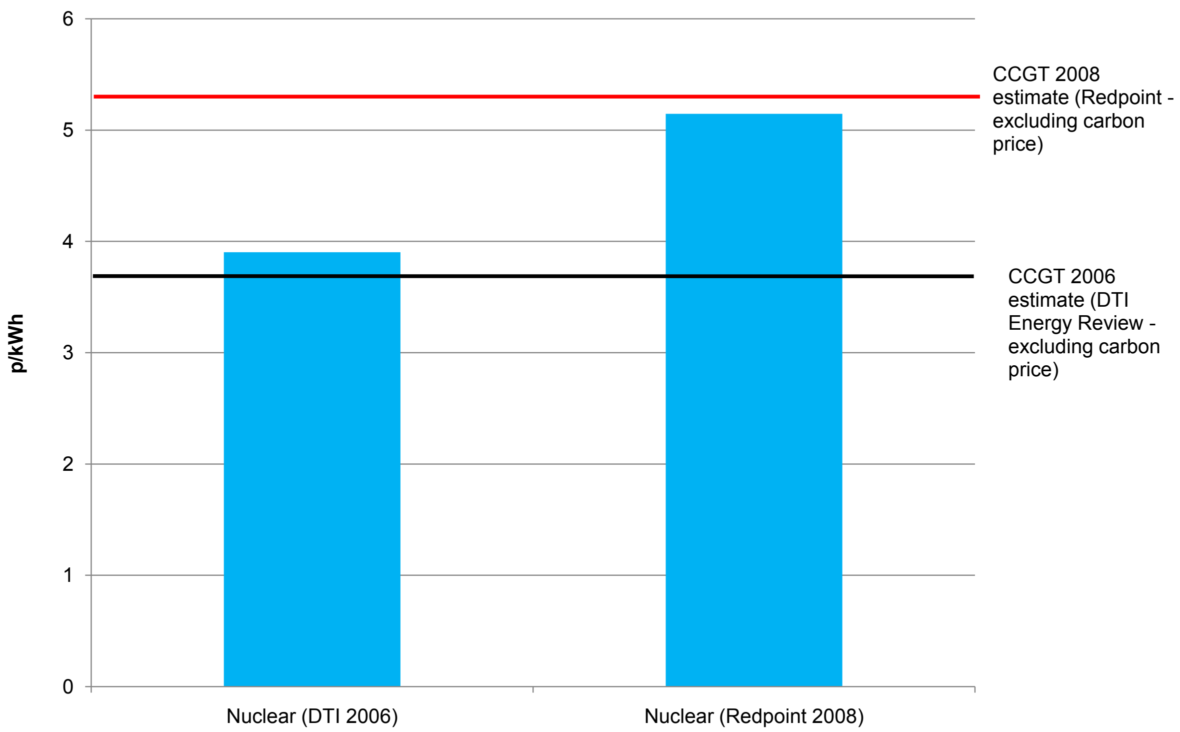
15 Costs cited are for discount rates ranging from 3.5-10%, SDC (2007)
16 As noted in UKERC (2006), *A Review of Electricity Unit Cost Estimates*, low levelised costs do not necessarily lead to investment. Other considerations will affect take up, for example, the correlation of gas prices to electricity prices can make investment in CCGT more attractive than its levelised costs would suggest due to a lower risk return.
17 SDC (2006) *The role of nuclear in a low-carbon economy.*

Figure 5.15 Current estimates of the levelised costs of nuclear plant relative to CCGT and coal under central, high, and high-high fossil fuel prices



Source: Redpoint et al (2008) SKM (2008) and CCC estimates of the carbon price.
Note: £2008. The carbon price rises with higher fossil fuel prices as the coal to gas price differential increases. SKM cost estimate is for 2020. All other estimates are current.

Figure 5.16 Levelised cost of nuclear relative to CCGT, 2006 and 2008 estimates



Source: Redpoint et al (2008) and DTI (2006) *Energy Review*.
Note: £2008.

The only valid basis for excluding nuclear power from the future generation mix therefore relate not to cost, but to concerns about the long-term sustainability of nuclear waste storage and about the possible implications of an extensive global nuclear power industry for nuclear military proliferation. The Committee recognises that these debates raise issues which go beyond cost economics alone.

If, however, nuclear power is in principle acceptable, it is likely that cost economics will argue for a significant nuclear role within the generation mix, particularly if and when greater use of battery electrical storage (for instance for electric cars) increases the demand for predictable off peak (e.g. overnight) capacity.

Within the first three budget periods, however, there are limits to the feasible pace of nuclear deployment, with the timetable for planning consent, licensing and construction, making it difficult to envisage that a new nuclear power plant could come on stream before 2017. And it is worth noting that if many countries in the world simultaneously opted for a significant expansion of nuclear power, significant supply bottlenecks could emerge. In our discussion of scenarios in Section 4 below, we therefore assume that up to three new stations represents a realistic range of possible new nuclear deployment by the middle of the third budget (i.e. by 2020). Beyond then, however, it is possible that new nuclear investment could and should at least replace, and possibly exceed, existing nuclear capacity.

Carbon capture and storage (CCS)

Chapter 2 described the elements of CCS technology and suggested that it is highly likely to be economically feasible within the next 20 years, and almost certainly essential if the world is to meet appropriate CO_2 reduction targets, given the pace at which coal-fired generating plant is now being built, for instance in China and India. Estimates of the cost of CCS, meanwhile, built up from engineering analysis of the separate system elements, suggests that it may add about 2-3p/kWh to the cost of coal or gas based electricity,[18] resulting in total costs under the central fossil fuel price scenario close to those for onshore wind, and higher than those for nuclear power. Under the high and high-high fuel price scenarios, the cost would be slightly higher than that of onshore wind.

It is important to note, however, as we did in Chapter 2: *Meeting a 2050 target*, that CCS is not yet a proven technology at full commercial scale, and cost estimates must therefore be considered more uncertain than those for wind or nuclear power. It should also be noted that if many countries were simultaneously to attempt the large-scale and rapid deployment of CCS, supply chain bottlenecks might well produce cost increases of the sort currently being experienced in wind and nuclear deployment. And the deployment of CCS will not be uncontroversial or straightforward: it will for instance require the building of pipelines which may well be opposed on local environmental grounds, delaying considerably the feasible pace of deployment.

It is not therefore prudent to assume that CCS is likely to make a major contribution to the achievement of emission reductions in the first three budget periods. Instead the key issue is how policy during those periods can best be designed to facilitate a major take-off of CCS in the 2020s. That issue is considered in Section 3 below.

18 Based on IPCC (2005) *Special report on carbon dioxide capture and storage*. This cost estimate relates to post demonstration. Inevitably, demonstration CCS projects in the 2010s will have significantly higher costs than those of plants built in the 2020s, which will benefit from the learning that takes place within earlier projects,

Relative costs: summary and implications

The technologies discussed above will make it possible to almost entirely decarbonise electricity generation over the next 20 years. The implication of the analysis above is that the cost of decarbonisation will depend crucially on the level of fossil fuel prices, and that this cost is likely to be manageable across the range of fossil fuel prices. Key summary points are illustrated in Figure 5.17 and discussed below:

- If onshore wind costs are towards the lower end of estimates, onshore wind will be competitive with coal and gas-fired generation in the central fossil fuel and carbon price scenarios. Under the high and high-high scenarios, onshore wind is almost certain to be fully competitive.

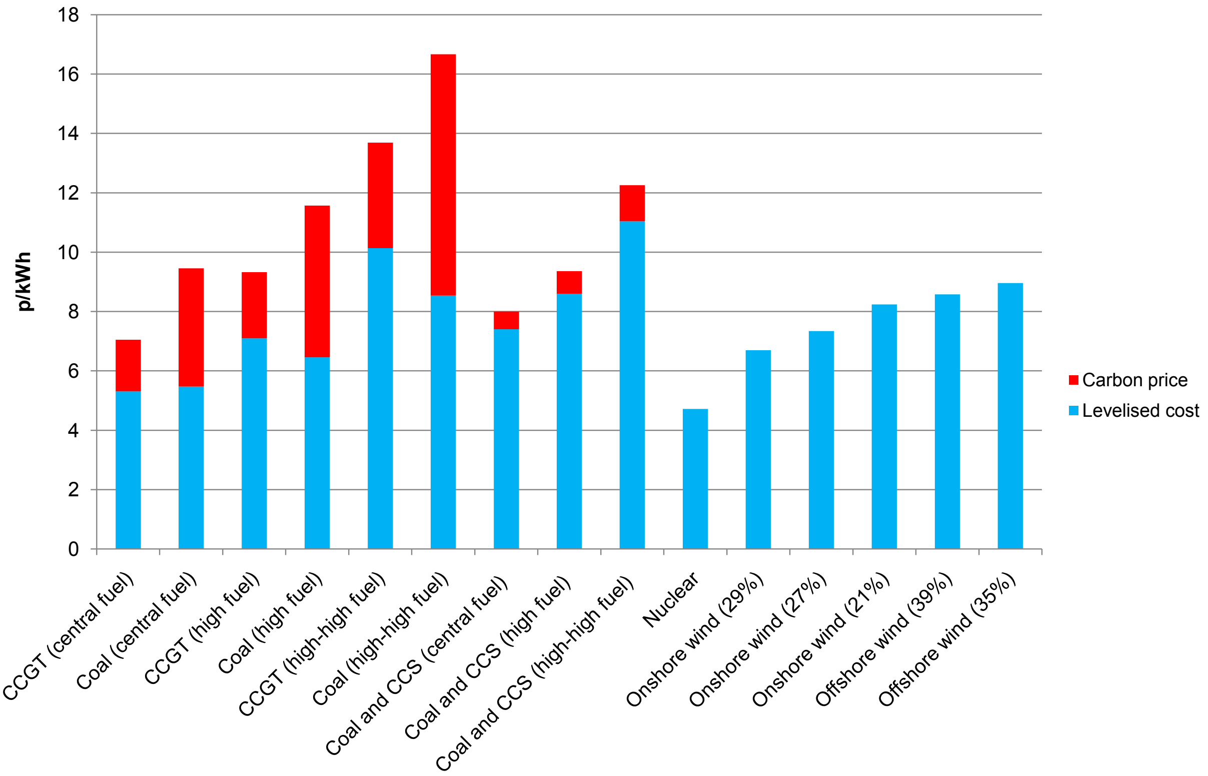
- Nuclear power is competitive with both coal and gas-fired generation in the central fossil fuel price scenario even without a carbon price. Under the high and high-high fuel price scenarios, nuclear is a clearly lower cost solution.

- Offshore wind is competitive with fossil fuel price generation under the high fossil fuel price scenario, with a carbon price.

- Given central carbon price forecasts, coal with CCS might be competitive with conventional fossil fuel price generation, but this relies on cost estimates which are inherently uncertain until large-scale deployment has been achieved. CCS options are similar to onshore wind under the central fossil fuel price scenario, and similar to offshore wind under high fossil fuel prices. CCS is unlikely to be cheaper than nuclear unless fossil fuel prices are significantly below the central scenario.

The cost of decarbonising electricity generation will therefore depend crucially on fossil fuel price assumptions. And the optimal mix of different low-carbon technologies will depend on the evolution of cost trends which cannot be predicted in advance. But the range of technologies available suggests that electricity generation can be significantly decarbonised without an unduly high cost penalty over the next 20 years, and that major emission reductions can be achieved over the first three budgets. Section 4 outlines alternative decarbonisation scenarios for those first three periods, and Section 5 analyses the aggregate costs involved. First, however, Section 3 addresses policy issues relevant to the definition of appropriate and credible scenarios.

Figure 5.17 Summary of levelised costs in 2020 under central, high and high-high fossil fuel prices[19]



Source: IPCC (2005) Redpoint et al (2008), CCC estimates of the carbon price.
Note: £2008. Percentages next to wind relate to average annual availability at the site. Intermittency costs are included in cost estimates.

19 Here we are presenting unit costs used in the 2008 analysis carried out by Redpoint for the draft Renewable Energy Strategy published by BERR in June 2008. These costs underpin the cost estimates presented elsewhere in this chapter.

3. POLICY ISSUES IN DRIVING LOW-CARBON INVESTMENT: IS A CARBON PRICE SUFFICIENT?

All emissions from major electricity generating plants are included within the EU ETS. In theory therefore, adequately tight emission reduction targets within the EU ETS should produce a carbon price which will automatically drive market behaviour compatible with those targets. A key policy issue is therefore whether this theory can be assumed to hold, or whether other policies, in addition to a carbon price, are required to ensure adequate progress towards electricity decarbonisation.[20] This section addresses this issue, considering in turn:

- The rationale for providing financial support to renewables in addition to a carbon price
- Whether nuclear energy deployment should receive support beyond that implicit in a carbon price, and whether a carbon price floor is desirable
- The appropriate policy stance towards any proposed investment in conventional coal-fired power generation

Renewable energy strategy: quantitative targets and non carbon price support

The UK is now politically committed to the EU's goal of sourcing 20% of all energy from renewable sources by 2020. The likely UK 'burden share' within this objective will require the UK to meet 15% of its demand for energy from renewable sources (see Box 5.2). Given limitations on the potential pace of renewables deployment in transport and heating, this is likely to imply that over 30% of UK electricity will need to come from renewable sources by 2020.

Box 5.2 EU renewables target and the UK draft Renewable Energy Strategy

At the Spring Council in 2007 the EU adopted a commitment to ensure that at least 20% of its final energy consumption comes from renewable sources by 2020. In January of this year the Commission published an energy and climate package which included details how this target would be met: the UK for its part must deliver 15% renewable energy by 2020, up from a baseline level of 1.5% in 2006. Recently BERR (DECC) published a draft strategy setting out how the UK might split effort between its power, heat and transport sectors and how policy can be developed to facilitate delivery. Investment in renewables will be particularly important in the power sector: BERR's analysis suggests that at least 30% of electricity generation must be delivered from renewable sources by 2020 in order for the target to be met.

This penetration of renewable electricity is very unlikely to be achieved by relying solely on the carbon price. Given the range of possible carbon prices suggested in Chapter 4, and under the central fossil fuel price scenario, wind deployment would not be economic if the only subsidy were via the carbon price. Only if the market confidently expected high or high-high fossil fuel prices would there be any possibility that carbon prices alone would drive wind deployment consistent with the required quantitative targets (see Figure 5.17 above).

The Government already has in place additional financial support through the Renewable Obligation Certificate (ROC) regime, with more support given to offshore wind than onshore (see Box 5.3). And in the draft Renewable Energy Strategy, the Government has laid out further non-financial measures likely to be required to drive renewables deployment.

20 The issue of whether a carbon price is a sufficient policy instrument alone also arises in relation to potential energy efficiency improvements and changes in consumer behaviour (see Chapter 4: *Carbon markets and carbon prices*)

Box 5.3 Financial mechanisms for encouraging renewables deployment

There are a range of support mechanisms for renewable electricity. In the UK the Renewable Obligation (RO) places a requirement on suppliers to source an increasing proportion of electricity from renewable sources. In other countries, such as in Germany and Spain, renewable generators are offered a guaranteed price for the output according to a fixed tariff (so called 'feed-in-tariff' or FIT mechanism). Here we describe the UK arrangement and a FIT mechanism (as in Germany) in more detail:

UK: Eligible generators are issued with Renewable Obligation Certificates (ROCs) for each unit (MWh) of electricity generated. Provisions to 'band' the RO were made in the 2008 Energy Act, so that the number of ROCs awarded to generators will vary according to generation types. Mature technologies (such as landfill gas) are eligible for fewer ROCs per MWh of electricity than less mature technologies such as wave or tidal. Generators, who also get a wholesale price for their electricity, can then sell their ROCs to electricity suppliers who can either present them, or pay a buy-out price to meet their obligation. At the end of each obligation period the buy-out 'fund' is recycled back to suppliers who have bought ROCs.*

Germany: The German system is similar to the banded RO insofar as it differentiates between technologies. However, grid operators are required to pay a fixed tariff for electricity from a range of technologies including landfill gas, geothermal, wind and solar. Tariffs are negotiated and guaranteed for a number of years (up to 20), but may be adjusted for new projects, and in the case of wind are related to the output of a reference plant.

Renewable generators in Germany do not necessarily receive higher subsidies than UK ones – indeed, in the UK market, (see Box 5.1, above) renewable generators potentially receive very high levels of subsidy under high fossil fuel prices. With no variable fuel costs, incumbent renewable generators benefit not only from selling ROCs but also high electricity prices. On the other hand, German renewable generators benefit from lower risk and uncertainty with a guaranteed income, therefore lowering the cost of capital for new and existing investors. It is consumers who are exposed to the risk and it is up to the government to set appropriate tariffs that set the right balance between supporting development without encouraging rent-seeking.

*In 2008/09 suppliers are required to present ROCs equivalent to 9.1% of total electricity sold, rising to 15.4% by 2015/16. The buy-out price is set for each Obligation period and is currently set at £34.30/MWh for 07/08, rising in line with RPI.

The UK's existing and evolving policy for renewable energy, and in particular for renewable electricity, already therefore represents a major departure from the pure market principle of relying on a carbon price instrument alone. The Committee believes that this departure is justified for the following reasons:

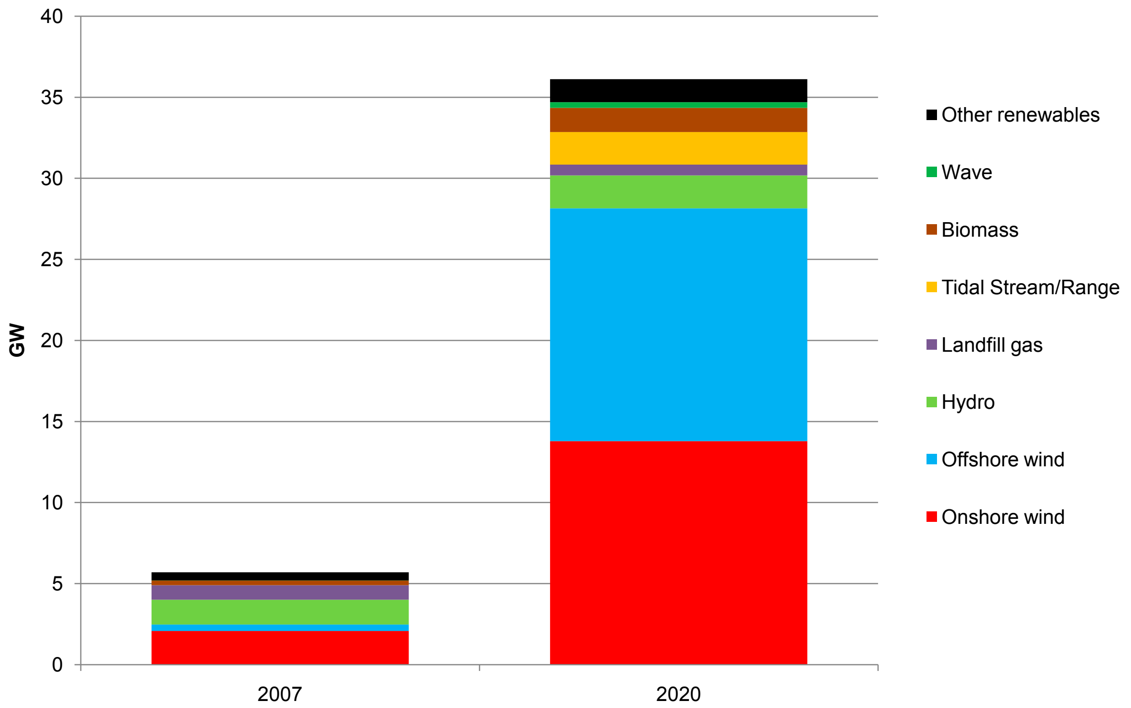
- Renewable technologies are still at an early stage of development with significant further cost reductions possible if scale is driven by initial government support. This may be particularly true for offshore wind, which is a relatively immature technology and where there may be significant opportunities for cost reduction going forward.

- Relying on other technologies to drive emission reductions would entail significant risks. Considerable progress in emission reductions in the first three budget periods could be achieved simply by replacing coal generation with gas, but further progress in subsequent budget periods would not be possible unless still lower carbon technologies were then available. Nuclear deployment is justified on cost grounds, but there are limits to the pace at which it can be deployed, and its deployment remains controversial for reasons unrelated to cost. And while CCS may be available to drive down emissions in the 2020s, the costs are uncertain and the pipeline construction required may be controversial, delaying deployment.

- Given this context, the deployment of renewable energy, in particular wind-based, makes sense even with a cost penalty. It is a proven technology, deployable in small capacity increments. And while its costs on central estimates are likely to be higher than those of fossil fuel based generation, they are within the range of possible fossil fuel generation costs given uncertainty over future fossil fuel prices.

The Committee therefore endorses the decision to set a quantitative target for renewable energy and renewable electricity.

Figure 5.18 Historic and projected renewable generation capacity, 2007 and 2020



Source: DUKES (2008); BERR Renewable Energy Strategy Consultation (2008).
Note: Other renewables includes solar PV, municipal solid waste (MSW) and sewage sludge.

The draft Renewable Energy Strategy has set out a scenario of how the UK's EU target could be met, with onshore wind power growing from 2 GW to 14 GW of capacity and offshore growing dramatically from 1 GW to 14 GW (see Figure 5.18). To achieve these targets, two sets of policies are required and are now either in place or envisaged:

- Financial support above the carbon price needs to be provided. Support mechanisms for renewable technologies are described in more detail in Box 5.3. In the UK support is provided via the Renewables Obligation, with the subsidy varying by renewable technology, and according to the balance of supply and demand in the market for renewable certificates (ROCs). There is some evidence to suggest that this regime may be less effective than a feed-in-tariff (i.e. more expensive per volume of renewable electricity supply stimulated)[21]. However there is considerable merit in continuity in the financial subsidy regime, and it seems likely that the key driver of the UK's lower rate of wind deployment compared with for instance Germany or Spain, has not been the different financial subsidy regime, but the existence of non-financial barriers such as those relating to planning consent and grid connection.

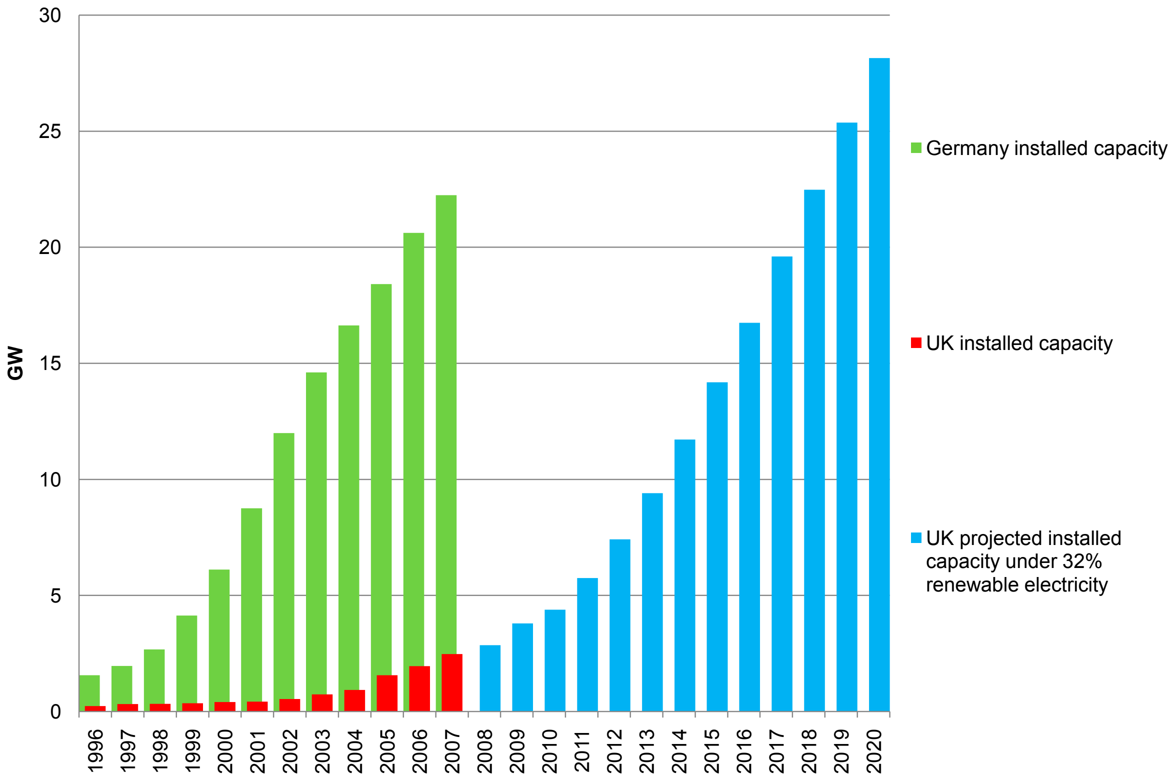
- Actions to remove non-financial barriers to deployment are therefore essential and are envisaged in the draft Renewable Energy Strategy. They include reforms to the planning system, changes to the Ofgem rules which determine the ease with which new wind operators

21 Redpoint et al (2008).

can connect to the grid, and additional investments within the high voltage transmission system. Rapid progress on all these dimensions is essential if the quantitative objectives of the draft Renewable Energy Strategy are to be met. More generally, Government will have to signal a very strong commitment in order to elicit the necessary supply chain response.

Provided these measures are taken, the objectives of the draft Renewable Energy Strategy should, in theory, be attainable. The increase in wind power deployment proposed in the UK for the next 12 years is no more rapid than that which has been achieved over the last 12 in Germany (Figure 5.19).

Figure 5.19 Cumulative installed wind capacity in UK and Germany 1996-2007 and projected UK 2008-2020 in the draft Renewable Energy Strategy



Source: European Wind Energy Association, DUKES (2008), BERR Renewable Energy Strategy Consultation (2008).
Note: Growth in wind capacity in the draft Renewable Energy Strategy, Redpoint et al (2008) achieving 32% electricity by 2020.

We therefore use the targets in the draft Renewable Energy Strategy as one key element in defining the scenarios for generation mix set out in Section 4 below, rather than presenting scenarios constructed on the basis of theoretical least-cost modelling.

But it also has to be recognised that the pace of deployment envisaged is very challenging, particularly in the face of the supply bottlenecks facing offshore wind deployment. Section 4 therefore also presents a scenario in which we fall somewhat short of the 30%+ target, but with more nuclear deployment offsetting that shortfall. Section 5 provides a cost estimate for this scenario, with cost savings resulting as nuclear is substituted for offshore wind, and which would also be attractive from a fuel poverty perspective.

These two scenarios are feasible alternatives today. If however the renewables option were to be chosen but then not achieved, the nuclear option could not be implemented rapidly, with increased investment in gas-fired generation the likely result.

- It is very unlikely that current electricity market arrangements would result in planned investment both in renewables at the levels envisaged in the draft Renewable Energy Strategy and in new nuclear before 2020. This is because if the market assumes that a high proportion of capacity will be intermittent, it will favour investment in low capital cost and flexible plant (e.g. gas) as the most economic complement. This is borne out in modelling commissioned in support of the draft Renewable Energy Strategy, which suggested that with high levels of intermittent renewables, investment in nuclear generation would be pushed back into the 2020s[22].

- If, however, it becomes apparent in future that renewables investment in line with the draft Renewable Energy Strategy is not feasible, it will not be possible to substitute nuclear for renewables at short notice, given long project lead times.

- The result would be more investment in gas-fired plant, which can be added relatively quickly to the system. This would not be desirable in terms of the radical decarbonisation of electricity generation that will be required through the 2020s.

This suggests that it is important to set a realistically achievable renewables target if emission reduction potential from the power sector is to be fully realised. It also raises questions about the functioning of the power market which are discussed in Chapter 13: *Energy security of supply*.

Nuclear energy: long-term expectations key

Putting aside the tension with renewables, nuclear energy is a long-established technology which has received very large public research and development support over the last 60 years. In contrast with renewables there is not therefore an ‘emerging technology’ argument for public support beyond that implicit in the carbon price. But there is a good argument that the costs of nuclear deployment would likely be reduced if multiple new nuclear stations were built rather than one or two: and the very long time scales of new nuclear deployment (both in the construction phase and in operation) mean that expectations of fossil fuel and carbon prices reaching far into the future are crucial to the investment case.

The key public policy priorities to facilitate new nuclear investment are therefore:

- A clear commitment to the principle of nuclear power deployment if and when cost justified, with supporting licensing and planning policies.

- Clear and radical long-term emission reduction objectives, such as the Committee’s proposed 80% by 2050 target, which will only be achievable if electricity generation is almost completely decarbonised by 2030.

- A clear commitment to keep tightening EU ETS caps and to appropriately limit the use of offset credit purchased within the EU ETS, to the extent required to meet long-term emission reduction targets. Given that the technology vision set out in Chapter 2 achieving a 80% cut by 2050 implies the almost total decarbonisation of electricity by 2030, and given that electricity generation accounted for around 70% of EU ETS emissions in the UK in 2007, the EU ETS emissions cap will need to fall particularly quickly in the 2020s.

22 As discussed in Chapter 2, the prospects for nuclear investment alongside intermittent renewables improve in the 2020s as off-peak electricity demand increases with the roll-out of electric cars and increased use of electric heating.

The planned evolution of EU ETS emission caps in the 2020s and 2030s is therefore crucial to the successful decarbonisation of electricity, and in particular to the prospects for both nuclear and CCS deployment, if these are not covered by quantitative targets of the sort applied to renewables. But it may be difficult to get political agreement on an appropriately tight cap regime sufficiently far ahead and with sufficient certainty to establish the carbon price expectations which will support the investment required to achieve radical decarbonisation. There is therefore a danger that fluctuating expectations and periodic low forward prices may deter required investment. Given this uncertainty there may be merit in considering whether policy for the development of the EU ETS should include not only setting emission caps as far in advance as possible, but also setting a floor price for carbon (i.e. a minimum price at which allowances will be auctioned) rising gradually over time. More clarity on the need for such a floor will be given following finalisation of the new EU ETS Directive (by early 2009) and the market and investor response to this.

CCS and conventional coal investment

The technology vision presented in Chapter 2 illustrated that any feasible path to a 80% reduction by 2050 will require the almost total decarbonisation of electricity generation by 2030, with further final steps in that process by 2050. This implies that any coal-fired generation plant operating in 2030 must only do so with CCS, and that CCS will need to be applied also to gas generating plant in the subsequent two decades. But the chapter also described the reality that CCS is not yet a proven technology at full commercial scale, that its costs are uncertain, and that the deployment of CCS will involve significant physical construction (e.g. of pipelines) which will in some cases be controversial and which therefore may produce significant delays. In a market context, any coal-fired power stations built over the next ten years are therefore almost certain to be built without CCS, notwithstanding the existence of a significant carbon price.

The reference emissions projections presented in Section 1 illustrated the retirement of existing coal generation capacity (see Figure 5.6). The mix of replacement capacity built will depend on expectations of both fossil fuel prices and carbon prices. Under some price expectations, it would theoretically make sense in least-cost terms only to build new gas plants (alongside renewables and some nuclear).

But it is also possible that proposals for coal-fired power stations will be brought forward, particularly if electricity generators have a preference in principle for a portfolio of different technologies in order to diversify risks of supply interruption and price volatility.

An important issue is therefore whether the only policy instrument influencing decisions on new conventional coal investments should be the carbon price, or whether other policies are required.

Provided that expectations of carbon prices in the 2020s and 2030s are consistent with the vision of radical decarbonisation, those expectations should themselves ensure that conventional coal stations are only built with the expectation and intention of retrofitting CCS, since conventional coal-fired generation will be in danger of becoming uneconomic in the face of those carbon prices.

But given the uncertainties of the political processes which determine EU ETS caps, and given uncertain and fluctuating carbon price expectations beyond the next few years, conventional coal investments could possibly go ahead without a clear acceptance of the need for future CCS installation.

There is therefore a strong case for buttressing the carbon price lever by establishing a clear and publicly stated expectation that coal-fired power stations will not be able to generate unabated through the 2020s and beyond the early 2020s.

One way to achieve this would be to establish a requirement that coal-fired power stations cannot be built beyond a certain date without CCS (say 2020), that those built before that date will be given a deadline for retrofitting CCS (say in the period 2020-2025), or that plants which choose not to retrofit should be allowed to generate for a very limited number of hours. Alternatives could be (i) to set emissions standards (i.e. company specific ceilings on the g/kWh emissions from power generation) implying the need for CCS retrofit in the 2020s to any conventional plant added over the next ten years, and ensuring that overall progress towards decarbonisation of electricity was in line with the required path to 2030 and beyond, and (ii) to establish a floor price within the EU ETS, as already discussed in the subsection on nuclear power above. These and other possible policy options warrant further consideration.

Alongside these possible policy measures, however, it is vital that planned demonstration projects of CCS technology go ahead as rapidly as possible, ideally on a larger scale and covering more variants of the technology than currently planned, whether in the UK or wider EU contexts.

4. SCENARIOS FOR GENERATION MIX AND IMPLICATIONS FOR EMISSIONS

The technology mix of UK electricity generation by the end of the third budget period will reflect both the new capacity investment decisions made over the next ten to fifteen years, and the operating decisions then being made on the capacity utilisation of the existing fossil fuel plants (coal or gas). The latter decision will be determined by the future relative balance of coal, gas, and carbon prices. The former decisions will be determined by expectations of fossil fuel and carbon prices, by the capital costs of alternative new capacity investments, and by the policy framework that the Government puts in place. Each of these is uncertain and will evolve over time. It is not therefore possible to define what the generation mix should or will be, rather decisions will be made by private companies within the framework of public policy.

All emissions from major power generators, moreover, are covered by EU ETS allowances. If therefore the Government accepts the Committee's recommendation that the UK's carbon budget should make no distinction between domestic UK emission reductions and those reductions achieved by allowance purchase within the EU ETS, different generation mix results will not change the UK's performance relative to the budget, but simply the degree to which the UK is a net buyer or seller of allowances within the EU ETS.

It is nevertheless useful to illustrate scenarios for the generation mix which might result from current policies for three purposes: (i) to gauge whether the UK is likely to be a net seller or buyer of allowances; (ii) to identify whether the UK is likely to be making adequate domestic progress towards a decarbonised electricity system; and (iii) as a basis for estimating possible cost implications.

The key variables which will affect generation mix and resulting domestic emissions will be the degree of success in achieving the renewable target, the extent of new nuclear deployment, and the balance between coal and gas plants in new fossil fuel investment. We have therefore modelled the impact of three scenarios with different assumptions along these dimensions, which illustrate the likely range of resulting possible generation mixes.[23]

- In Scenario 1 we assume the full success of the draft Renewable Energy Strategy, achieving in excess of 30% electricity from renewables by 2020,[24] with one CCS demonstration coal plant (0.3GW) by 2014. In addition we impose a CO_2 price as set out in Chapter 4 which stimulates all other new fossil fuel plants to be gas, and therefore no new conventional coal build. The capacity and generation mix in this scenario are shown in Figures 5.20 and 5.21. This would result in domestic electricity emissions falling by around 30% relative to what they otherwise would have been (i.e. the reference projection), or 40% on 1990 levels (Figure 5.22).

- To consider implications for progress against our EU ETS cap, we have combined the savings from supply side measures in Scenario 1 with the electricity demand reductions identified in Chapter 6: *Energy use in buildings and industry*, which together result in an emissions reduction from the power sector of 55% relative to 1990. Under our Interim budget (see Chapter 3: *The first three budgets*), this would make the UK a net seller of around 2 million tonnes of allowances in 2020, but in our Intended budget the UK would be a net purchaser of around 41 million tonnes of allowances in 2020.[25]

23 In these scenarios, we do not include abatement through merit order fuel switching, as the DECC model runs found that this did not occur under our central carbon price estimates, due to the relatively low amount coal burn in the reference case. However, other models (e.g. Pöyry's EurECa model) suggest that under a £40/tCO_2 carbon price, fuel switching would occur in the UK.

24 In line with the scenario presented in the draft Renewable Energy Strategy this is around 120TWh of renewable generation by 2020.

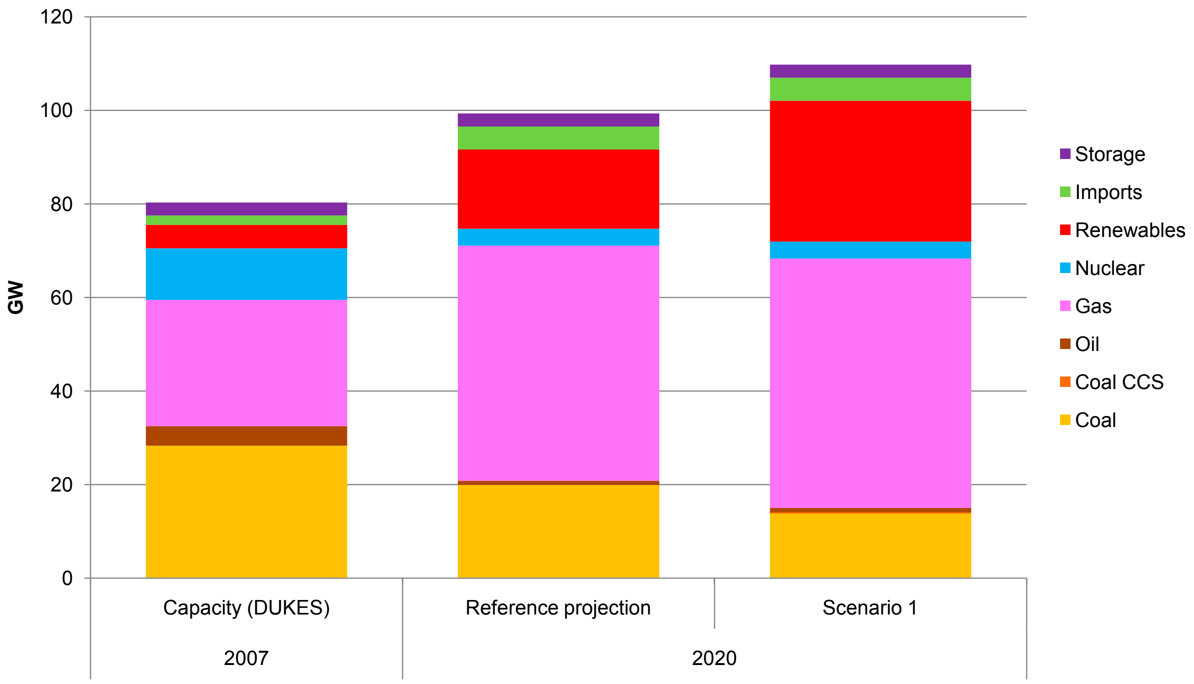
25 Under our intended budget the carbon price will be higher as the cap on the EU ETS sector will be tighter in line with the 30% GHG target (see Chapter 4). However, our modelling suggests that that UK power sector abatement would be similar under both carbon prices and the tighter cap would be mainly reached through additional purchases.

- In Scenario 2 we assume that the draft Renewable Energy Strategy is only around 75% successful, resulting in a capacity and generation mix shown in Figures 5.23 and 5.24[26]. Emissions here are the same as in Scenario 1 as the shortfall of the renewables is simply met by three new nuclear plants by 2020.[27]

- In Scenario 3, again we assume that the draft Renewable Energy Strategy is only 75% successful, but, that there is only one new nuclear power plant, and one-third of retiring coal capacity is replaced by new coal rather than new gas (Figure 5.23, Figure 5.24). Under this scenario the UK would be a net buyer of around 67 million tonnes of allowances against the Intended budget, and as a result could face an increasing economic burden with rising carbon prices in the 2020s and 2030s.

The emissions intensity in 2020 for all Scenarios is shown in Figure 5.25. In Scenarios 1 and 2 emissions intensity falls to around 310 gCO_2/kWh, compared with around 560g today. In Scenario 3, due to higher coal burn intensity falls to 375 gCO_2/kWh.

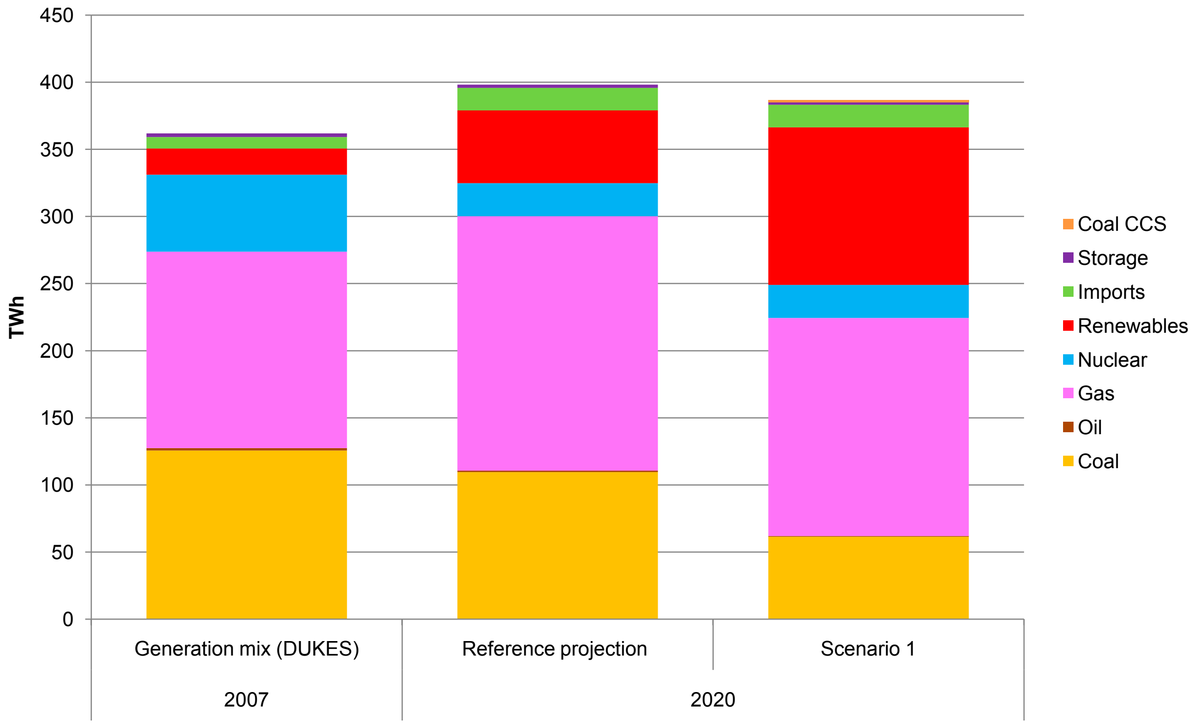
Figure 5.20 UK generation capacity in 2007 and projected in 2020, reference projection and Scenario 1 (central fossil fuel prices)



Source: DECC Energy Model based on CCC assumptions, DUKES (2008).

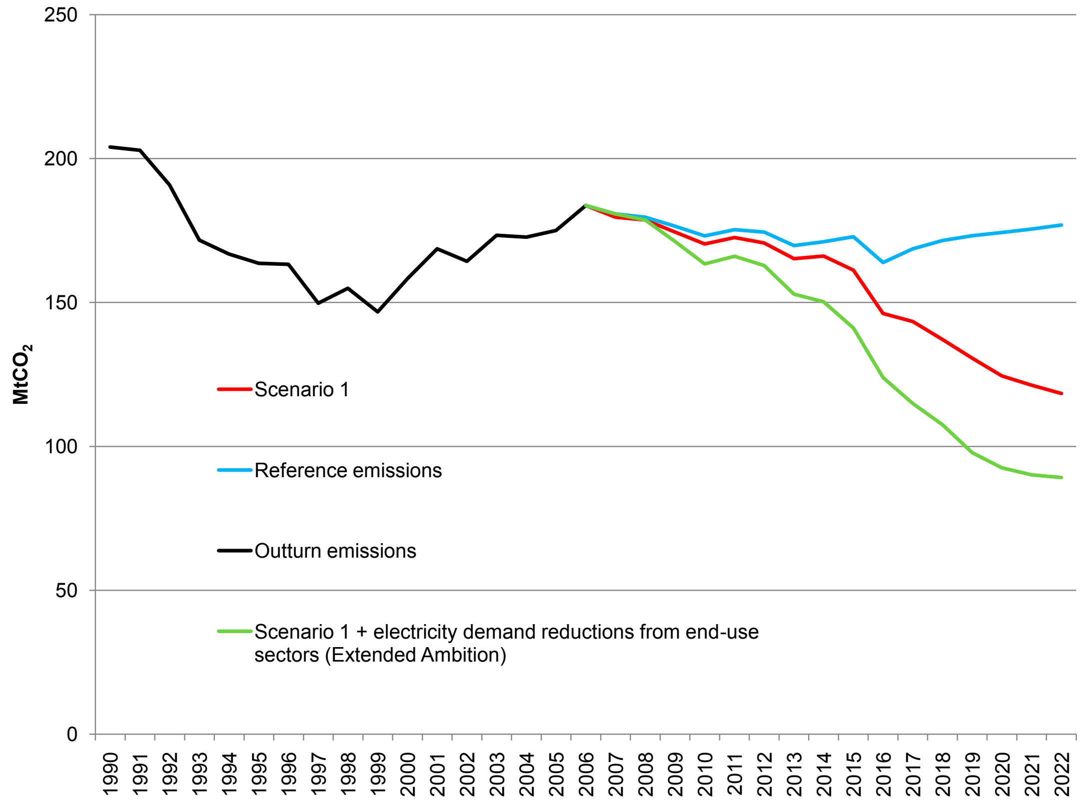
26 In Scenarios 2 and 3 renewable generation rises to around 90TWh in 2020, instead of around 120TWh in Scenario 1.
27 Emissions could be lower than Scenario 1 if, because of less wind capacity, there is also less need to hold gas plant as spinning reserve.

Figure 5.21 UK generation in 2007 and projected in 2020, reference projection and Scenario 1 (central fossil fuel prices)



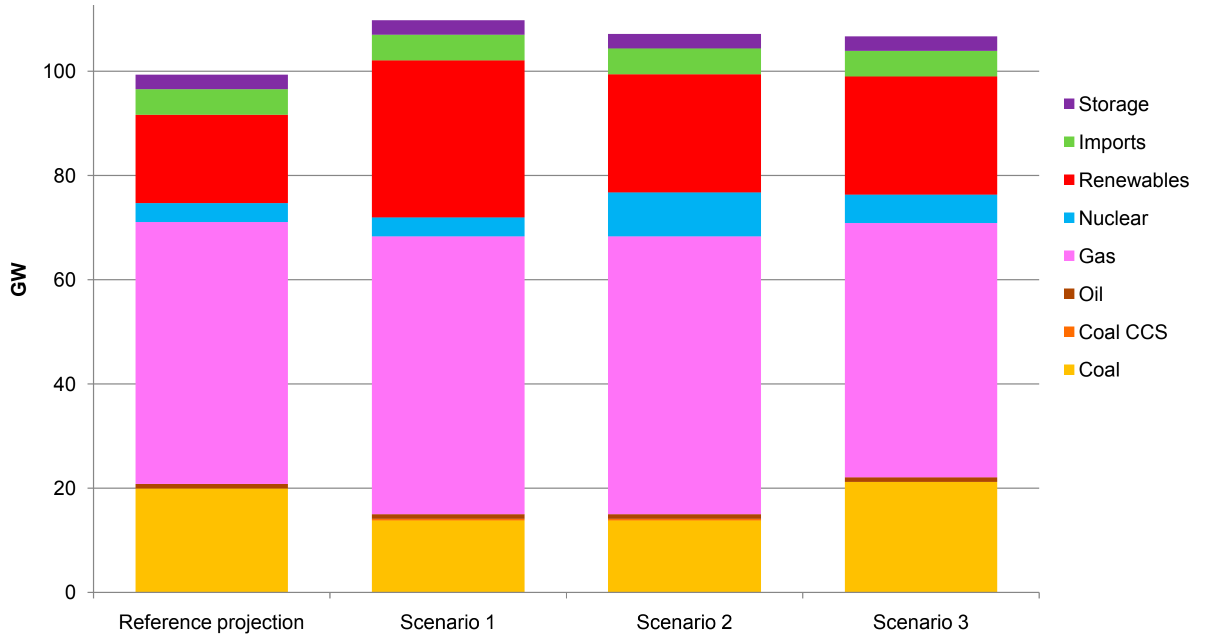
Source: DECC Energy Model based on CCC assumptions, DUKES (2008).

Figure 5.22 Historic and projected emissions in the power sector, reference projection and Scenario 1 (central fossil fuel prices) 1990–2022



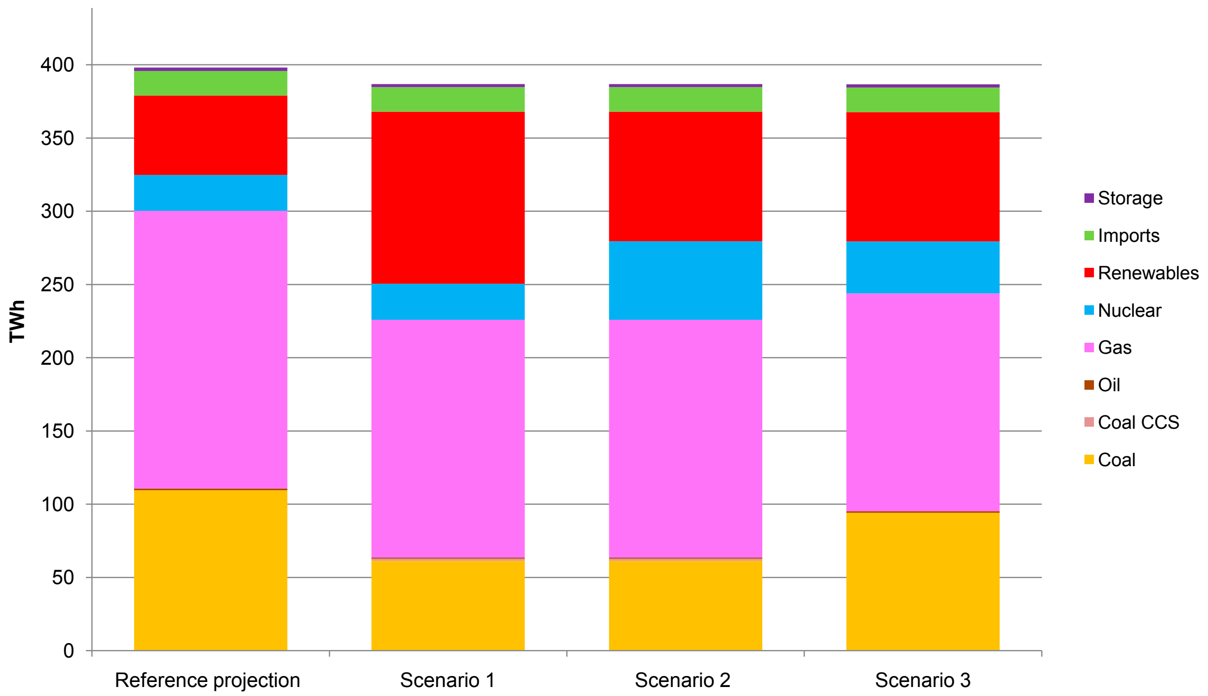
Source: DECC Energy Model based on CCC assumptions.

Figure 5.23 Projected UK generation capacity, reference projection and Scenarios 1, 2 and 3, 2020



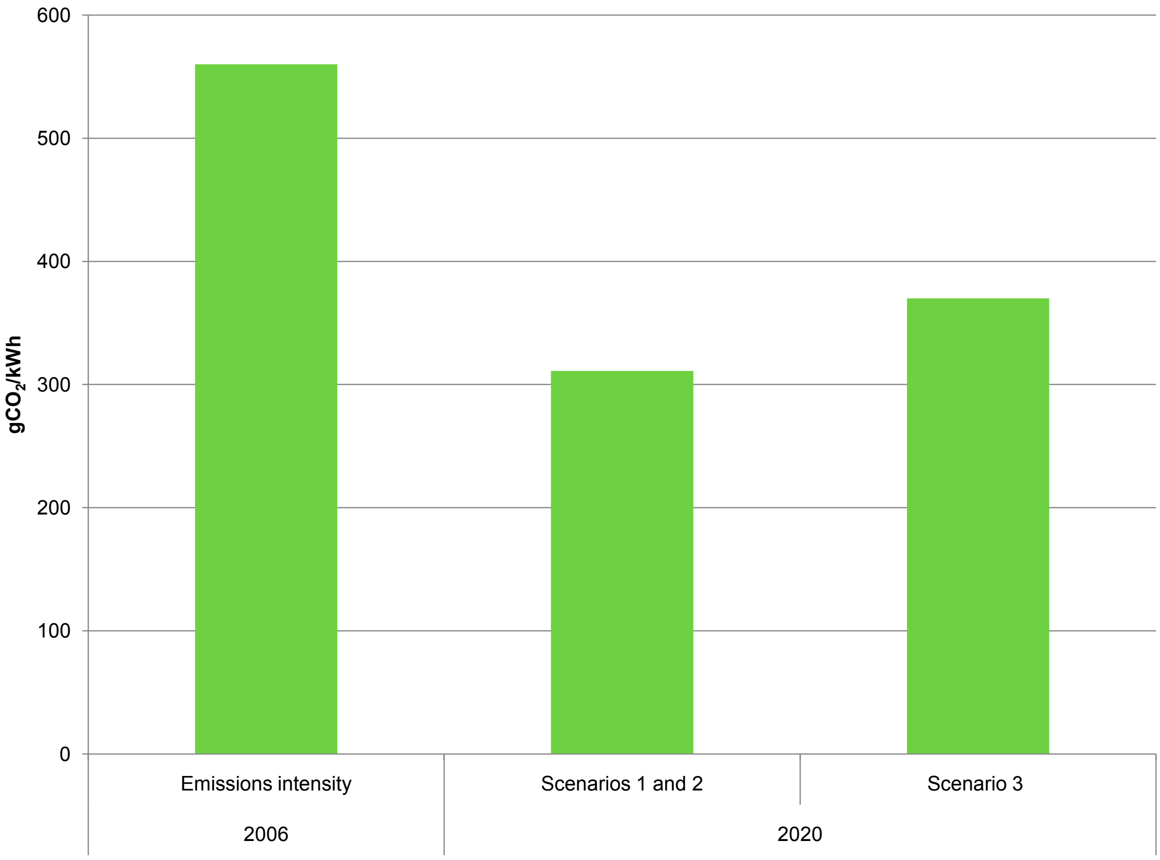
Source: DECC Energy Demand model (Scenario 1), CCC modelling (Scenarios 2 and 3)

Figure 5.24 Projected UK generation, reference projection and Scenarios 1, 2 and 3, 2020



Source: DECC Energy Model (Scenario 1), CCC modelling (Scenarios 2 and 3)

Figure 5.25 Emissions intensity per kWh of generation in 2020, Scenario 1, 2 and 3



Source: DUKES (2008); DECC Energy Model (Scenario 1, 2); CCC modelling (Scenario 3).

5. AGGREGATE COSTS TO GDP AND TO THE CONSUMER

The cost of decarbonising electricity generation is given by the costs of producing electricity in the emission reduction scenarios, minus the cost which would be incurred under the reference projection. The size of this additional cost burden is determined not only by the costs of deploying low-carbon technologies but also crucially by the level of fossil fuel prices and the carbon price. Given these multiple uncertainties, a wide range of estimates can be produced. But three key messages are clear from our cost modelling:

- In 2020 the total cost of the more aggressive Scenario 1 might lie around 0.2% of GDP (in a central fossil fuel price world) or 0.1% of GDP (if fossil fuel prices were as in the high-high scenario).[28] The fact that the costs fall as fossil fuel prices rise illustrates that decarbonising electricity provides a hedge against fossil fuel price uncertainty: the value of this hedge is considered in Chapter 13: *Energy security of supply.*

- In terms of the impact on electricity prices, however, costs are obviously much more significant. Under Scenario 1, relative to the reference projection, the residential retail electricity price could be around 15p/kWh (ie. 25% higher in 2020), if the central fossil fuel price scenario held. If the high-high fuel prices held, prices would be even higher at 20p/kWh (or around 25% higher than the high-high reference projection of 16pkWh,[29] see Figure 5.29). This raises important issues about the potential impact of decarbonising electricity on fuel poverty: these are discussed in Chapter 12: *Fuel poverty implications.*

- Resource costs could be significantly reduced if new nuclear build were to replace offshore wind investment. The cost of Scenario 2 as a proportion of GDP in 2020 would be 0.1%, which is £2 billion lower than the cost in 2020 in Scenario 1.

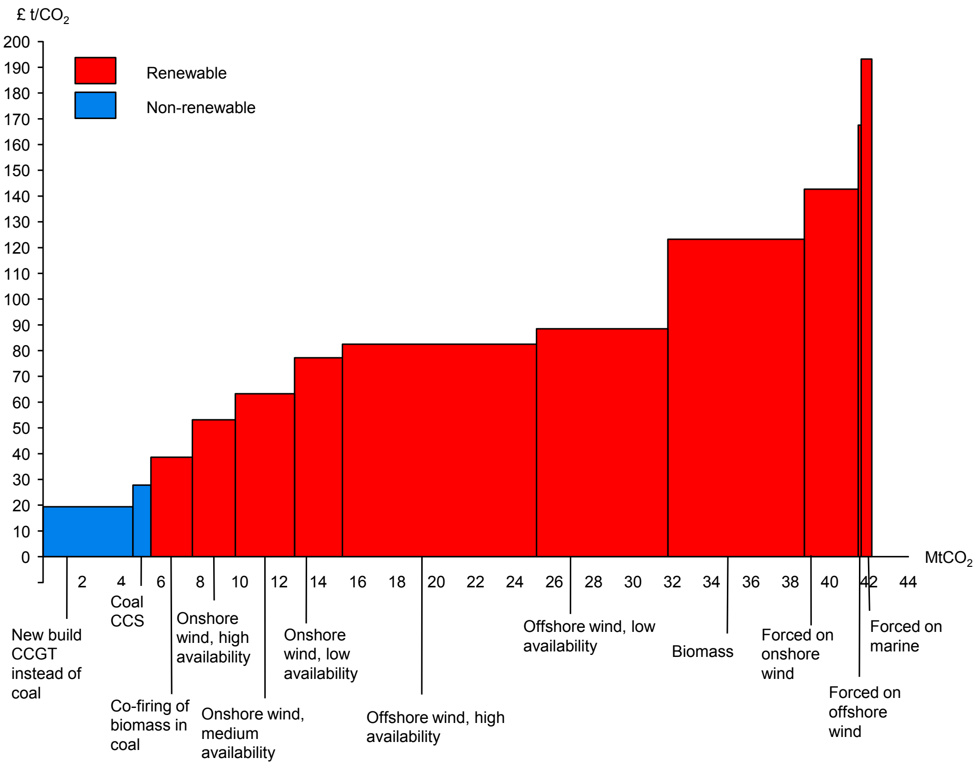
Marginal abatement cost curves (MACCs, see Chapter 3) showing quantities of emissions reductions and associated costs for each scenario are shown in Figures 5.26–5.28[30].

28 This is close to estimates made in work carried out for the draft Renewable Energy Strategy. Estimates in Redpoint (2008) suggest that these costs would be closer to 0.3% of GDP in 2020 under the central fuel price scenario.

29 Electricity prices are higher in the high-high fuel price scenario because of the higher gas and carbon prices. Even in a world with 30% or more renewables, gas could continue to set the electricity price as the marginal plant. Under high-high fuel prices, the carbon price is higher as the absolute difference between the coal and gas price is higher (see Chapter 4).

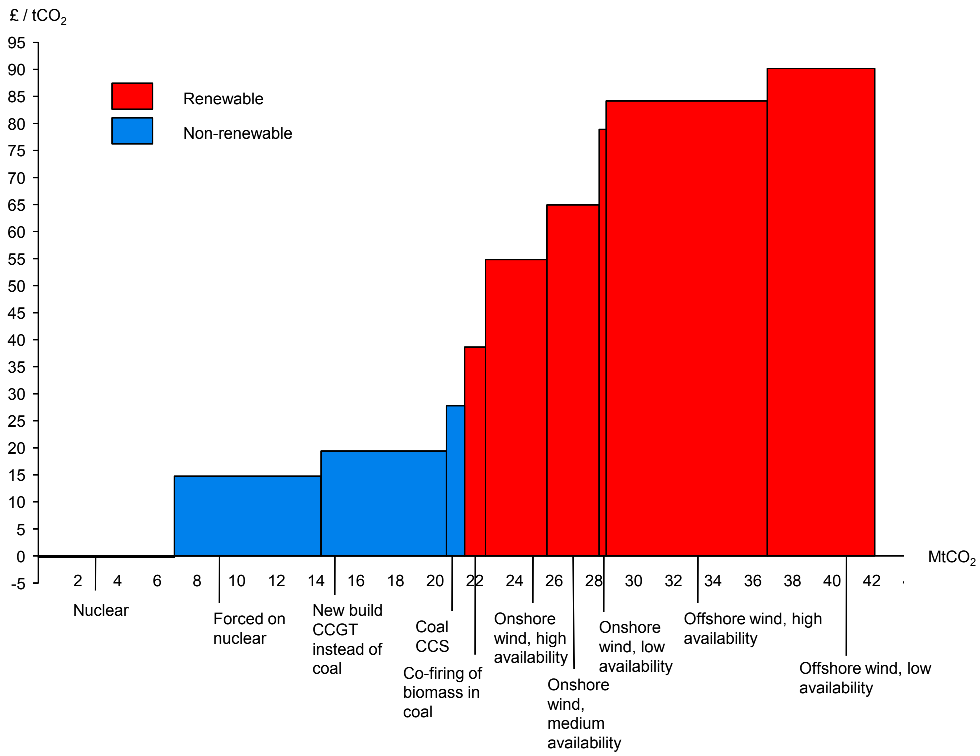
30 The MACCs are generated from a model originally built for us by McKinsey. We have subsequently developed this model substantially, and run our own scenarios across it.

Figure 5.26 Power sector MACC, Scenario 1



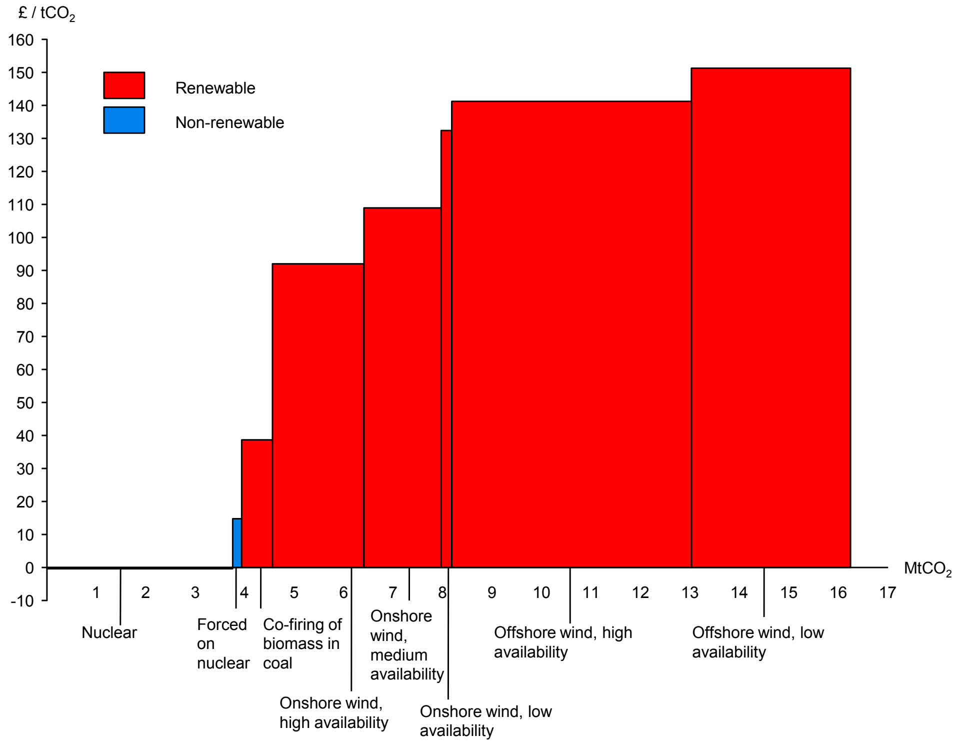
Source: CCC Modelling.
Note: 'Forced on' plant refers to plant which is built despite the existence of enough generation capacity on the system (e.g. to meet a target). It therefore displaces existing plant rather than new plant.

Figure 5.27 Power sector MACC, Scenario 2



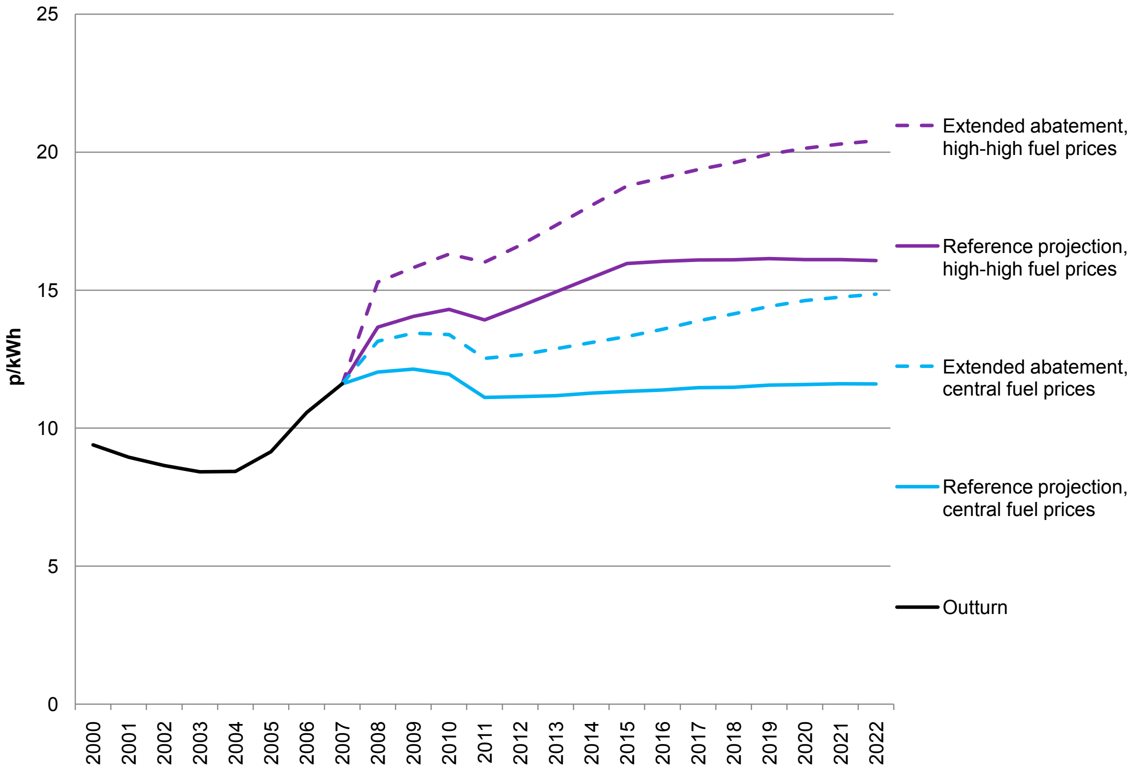
Source: CCC Modelling.
Note: 'Forced on' plant refers to plant which is built despite the existence of enough generation capacity on the system (e.g. to meet a target). It therefore displaces existing plant rather than new plant.

Figure 5.28 Power sector MACC, Scenario 3



Source: CCC Modelling.
Note: 'Forced on' plant refers to plant which is built despite the existence of enough generation capacity on the system (e.g. to meet a target). It therefore displaces existing plant rather than new build plant.

Figure 5.29 Retail electricity prices in the residential sector in reference projection and Extended Ambition scenario, central and high-high fuel prices



Source: DECC Energy Model and CCC calculations.
Note: 'Extended Ambition' models Scenario I.

6. POWER GENERATION SCENARIOS IN THE ECONOMY-WIDE ABATEMENT SCENARIOS

We have used Scenarios 1 and 2 in the economy-wide scenarios presented in Chapter 3: *The first three budgets*, to define the emission reductions that could occur in the first three budget periods. Specifically, we have used the trajectory in Scenarios 1 and 2 across the *Current, Extended* and *Stretch Ambition* scenarios for economy-wide emissions reduction. The reason we have done this is because we think that these reductions are achievable, desirable and necessary, given the path to complete decarbonisation of electricity generation by 2050.