THE COSTS OF DECARBONISING ELECTRICITY GENERATION

This technical annex to *Building a low-carbon economy* presents further details on the analysis underlying the estimates of the costs of decarbonising the power sector in Chapter 5.

Building a low-carbon economy found that there exist a set of technological options which will make it possible to reduce the carbon intensity of generation from around 560 gCO_2/kWh to around 310 gCO_2/kWh by 2020. Chapter 5 provided estimates of the costs of achieving this reduction. It first looked at the costs of individual technologies and compared them to the costs of the fossil fuel generation. It then presented estimates of the overall costs associated with different abatement scenarios.

The aim of this annex is to present further details on the assumptions used in the analysis in Chapter 5. The note thus covers:

- The cost of electricity generation by technology;
- Costs associated with increasing the level of intermittent generation on the system; and
- Total costs of power sector abatement scenarios.

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1. THE COST OF ELECTRICITY GENERATION BY TECHNOLOGY

This section presents further details on levelised cost estimates of low-carbon technologies presented in Chapter 5 of the CCC's report.

Levelised cost estimates attempt to capture the lifetime costs and output of a generation installation in a single indicator of the costs per unit of power produced. They can be used to compare generation costs across technologies and give some indication of the attractiveness of investing in different technologies.

This section covers the following:

- Levelised cost estimates used by the CCC in *Building a low-carbon economy*
- Key inputs and assumptions and comparisons with other sources
- Changes over time due to learning

Levelised cost estimates used by the CCC in *Building a low-carbon economy*

Figure 1.1 present the CCC's estimates of levelised costs for key technologies in 2010 and 2020. These are based on work for the BERR draft Renewable Energy Strategy (Redpoint *et al* 2008), CCC estimates of the carbon price, and IPCC's 2005 report on carbon capture and storage (CCS)[1].

As discussed further below, there is significant uncertainty about the inputs to levelised cost estimates. In choosing to use the costs and assumptions from Redpoint *et al* (2008) the CCC have:

- Used assumptions that are comparable to others in the literature
- Ensured internal consistency, allowing costs to be compared on the same basis.

The CCC's estimates suggest that the following comparisons can be made between the costs of low-carbon technologies and the fossil-fuel alternatives:

- Onshore wind is competitive with fossil fuel generation in the central fossil fuel and carbon price scenarios at the windier sites. Under the high fossil fuel price scenario, onshore wind is likely to cost less than fossil-fuelled alternatives, except at the least windy sites and under the high-high fuel prices, onshore wind is competitive with fossil fuel generation even at the least windy sites.
- Offshore wind is competitive with fossil fuel price generation under the high fossil fuel price scenario by 2020, though in 2010 it is only clearly competitive under the high-high fossil fuel price.
- Nuclear power is competitive with both coal and gas-fired generation under all fossil fuel price scenarios.
- Coal 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. However, it is important to emphasise that the cost estimates represent the

[1] The additional costs of CCS were taken from the IPCC report, These were added to estimates of the costs of coal used by Redpoint *et al* 2008.

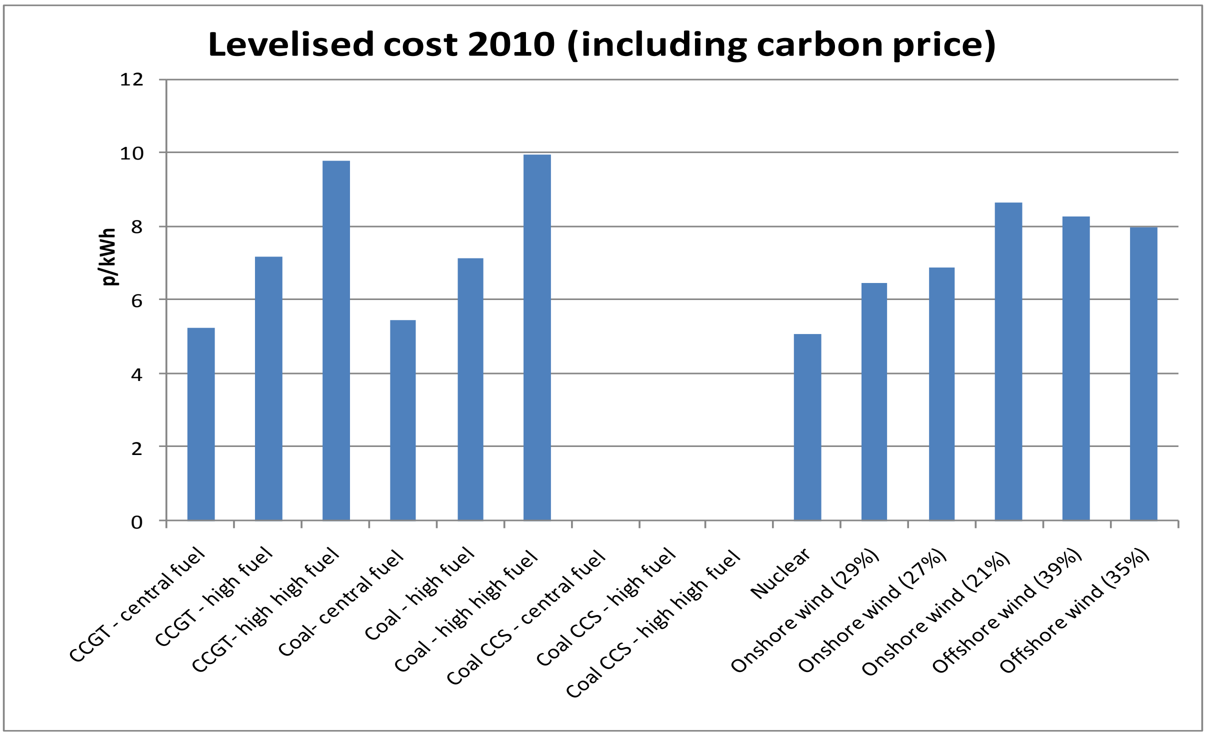
likely cost for a fully demonstrated, nth-of-a-kind plant and that demonstration plants will inevitably be considerably more expensive than this.

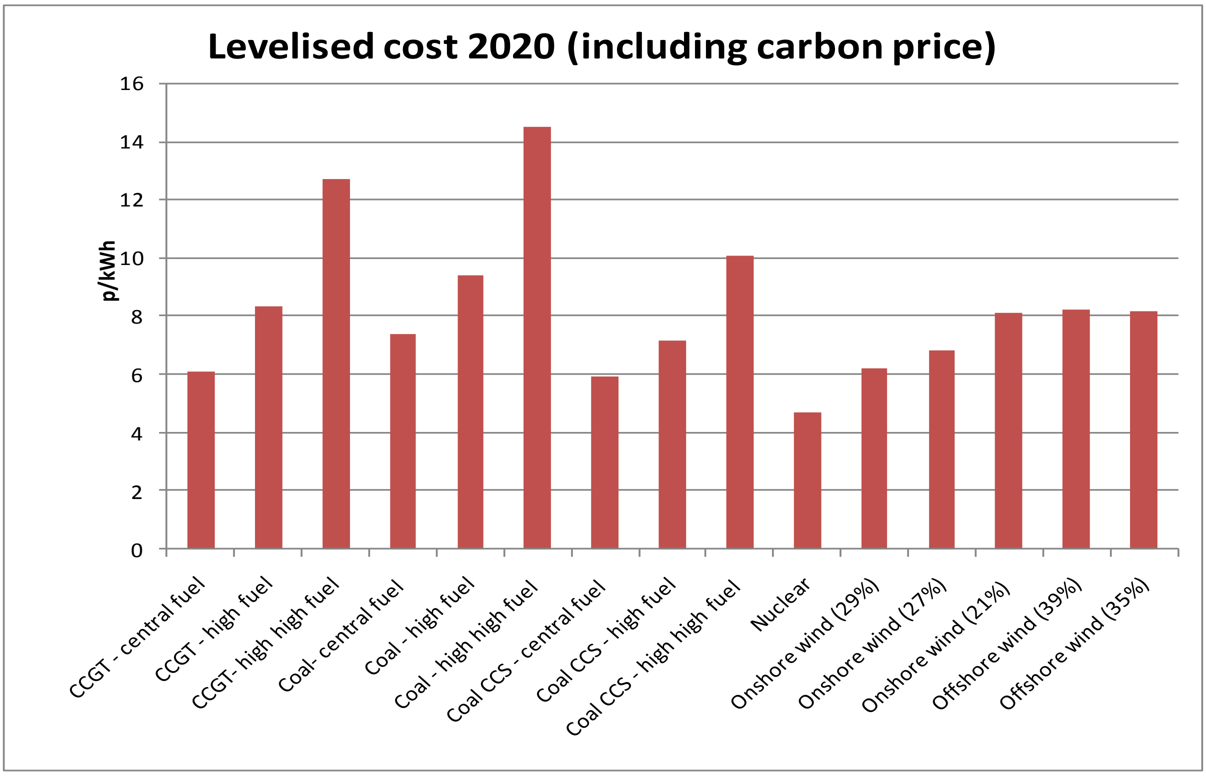
The following points can also be made about how the CCC expects the costs to change over time:

- The costs of coal and gas-fired generation are expected to rise over time. This is wholly driven by the fact that fossil fuel and carbon prices rise considerably between 2010 and 2020, according the projections used by the CCC[2]. This more than offsets the small increase in efficiencies which may be associated with these technologies.
- The costs of renewable technologies are expected to fall over time due to the learning associated with the global uptake of these technologies. As discussed below, this learning effect is partly offset by the costs of the supply chain bottlenecks which are expected as investment in these technologies increases in order to meet the EU 2020 target.
- The cost of nuclear is expected to fall slightly over time, driven by a small decrease in capital costs.
- CCS costs are only shown for 2020 as it is not expected that CCS will be deployed on a commercial scale before then. CCS is not yet a proven technology at full commercial scale, and the cost estimates shown here must therefore be considered more uncertain than those for wind or nuclear power. For example, the possibility of the same kind of supply chain bottlenecks currently predicted in the wind sector is not accounted for in these estimates.

[2] See Chapter 3 of *Building a low-carbon economy* for fossil fuel prices and carbon prices estimates.

Figure 1.1: Levelised cost estimates for key technologies, 2010 and 2020





Source: CCC calculations based on Redpoint *et al* (2008), IPCC(2005) and CCC estimates of the carbon price. Notes: All costs are in £2008. Estimates of the carbon price are included (in line with those presented in Chapter 4 of the CCC's report). Percentages associated with wind estimates refer to the annual percentage of time that wind at these sites will be high enough for generation. System balancing and back up costs are not included. These estimates differ slightly from those published by the CCC in December 2008 due to a correction in the way the EUA price is included in the costs of the fossil fuel based technologies. The comparative assessment of the costs given in the report has not been affected by this correction.

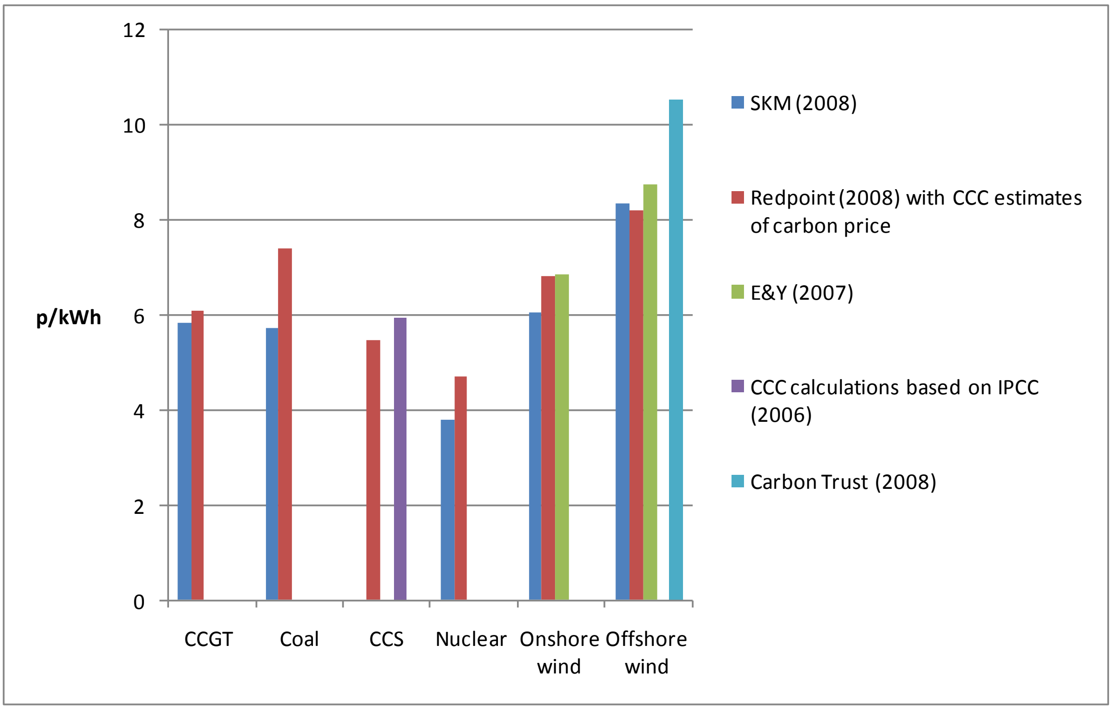
Key inputs and assumptions and comparison with other sources

While levelised cost estimates provide a useful indication of the likely relative costs of different technologies, it is important to look further at the inputs to the levelised cost calculation, and the uncertainties around them:

- Like any reduction of complex information into a single indicator, levelised cost estimates can mask some attributes of technologies which may make them more or less attractive from society's point of view or to investors. Apparently small changes in assumptions on the technologies can impact greatly on the levelised cost estimates, and on the relativity between technologies.
- Related to this, it is also useful to understand how levelised costs may change depending on future developments, for example it is useful to know which technology costs would be most impacted by an increase in certain commodity prices.
- Levelised cost estimates from different sources vary quite significantly (Figure 1.2). It is useful to understand what is driving the difference between these estimates.

This section therefore provides more information on the inputs to the levelised cost estimates, how the CCC's view of these compares to other sources, and the sensitivities of various technologies to changes in these inputs.

Figure 1.2: Levelised cost estimates for 2020 from variety of sources



Notes: Where a range of costs have been presented in a report, the centre point of the range has been taken . Redpoint coal and gas costs are based on BERR central fuel costs. All costs are for 2020 and in £2008.

Levelised costs are calculated by allocating the lifetime costs of a generation installation over its lifetime electrical output, discounting both costs and outputs back to their present values. Assumptions need to be made on the following variables:

- Capital costs
- Discount rate or cost of capital
- Load factor
- Efficiency
- The timing of costs and economic life (i.e. the payback period)
- Fixed and variable operating and maintenance costs, including fuel and carbon costs where relevant

The CCC's view of each of these inputs is now compared to other published sources and the relative sensitivities of each technology to the changes in each input is discussed.

Capital costs

Capital costs usually consist of the engineering, procurement, construction costs associated with building a plant, including grid infrastructure costs and pre-development costs, such as the costs of the planning process.

Estimates of the current capital costs of technologies are set out in Table 1.1. This shows that while there is a significant variation in the estimates of costs, especially for wind, the CCC's view of these costs are within the range of estimates from other sources.[3]

However, though the capital costs of onshore and offshore wind look very similar across publications, this is partly due to the fact that some of the estimates have been drawn from the same sources. For example, the baseline capital costs for 2010 in Redpoint *et al* (2008) were based on those in Poyry (2008) which in turn drew on Ernst and Young (2007), among other studies. Hence the similarity in the estimates from these three studies should not be taken as an indication of the existence of a consensus.

[3] While the CCC's view of the capital costs for offshore wind look quite low relative to SKM and Carbon Trust, this is partly offset in the levelised cost calculation by the fact that the load factor is assumed to be higher in Carbon Trust and SKM. This is consistent with the argument sometimes made that capital cost and load factors are correlated for wind technologies (e.g. because windier sites are often located in remote or elevated areas where development is more difficult).

Table 1.1: Estimates of current[4] capital costs (per kW)

	CCC view based on Redpoint *et al* (2008)	Poyry (2008)	SKM (2008b)	Ernst and Young (2007)	Carbon Trust (2008)
Onshore wind	£1111	€1576	£900	£948-£1329	
Offshore wind	£1574	€2232	£1800 + £380 for grid connection	£1326-£1658	£2180-3050
Coal CCS	£1658				
Nuclear	£1500		£1500		
Coal	£1248		£1050		
CCGT	£532		£500		

Note: Poyry and Redpoint costs are equivalent under an assumption of an £/€ exchange rate of 0.7.

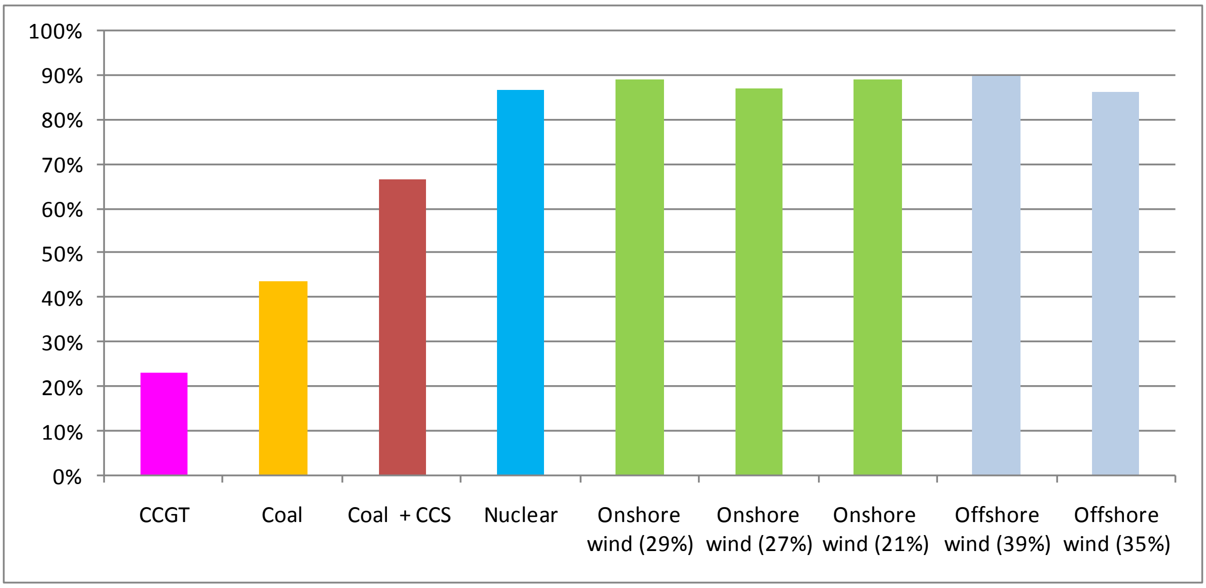
Figure 1.3 shows that the low carbon technologies, especially nuclear and wind, are much more capital intensive than coal and gas-fired plant. This means that the levelised costs of these technologies will be disproportionately impacted on by any factor that changes the capital costs such as the following:

- The price of commodities used in the construction of generating plants, such as the price of steel and cement;
- Supply chain bottle necks or market power in the supply of components of plants
- Shifts in the exchange rate (for example at the end of 2008, the fall in Sterling against the Euro put upward pressure on the price of wind turbines, which are currently purchased mainly from continental Europe).

[4] 2008 or 2010

The importance of the impact of these factors on capital costs suggests that capital cost estimates should be based on a view of the above factors that is as up to date as possible.

Figure 1.3: Capital costs as a proportion of levelised costs by technology



Source: CCC calculations based on Redpoint *et al* (2008)
Notes: All costs relate to plants built in 2010 except for CCS costs which are for 2020. Capital costs are divided by output discounted over the economic lifetime of the plant using a uniform real discount rate of 10%. Percentages associated with wind estimates refer to the annual percentage of time that wind at these sites will be high enough for generation. Assumed load factors are outlined below.

Even where there is broad consensus on the capital costs of technologies, other inputs to the levelised cost calculation can impact heavily on how much weight is attached to capital costs in the calculation. In particular, the choice of discount rate and load factor are crucial. These are covered in the next two sections.

Discount rate

In the levelised cost calculation, future costs and outputs are discounted at a cost of capital. This rate captures the time preference and the risk associated both with the various technologies, and with the revenues expected through the electricity price.

Discount rates for less proven and highly capital intensive technologies, such as offshore wind, are usually assumed to be higher than those for proven and less capital intensive technologies, such as CCGT. The regulatory regime also has an impact; incentive schemes which guarantee a certain price for electricity supplied, such as feed-in-tariffs, are likely to put downward pressure on the discount rate by reducing the risk that suppliers face on the electricity price.

A commercial discount rate close to 10% (rather than the social discount rate of 3.5%, recommended by the Treasury Green Book) is generally used to calculate levelised costs in the power sector, even when these costs are being viewed from society's point of view. The rationale for this is that the risks faced by private investors and reflected in the costs of financing projects constitute a real resource cost to society.[5]

The CCC's levelised cost estimates used rates determined by modelling undertaken by Redpoint, which vary by scenario and incentive scheme, but are close to 10% for most technologies[6]. This is broadly in line with the discount rates used in other publications (Table 1.2).

Table 1.2: Discount rates (real)

	Poyry (2008)	SKM (2008b)	Ernst and Young (2007)	Carbon Trust (2008)
Onshore wind	10%	10%	10%	
Offshore wind	12%	10%	12%	10%
Coal CCS		10%		
Nuclear		10%		
Coal		10%		
CCGT		10%		

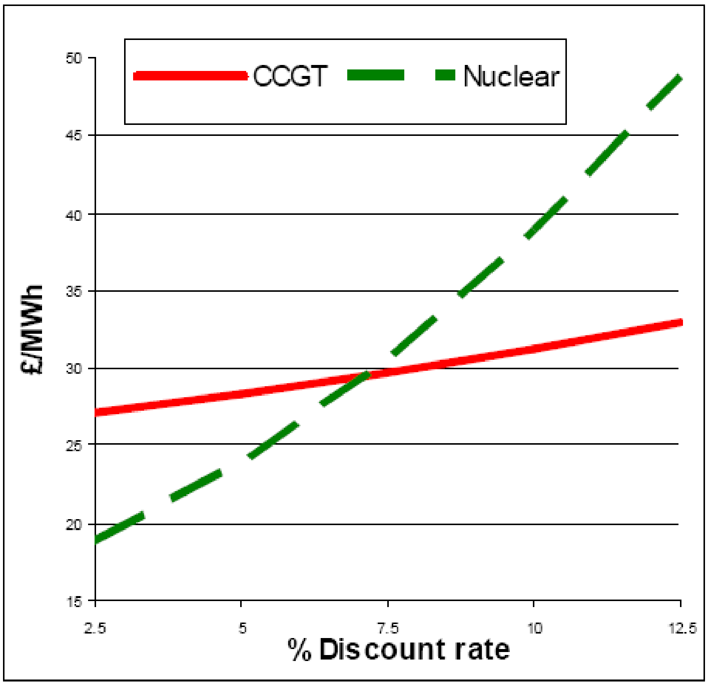
Notes: Redpoint's estimates of the cost of capital are not included in this table as they vary by scenario and type of investor.

The choice of discount rate is important as it impacts on the weight that is attached to costs at different points in time. The higher the discount rate, the more weight is put on costs that occur in earlier years as opposed to costs that occur in later years. Capital costs occur up-front, so those technologies with a high proportion of capital costs (see Figure 1.3) will look more economic the lower the discount rate. Technologies with lower capital costs are much less sensitive to the discount rate. This is illustrated in Figure 1.4 for CCGT and nuclear.

Given its long life, and very high capital cost, the choice of the discount rate is especially important for a project like the proposed tidal range project in the Severn Estuary. *Building a low-carbon economy* noted that the choice of the discount rates used to compare the costs of technologies may warrant further investigation.

[5] These risks include the risks that the completed project will not be able to generate sufficient revenue, the risk of costs overrunning, and political and regulatory risks.
[6] In the marginal abatement cost curve analysis, the CCC used a flat real rate of 10% across all technologies.

Figure 1.4: Impact of varying discount rate on levelised costs



Source: UKERC (2007) *A Review Of Electricity Unit Cost Estimates*
Notes: Estimates for capital and running costs, plant efficiency, discount rates, fuel prices, and plant life are taken from DTI (2006) *Energy Review. Energy Review* costs for nuclear are similar to the CCC's estimates, but for CCGT are significantly lower. All are in £2006.

Load factor and availability

The load factor or availability provides an estimate of the annual % of time the plant will operate.

For wind, the load factor is determined by the amount of time the wind plant will be able to operate, given availability of natural resources. Given the fact that the short run marginal costs of wind are close to zero, it is usually implicitly assumed in the levelised cost calculation that whenever the wind is blowing, the wind plant will sell power to the system, though some studies account for the need to curtail output at high levels of penetration (e.g. SKM 2008b).

For thermal plants and nuclear, the load factor is the annual % of time the plant can operate, given outages (e.g. for maintenance). For thermal plants, which have significant short run marginal costs, the estimate of the load factor also includes the impact of market conditions, for example, in a market with a high penetration of plants with low short run marginal costs like wind and nuclear, the annual percentage of time thermal plants are used will decrease.

The CCC's view of load factors for wind are set out in Table 1.3. Load factors for other plants are not shown, as these depend on generation mix in the scenarios being modelled. Table 1.3 shows that the estimates used in the CCC calculations are similar to those published elsewhere, though the bottom of the range for onshore wind is significantly below other estimates, and the offshore wind estimates are at the low end of those used by the Carbon Trust (2008).

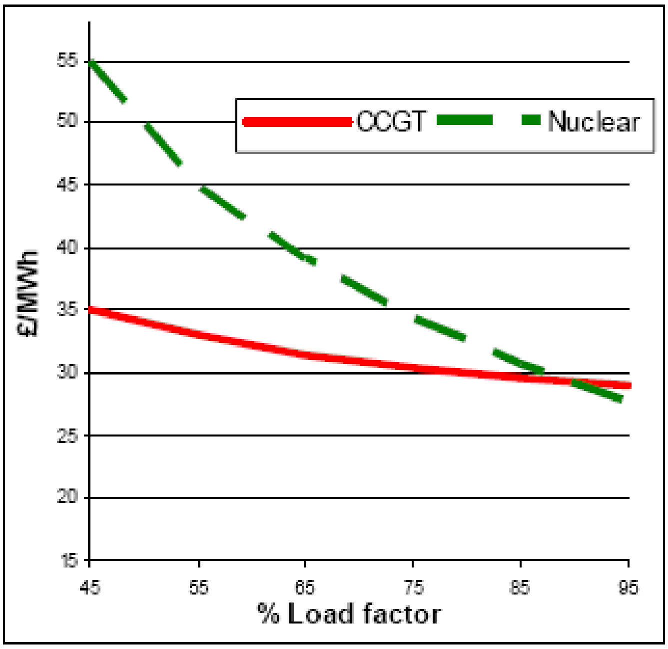
Table 1.3: Load factors.

	CCC view based on Redpoint *et al* (2008)	Poyry (2008)	SKM (2008b)	Ernst and Young (2007)	Carbon Trust (2008)
Onshore wind	21%-29%	27%	28%	26-31%	
Offshore wind	35%-39%	37%	39%	35%	34-45%

Note: SKM load factors relate to 2020.

Again, those plants with higher capital costs are more sensitive to the assumptions on load factor. This is illustrated by Figure 1.5 which shows the sensitivity to CCGT costs and nuclear to changes in load factor.

Figure 1.5: Sensitivity of levelised costs to changes in assumptions on load factor



Source: UKERC (2007) Working Paper A Review Of Electricity Unit Cost Estimates
Notes: Estimates for capital and running costs, plant efficiency, discount rates, fuel prices, and plant life are taken from DTI (2006) *Energy Review*. *Energy Review* costs for nuclear are similar to the CCC's estimates, but for CCGT are significantly lower All are in £2006.

Efficiency

The efficiency of plants is the rate at which plants can convert the energy in fuel to electricity.

This term only enters the calculation for nuclear plants and thermal plants. However, given that fuel costs make up a tiny proportion of the total costs of nuclear, this input is only important for thermal plants. Table 1.4 shows The CCC's estimates for efficiency are very similar to those used by SKM.

Table 1.4: Estimates of efficiency for new build plants

	CCC view based on Redpoint *et al* (2008)	SKM (2008b)
Nuclear	36%	36%
Coal	45%	46%
CCGT	53%	55%

Note: Coal estimates are based on new build advanced super-critical technology.

Economic lifetime

The economic life of a plant is the payback time that investors will require. The longer the economic life of a plant, the lower the levelised costs will be, as a longer economic life means capital costs are annualised over a longer period. Economic life is distinguished from the total lifetime of a plant, which is used in nuclear levelised cost calculations to determine when decommissioning costs will occur.

Table 1.5 shows that there is some variation in different publications on how this assumption is used across technologies. However, the estimates used by Redpoint *et al* (2008) look similar to most other sources.

Table 1.5: Estimates of economic life

	CCC view based on Redpoint *et al* (2008)	Poyry (2008)	SKM (2008b)	Ernst and Young (2007)	Carbon Trust (2008)
Onshore wind	20	15	20	20	
Offshore wind	20	15	20	20	20
Coal CCS	25				
Nuclear	30		40		
Coal	25		20		
CCGT	20		30		

Fixed and variable operating and maintenance costs

While operating and maintenance costs make up a low proportion of levelised costs for nuclear and wind, they are a key determinant of the cost of coal and gas-fired technologies, and coal with CCS. These costs are principally made up of fuel and EUA costs

The CCC used a set of fossil fuel price estimates published by BERR (2008a). The choice of fuel price estimate is discussed in Chapter 3 of *Building a low-carbon economy*.

Table 1.6 sets out the carbon price estimates used in different reports. This shows that the CCC's view of the carbon price is higher in 2020 than that used in other recent reports (it starts lower than the estimates used by Redpoint and SKM in 2008 but rises over time). This is the main reason why the levelised costs used by the CCC for coal and gas are higher than those used in other reports by 2020. This is partly because the CCC assume a global agreement will be reached and thus the EU target will move from 20% to a 30% reduction in 2020. Clearly in the absence of such an agreement carbon costs would be lower and the economics of fossil plant would be more attractive. The assumption of a rising price to 2020 reflects an assumed tightening cap in the EU ETS and a real cost to holding allowances. The CCC's modelling of the carbon price is set out in Chapter 4 of *Building a low carbon economy*.

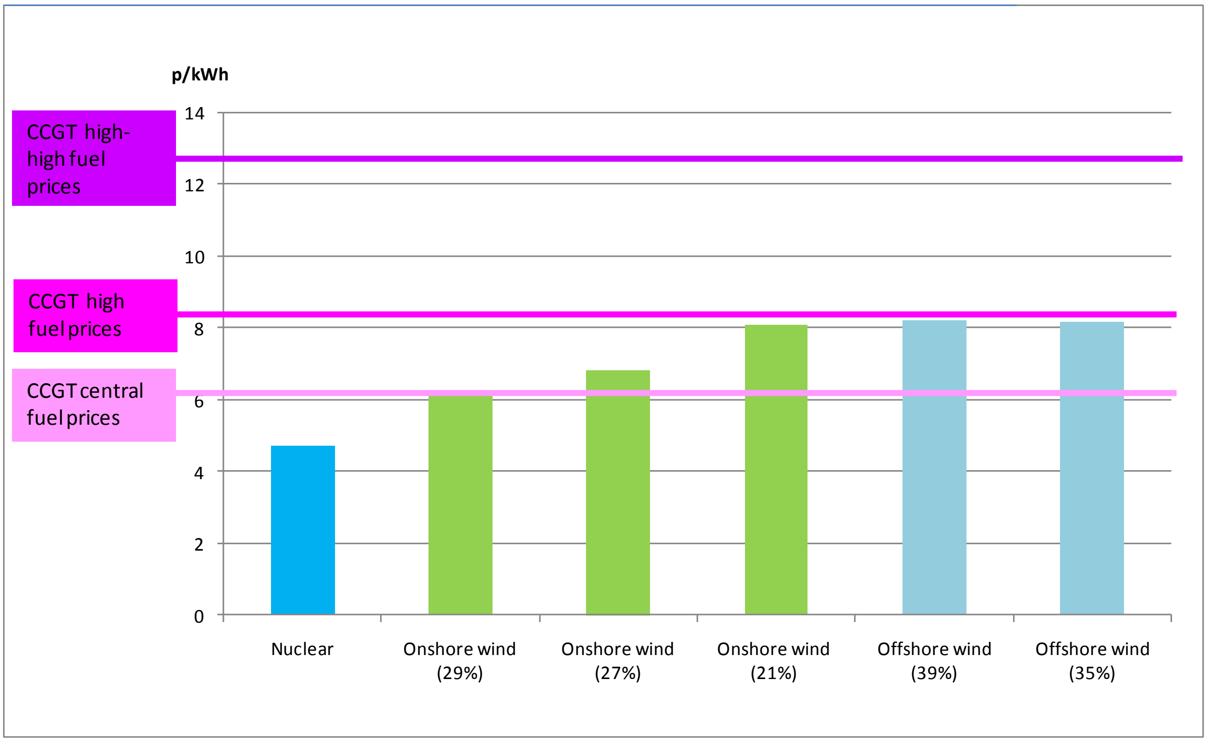
Table 1.6: Carbon price estimates.

	CCC view	**Redpoint et al (2008)**	**SKM (2008b)**
EUA price in 2020	€51	€37	€30
Change in EUA price over time	Rising at 5% a year from €28 in 2008)	Constant from 2014-2030	Constant

Figure 1.6 shows the costs of wind and nuclear relative to CCGT under different fossil fuel prices, including the impact of those fossil fuel prices on EUA costs. This illustrates that the relativity between gas-fired plant and wind and nuclear shifts significantly depending on the fuel price scenario. This shift is even greater for coal, driven by the fact that EUA costs are much greater for coal-fired technologies[7].

[7] Coal fired plants emit more than twice the carbon of CCGTs.

Figure 1.6: Relative costs of technologies under different fossil fuel scenarios

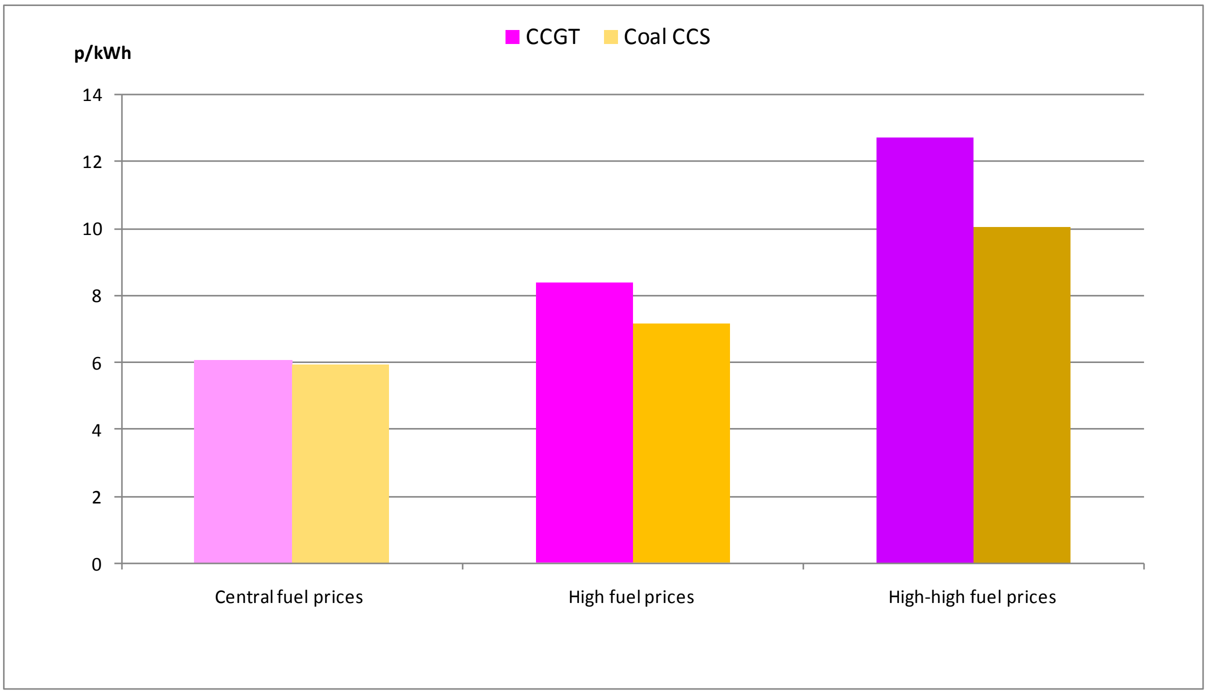


Note: CCGT costs include the cost of EUAs.

Figure 1.7 looks at how CCS and CCGT compare under different fuel price scenarios. While CCS and CCGT are both impacted on by fossil fuel prices, under higher fossil fuel price scenarios CCGT becomes more expensive than CCS. This is driven by the impact of the carbon price (as fossil fuel prices increase, the CCC project that the carbon price will also increase[8]). This affects CCGT costs much more than CCS costs: emissions from CCS are low, and so relatively few EUAs have to be purchased in order to cover them.

[8] See Chapter 4 of *Building a low-carbon economy* which provides further details of the modelling which was undertaken to estimate the carbon price in the EU ETS and explains that the EUA price is correlated to the absolute difference between the coal and gas prices, which is greatest under the higher fuel price scenarios.

Figure 1.7: Relative costs of CCS under different fossil fuel scenarios



Notes: CCC calculations based on Redpoint et al (2008), IPCC (2005) and CCC estimates of the carbon price.

In reality fossil fuel prices would tend to impact on the capital costs of the renewable and nuclear technologies since they have knock-on impacts on other commodity prices such as steel. This impact is not captured in the estimates used by the CCC, nor in the other publications reviewed, which may suggest that the costs of these technologies would be increased under higher fossil fuel prices.

Change in costs over time due to learning and economies of scale

As discussed in *Building a low-carbon economy*, estimates of the future cost of renewables, of new generation nuclear plants and of CCS, 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. However, estimating the levelised costs for technologies in future years is even more challenging than estimating the current costs and we would expect the gap between estimates in the literature to increase.

A number of effects occur which may change these prices over time:

- Capital costs may decrease or efficiency may increase due to learning and economies of scale. 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.
- Supply chain bottlenecks may occur or be overcome, thus increasing or decreasing capital costs.
- Commodity prices made change over time driving changes in capital or operating costs.

The first of these two impacts are likely to be the most pronounced for the least proven and most specialised technologies, such as wave or offshore wind. In contrast, technologies such as onshore wind, nuclear, coal and CCGT are already installed on a significant scale and in normal commercial generation across the world.

Learning

Learning rates are applied to capital costs for every doubling of global capacity. It is usually assumed that learning will decrease the costs. However, in theory at least, learning can also put upward pressure on costs as it is possible that previously unknown risks can become apparent through increased deployment.

Table 1.7 shows learning rates by publication. Redpoint halved the rates used in Poyry (2008) to take account of the fact the strong demand for renewables technologies resulting from the EU2020 targets is likely to partially offset the learning curve effects. The fact that learning rates in Redpoint *et al* (2008) encompass some supply bottleneck affects explains why they are significantly lower than those used in other publications.

Table 1.7 Learning rates per doubling of global capacity.

	Redpoint (2008)	**Poyry (2008)**	**Carbon Trust (2008)**
Onshore wind	4.5%	9%	
Offshore wind	4.5%	9%	9-15%

Supply chain bottlenecks

Estimates of the relative cost of different technologies in the future are sensitive to the date at which the costs were calculated. This is because prevailing commodity prices and the extent to which temporary supply chain bottlenecks exist can easily impact on projected costs, given how difficult it is to judge whether price fluctuations are temporary or likely to be long-lasting.

For example, over the last few years, 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. This may have impacted on the estimates of costs used in recent reports.

Further, 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 supply chain bottlenecks are very difficult to predict. However, it is clear that they are likely to have the biggest impact on those technologies which require very specialised construction or installation equipment (e.g. installation vessels for offshore wind).

Our central estimates of costs are based on the Redpoint work which includes scaling factors to account for supply chain impacts.

Conclusions

The levelised cost estimates used in *Building a low-carbon economy* are reasonable when compared to other estimates in the literature. However, there are significant uncertainties around all components of these costs, and in the projections of how they will change over time.

Different assumptions would inevitably imply changes in the relative costs of different technologies and therefore in the overall cost of delivering a lower carbon system. However, we consider our cost estimates to be a reasonably central relative to other published estimates. Further, the decarbonisation scenarios presented in section 3 are robust to the considerable uncertainties, both in terms of what can be achieved and in the order of magnitude of the costs involved.

2. COSTS ASSOCIATED WITH INCREASING THE LEVEL OF INTERMITTENT GENERATION ON THE SYSTEM

Intermittency

The output of wind generation is described as being intermittent; it varies with weather conditions over which the operator has no control and in a way that is difficult to predict far in advance.[9]

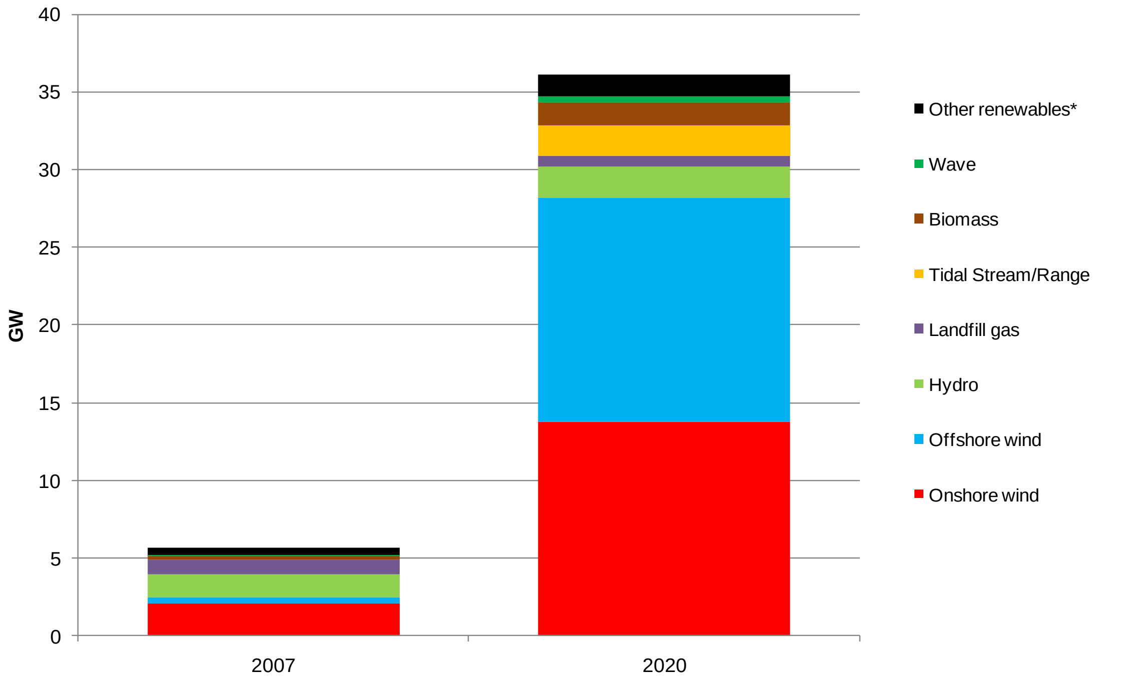
Intermittency matters because electricity cannot be stored easily, and supply and demand need to be balanced at each moment in time. For an electricity system to be reliable, there must exist some extra capacity that can respond to unexpected changes in demand or supply to ensure that the system remains in balance. Unexpected changes in supply can come from all plants, for example thermal or nuclear plants may have unplanned outages due to technical faults. However, output from generators dependent on environmental conditions, such as wind plants, will fluctuate unexpectedly much more often than output from conventional generators and unlike unplanned outages from conventional plants, these fluctuations will often be correlated across the installed capacity. Thus the amount of capacity needed to respond to unexpected changes to supply increases as the level of intermittent generation on the system increases.

Meeting the renewables target in the UK is likely to involve significant investment in new wind capacity (see Figure 2.1). Given the need to balance supply and demand of power at each point in time, and the frequent lack of control over the output of wind generations, the dramatic expansion of wind expected over the next 15 years is likely to lead to additional costs to the UK electricity system.

It is important to note there is no inherent security of supply problem created by intermittency, but one of cost: how much back-up capacity and fast response plant is required to keep supply and demand balanced, and how much does it cost to keep this capacity available.[10]

[9] Wave and solar are also intermittent, but these will be less important in the UK context up to 2020.
[10] See Chapter 13: *Energy security of supply*

Figure 2.1: Current penetration and projected penetration of renewables based on meeting the 2020 renewables target.



Source: DUKES (2008), BERR (2008b)
Note: Other renewables includes solar PV, municipal solid waste (MSW) and sewage sludge.

Costs of intermittency[11]

There are two main categories of cost associated with intermittency:

- System balancing costs
- Back up costs

System balancing costs

System balancing costs relate to the relatively rapid short term (i.e. minutes to hours) adjustments which are needed to manage the balance between supply and demand at each instant in time. The system operator (National Grid in England, Scotland and Wales and SONI in Northern Ireland) is responsible for making these adjustments.

The costs of system balancing are made up of the following two components:

- The costs of building and running fast response reserve plant
- Costs associated with changes in the use of other plants on the system, for example, efficiency losses due to increased variation in the output of thermal plant, and wasted energy if intermittent output exceeds the ability of the system to use it.

In the assessment of the total costs of the power sector decarbonisation scenarios, the CCC have used Redpoint's estimates for the costs of system balancing, as described below.

[11] This section draws on UKERC 2006b and SKM 2008b

Back up costs

Back-up costs (or reliability costs) are the longer term costs associated with ensuring that sufficient installed generation capacity will be available at times of peak demand even if wind levels are low. At present, the market is relied on to provide this back up.

Back-up costs arise from the fact that the contribution of an intermittent generator to reliability is lower than a conventional generator that can deliver on average the same amount of energy, as the variability in output of intermittent generators means they are less likely to be generating at full power at times of peak demand.

Costs are incurred when conventional plant is retained on the system or constructed to provide the necessary back-up capacity to ensure that peak demand is met. Back-up costs are thus made up of the capital and fixed operating and maintenance costs of adding to the reserve capacity.

Reserve requirements depend on the capacity credit of the intermittent plant, that is, the extent to which the intermittent generator can be relied on to provide power at peak times.[12] The difference between the annual average output from an intermittent plant and its capacity credit is the amount of additional back up that needs to be provided.

In the assessment of the total costs of the power sector decarbonisation scenarios, the CCC have used Redpoint's estimates for the costs of back-up, as described below.

Factors which impact on costs of intermittency

Estimates of the costs of intermittency can differ across studies, including for the following reasons

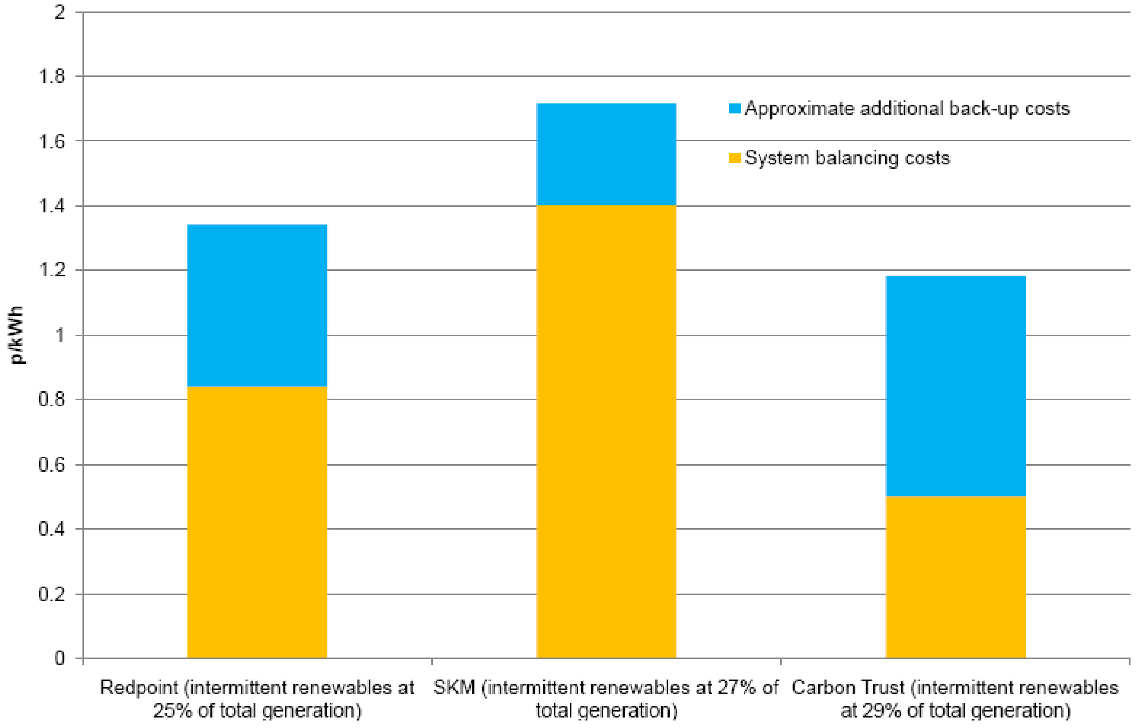
- Assumptions on the type of plant used for back-up and balancing (e.g. existing plant versus new build OGCT)
- Estimates of capital and fuel costs
- Assumptions on wind patterns (and therefore the level and correlation of intermittency in different areas)
- Assumptions on the geographical spread of intermittent generation and the extent to which this will reduce the variance of the available supply and increase the capacity credit.

[12] The capacity credit is estimated by statistical methods such that the loss-of-load probability with intermittent generation is the same as that on a system comprising conventional capacity only. (UKERC 2006). It is usually presented as a percentage that can be interpreted as the probability a plant will be available when needed at times of peak demand.

Alternative estimates of intermittency costs

This section provides more details on the estimates of the costs of intermittency set out in Chapters 5 and 13 of *Building a low-carbon economy* and shown again here in Figure 2.2.

Figure 2.2: Additional system balancing costs at different penetrations of intermittent renewables



Source: CCC Calculations based on SKM (2008b) Redpoint *et al* (2008) Carbon Trust (2008)

Redpoint estimates of intermittency costs

Estimates by Redpoint for the draft Renewable Energy Strategy consultation 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[13].

The system balancing component of this cost covers the cost for the system operator for providing reserve, frequency responses, transmission management etc. roughly from the 4hr out time period. Redpoint calculated these costs by estimating the relationship between costs and penetration of intermittent renewables based on the various published studies. The resulting curve was then calibrated to the estimates of current system balancing costs (National Grid, 2007). The curve is flatter at higher levels of intermittent renewables, following on from the assumption that as the quantity of intermittent renewables increases, geographical dispersion also increases, thus reducing the aggregate variance of supply.

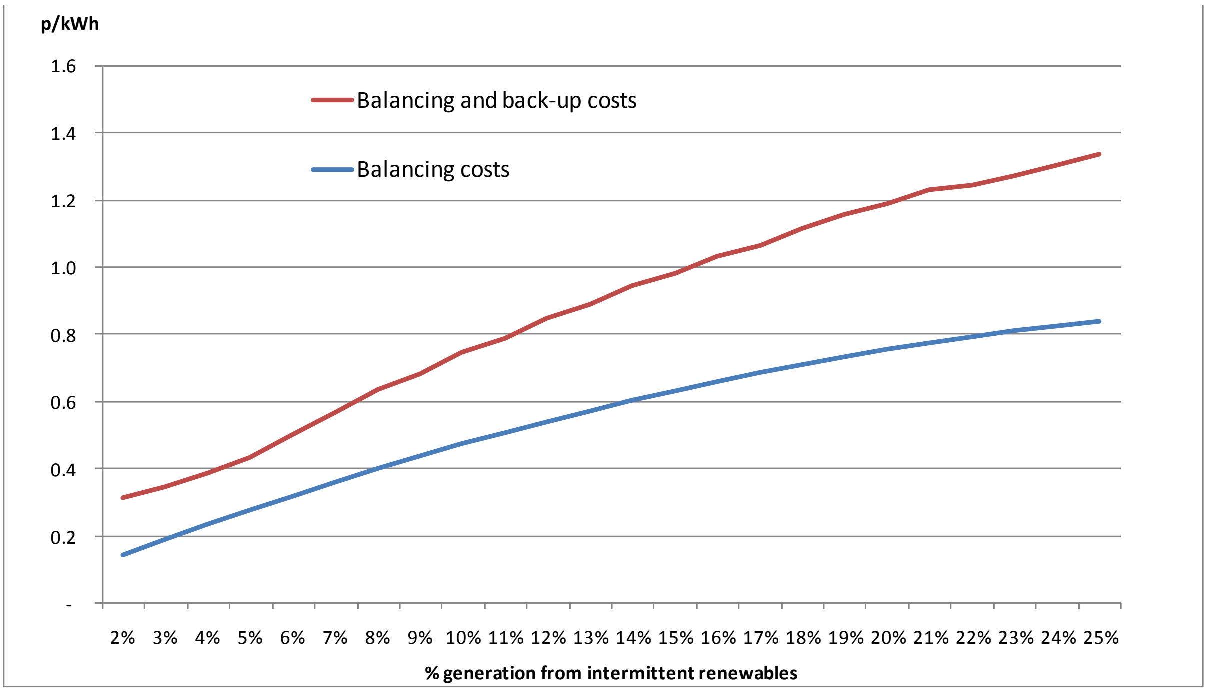
Redpoint also provided a rough estimate of the costs of back-up generation for the penetrations of intermittent renewables looked at by the CCC. In order to estimate the amount of back up that would be required, Redpoint looked at the difference between the annual average generation from intermittent renewables (by multiplying intermittent

[13] This is based on Redpoint's RO32 scenario, where wind and wave together reaches 25% of generation.

renewables capacity by its average annual availability[14]) and the generation which could be relied to come on at peak (calculated by multiplying the total renewable capacity by its capacity credit[15]).The difference between these two figures divided by the annual generation of a CCGT plant yields an estimate of the amount of CCGT capacity that would be required to be available as back-up to cover the peak times when intermittent renewables are not available. The cost of this back up was then estimated using the capital and fixed cost elements of new CCGTs.

Redpoint estimates of intermittency costs were used in the CCC's overall assessment of costs of decarbonising the power sector on Chapter 5.

Figure 2.3: Estimates of balancing and back-up costs based on Redpoint *et al* (2008)



Source: CCC calculations based on estimates used in Redpoint et al (2008)
Note: Costs are indicative only. The lack of smoothness is the total balancing and back-up costs may be due to rounding in the calculation.

SKM estimates of intermittency costs

Estimates by SKM for the draft Renewable Energy Strategy consultation put the costs of intermittency at around 1.7p/kWh of intermittent renewable electricity.

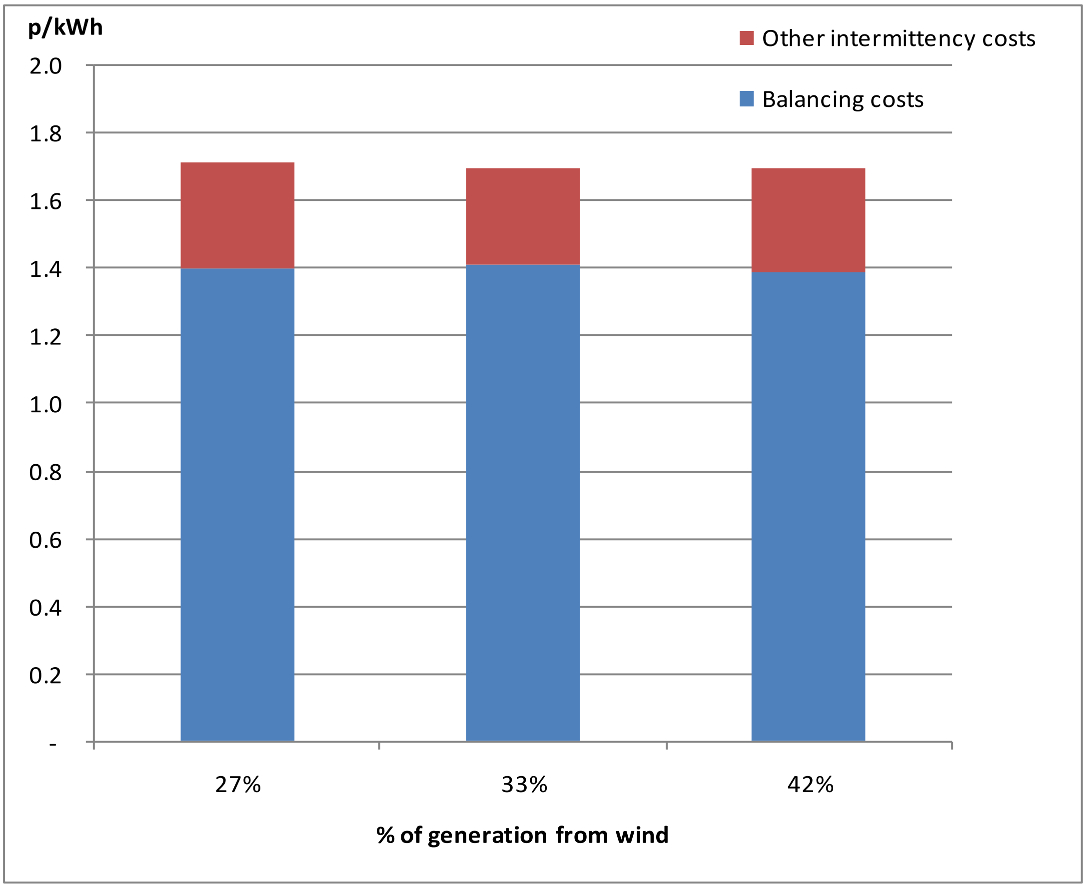
SKM estimate system operating costs based on the marginal cost of the generation required to respond to wind output variability, taking into account the level of wind penetration and the underlying generation mix. In order to assess the costs associated with maintaining back-up capacity, SKM estimate the volume of capacity that does not operate throughout the year and estimate the fixed and capital costs associated with this.

[14] Average annual availability was assumed to be between 21%-29% for onshore wind and 35%-39% for offshore wind.

[15] The capacity credit is assumed to be around 18% at about 25% penetration of intermittent renewables)

The resulting cost estimates are shown in Figure 2.4. SKM did not publish estimates for lower penetrations of intermittent renewables and these estimates are more comparable to the flat end of the curves in Figures 2.3 and 2.5.

Figure 2.4: Estimates of balancing and back-up costs based on SKM (2008b)

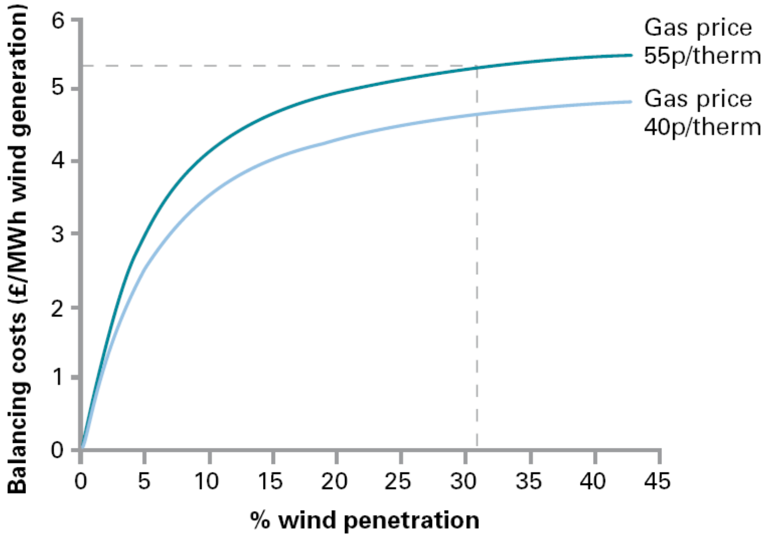


Source: CCC calculations based on SKM (2008b)

Carbon Trust estimates of intermittency costs

Balancing costs as estimated by Carbon Trust follow a similar pattern to Redpoint. These are shown in Figure 2.5

Figure 2.5: Balancing costs and wind penetration in Carbon Trust (2008)



Source: David Millborrow, BCG analysis, in Carbon Trust (2008)

On top of these balancing costs are added back-up costs, which are estimated by looking at the difference in gas capacity costs required between a scenario where wind reaches around 30% generation, and one where non-intermittent generation (nuclear) reaches 30%.

This results in an estimate of 0.68p/kWh (£6.8/MWh) on top of the balancing costs show in Figure 2.5 at intermittency levels of around 30%.

Other estimates of intermittency costs

Other studies have come up with lower estimates, for example, work by UKERC (2006) estimated that the costs would be 0.7p/kWh at 20% penetration of intermittent renewables, and a systematic review in the same study found a wide range of estimates in the literature (Table 2.1). These were not included in *Building a low-carbon economy* on the basis that the levels of penetration of intermittent generation examined were significantly lower than those expected under the 2020 renewable energy target.

Table 2.1: Cost of intermittency collated in UKERC (2006) for 15-20% intermittent generation

	Dale et al	**SCAR report**	**Carbon Trust**	**R. A. Eng.**	**Present Study**
Capacity Factor for Wind, % [a/]	35	35	35	35	35
Capacity credit for wind, MW/MW wind capacity, %	19.2	22.9	20.0	Not estd[e/]	22.1
Backup capacity for Wind, MW additional reserves/MW wind, % [f/]	18.9	18.3	21.2	65.0	19.1
Capital and O&M costs of reserves	0.32	0.26	0.45	1.86	0.43
Energy costs of using reserves	0.08 [d/]	Not estd.	Not estd.	Not estd.	0.05 [d/]
Balancing costs	0.25	0.22	0.20	Not estd.[c/]	0.25 [b/]
Total costs, p/kWh	**0.65**	**0.48**	**0.65**	**1.86**	**0.73**

Source: UKERC (2006).

Conclusions

There is significant uncertainty around estimates of the cost of intermittency which is no surprise, given that the levels of intermittent generation being looked at are unprecedented in the UK electricity system, and the fact that it is difficult to generalise from international studies, given the importance of the national infrastructure and weather patterns.

However, 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. These costs are included in the overall assessment of the cost of actions to decarbonise the power sector included in Chapter 5 of *Building a low-carbon economy*.

Over the long-term, and in the context of the technological vision presented in Chapter 2 of *Building a low-carbon economy*, 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.

3. TOTAL COSTS OF POWER SECTOR ABATEMENT SCENARIOS

This section begins by giving an overview of the power sector abatement scenarios examined by the CCC in *Building a low-carbon economy*. The methodology for assessing the costs and emissions savings associated with these scenarios is then set out, along with the key inputs and assumptions on which the model is based.

Abatement scenarios

As well as looking at the costs of individual technologies, the CCC also estimated the total costs of alternative abatement scenarios.

The CCC looked at three power sector abatement scenarios in *Building a low-carbon economy*:

- In Scenario 1, the draft Renewable Energy Strategy is assumed to achieve its aims of in excess of 30% electricity from renewables by 2020. In addition, one CCS demonstration coal plant (300MW) is assumed to be operating by 2014. It is assumed Chapter 4. The CO_2 price stimulates all other new fossil fuel plants to be gas, and therefore there is no new conventional coal build.
- In Scenario 2 it was assumed that the draft Renewable Energy Strategy is only around 75% successful, and that the shortfall in renewables generation is met by three new nuclear plants by 2020.
- In Scenario 3, again it is assumed 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.

These scenarios were chosen in order to illustrate the costs and emissions implications associated with alternative outcomes in the power sector. The first two of these scenarios represent a world where the UK power sector is on track to meet its long-term goal of decarbonisation of the power sector by 2050. In contrast, Scenario 3 represents a world where, despite a degree of progress with renewables, the carbon budgets are met through a substantial purchase of EUAs, and a large increase in new coal and gas capacity means that decarbonisation is likely to be more difficult and costly in the coming decades.

These scenarios were developed to illustrate the cost and emissions impacts of different states of the world. They are not necessarily optimal nor cost-minimising.

Methodology for assessing the costs of abatement

In order to estimate the resource costs of abatement scenarios, the CCC developed a marginal abatement cost curve (MACC) for the power sector[16]. Though the MACC only provides a simple representation of the power sector, it allows several 2020 abatement scenarios to be set out on the same basis. Presenting these scenarios illustrates the difference between the costs and emission savings associated with alternative paths for decarbonising the power sector

[16] 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.

The power MACC assesses the costs and emissions savings associated with different scenarios by comparing generation and investment in these scenarios to a reference scenario. Changes in electricity demand are exogenous to the MACC, it only examines the costs and carbon savings associated with changing patterns of new investment and generation.

An abatement scenario is chosen by setting a target for each type of low carbon generation (renewables, nuclear and CCS). The cost and carbon savings associated with reaching this target relative to the costs and emissions associated with reference case generation are then calculated by assessing the costs and emissions of the low carbon generation relative to the costs of the fossil fuel generation being displaced.

New low carbon generation first displaces any fossil fuel fired new build that would have occurred in the reference case. If the amount of low carbon generation built in a certain year is greater than the amount of new build that would have occurred in reference case, then the low carbon generation is assumed to have displaced generation from existing plant.

The costs and CO_2 savings are calculated by looking at the cost and CO_2 intensity of the plants that have been displaced. Where new build plants are displaced, the cost of the abatement action is the difference between the levelised cost of the low carbon generation and the levelised cost of the new build fossil plant that would have been built. Where existing plant is displaced, the levelised costs and CO_2 intensities of the new low-carbon plant are compared to the short run marginal costs and CO_2 intensities of the existing plant with the highest short run marginal cost (assumed to be last on the merit order).

Key assumptions

The inputs to the MACC are consistent with the analysis presented elsewhere in *Building a low-carbon economy* . This section sets out the key assumptions and sources for the data used in the power MACC. These assumptions are summarised in Table 3.3 below.

Generation

Generation in the reference case is taken from the DECC energy model, adjusted to take account of generators' own use.[17] It is based on the level of demand projected in the CCC's scenarios that include measures to encourage energy efficiency in end use and price response to electricity costs that include a carbon price. Generation does not change across the power sector abatement scenarios. However, it is slightly lower in abatement scenarios than in the reference case due to a demand response to the increased electricity price caused by the introduction of the EU ETS and a tighter renewables policy (see Table 3.3).

Choice of low carbon technologies

The power MACC allows a target for the three main categories of low carbon generation (nuclear, renewables, CCS) to be set. Fossil fuel generation is first displaced with any new nuclear. The small CCS demonstration plant is the second option to come on. Renewable

[17] Generation from the DECC model already includes electricity that will be lost during transmission and distribution (i.e. it is power generated, rather than delivered). In order to adjust for generators' own use, data from DUKES was used to estimate the current average own use of each type of plant, as a percentage of generation from each type of plant. This percentage was assumed to stay constant to 2020.

options are then chosen in the following predetermined order, based on the relative costs of the low-carbon generation options:[18]

- Onshore wind
- Offshore wind
- Biomass
- Marine

Savings can also be made by building new gas-fired plants instead of new coal, or by running existing gas plant instead of coal. These measures come after renewables in the order of abatement options because the amount of new build switching that can take place is limited by the residual amount of new coal plant that is being built after all the other abatement options have been taken up, and the amount of merit order fuel switching that can take place is limited by the remaining amount of generation from existing coal plants and the spare capacity in existing gas plants. Finally, once all the other measures have been taken into account, co-firing with biomass can be applied to the remaining coal generation (up to a maximum of 10% of fuel used).

The order of take up of options matters for the shape of the MACC curve as the earlier in the order is an abatement option, the more likely it is to displace new build generation rather than existing generation. A measure which displaces new build generation will be cheaper than a measure which displaces existing generation (referred to in *Building a low-carbon economy* as 'forced' new capacity). This is shown in Figures 3.1-3.3 where, for example, 'forced' onshore wind is more costly per tonne of carbon saved than onshore wind which comes on to displace new fossil fuel fired plant.

Technology cost

Technology costs in the power MACC are principally taken from Redpoint's work for the BERR draft Renewable Energy Strategy, with the exception of CCS costs which come from IPCC (2005).

The additional costs associated with the increase in intermittent generation also come from Redpoint's work for the BERR renewable strategy (see Figure 2.2 above). These are added to the costs of the intermittent technologies (wind and wave) in the MACC.

Technological potential

Maximum potential for renewable technologies come from SKM's study for the BERR Renewable Energy Strategy (SKM 2008a). This study looked at supply chain constraints (including for wind turbine generators, specialist vessels for the installation of offshore wind generation, biomass fuel, and HVAC and HVDC cables), planning constraints, and grid constraints (grid infrastructure bottlenecks, grid entry capacity and system operator flexibility.) The high growth scenario in this study was used in the MACC. This assumes that much of the constraints on growth that currently exist can be relaxed between now and 2020.

[18] There was very little potential for additional hydro and solar PV over and above what is likely to be installed in the reference case (SKM 2008a). These measures are thus not covered in the marginal abatement cost curves produced for the power sector.

Assumptions were also made on the maximum potential CCS and nuclear that could be built before 2020. It was assumed that no new nuclear would be able to come online before 2018. The maximum amount of nuclear that could come online before 2020 would be three new plants of 1.6GW each. It was also assumed that the maximum amount of CCS that could come online before 2020 was the 300MW demonstration planned to be introduced by 2014.

In all scenarios it is assumed that major tidal range projects, such as that proposed at the Severn Estuary, are not completed until after 2020.

CO_2 intensity

The following assumptions were made on the CO_2 intensity of generation:

- Renewables and nuclear were assumed to emit no CO_2
- CCS was assumed to reduce the emissions from coal plants by 85%. This assumption is based on IPCC (2005) and takes account of the fact that coal CCS plants are likely to be operating at a reduced efficiency than conventional coal.
- Co-firing coal with biomass at 10%, was assumed to reduce the emissions from coal plants by 10%.
- CO_2 intensities were based on those used in the DECC energy model and are set out in Table 3.1. An adjustment was made to the figures set out in Table 3.1 to account for losses in transmission and distribution (assumed to 8%).

Table 3.1: Summary of sources for assumptions on technologies

I	2008-2020
New coal	0.78
Pre-2008 coal	0.95
New gas	0.35
Pre-2008 gas	0.40

Table 3.2 summarises the sources for the assumptions on all technologies.

Table 3.2: Summary of sources for assumptions on technologies

Input	Source
Capital and operating costs, efficiencies and availabilities for renewable and conventional plant	Redpoint (2008)
Capital and operating costs, efficiency and availability for CCS	IPCC (2005)
Fossil fuel prices	BERR (2008a)
System balancing and back up costs for intermittent renewables	Redpoint work for the CCC
CO_2 intensities associated with fossil fuel plant	IPCC (2005), DECC energy model assumptions.
Annual constraints on renewables new build (e.g. because of supply of suitable sites, planning, supply chain bottlenecks)	Redpoint (2008) and SKM (2008a)

Reference scenario assumptions

The reference scenario is the baseline against which the abatement scenarios are assessed. In the power sector, all firm and funded UK policies up to, but not including, the Energy White Paper were included, and the EU ETS was excluded. Thus the reference scenario represents a world without a carbon price, and with a renewables target of only 15% of electricity generation by 2020.

The reference scenario was produced by a DECC energy model run. Table 3.3 sets out the key inputs to the MACC from the reference scenario. This scenario is described in more detail in a technical appendix to Chapter 3 of *Building a low carbon economy*.

Table 3.3: Reference scenario

	Estimate	Source
Total emissions in 2020	174MtCO_2	DECC energy model runs for the CCC
Total generation in 2020	398 TWh	DECC energy model runs for the CCC
Coal-fired generation in 2020	110 TWh	DECC energy model runs for the CCC
Gas-fired generation in 2020	190 TWh	DECC energy model runs for the CCC
Nuclear generation in 2020	25 TWh	DECC energy model runs for the CCC
Generation from renewables in 2020	54 TWh	DECC energy model runs for the CCC
Generation from wind in 2020	32 TWh	Based on wind as a proportion of renewable electricity in Redpoint (2008)
Carbon price	€0/tonne	Decision to assume no EU ETS in the baseline
Coal price in 2020	£32/tonne	BERR (2008a)
Gas price in 2020	46p/therm	BERR (2008a)

Abatement scenario assumptions

Table 3.4 presents further details on the three abatement scenarios looked at in Building a *low-carbon economy*. As shown in the table, fuel and EUA prices, and energy demand, are constant across all scenarios.

Table 3.4 Summary of abatement scenarios

	Reference Scenario	Scenario 1	Scenario 2	Scenario 3
Total generation in 2020	398	386	386	386
Renewable generation in 2020 (TWh)	54	117	88	88
Nuclear generation in 2020 (TWh)	25	25	54	34
CCS in 2020 (TWh)	0	1	1	0
Total low carbon generation in 2020 (TWh)	79	143	143	122
Coal generation in 2020 (TWh)	110	68	70	93
Gas generation in 2020 (TWh)	191	155	153	150
Abatement relative to reference case in 2020 ($MtCO_2$)[19]	N/A	42	42	16
Annual cost in 2020 relative to reference case (£b)	N/A	4	2	2

While the reference case is the same for all scenarios, the plant displaced by each abatement option is different in Scenarios 1 and 2 to Scenario 3:

- In Scenarios 1 and 2, any renewables or nuclear that comes on displaces this mix of new coal and gas that would have been built in the reference case except for biomass co-firing which replaces coal, and ‘forced on’ nuclear or renewables which displaces the marginal existing plant.
- For Scenario 3, one third of new plant is assumed to be coal. In order to allow this a higher proportion of the displaced new build has to be gas rather than coal. As in Scenarios 1 and 2, biomass co-firing which replaces coal, and ‘forced on’ nuclear or renewables which displaces the marginal existing plant

This explains why the costs per tonne of renewables and nuclear are higher in Scenario 3: the CO_2 savings from displacing gas are much lower than the CO_2 savings from displacing coal, while the additional cost is in the same ballpark (see figures 3.1 to 3.3).

[19] Refers only to abatement from actions in the power sector (i.e. the abatement resulting from changes in demand is not counted here).

Results

Figures 3.1 to 3.3 present the results of the MACC analysis. The area under the MACC represents the total resource cost associated with each scenario. The horizontal axis shows the emissions savings. Key results are as follows:

- In Scenario 1 (more than 30% electricity from renewables by 2020, no new coal build) domestic electricity emissions fall by around 42Mt in 2020. The cost of this scenario is around £4bn in 2020 (0.2% of 2020 GDP). Under high- high fossil fuel price assumptions, the cost of this scenario is approximately halved.
- In Scenario 2 (around 25% of electricity from renewables, no new coal build, three new nuclear plants by 2020) emissions fall by the same percentage as in Scenario 2 as the shortfall in renewable generation is met by three new nuclear plants by 2020. Costs are approximately halved due to the fact that cheap nuclear is replacing the most expensive renewables options (those shown to the right of the Scenario 1 MACC). The total costs of this scenario are approximately £2bn in 2020 (0.1% of 2020 GDP)
- In Scenario 3 (around 25% of electricity from renewables, some new coal capacity, one new nuclear plant by 2020) the emissions saving is more than halved, at 16Mt in 2020. Costs are comparable to those incurred in Scenario 2.

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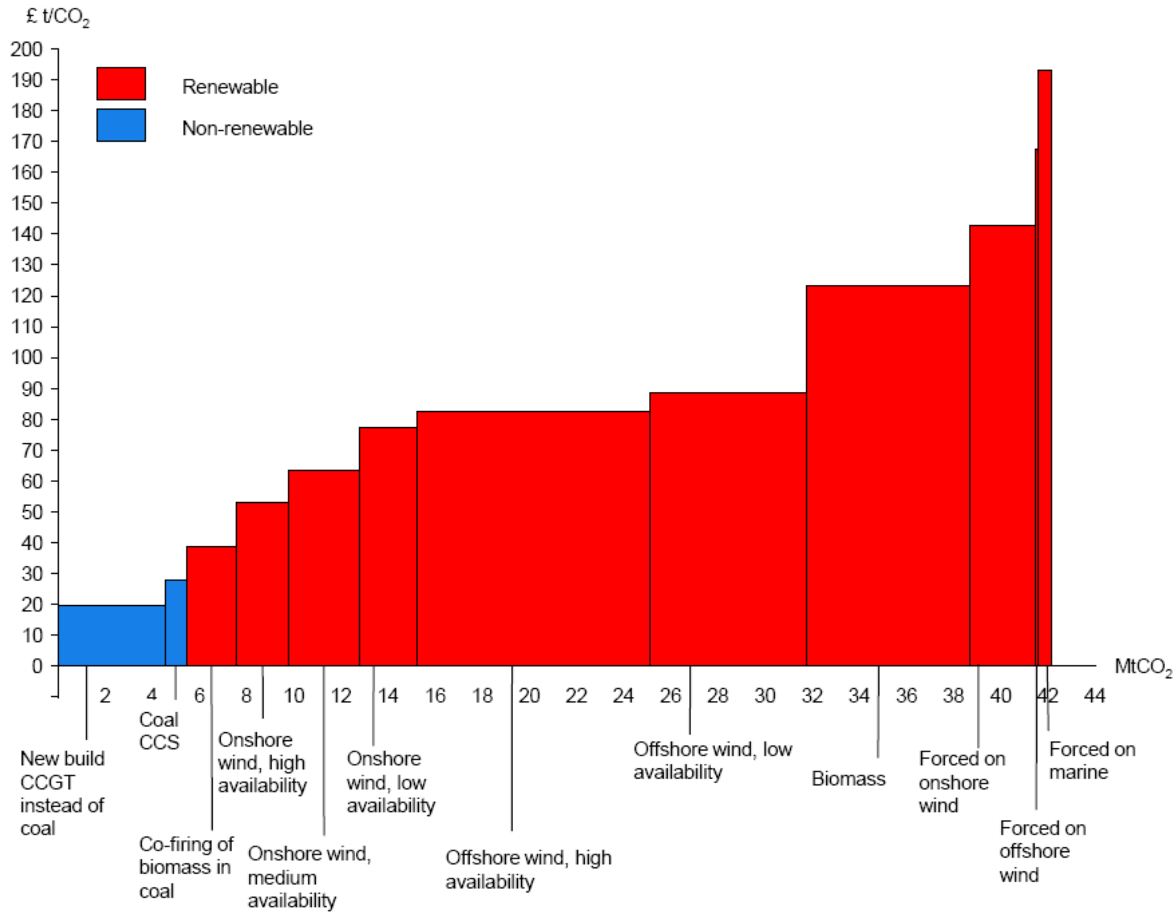
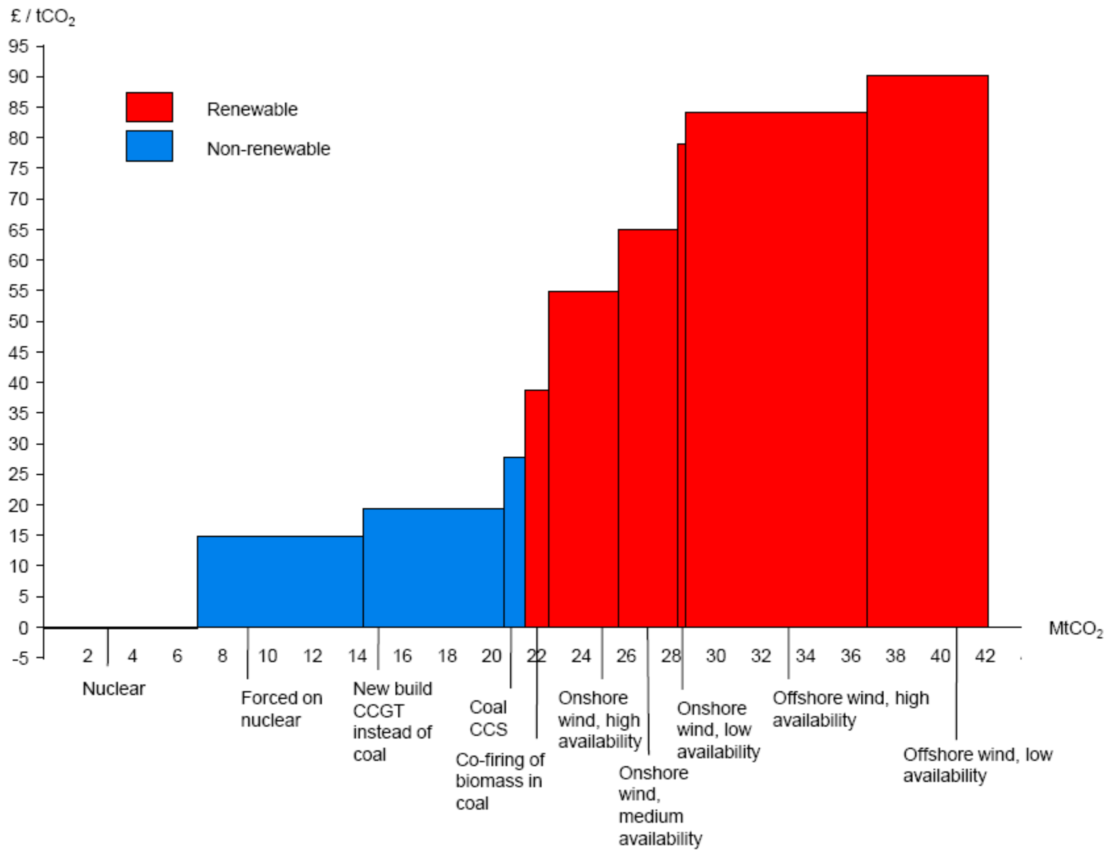
Figure 3.1: *Power MACC, Scenario 1*



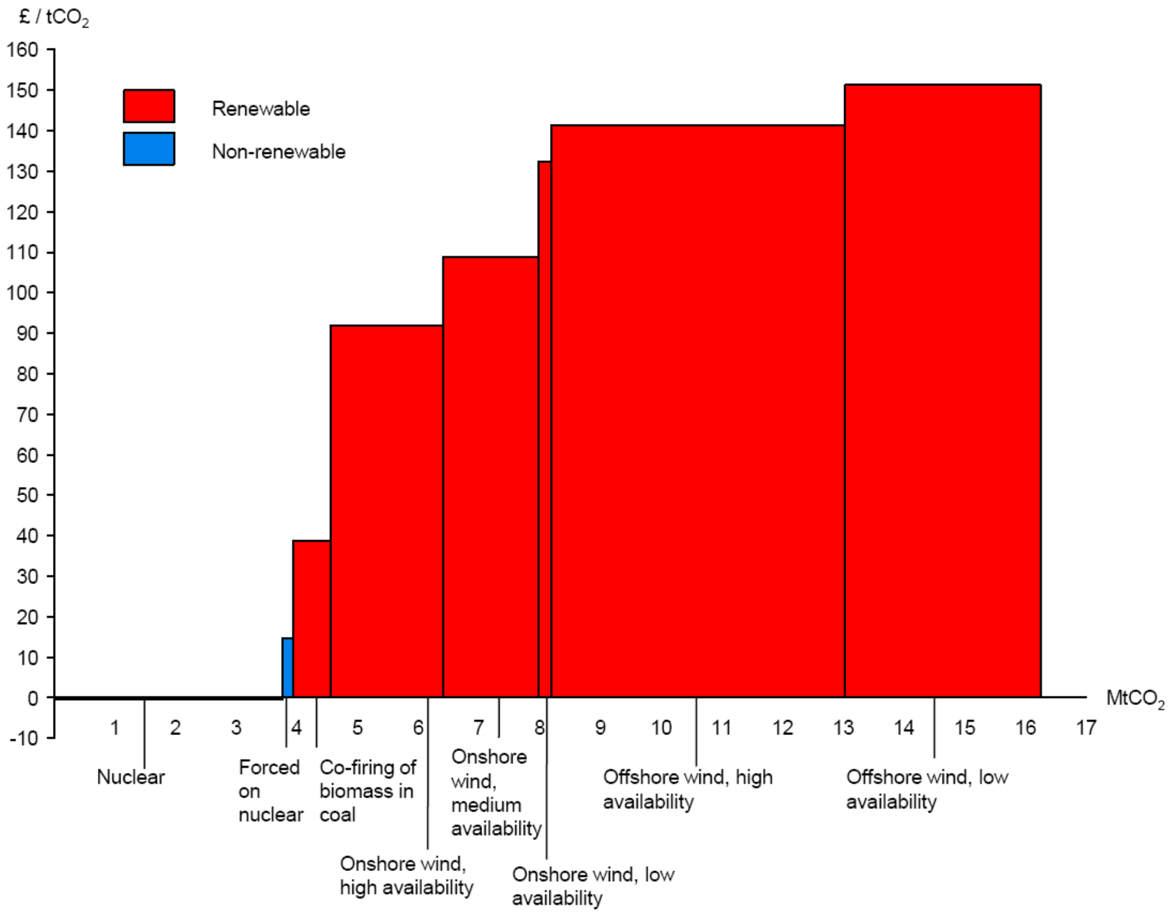
Source: CCC modelling
Notes: Based on scenario 1, central fuel prices. 'Forced on' plant refers to plant which is built despite the existence of enough generation capacity on the system (e.g. to meet a target).
It therefore displaces existing plant rather than new plant.

Figure 3.2: 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 3.3: 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 plant.

Conclusions

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. However, the following messages can be drawn:

- In 2020 the total cost of a scenario where renewables are the main abatement option might lie around 0.2% of GDP (in a central fossil fuel price world).
- Resource costs could be significantly reduced if new nuclear build were to replace the most costly renewables 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.
- Overall, the assessment of power sector abatement scenarios suggest that substantial emissions savings can be made at reasonable costs by 2020.

While *Building a low-carbon economy* 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 even though nuclear may be less costly. There are good reasons for this:

- Renewable technologies are still at an early stage of development with significant further cost reductions possible if scale is driven by initial government support.
- Renewables are deployable quickly, and in small capacity increments which should allow them to be deployed in time to cover some of the capacity gap caused by the large amount of fossil fuel retirements which will occur in 2015/16.
- 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.

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