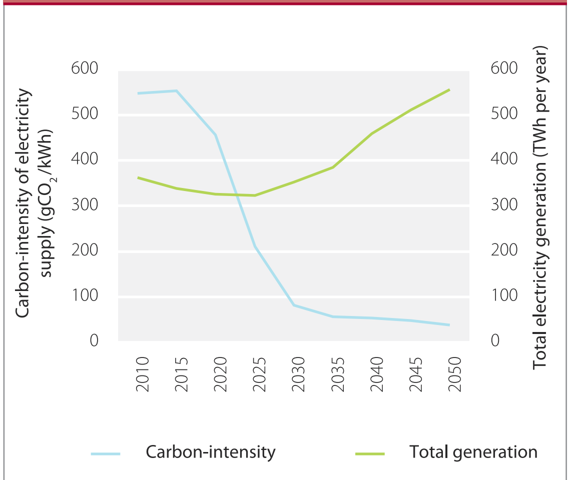
Chapter 4: Delivering low-carbon power

Introduction and key messages

In our December 2008 report, we set out a range of scenarios to meet our 80% emissions reduction target in 2050. The common theme running through these scenarios was the need for early decarbonisation of the power sector, with the application of low-carbon electricity to transport and heat. We showed therefore that the carbon-intensity of power generation should decline over time, whilst at the same time electricity demand could increase (Figure 4.1).

Figure 4.1 Declining carbon-intensity and increasing generation of electricity to 2050



Source: CCC calculations.

We argued that the economics of wind and nuclear generation are favourable in the context of meeting the 2050 target, and we expressed optimism that carbon capture and storage (CCS) will also be shown to be economically viable. We envisaged emissions cuts in the power sector initially through increasing levels of wind generation in the period to 2020, with deployment of a portfolio of low-carbon technologies – renewables, nuclear and CCS – in the 2020s resulting in a substantially decarbonised electricity system by 2030.

We highlighted the multiple risks associated with the current market arrangements. Specifically, investors are subject to significant uncertainty over fossil fuel prices and technology costs. This is compounded by policy induced risks stemming from carbon price uncertainty and increasing electricity price volatility resulting from high levels of intermittent power generation. Given these risks, we questioned whether current market arrangements would deliver required investments in low-carbon technology.

In this chapter we consider in more detail trajectories for power sector decarbonisation over the first three budget periods. We develop indicators, including forward indicators, setting out what has to happen in order to drive decarbonisation, and against which we will judge progress in reducing emissions when we report annually to Parliament (Box 4.1). We set out our response to the Government's proposals for investment in coal-fired generation. We also present detailed analysis of current market arrangements and our assessment of whether these will provide the right incentives for investment in low-carbon generation.

The main messages from our analysis are:

- Key decisions should be taken over the next two years on power transmission access and investment, and planning approvals should be granted, in order to support investment in around 23 GW of new wind generation capacity by 2020 and up to three new nuclear plants in the first three budget periods.
- We welcome the Government's proposals on coal generation. We recommend, however, that economic viability of CCS should be considered in the strategic context of moving towards our 80% emissions reduction target rather than narrower definitions (e.g. Best Available

Technology) of technical and commercial viability. An early decision (e.g. no later than 2016) on any required financial support for roll-out should be taken to support potentially high levels of investment from the early 2020s. For coal plant without CCS, the Government should provide a very clear signal that this will have a limited role in the 2020s on the way to an 80% cut, whether or not CCS is satisfactorily proven.

- We are not confident that current market arrangements will deliver required investments in low-carbon generation through the 2020s. We propose a set of options for power market intervention to support low-carbon investments and urge that these are seriously considered in the near term.

Box 4.1 Power sector indicators

- Addition of 23 GW of new **wind** generation to reach 27 GW in total by 2020, supported by streamlined planning processes, improved transmission access and an expanded supply chain.
- Addition of up to three new **nuclear** plants by 2022, supported by an improved enabling framework to contain the development timeline.
- Addition of up to four **CCS** (clean coal) demonstration plants by 2020, with financial support provided as required.
- Policy strengthening to support these and future investments:
  - **Market rules** – A review of options for strengthening low-carbon generation investment incentives.
  - **Support for CCS** – A new framework to support investment in CCS generation beyond initial demonstrations.
  - **Grid strengthening** – Timely decisions on transmission network access and investment.

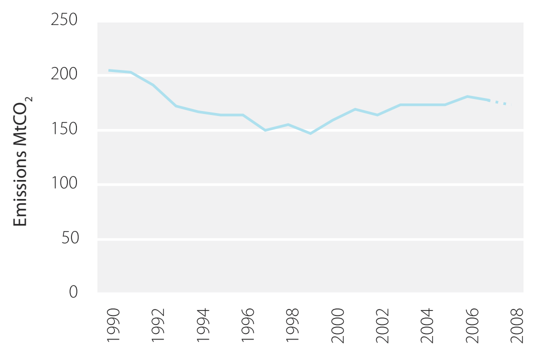
We set out our analysis underpinning these conclusions in seven sections:

1. Power sector emissions trends
2. Scenarios for power sector decarbonisation to 2022
3. Wind generation: indicators and the enabling framework
4. Investment in nuclear new build
5. Demonstration and roll-out of CCS technology
6. Assessment of current power market arrangements and possible interventions
7. Summary of power sector indicators.

1. Power sector emissions trends

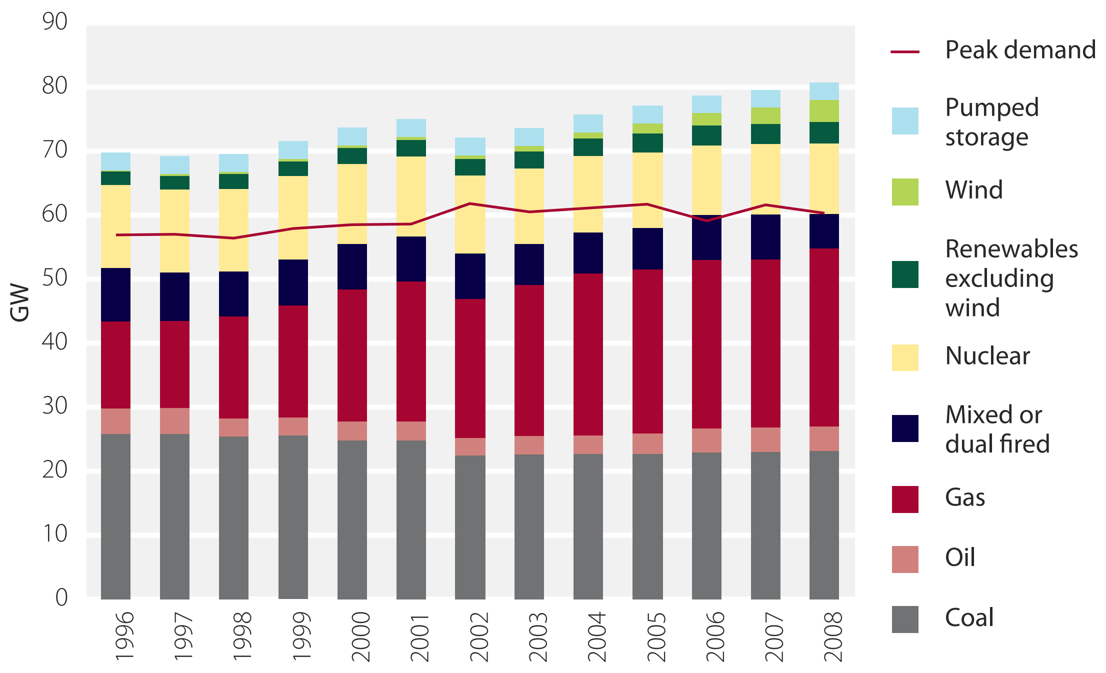
UK CO_2 emissions from power generation fell from 205 $MtCO_2$ in 1990 to 171 $MtCO_2$ in 2008 (Figure 4.2). The main driver of this reduction was the 'dash for gas' through the 1990s when new gas-fired generation capacity replaced existing coal-fired capacity (Figure 4.3), rather than significant increases in low-carbon capacity (which will be needed going forward). More recently progress reducing emissions has reversed.

Figure 4.2 CO_2 emissions (1990-2008) from the power sector



Source: NAEI (2009); DECC (2009); *DUKES*; Table E.1.
Note: 2008 figures are provisional.

Figure 4.3 Installed capacity (1996-2008)



Source: CCC calculations.

In the last year, small increases in the level of renewable power generation have been offset by lower levels of nuclear and increased gas generation (Figure 4.4):

- The share of renewable generation rose from 5.5% in 2007 to 6.2% in 2008, reflecting the addition of new wind capacity to the system.
- There was a decline in nuclear generation in 2008 due to plant outages – specifically two plants (2.3 GW) were closed for the whole of 2008. These plants were brought back on line earlier this year, so nuclear generation was up 17.5% in Q1 2009 compared to the same period in 2008.
- The most recent quarterly data[1] shows that coal has increased in the first period of 2009 compared with a year earlier. Coal generation during Q1 2009 was 12% higher compared to Q1 2008, while gas use declined 22%. Wind generation increased 17% over the same period.

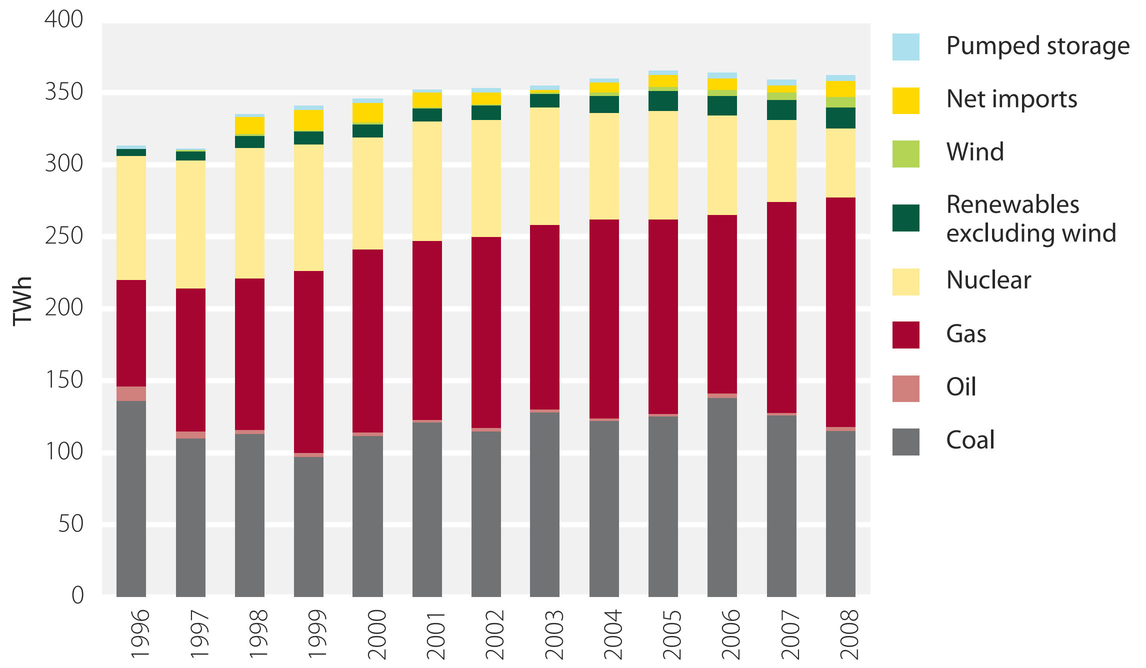
Electricity demand has increased across the period since 1990 (Figure 4.5):

- From 1990 to 2005, electricity demand increased by around 1.6% per annum, driven by growth across all sectors.
- Following a 1.5% fall in demand to 2007, overall demand has been flat to 2008, with a fall in industry demand offsetting increasing residential sector demand.
- The most recent quarterly data suggests that the economic downturn may have intensified this trend into 2009. Overall electricity consumption was 5% lower in the first quarter of 2009 compared with the same period in 2008.

Overall, the emissions intensity of power generation has fallen since 1990, and fluctuated in the last three years:

- The average carbon-intensity of the power sector fell from 770 gCO_2/kWh in 1990 to 527 gCO_2/kWh

Figure 4.4 Electricity generation (1996-2008)



Source: DECC (2009); *DUKES*; Table 5.1, 5.6 and 7.4.
Note: Data for net imports is only available from 1998. Chart begins in 1996 because data for previous years is not available on the same basis.

1 DECC (2009) Energy Trends, June 2009.

in 2005. Intensity increased to 543 gCO_2/kWh in 2007[2] but provisional estimates suggest intensity fell to around 537 gCO_2/kWh in 2008[3].

- The reduction in the 1990s reflects the dash for gas, whilst the short-term trend reflects movements in fossil fuel and carbon prices, demand and availability of nuclear plant.

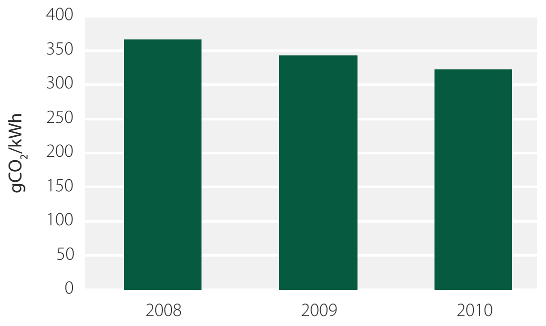
The achievable emissions intensity for the power sector – the least emissions dispatch to meet demand from available capacity – was around 370g/kWh in 2008 (Figure 4.6).

Looking forward we expect the achievable emissions intensity to steadily fall as:

- Just over 2 GW of wind capacity is currently under construction, with an expectation that the majority will be completed and commissioned in 2009 and 2010
- There are no planned nuclear retirements before 2011, and all existing plants are currently online
- No new unabated coal plant is currently under construction, whilst around 4.7 GW of new gas plant is expected to come online over 2009 and 2010.

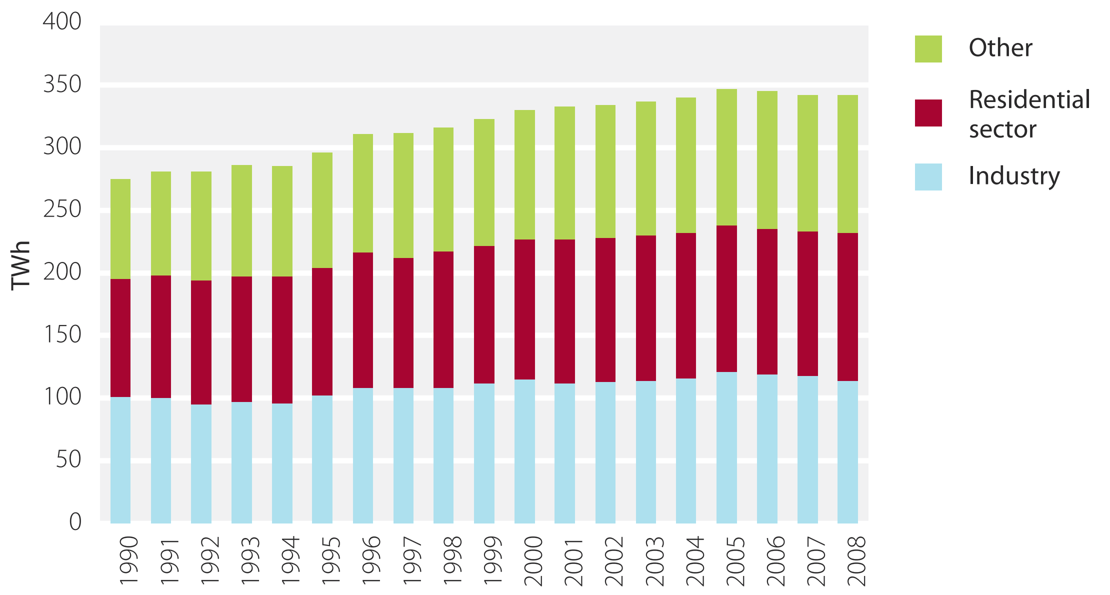
Together we expect these to lead to an achievable emissions intensity of around 320 g/kWh in 2010, whilst outturn intensity and emissions will depend on actual outages and fuel and carbon prices.

Figure 4.6 Estimated achievable emissions intensity



Source: CCC calculations.
Note: Achievable emissions intensity is the minimum average annual emissions intensity that could be achieved in a given year, given the installed capacity, demand and the profile of that demand . Emissions intensity is on an end use basis (includes transmission and distribution losses).

Figure 4.5 Electricity consumption (1990-2008)



Source: DECC (2009); *DUKES*; Table 5.1.2.
Note: Other includes public administration, transport, agriculture and commercial sectors. Does not include energy industry use and losses.

2 Defra/DECC (2009) 2009 guidelines to Defra/DECC's GHG conversion factors for company reporting.
3 2008 figures are based on CCC calculations from DECC (2009), Dukes.

2. Scenarios for power sector decarbonisation to 2022

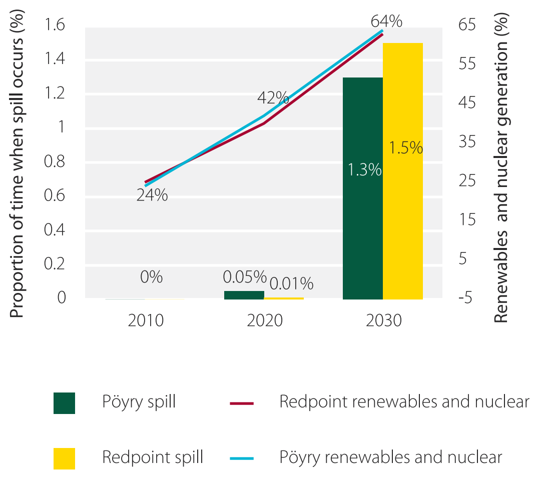
There is an approach to power generation that says emissions from the sector are capped and that we can entirely rely on the market to determine the appropriate path to decarbonisation. This is not, however, an approach that the Committee accepts. Whilst inclusion of the power sector in the EU ETS will deliver the emissions cuts required in the sector to 2020, it will not automatically bring forward the low-carbon investment to deliver required emissions cuts in the 2020s and beyond. This is because the EU ETS cap to 2020 could be met through coal to gas switching without any significant new investment in low-carbon plant, and because the cap beyond 2020 is highly uncertain.

Given the importance of early power sector decarbonisation, we set out in our December 2008 report two scenarios for power sector decarbonisation over the first three budget periods that would put us on track to meeting our longer-term goals:

- The first scenario was based on a high level of renewables consistent with scenarios in the Government's draft Renewable Energy Strategy.[4]
- The second scenario had a slightly lower level of renewables, with three new nuclear plants added to the system during the third budget period. In setting out this scenario, we noted that there are concerns about the long-term sustainability of nuclear waste storage and about the possible implications of a global nuclear power industry for military nuclear proliferation. The Committee recognises that these issues go beyond cost economics alone. The Committee argued, however, that if nuclear is in principle acceptable, then cost economics will argue for a significant role in the generation mix.

The premise for these scenarios was a hypothesis that there may be a tension between high levels of renewables and the economics of nuclear new build. Subsequent modelling, however, does not appear to bear out this hypothesis, and suggests that the projected demand/supply balance is such that there may only be limited periods of excess supply ('spill') even with both high levels of renewable and nuclear new build (Figure 4.7).

Figure 4.7 Spill with high levels of wind and nuclear



Source: CCC calculations based on Redpoint (2009), *Decarbonising the GB power sector*; Pöyry (2009) *Impact of Intermittency*.

High levels of wind generation and nuclear new build are both desirable over the first three budgets:

- Wind generation offers the best opportunity for early decarbonisation of the power sector because it is the only low-carbon technology that is ready for deployment now.
- Nuclear new build is a cost-effective form of low-carbon generation and early entry into the mix will contain the costs of decarbonisation through the 2020s and beyond.

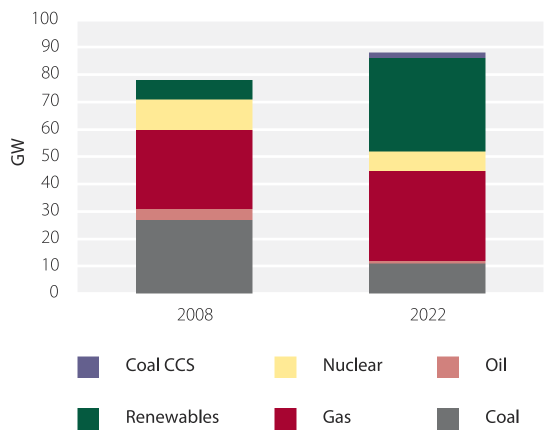
4 BERR (2008) *UK Renewable Energy Strategy consultation.*

We have therefore designed a new indicative scenario which includes both high levels of wind and nuclear new build and which our analysis shows is consistent with being on track to meeting the 80% emissions reduction target:

- The scenario includes addition of 23 GW new wind capacity and four CCS demonstration plants by 2020, with three new nuclear plants by 2022, together with 4 GW of new non-wind renewables (Figure 4.8 and Figure 4.9).
- It does not include the Severn Barrage project, which could deliver low-carbon electricity at reasonable cost but is relatively expensive compared to other low-carbon options currently available and offers limited scope for driving down costs through learning/wider technology deployment. Whilst this project may become an attractive option in the future if other technologies fail to deliver, it is not a clear current priority (Box 4.2).
- Emissions fall by around 50% from 2008 levels to 2020 under this scenario, putting emissions intensity on the path to deep emissions cuts required by 2030 and beyond to meet the 80% economy-wide emissions reduction objective in 2050 (Figure 4.10 and Figure 4.11).

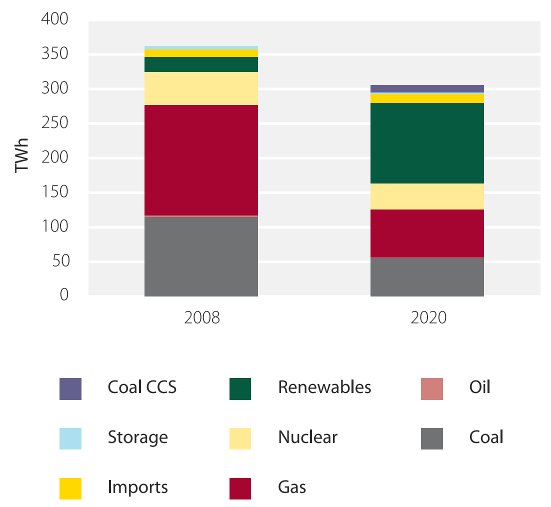
We include this scenario in our economy-wide Extended and Stretch Ambition scenarios (Chapter 3). We will use it pragmatically to provide a high level assessment of progress in reducing power sector emissions. To achieve this scenario, however, there is a set of required measures around the enabling framework and project development and implementation. We now turn to a detailed consideration of these measures for wind, nuclear and CCS generation.

Figure 4.8 CCC scenario for capacity mix in 2020 compared to actual capacity mix in 2008



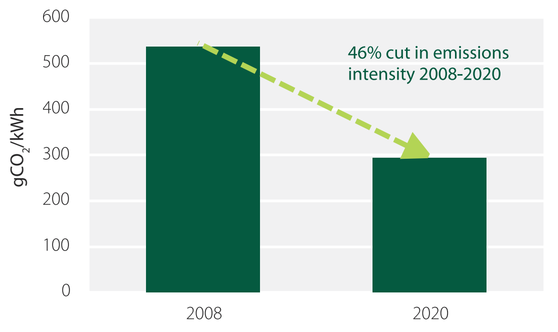
Source: DECC (2009); *DUKES*; Table 5.7 and 7.4 and CCC.
Notes: Capacity is on nameplate basis. Renewables in 2020 are made up of 27 GW of wind and 7 GW of other renewables.

Figure 4.9 CCC scenario for generation mix in 2020 compared to actual generation mix in 2008



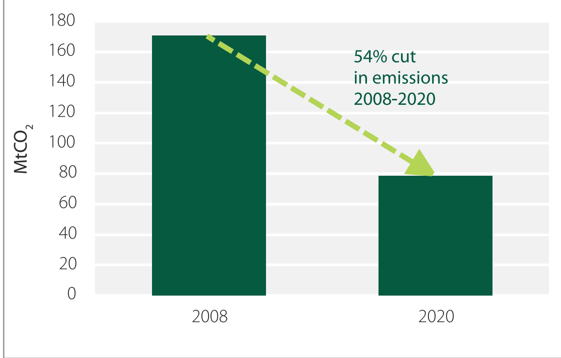
Source: DECC (2009); *DUKES*; Tables 5.6, 7.4 and 5.1 and CCC.

Figure 4.10 Emissions intensity in 2020 under CCC scenario compared to 2008



Source: CCC calculations based on DECC (2009); *DUKES*; Tables 5.1, 5.6, 7.4 and E.1.

Figure 4.11 Emissions in 2020 under CCC scenario compared to 2008



Source: CCC calculations based on DECC (2009); *DUKES*; Table E.1.

Box 4.2 Severn Tidal Power

The Government is currently investigating a number of options to use the tidal range (the height difference between low and high tide) in the Severn estuary to generate electricity. The feasibility study will make recommendations in 2010 after further technical, environmental, and economic analysis and a second public consultation. A smaller barrage could be completed in time to contribute towards the 2020 renewable energy target, whilst a large barrage would take longer.

The Committee has made its own assessment as to whether or not a Severn barrage should be pursued. In doing so we have considered:

- The cost per kWh of low-carbon electricity generated, relative to other options available to decarbonise the power sector.
- The potential of investment in a barrage to drive learning, and to bring down the future cost of generating low-carbon electricity.

Cost

In the context of a commitment to power sector decarbonisation, an option to deploy a barrage in the early 2020s should be compared with other low-carbon generation options available for deployment from the early 2020s, i.e. other renewables, nuclear and CCS.

A tidal barrage would be highly capital intensive and would have a much longer life than most other technologies in the power sector (around 120 years, compared to around 40 years for a nuclear power plant, and 20 years for a wind farm). The choice of discount rate is therefore critical. Given we are considering societal choices about alternative low-carbon technologies, we have used a social rather than commercial discount rate in comparing these technologies.

The figure below shows the levelised costs for a barrage compared to other technologies. It abstracts from the need to back up plant which cannot be relied upon to generate in the peak. It is therefore favourable both to the barrages and wind generation, which require significant back up.

We have looked at two barrages: the Cardiff-Weston barrage – the largest barrage being studied in detail by Government, and the Shoots barrage – the most cost-effective of the barrages being investigated further by Government.[5] Figure B.4.2 shows that the costs for these options are at the high end of the range for all low-carbon technologies.

5 DECC (2009) *Partial impact assessment of Severn tidal power shortlisted schemes.*

Box 4.2 continued

Learning

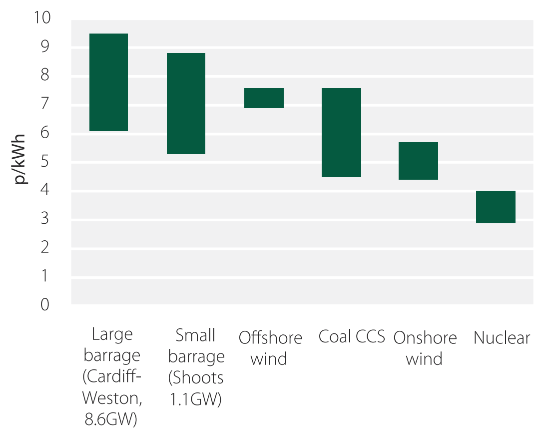
A key part of the rationale for the Government's renewables target, is to encourage investment in emerging low-carbon technologies and thereby drive the costs down. However, in contrast to technologies such as offshore wind, and other marine technologies such as tidal stream and wave, there is likely to be little scope for learning from the construction of a barrage in the Severn estuary. Firstly, the technology has already been proven (in La Rance in France a 240 MW barrage has operated since the 1960s). Secondly, the Severn resource is exceptional. There are only a handful of sites in the world where tidal range could be introduced on a comparable scale.

Conclusions

A Severn barrage would generate electricity at a low enough cost that if other options were not available it could form part of a clearly affordable low-carbon strategy. However, it currently appears more costly than the leading low-carbon alternatives, whilst investment in a barrage is not likely to drive down the future costs of generating low-carbon electricity. Investing in a barrage is therefore not clearly attractive if these alternatives are available.

However, we note that nuclear, CCS and other renewables carry their own delivery risks, and the option of constructing a barrage at the Severn in future should therefore be kept open. As such, even if building a smaller barrage or lagoon proves more cost-effective it may not be desirable to proceed with this option if it rules out the addition of a large barrage in the future.

Figure B4.2 Levelised cost at social discount rate for low-carbon technologies built in 2020



Source: CCC calculations based on DECC (2009), *Partial impact assessment of Severn tidal power shortlisted schemes*; IPCC (2005) *Special report on CCS*; DECC capital and operating cost assumptions.
Note: Lower ranges for the barrages are based on no requirement for compensatory habitat and 15% optimism bias on costs. Upper ranges are based on 2:1 requirement for compensatory habitat and 66% optimism bias on costs.

3. Wind generation: indicators and the enabling framework

This section sets out our indicators for wind generation, against which we will judge progress in our annual reports to Parliament. It covers the various stages of the project cycle for investment in wind generation (Figure 4.12). It presents a scenario for investment in wind generation consistent with our overall power scenario outlined above and with the Government's ambition for renewable electricity as set out in its Renewable Energy Strategy, and critical factors in realising this scenario. It sets out departures from this scenario under alternative assumptions about different stages of the project cycle. It also considers access rules and investment in power transmission required to support renewable investment.

We now consider:

(i) Scenarios for investment in wind generation

(ii) Power transmission investments and access rules

(iii) Summary of wind generation indicators.

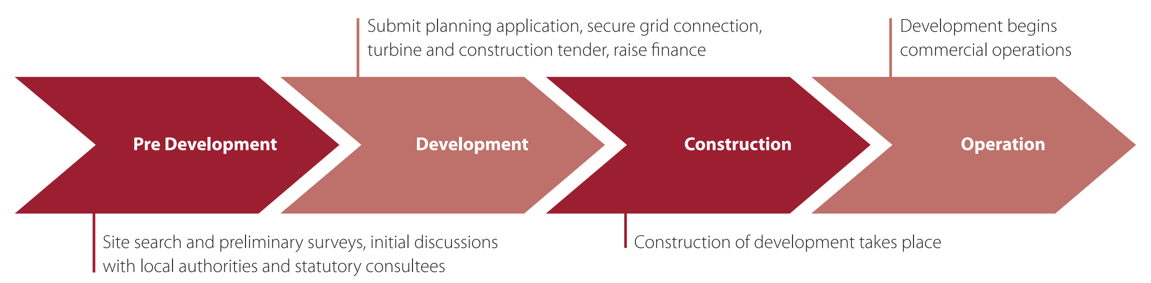
(i) Scenarios for investment in wind generation

High feasible investment

In developing our high scenario for feasible investment in wind generation, we have considered:

- Current wind capacity in the pipeline at different stages of the project cycle.
- Time required for project development (planning, gaining access to the grid, and securing finance – Box 4.3).
- Time required for construction (Box 4.4).
- Barriers to project implementation (e.g. supply chain constraints).

Figure 4.12 The project cycle for a wind development



Source: Pöyry Energy Consulting (2009) *Timeline for wind generation to 2020 and a set of progress indicators.*

Box 4.3 Constraints within development phase

In order to proceed, a project must have planning approval, transmission access, finance and a turbine contract:

- Planning approval has historically often been slow (e.g. taking up to several years), resulting in projects being delayed or cancelled. Recent planning reforms are aimed at reducing the planning period and increasing approval rates (Box 4.5).
- The UK grid is currently constrained in areas with wind generation potential. This has resulted in access being delayed ten or more years in some cases. Recent reforms are aimed at providing access for any project that is ready to proceed.
- Accessing finance has become more challenging as a result of the credit crunch. In particular, there has been limited project finance available to independent developers. A combination of finance from the European Investment Bank with possible Government support should address this issue (Chapter 2).
- Until recently, there was limited availability of turbines for new wind generation projects. Supply constraints have eased, however, as the global recession has reduced turbine demand, potentially allowing increased turbine supply to the UK (Box 4.6).

Box 4.4 Construction of a wind farm

Onshore: In our analysis, we have assumed construction takes one year. Activities include installation of a substation, laying of turbine foundations, erection of turbines and the commissioning and testing of turbines.

Offshore: We have assumed a two year construction period. Activities include installation of the offshore substation, laying of subsea export cable, installation of steel foundations, securing of transition piece (to enable access to wind farm) and turbine installation.

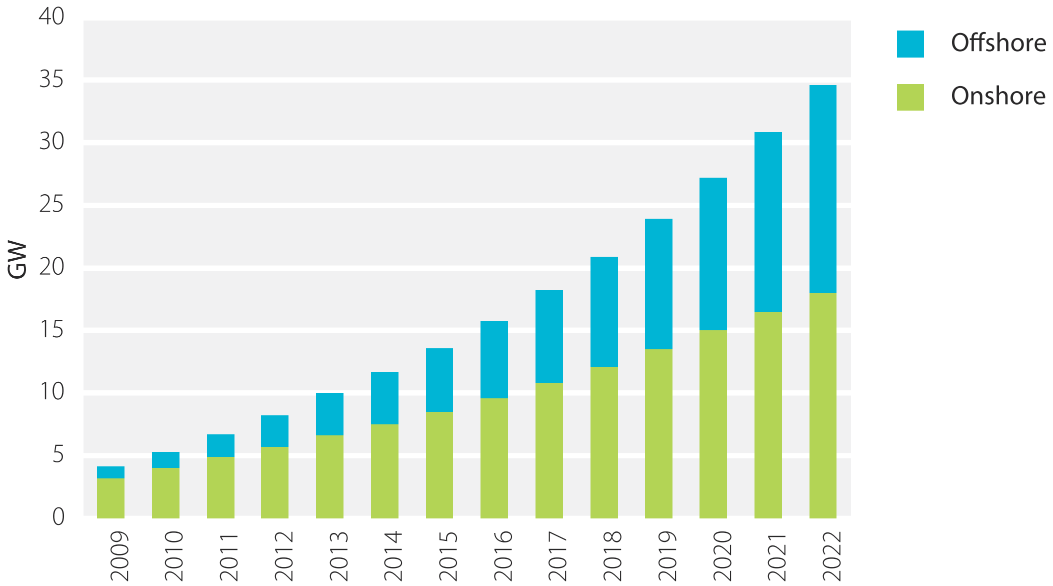
Allowing for all these factors and drawing on analysis carried out for us by Pöyry Energy Consulting, we estimate that it would be feasible to add up to 23 GW of new wind capacity by 2020 (i.e. to reach 27 GW in total given the 4 GW currently on the system – Figure 4.13):

- This comprises an additional 12 GW onshore and 11 GW offshore.
- Onshore wind is added along a reasonably smooth trajectory at an annual average rate just under 1 GW to 2014, rising to 1.5 GW by 2020.
- Offshore wind is added at the rate of under 1 GW per year in the near term, rising to almost 2 GW per year by 2020.

Delivering this level of investment is contingent on four key factors:

- Planning system reform reduces the planning period and increases the approval rate (Box 4.5).
- Renewables have access to a power transmission network without bottlenecks; we discuss issues around power transmission in the next section.
- The supply chain adjusts to accommodate over a threefold expansion in annual installation capability for both onshore and offshore generation. This will require, for example, the UK accessing ten additional offshore installation vessels, costing between £50-150 million each and with up to a three year procurement period (Box 4.6).
- Projects are able to secure finance. We discuss financing of renewable projects in the current macroeconomic context in Chapter 2.

Figure 4.13 Operational wind capacity in the high feasible scenario



Source: CCC modelling based on Pöyry Energy Consulting (2009), *Timeline for wind generation to 2020 and a set of progress indicators.*

Box 4.5 Getting planning approval

Evidence from the British Wind Energy Association (BWEA) suggests that it took on average 14 months for the relevant Local Planning Authority (LPA) to determine onshore projects under 50 MW, as opposed to the statutory timescale of 16 weeks. Applications that go to appeal (around a quarter) take an average of 26 months.[6] For larger onshore projects (over 50 MW) the average time from application to the Secretary of State to decision is around 25 months, with those going to inquiry (around 15% in England, 30% in Scotland) taking a further 10 months. Large offshore projects are usually determined within 21 months.[7]

The Planning Act 2008 introduces new rules to simplify the consent procedure for large energy projects (defined as Nationally Significant Infrastructure Projects), including wind but also transmission infrastructure. A suite of National Policy Statements (NPSs) will establish the national case for infrastructure development, including renewables.

The Act establishes the Infrastructure Planning Commission (IPC), to take over decisions on major infrastructure applications. This means onshore projects 50 MW or above will seek approval from the IPC along with offshore installations over 100 MW. The IPC must have regard for the relevant NPS when considering applications, and have a legal duty to determine the application within a set time period (around nine months). The new process places a greater onus on developers to consult with interested parties before an application is submitted, which is also expected to reduce the risk of inquiry and improve the approval rate.

6 BWEA (2008), *State of the Industry Report.*
7 Pöyry Energy Consulting (2009), *Timeline for Wind Generation to 2020 and a set of Progress Indicators.*

Box 4.5 continued

For onshore projects below 50 MW (around 40% of capacity currently awaiting approval) the Renewable Energy Strategy sets out a number of reforms being taken forward to speed up and improve the approval rate for such projects, including:

- Increased funding for LPAs
- Performance agreements between developers and LPAs on timescales
- A requirement for each Devolved Administration to assess the potential for renewable electricity and heat, as the basis for a level of ambition for deployment by 2020.

Box 4.6 Supply chain constraints

The onshore market is relatively more mature than offshore, where the barriers are generally considered more severe.

The key supply chain issues for offshore generation are:

- Turbine technology is at an early stage of development, and the market for turbine supply is very limited,
- The market for subsea cables – of which around 7,700 km will be required for Round 3 projects – is undeveloped,
- There are currently only two installation vessels available to install wind turbines in the UK – with up to 12 needed by 2020.

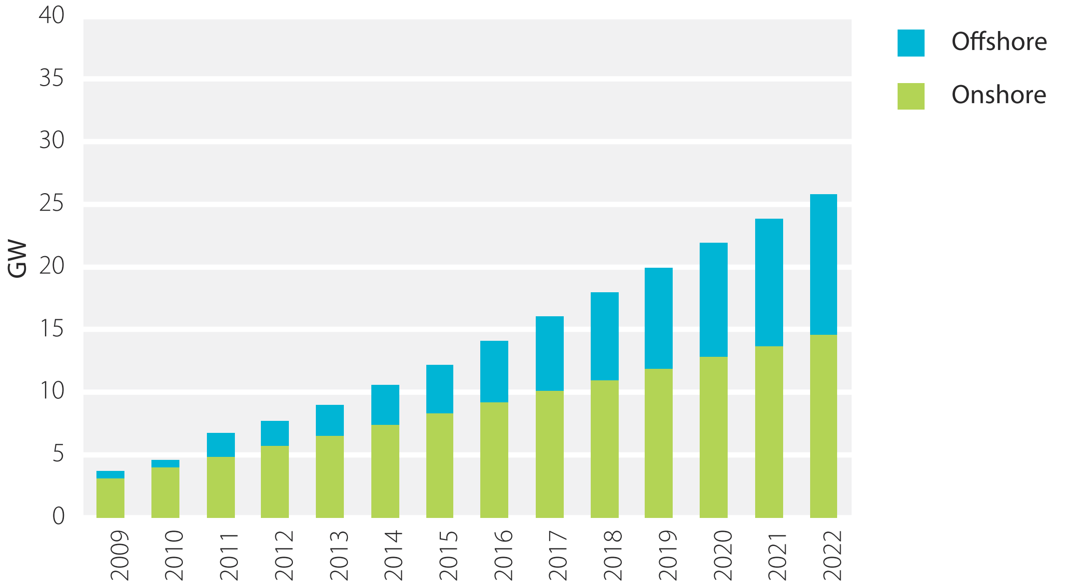
Supply chain constraints can potentially be eased through provision of clear signals on the level of ambition for offshore wind and supporting delivery mechanisms (e.g. continued financial support).

Departures from high feasible investment

We have also developed alternative scenarios to highlight outcomes under alternative assumptions about key drivers:

- With even higher growth in supply chain capability (e.g. such that up to 2 GW of onshore wind and 3 GW of offshore wind could be added annually by 2020) we estimate that up to 29 GW of capacity could be added (split 14/15 GW on/offshore), with total capacity reaching just over 33 GW by 2020.
- We estimate that just 18 GW of new capacity could be added by 2020 (22 GW in total), if the planning period and approval rate is around equal to the historical average and the supply chain capability is around half of that in the maximum feasible investment scenario (Figure 4.14). This is split 10 GW onshore and 8 GW offshore.
- We have explored a further scenario, where supply chain capability fails to expand beyond 2010, together with further prolonged planning periods and poor approval rates, strenuous conditions for raising finance and some constraints on the transmission network. In this scenario, as little as 13 GW of new capacity is added (17 GW in total), split 8 GW onshore and 5 GW offshore.

Figure 4.14 Operational wind capacity in the alternative scenario



Source: CCC modelling based on Pöyry Energy Consulting (2009), *Timeline for wind generation to 2020 and a set of progress indicators.*

Summary of scenarios

The high feasible scenario we have developed in our bottom-up analysis of wind generation is consistent with the scenario presented in Section 2 above. The bottom-up analysis suggests that it is challenging but feasible to add the levels of wind capacity required to be on track to meeting our 80% emissions reduction target in 2050 and to meet the Government's ambition set out in its Renewable Energy Strategy. The analysis also highlights the risk that if improvements to the planning system and growth in the supply chain are insufficient there will be a consequent shortfall in wind investment relative to our scenario. Even with reduced planning periods and supply chain growth, delivering more ambitious scenarios will require a number of measures to be implemented for power transmission.

(ii) Power transmission investments and access rules

It is crucial that the power transmission network is developed in a way to support a significant increase in the level of wind generation. The current network has limited capacity, with severe bottlenecks in some areas where there is wind resource (e.g. there is limited capacity from north to south Scotland and from Scotland to England), and a very limited offshore network. Onshore and offshore transmission investments will therefore be required as a matter of urgency.

The onshore transmission network

In the context of developing a strategy for renewable energy, an Electricity Network Strategy Group (ENSG) jointly chaired by DECC and Ofgem and comprising power generators and transmission owners has been formed. The ENSG has carried out analysis of required transmission investments to support increased wind generation, and has identified a set of 'least regrets' investments (i.e. where there is a high degree of confidence that these investments will not turn out to be stranded – Figure 4.15)[8]. Implementation of these projects is a necessary condition for delivering the scenarios for wind generation investment that we set out above.

In order that these projects proceed, they must be approved by Ofgem. Currently Ofgem has agreed in principle that these projects can proceed and be included in National Grid's regulated asset base. There is ongoing discussion about the return on investment that will be allowed, and the risks that National Grid will accept (e.g. cost overrun, lower demand than currently anticipated). This is a matter for Ofgem and National Grid, and possibly the Competition Commission if these two parties cannot come to agreement. The key issue for the Committee is the timing of approval, which should ideally be early in 2010, with planning permission granted by the new Infrastructure Planning Commission before the end of 2011, in order that project implementation can commence as required in 2012 (Figure 4.16).

The offshore transmission network

Up to £15 billion of investment will be required to develop the offshore transmission network to eventually support up to 40 GW of offshore wind generation, should all the resource currently identified in the Crown Estate and Scottish Territorial Waters be taken up.

A new regime to govern this investment was introduced under the Energy Acts 2004 & 2008 whereby there will be competitive tendering (run by Ofgem) for the right to build and operate offshore transmission networks, with National Grid – as System Operator – providing strategic oversight to ensure that these networks are developed in a coherent manner.

Offshore grid investments will be tendered in two categories:

- Tendering for the first 'transitional' projects started in June 2009. A licensed Offshore Transmission Owner (OFTO) should be in place to operate the existing offshore transmission network by 2010.
- Tendering for the construction of the first projects under the enduring regime will start in June 2010, for construction to start in 2011 and complete in 2012/13. It is currently envisaged there will be annual tendering rounds.

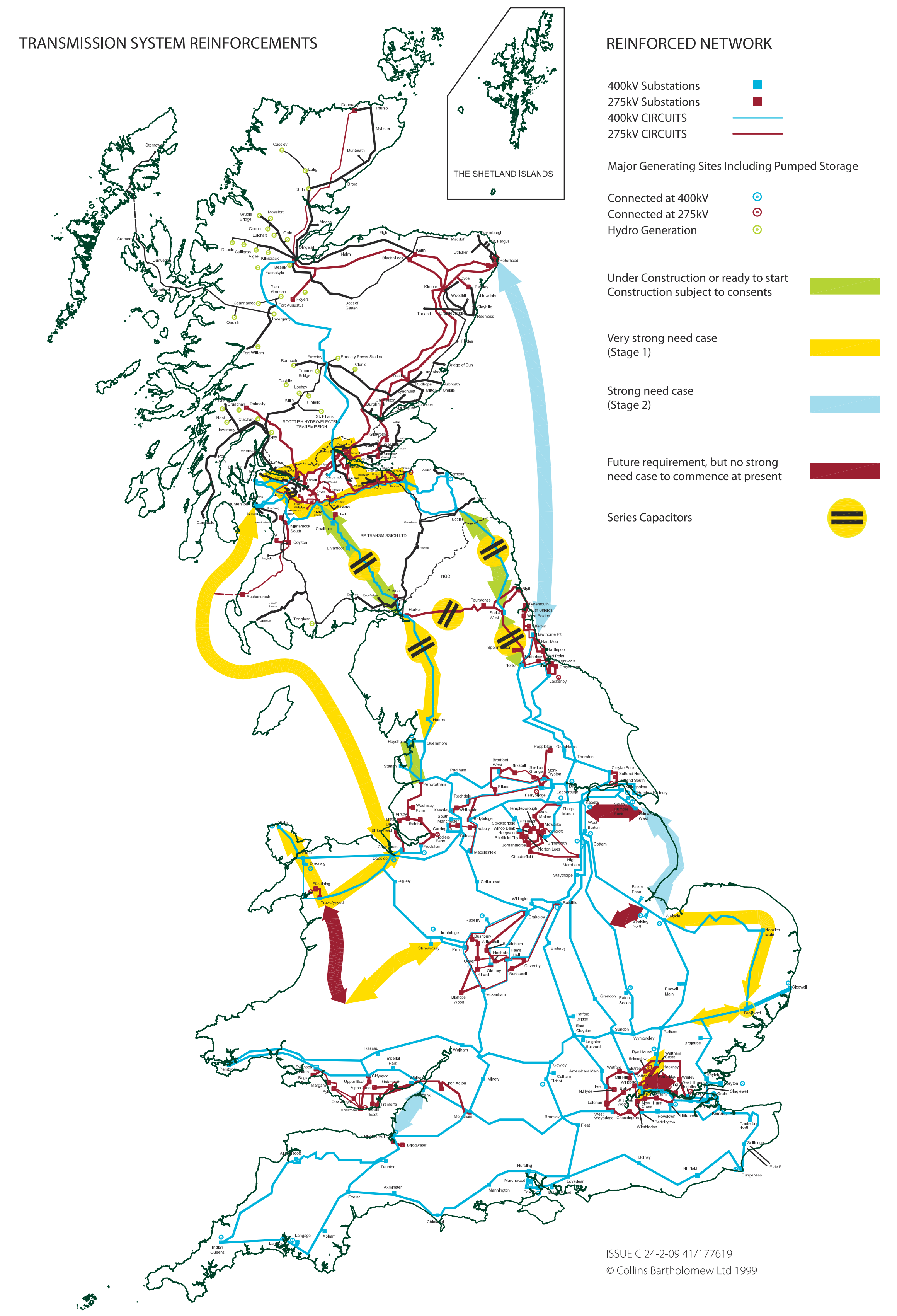
These schedules underpin the envisaged addition of 11 GW offshore capacity by 2020 in our high feasible investment scenario, and the Committee will therefore focus on achieving milestones in the schedules as part of annual monitoring of progress reducing emissions (Figure 4.17).

Transmission access

It will inevitably be the case that there will continue to be transmission network bottlenecks in the near term given the lead time for transmission investment projects. An interim arrangement is in place to ensure that renewable capacity is able to gain access to the network even where this is capacity constrained. There are a number of alternatives for replacing the interim arrangements, and which differ on distributional grounds (e.g. whether or not incumbent generators are paid compensation for not generating – Box 4.7); the choice between these mechanisms goes beyond the remit of the Committee. An important issue for the Committee, however, is the timing of this choice; an enduring mechanism that allows network access to wind generation should be in place by mid-2010 in order to support delivery of our scenarios for investment in wind generation.

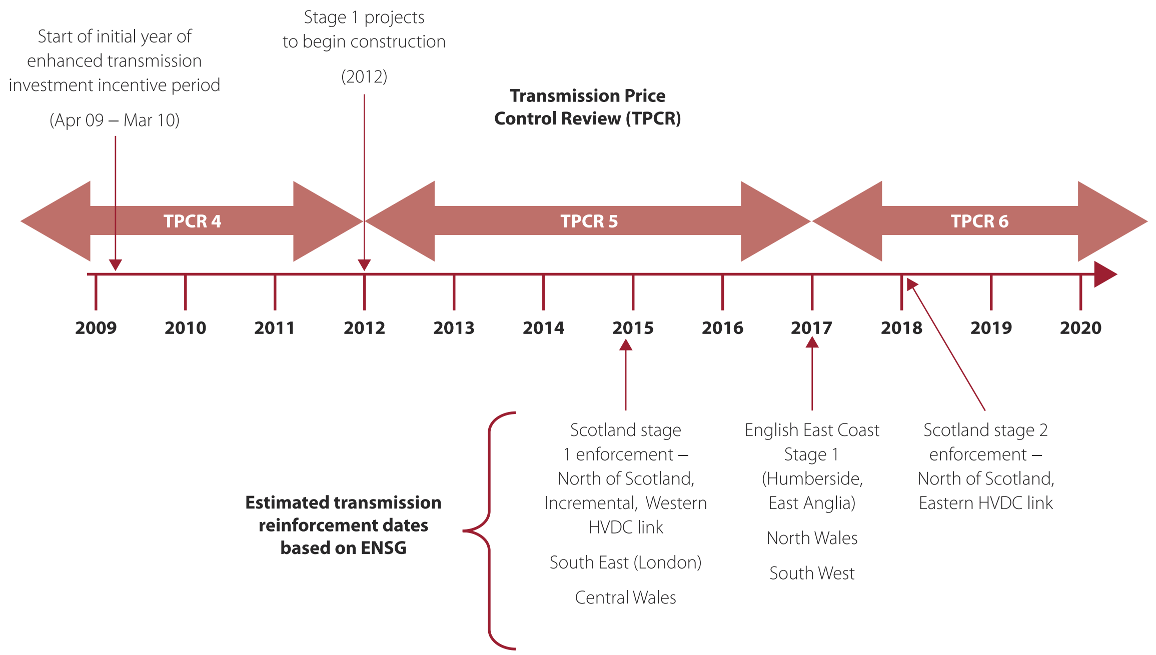
8 ENSG (2009) *Our Electricity Transmission Network, A Vision for the Future*, http://www.ensg.gov.uk/assets/1696-01-ensgvision2020.pdf

Figure 4.15 Stage 1 and 2 transmission reinforcements recommended by ENSG



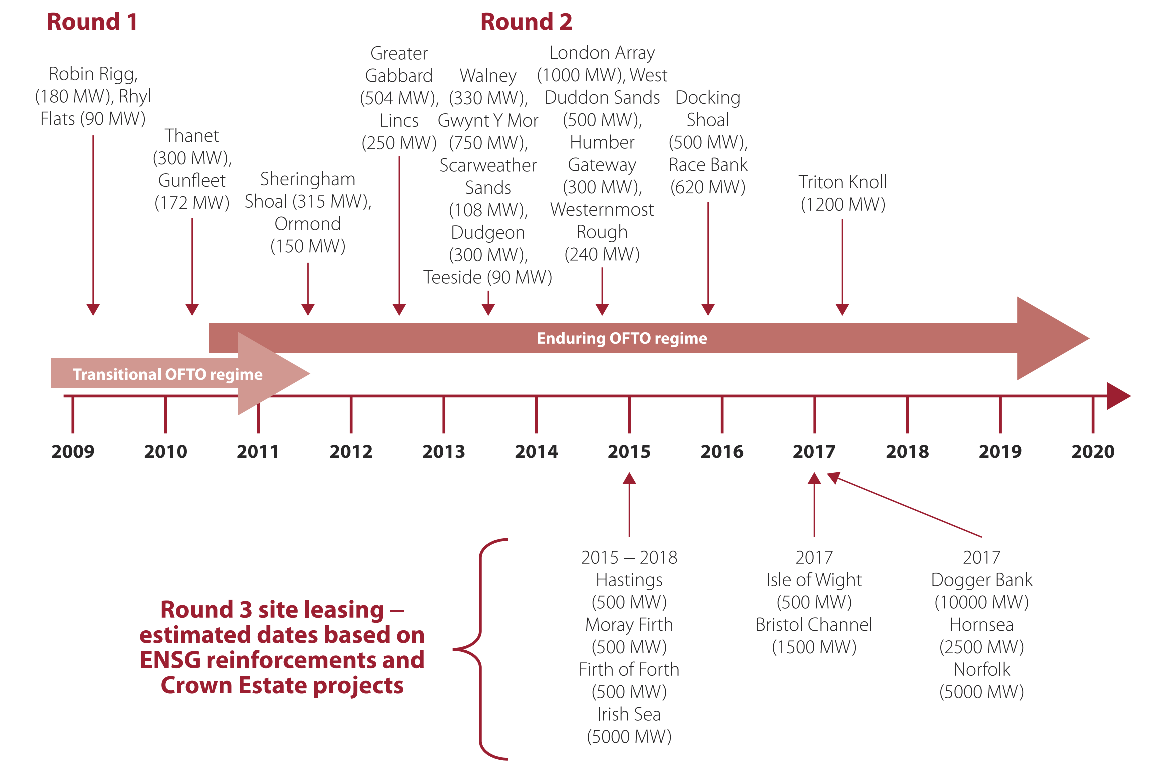
Source: ENSG (2009), *Our Electricity Transmission Network, A Vision for the Future.*

Figure 4.16 Timeline for investments in transmission capacity, onshore



Source: Pöyry Energy Consulting (2009), *Timeline for wind generation to 2020 and a set of progress indicators*; ENSG (2009), *Our Electricity Transmission Network, A Vision for the Future.*

Figure 4.17 Indicative timeline for offshore capacity



Source: BWEA, DECC, Crown Estate, Pöyry Energy Consulting (2009), *Timeline for wind generation to 2020 and a set of progress indicators*; ENSG (2009), *Our Electricity Transmission Network, A Vision for the Future*, Crown Estate.
Note: Due to space, not all Round 2 projects are shown

Box 4.7 Rules for accessing the grid

The 2008 Transmission Access Review (TAR) set out the need for grid access reform. A range of models have been put forward, broadly falling into two categories:

- 'Connect and Manage' as under the interim arrangements, whereby generators are offered a fixed connection date ahead of necessary reinforcements. Any constraints on the network are managed by the System Operator (National Grid).
- Auctioning – unlike Connect and Manage (where incumbent generators will effectively be paid for not generating in the event of a bottleneck), auctioning would require the removal of existing rights, and reallocation via an auction.

In August 2009, the Government published a consultation seeking views on the options, and their implementation.

(iii) Summary of wind generation indicators

The indicators against which we will monitor progress cover all stages of the project cycle, together with the supply chain and power transmission. We will therefore not only be able to make an assessment of whether there is sufficient investment in new wind capacity, but whether there is likely to be sufficient investment given progress in the drivers of investment. Our indicators include:

- The number and type of planning applications made for wind generation projects, time taken to process applications and approval rates.
- The number of wind generation projects commencing and completing construction, along with the time taken and any barriers faced.
- Key stages for development and implementation of the transmission investments identfied by the ENSG.
- Key milestones for development of the enabling framework (e.g. agreement of an enduring regime for transmission network access).

We set out the indicators underpinning our high feasible investment scenario in Table 4.1.

Table 4.1 Table of indicators – wind

Wind	2008	2009	2010	2011	2012
Headline indicator					
Total generation (TWh)	**7.6**	**9.7**	**13.4**	**16.8**	**20.9**
Onshore	5.8	7.0	9.0	11.0	12.9
Offshore	1.8	2.7	4.3	5.9	8.0
Supporting indicators					
Project cycle					
Total installed capacity (GW)	**3.4**	**4.1**	**5.4**	**6.7**	**8.2**
Onshore	2.8	3.2	4.0	4.9	5.7
Offshore	0.6	0.9	1.3	1.8	2.5
Additional capacity (GW)	**0.9**	**0.7**	**1.3**	**1.3**	**1.5**
Onshore	0.7	0.4	0.8	0.9	0.9
Offshore	0.2	0.3	0.5	0.5	0.7
Capacity entering construction (GW)	**1.0**	**1.4**	**1.5**	**1.8**	**1.7**
Onshore	0.5	0.9	0.8	0.9	0.9
Offshore	0.5	0.5	0.7	0.9	0.9
Average planning period (months) onshore/offshore, all sizes	**various***	**<12 months**			
Capacity entering planning (GW)	**2.3**	There are currently around 9 GW of projects awaiting planning consent (7 onshore and 2 offshore), as well as just under 7 GW that have planning consent but are not yet in construction (3.2 onshore and 3.6 offshore)**.			
Onshore	1.4				
Offshore	0.8				
Transmission					
Transmission policy					
Implementation of enduring regime for accessing grid			🟩		
Agreement on incentives for anticipatory investment for Stage 1 reinforcements			🟩		
Transitional OFTO regime in place		🟩			
Enduring OFTO regime in place			🟩		
Onshore transmission reinforcement dates					
Scotland Stage 1 (North, Incremental and Western HVDC link)				🟥	🟨
Scotland Stage 2 (North, Eastern HVDC link)					
Wales Stage 1 (Central)				🟥	🟨
Wales Stage 1 (North)					
English East Coast Stage 1 (Humberside, East Anglia)					
South East (London)				🟥	🟨
South West					
Offshore transmission reinforcement dates					
First offshore connections under enduring OFTO regime			🟥	🟨	🟩
Moray Firth, Firth of Forth, Hastings, Irish Sea					
Dogger Bank, Hornsea, Norfolk, Isle of Wight, Bristol Channel					
Other drivers					
We will also be monitoring qualitative indicators including average load factors, planning approval rates and frequency of public inquires to decisions of Infrastructure Planning Commission, availability of offshore installation vessels and supply of turbines to the UK market.					

Key:

🟥 seek and gain planning permission 🟨 in construction 🟩 in operation

Source: CCC calculations, Pöyry Energy Consulting (2009) *Timeline for wind generation to 2020 and a set of progress indicators*, BWEA UK Wind Energy Database (UKWED), RESTATS Planning database.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	25.7	**30.5**	**35.6**	**43.6**	**50.5**	**58.2**	**66.8**	**76.3**	**86.8**	**98.0**
	14.8	16.8	19.0	23.5	26.5	29.7	33.1	36.8	40.4	44.1
	10.9	13.6	16.6	20.1	24.0	28.6	33.7	39.6	46.4	53.8
	9.9	**11.7**	**13.6**	**15.8**	**18.2**	**20.9**	**23.9**	**27.2**	**30.8**	**34.6**
	6.6	7.5	8.5	9.6	10.8	12.1	13.5	15.0	16.5	18.0
	3.4	4.2	5.1	6.2	7.4	8.8	10.4	12.2	14.3	16.6
	1.8	**1.8**	**1.9**	**2.2**	**2.4**	**2.7**	**3.0**	**3.3**	**3.6**	**3.8**
	0.9	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.5
	0.9	0.9	0.9	1.1	1.2	1.4	1.6	1.8	2.1	2.3
	1.8	**2.1**	**2.3**	**2.6**	**2.9**	**3.2**	**3.6**	**3.8**	**3.8**	**4.1**
	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.5	1.5
	0.9	1.1	1.2	1.4	1.6	1.8	2.1	2.3	2.3	2.6
	Going forward we expect at a minimum new planning applications required towards the end of the second budget period, or sooner in the event of low approval rates for the current stock. For offshore, we will expect a schedule in line with site leasing (e.g. for Round 3, projects entering planning in 2012/13 for operation from 2015 onwards.									
			■							
		■	■			■				
			■							
	■	■			■					
	■	■			■					
			■							
	■	■			■					
	■	■	■							
			■	■	■					

Key:
Headline indicators | Implementation indicators | Forward indicators | Milestones | Other drivers

Notes: *For example, BWEA found average period for onshore <50 MW was 14 months for determination by LPA (for those not going to appeal), and 26 months for those going to appeal (around 30%). From a sample, Eversheds (on behalf of Pöyry) found onshore 100 MW+ took around 25 months for determination by the Secretary of State, and Offshore (<100 MW) around 21 months. **BWEA Statistics, September 2009

4. Investment in nuclear new build

Our scenario for decarbonisation of the power sector includes up to three new nuclear plants by 2022. In this section we consider what has to happen in order that the first of these plants comes onto the system in 2018, differentiating between development of an enabling framework and project development/implementation.

Development of an enabling framework

Planning has been a particular problem for past investment in nuclear power in the UK, with planning approval of the Sizewell B project taking around six years. Going forward, this period will have to be reduced both to contain costs of nuclear development and to ensure that investment occurs in a timely manner without compromising due process. In this respect, the Government is making progress on a number of fronts:

- Regulatory Justification of nuclear new build will be completed by early 2010.
- A National Policy Statement (NPS) outlining the importance of nuclear new build in the context of energy strategy will be published by Spring 2010. The NPS will also set out the policy framework within which the Infrastructure Planning Commission (IPC) will make its decisions (see Box 4.6 above).
- A Strategic Siting Assessment pre-approving sites for nuclear new build will be completed in April 2010.
- Generic Design Assessment of reactor designs is due to be completed by mid-2011, leaving only some site specific aspects for further regulatory approval.
- Regulations for a Funded Decommissioning Programme covering back-end waste and decommissioning costs is expected to be in place by 2010.

Project development/implementation

Key aspects within the project cycle are the time taken for approval of a planning application, and the construction period for new plant:

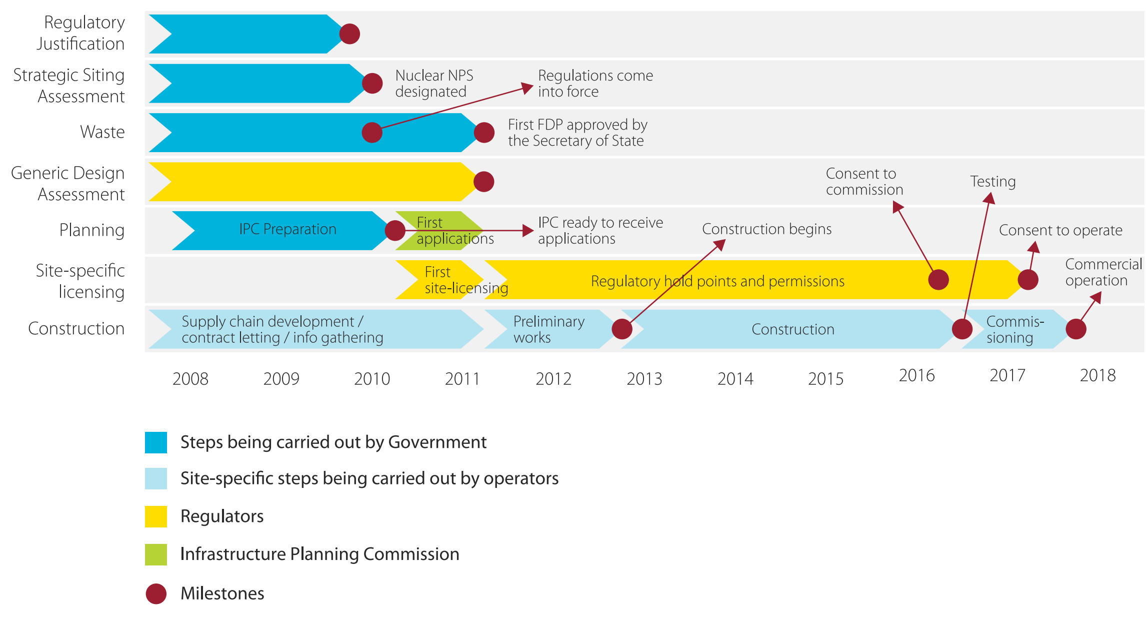
- The current expectation is that it would take the new IPC around nine months to approve a planning application.
- The Government has suggested a period of six and a half years from planning consent to commercial operation (covering site preparation, construction and testing).

Nuclear timelines and risks

Timelines for the enabling framework and project development together define our forward indicators for nuclear power (Figure 4.18). We currently expect the first planning application to be made in 2010, with approval by 2011, which would result in a completed plant by 2018 under a five year assumed construction period with one and a half years for site development. The Government's assumption, which we accept, is that plants could subsequently be added at 18 month intervals.

There are a number of risks to successful implementation related to regulation and planning. For example, the IPC might not function as intended, or the regulations for the Funded Decommissioning Programme may not be in place by 2010 as currently envisaged. In addition, the new regulatory framework may be subject to judicial review and subsequent change. Successful implementation will also require that there is an adequate supply chain, and that there continue to be sufficient numbers of specialist trained staff. We will actively monitor risks around the enabling framework and project implementation; we will cover both of these aspects as part of our wider monitoring exercise.

Figure 4.18 Nuclear timeline



Source: CCC based on DECC (2009), *Indicative timeline for first new nuclear power stations.*
Note: NPS – National Policy Statement, FDP – Funded Decommissioning Programme, IPC – Infrastructure Planning Commission.

5. Demonstration and roll-out of CCS technology

We highlighted in our December 2008 report the importance of carbon capture and storage (CCS) fossil generation both for decarbonisation of the UK power sector and for achieving required global emissions cuts. We also highlighted uncertainty over technical and economic aspects of CCS when applied at scale to a power station, and stressed the need to demonstrate this technology. We argued that there is no role for conventional coal generation through the 2020s on the path to an 80% emissions reduction target in 2050, and argued that this should be signalled by the Government to investors.

In this section, we set out our indicators for CCS demonstration and subsequent roll-out both through retrofit of existing plant and application to new plant. We also revisit our position on investment in conventional coal in light of the Government's response to our proposals.

There is an issue over the appropriate role for CCS in gas generation. Analysis in our December report showed that there is a longer term role for unabated gas generation reflecting lower emissions intensity and a potential role as back-up generation. The clear priority is therefore for early application of CCS to coal generation. The Committee will further consider viability of gas CCS as part of its advice on the fourth budget, to be published in 2010.

We consider in turn:

(i) Indicators for CCS

(ii) The framework for investment in conventional coal generation.

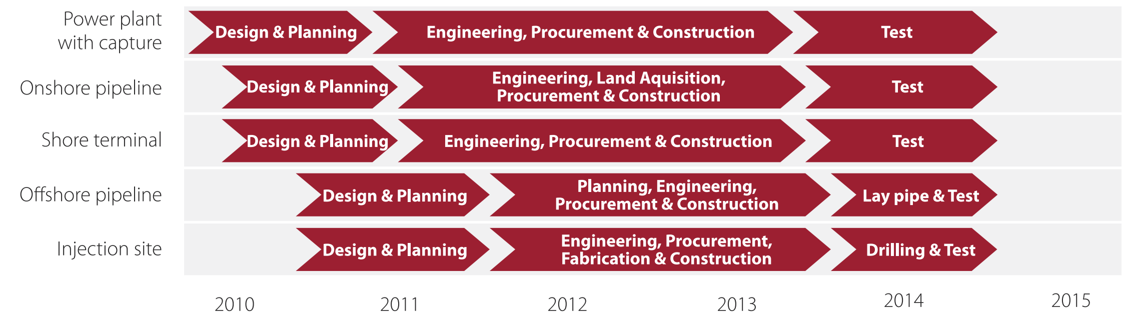
(i) Indicators for CCS

CCS demonstrations in the UK

In June 2009, the Government set out a new framework for CCS demonstration under which there will be up to four demonstration projects operational in the UK before 2020.

- The first demonstration project will be awarded funding under a competition to be concluded in 2010.

Figure 4.19 Project cycle for CCS demonstration



Source: Pöyry Energy Consulting (2009), *Carbon Capture and Storage: Milestones to deliver large-scale deployment by 2030 in the UK.*

- The Government's stated objective is that the first plant should begin operation in 2014, which would require (Figure 4.19):
  - Front-End Engineering and Design (FEED) studies are undertaken in 2010
  - the Competition winner is announced by the end of 2010
  - by the end of 2011 each of planning and authorisation approval, land acquisition, and storage site testing is complete, and construction should have started
  - the period for construction and testing of generation and transport/storage infrastructure is three years.
- A subsequent competition could in principle be launched and concluded in 2010, covering one or more projects with plants coming onto the system in 2015 or 2016.

The Committee welcomes this new framework and will use it as a basis for assessing progress in future reports to Parliament. In particular, we will focus on timely conclusion of the first competition and subsequent milestones towards having a plant in operation in or before 2015, and timely commencement of a second competition.

There are a number of questions around design of a second competition:

- How many projects should be included (one or more)?
- What technologies should this include (e.g. pre- and/or post-combustion)?
- What is the relative benefit of demonstrating CCS on existing versus new plant?
- How quickly can the competition process be completed?

We have not attempted to answer these questions in detail but have, however, taken a high-level view based on the imperative to get a critical mass of CCS in operation at the earliest opportunity:

- The second competition should follow as soon as possible after the first (e.g. in 2010), with the aim to reach operation soon after the plant financed under the first competition (e.g. in 2015 or 2016).
- It should award support to more than one plant in order to maximise learning and the probability of success, provided that there is a sufficient number of competitive bids.
- It should allow a range of technologies applied to both new and existing plant with a view to developing a portfolio of options for roll-out going forward.
- It should allow proposals based on shared infrastructure and oversized pipes to highlight scope for cost savings due to economies of scale.

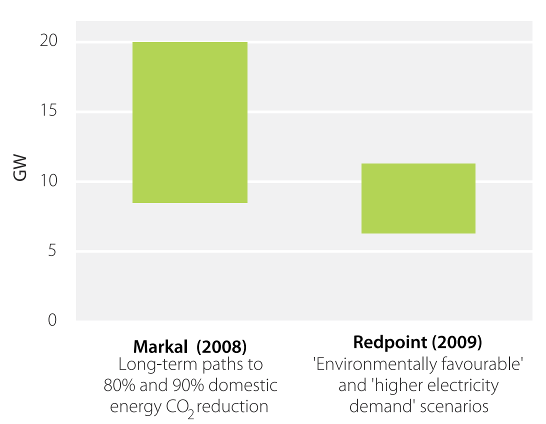
We will therefore use commencement in 2010 and conclusion in 2011 of a second competition designed along the high level principles set out above as a benchmark in our future progress reports.

From demonstration to deployment

We commissioned Pöyry Energy Consulting to help us develop a timeframe for post-demonstration roll-out of CCS, and approached this both from top-down and bottom-up perspectives:

- The top-down approach draws on modelling of power sector decarbonisation in the 2020s for our December report, which included up to 20 GW of CCS plant being added to the power system by 2030, depending on evolution of electricity demand and the levels of investment in nuclear and renewables (Figure 4.20). It assumes maximum feasible construction of 2.5 GW annually based on historical evidence of past power generation investment in the UK (Box 4.8). It therefore requires roll out of CCS to start in the early 2020s in order to keep open the option of delivering the levels of CCS deployment indicated in this scenario.
- The bottom-up approach recognises that the first demonstration project should be on the system in 2014 or 2015, with the second phase of demonstrations operational in 2015 and 2016. A decision on roll-out could then be taken as early as 2016, which with a period of five or six years for design, planning and construction would allow additional CCS to come on the system at significant scale from the early 2020s.

Figure 4.20 Ranges of CCS deployment by 2030 across core modelling runs



Source: CCC based on AEA (2008), *MARKAL-MED model runs of long-term carbon reduction targets in the UK*; Redpoint (2009) *Decarbonising the GB power sector*

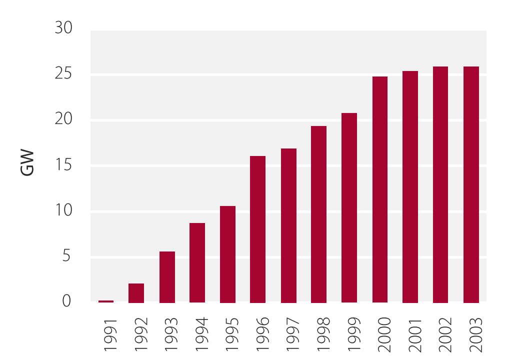
Box 4.8 Feasible build assumptions for CCS

Analysis for the CCC by Pöyry Energy Consulting suggests that it may be possible to deploy 20 GW of CCS plant by 2030 if:

- roll-out were to start in the early 2020s
- build rates of around 2.5 GW per year were achievable.

A historical comparison suggests that it would be very challenging to achieve such high build rates. A build rate of around 2.5 GW per year was sustained for gas CCGT plant in the 1990s, during the 'dash for gas'. But it must be recognised that CCS is both more risky and more technically challenging, comprising not only a thermal power plant, but also CO_2 capture, transportation and storage.

Figure B4.8 Cumulative additions to CCGT capacity (1991-2003)



Source: Pöyry Energy Consulting (2009) *Carbon Capture and Storage: Milestones to deliver large-scale deployment by 2030 in the UK.*

It is the view of the Committee therefore that the aim should be to roll out CCS from the early 2020s subject to technical and economic viability being demonstrated. A key milestone on this path is an early decision on a financing mechanism to support roll-out following demonstration plants coming into operation both in the UK and internationally (e.g. no later than 2016).

CCS infrastructure

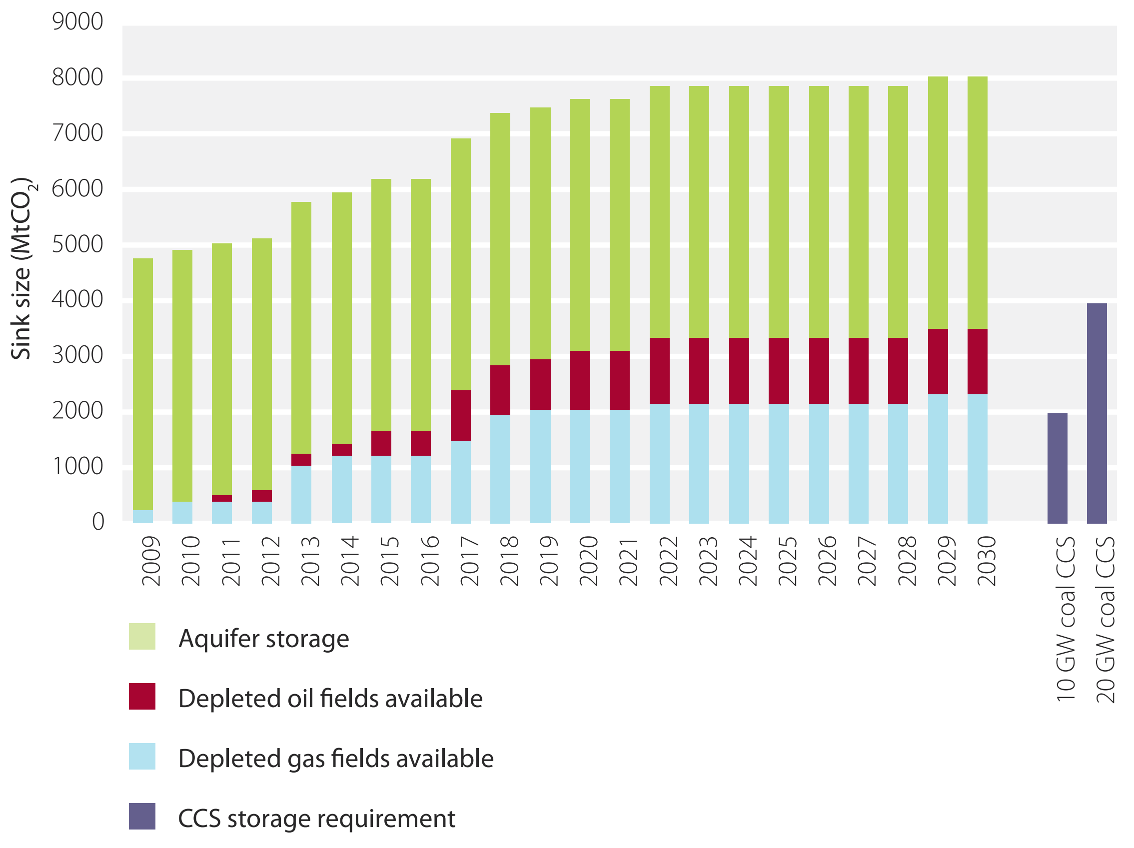
There will be some infrastructure in place by the time any decision is made to roll out CCS. This will not, however, be of sufficient scale to support levels of investment envisaged under our power sector scenarios. There is therefore a question over the appropriate approach to developing infrastructure to support roll-out.

Part of any approach will have to be a view on what type of infrastructure might be required. Analysis by Pöyry suggests that in order to support CCS deployment of 20 GW, a range of storage options would be required, with physical testing of saline aquifers, which are less well characterised than depleted oil and gas fields, an important near-term objective (Figure 4.21).

There is also a question over whether development of infrastructure should be market based (i.e. where energy companies develop their own infrastructure), or whether a more strategic approach (e.g. based on a statutory monopoly) is required. The issue here is whether energy companies could reasonably be expected to coordinate and exploit economies of scale (e.g by oversizing pipes and granting shared access).

It will be important that there is a clear strategic plan and regulatory framework for infrastructure development in place no later – and ideally sooner – than any decision to roll out CCS. As part of monitoring progress in CCS therefore, the Committee will track progress in early development of a strategic plan for infrastructure development.

Figure 4.21 Availability of CO_2 storage capacity



Source: Pöyry Energy Consulting (2009), *Carbon Capture and Storage: Milestones to deliver large-scale deployment by 2030 in the UK*.
Note: CO_2 storage requirements for CCS deployment based on the full lifetime output of a single generation of new-build coal CCS plants.

(ii) The framework for investment in conventional coal generation

In our December report we presented analysis that suggested there is no role for unabated coal-fired generation beyond the 2020s on the way to an 80% emissions reduction in 2050, which is borne out in new modelling that we have commissioned from Redpoint Energy (Figure 4.22).

We considered whether we could rely on the carbon price to signal this to investors and concluded that the signal is unlikely to be sufficiently robust. We argued that any investment in conventional coal generation should only be allowed for an interim period and should be made on the full expectation that CCS would be retrofitted.

We proposed an approach that would require that:

- Coal-fired power stations cannot be built beyond a certain date without CCS (say 2020)
- Those built before that date will be given a deadline for retrofitting CCS (say in the period 2020-2025)
- Or plants which choose not to retrofit should be allowed to generate for a very limited number of hours.

In April 2009 the Government responded with a proposed approach:

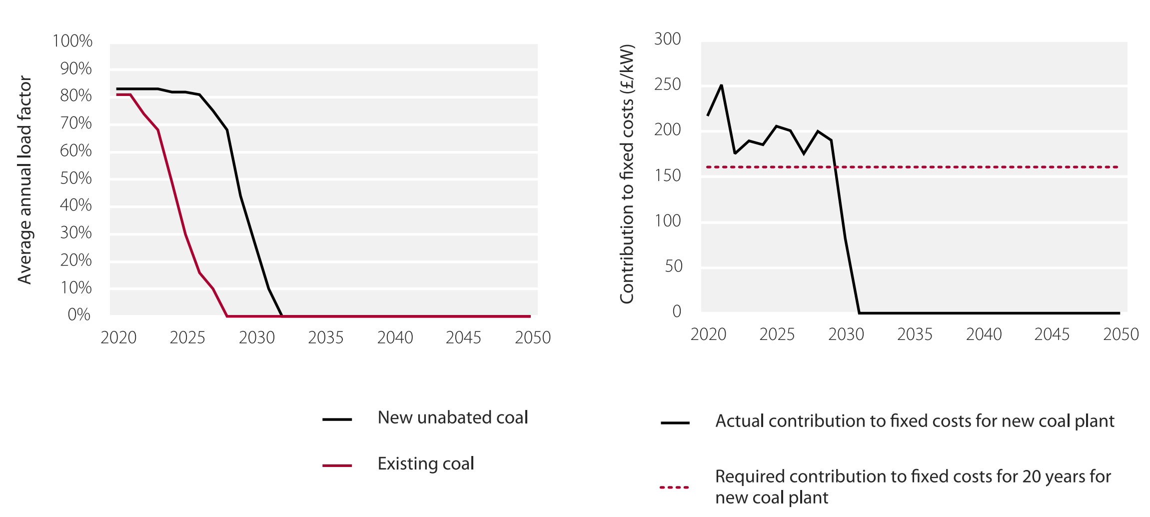
- Any investment in new coal-fired power generation would have to be at least part fitted with CCS.
- The remainder of plant built will have to be retrofitted with CCS if this is regarded as proven under a review to be carried out in 2020.
- If the review in 2020 does not regard CCS as proven, operation of any plant that is not retrofitted could be limited.

The Committee broadly welcomes the Government's proposals which will support development of CCS technology.

We are concerned, however, whether the proposed framework would lead to appropriate application of CCS technology in a timely manner:

- In particular, we envisage a situation post-demonstration where the carbon price is insufficient to cover CCS costs, but where deployment is desirable given the strategic importance of decarbonising the power sector and the potential to further reduce CCS costs through learning. It is not clear that CCS would be regarded as proven in these circumstances under the Government's proposals.

Figure 4.22 Projected load factors and profitability for conventional coal



Source: CCC calculations based on Redpoint (2009), *Decarbonising the GB power sector* to 2030 and assumed carbon price above €100t/CO_2.

- There is a long lag between when the first demonstration plant is scheduled to be up and running (2014) and the proposed timing for the review (2020), which is particularly problematic given the lead-times of five or six years for a CCS plant and the need to roll out CCS from the early 2020s.

We are also concerned as to whether the proposals give a strong enough signal that for any plant not fitted with CCS there will be little or no role further into the 2020s; the fact that there will be a review does not ensure an expectation that the generation would be severely limited.

Given our concerns, we therefore recommend that:

- Whether CCS is deemed proven should not be judged only on the basis of the carbon price. Rather it should be considered in the wider context of power sector decarbonisation required both in the UK and internationally, and on the basis of UK and international evidence.
- To the extent that retrofit might be considered desirable in this context but would require additional support over and above what is likely to be provided by the carbon price, investors should be given comfort now that a mechanism would be introduced to provide this support.
- Such a mechanism should be introduced no later than 2016 to support roll-out once the first demonstration plants become operational. Some decisions on regulation and financing structure could be made in advance of this date.
- The Government should make it absolutely clear now that whether or not CCS can be deemed economically viable any conventional coal plant still operating unabated beyond the early 2020s would only generate for a very limited number of hours. Such a statement should be complemented by a review (e.g. in 2020) to determine the precise level and timing of such a limit.

6. Assessment of current power market arrangements and possible interventions

In this section we assess whether current electricity market arrangements will deliver sector objectives:

- Power generation should be substantially decarbonised by 2030
- Security of supply should be maintained, with the risk of power outages kept to very low levels
- Electricity should be produced in a way that minimises costs and be delivered at affordable prices to consumers.

Our assessment is based on analysis of private and social risks associated with investment in low-carbon technology, and detailed modelling of the UK power system carried out for us by Redpoint Energy and Pöyry Energy Consulting. We set the analysis out as follows:

(i) Investment risks under current arrangements

(ii) Modelling approach and results

(iii) Conclusions and next steps.

(i) Investment risks under current arrangements

Current arrangements were designed for a different set of circumstances where there was excess capacity and where it was envisaged that any new investment would probably be in gas-fired generation (Box 4.9). Going forward, however, there is an emerging capacity deficit which must be addressed through investment in low-carbon generation on the path to meeting the 80% emissions reduction target.

Box 4.9 Existing market arrangements

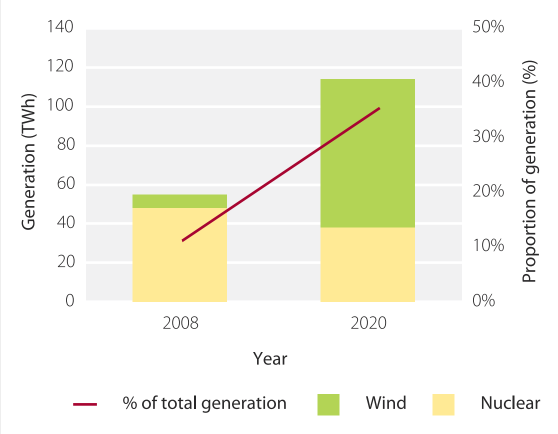
The market for electricity is governed by a complex set of regulatory arrangements (BETTA – British Electricity Trading and Transmission Arrangements) within which electricity is traded between generators and suppliers or large consumers.

BETTA contains a number of forward markets covering months and years ahead. It also includes a balancing market, which operates close to real time and allows matching of demand and supply.

Prices in the balancing market reflect either the cost of the last plant dispatched or, where the system is capacity constrained, willingness to pay of suppliers or large energy consumers. Balancing market prices are very 'peaky', reflecting short run marginal cost much of the time, and rising to very high levels when capacity is constrained and demand reductions are therefore required.

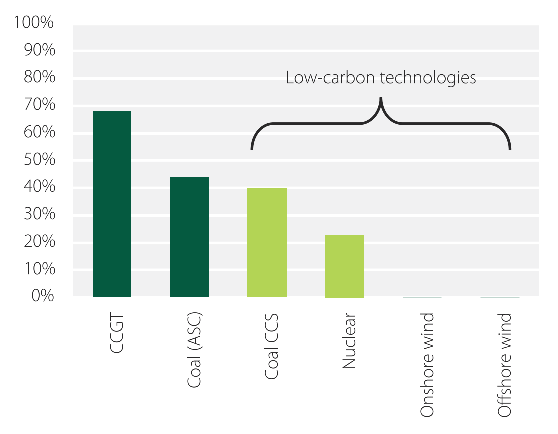
Prices in forward and retail markets are smoothed, and therefore do not reflect volatility in the balancing market. Trends in balancing market prices are however reflected in forward and retail prices. Gas price increases, or system capacity constraints, will result in increased balancing, forward and retail prices.

Figure 4.23 Generation from intermittent and inflexible plant 2008 and 2020 in CCC scenario



Source: CCC and DECC (2009); *DUKES*; Table 5.6 and 7.4.

Figure 4.24 Short run marginal cost as a proportion of long run marginal cost for a range of technologies



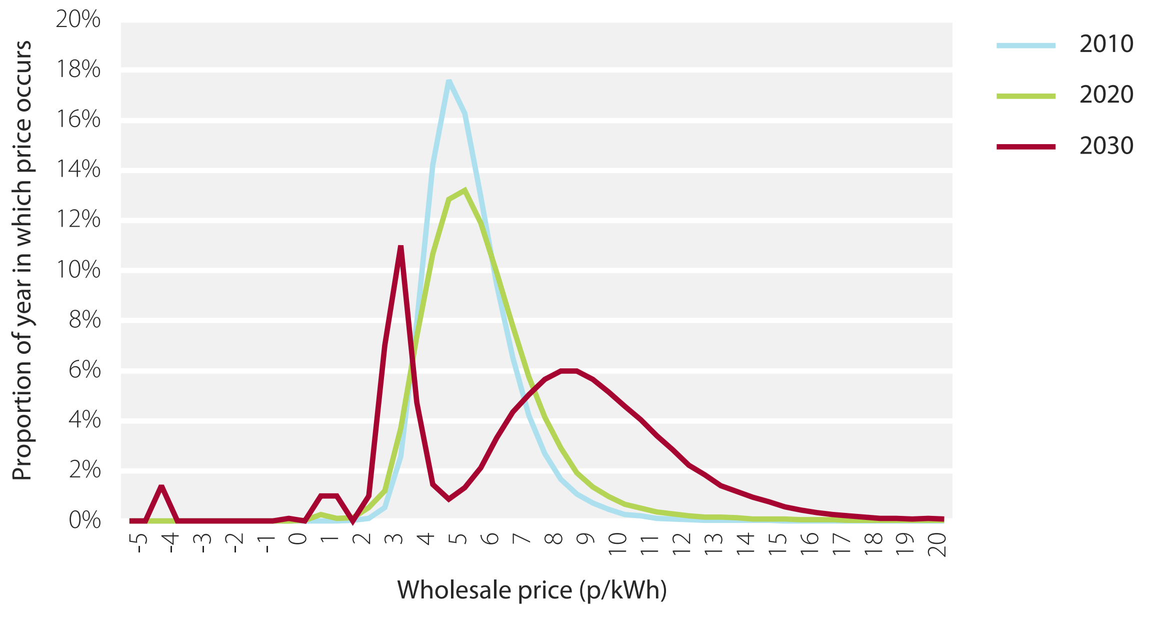
Source: CCC calculations based on Redpoint (2009), *Decarbonising the GB power sector* and SKM (2008) *Growth scenarios for UK renewables generation and implications for future developments and operation of the electricity network.*
Note: Costs refer to plants built in 2020.

The power system that we have committed to create will be characterised by increasing amounts of intermittent and inflexible generation operating with very low short run marginal costs (Figure 4.23, Figure 4.24). Under current arrangements, the electricity price in this system would be increasingly peaky (i.e. low for much of the time and very high for a small number of time periods – Figure 4.25); this price volatility would compound uncertainty associated with the volatile EU ETS price (Chapter 2).

These two sources of policy uncertainty exacerbate a potential problem caused by a mismatch between private and social risk under current arrangements:

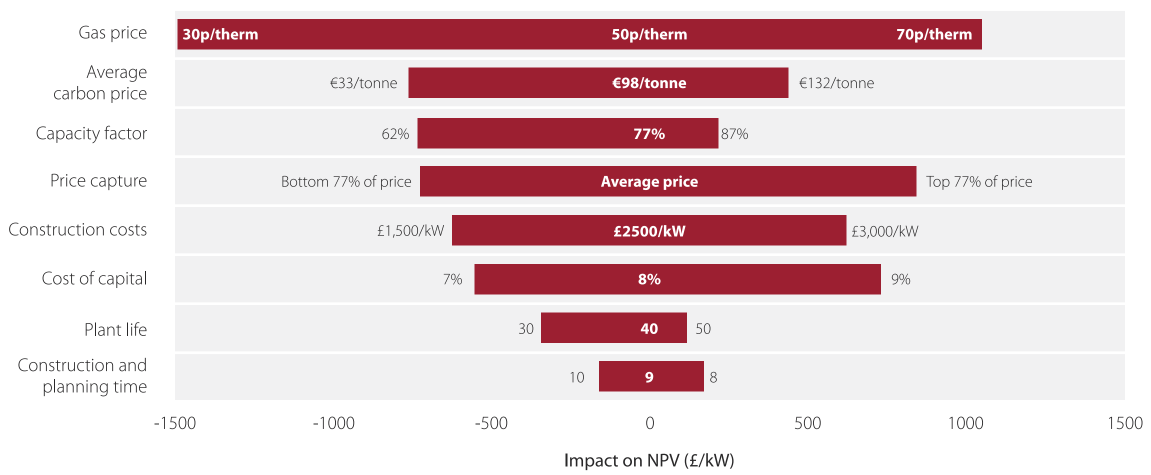
- A private investor in a low-carbon technology (e.g. nuclear) is subject to fossil fuel price risk, carbon price risk, electricity price risk, and technology cost risk (Figure 4.26).

Figure 4.25 Price density functions for 2010, 2020 and 2030



Source: Redpoint (2009), *Decarbonising the GB power sector.*
Note: By 2030, generation is made up of 34% renewables and 28% nuclear.

Figure 4.26 Relative importance of uncertainties faced by nuclear investors



Source: CCC calculations, based on the analysis presented in CBI (2009), *Decision time*; Redpoint (2009) *Decarbonising the GB power sector.*

- For a society committed to power sector decarbonisation, the only relevant risks are those associated with the costs of the low-carbon technology (i.e. risks associated with capital and fuel costs and operational characteristics of that technology).

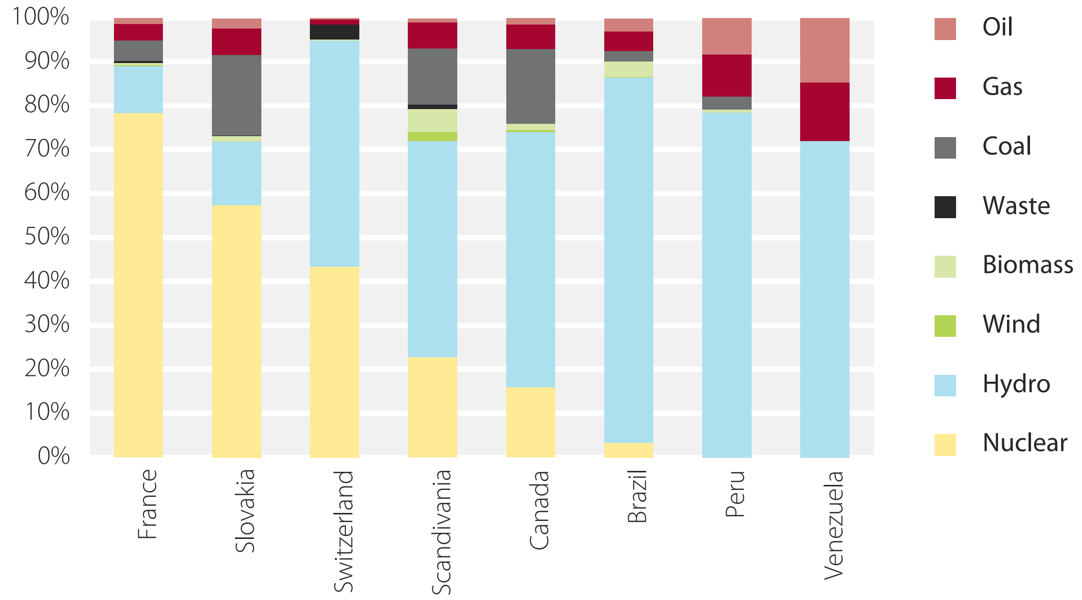
Given this mismatch there is a danger that private investors will tend towards investing in gas-fired power generation rather than the low-carbon generation which is required, and that this will jeopardise meeting carbon budgets and/or increase the costs of doing so. We note that no other country has relied on a fully liberalised electricity market of the type that we have in the UK to deliver investments in low-carbon generation (Box 4.10).

Box 4.10 International experience of incentivising investment in low-carbon generation

Several countries already source over 70% of their power generation from low-carbon sources (Figure B4.10)[9]. For these, investment has typically only occurred with substantial government intervention, even where markets have subsequently been liberalised:

- Several of these countries benefit from a large hydro resource. Hydro has very different technical and economic characteristics to wind and nuclear, and is more comparable to thermal plant: though it has low marginal costs, it has a high opportunity cost, is flexible and can be run at peak times. However, even where the main source of electricity is hydro, investment has relied on government intervention – markets in Canada and Venezuela are still dominated by state-owned firms, whilst most major hydro plants in Brazil and Peru were built prior to market reforms.
- In France, Slovakia and Switzerland over 80% of generation is provided by state-owned companies, with government having directed investment to reach high levels of nuclear capacity. France has the highest level of non-hydro low-carbon generation, with 78% of generation from nuclear, which has been adapted to load follow (i.e. is more flexible than current UK capacity) and benefits from good interconnection with the rest of Europe, allowing it to export electricity at times of low domestic demand.
- The integrated Scandinavian electricity market (Nordpool) has been liberalised and has a high level of low-carbon generation. However, most of the investment in low-carbon, capital intensive plant happened before liberalisation and was driven by state-owned utilities. Investment in renewables has continued since liberalisation, incentivised by a range of interventions to the market including taxes and tax rebates, investment support schemes, feed-in tariffs and obligations.

Figure B4.10 Generation mix in predominantly low-carbon electricity markets (2006)



Source: International Energy Agency www.iea.org

9 We do not cover Costa Rica, Columbia or Iceland due to lack of data.

(ii) Modelling approach and results

Having identified a risk mismatch, we commissioned Redpoint Energy to explore the implications by simulating investment scenarios which model variation in:

- Parameters that determine the economics of generation investment (e.g. electricity demand, fossil fuel prices, levels of intermittent generation – Box 4.11)
- Investor behaviour (e.g. the extent to which investors perceive levels of risk to be higher, the way that carbon price expectations are formed – Box 4.12).

Box 4.11 Summary of Redpoint scenarios

Redpoint modelled around 30 scenarios for the CCC. A core scenario was based on environmentally favourable conditions (a carbon price consistent with a global deal, low electricity demand and successful delivery of 32% renewable generation by 2020). The rest of the scenarios varied either exogenous conditions (e.g. commodity prices), policy choices (e.g. restricting wholesale price peaks), investor behaviour (e.g. perception of risk and foresight on the carbon price – Box 4.12), or a combination of one or more of these factors. The most important of the scenarios are summarised in the below table. Detailed descriptions of the full set of scenarios are set out in the Redpoint study[10].

Table B4.11 Modelled scenarios

Scenario	Description	Modelled with alternative investor behaviours
Environmentally favourable conditions	Fuel prices based on DECC scenario 2[11] Carbon price consistent with global deal (€120 in 2030)	Yes
Peak price constraint	Wholesale electricity prices are restricted in the modelling from peaking above £500/MWh	No
More renewables	Target of 36% of generation in 2020, reflecting maximum feasible use of UK resource	Yes
Reduced interconnector flexibility	A reduction of export capability at times of high wind output simulating a higher correlation between wind output in GB and the continent	Yes
High fossil fuel prices	Fuel prices based on DECC scenario 4	No
Low fossil fuel prices	Fuel prices based on DECC scenario 1	No
Less successful energy efficiency policy	0.6% growth in electricity demand per year	No
Low EUA prices	EUA prices reaching only €45 by 2030	Yes

10 Redpoint (2009) *Decarbonising the GB power sector.*
11 DECC (2009) *Communication on Fossil Fuel Prices.*

Box 4.12 Summary of investor behaviour scenarios in the Redpoint modelling

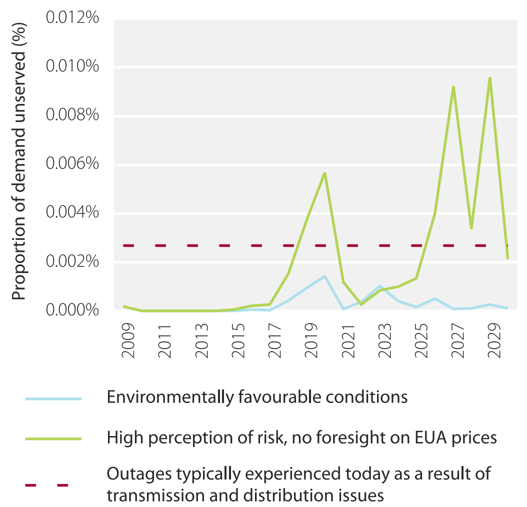
In order to take account of the fact that investors will not always behave as 'textbook' economic agents, we asked Redpoint to model a number of alternative investor behaviours. These were looked at alone, and in combination.[12]

Table B4.12 Summary of alternative investor behaviours

	Central behaviour	Alternative behaviour	Rationale for scenario
Foresight on EUA prices	Investment decisions made on the basis of ten year forward look on EUA price.	Investment decisions based on in-year EUA price.	It is very difficult for investors to make an investment case on the expectation of a high EUA price in ten years' time. There is anecdotal evidence that the current price is often used in investment decisions as a best estimate of the future price.
Hurdle rates required for investment	Hurdle rates determined in Redpoint modelling – around 10% for low-carbon technologies, slightly lower for CCGT and coal.	3% added to hurdle rate in each scenario.	Risk averse investors will require a premium when faced with multiple market risks.

The analysis suggests that across the range of scenarios, and with sufficiently high prices in peak periods to which investors respond, security of supply in terms of unserved demand due to generation shortage should not be an issue (Figure 4.27). Where market risks are perceived to be high, investors revert to investment in (relatively low risk) gas-fired generation. This finding is consistent with analysis underpinning the 2006 Energy Review and 2007 Energy White Paper, which focused on security of supply in the period to 2016 and concluded that the market would fill the emerging capacity deficit with gas-fired generation.

Figure 4.27 Expected energy unserved due to generation shortage



Source: Redpoint (2009), *Decarbonising the GB power sector.*

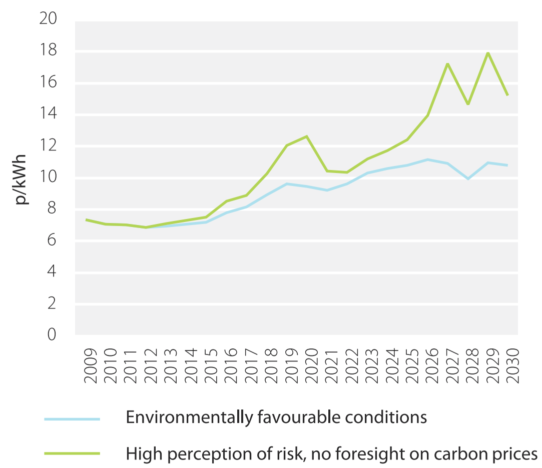
12 Full results available in the supporting research paper: Redpoint (2009) *Decarbonising the GB power sector*

The analysis suggests, however, that under current arrangements there are risks of unnecessarily high prices for consumers and that required decarbonisation will not be achieved (Box 4.13):

- Even where current arrangements function ideally, gas-fired generation will continue to set the electricity price most of the time. Electricity prices will increase over time as the carbon price increases, and low-carbon generators will capture significant rents. Increasing prices are likely to be problematic from fuel poverty and wider political economy perspectives and could rise much less significantly under a different set of arrangements where gas-fired generation did not continue to determine the return for all generators (Figure 4.28).
- There are plausible scenarios where investors favour investment in gas-fired rather than low-carbon generation. This is likely to ensue where investors require higher returns in response to risks that are induced by the current arrangements, and/or where investments are made on the basis of prevailing carbon prices rather than an assumption of increasing carbon prices. These scenarios lead to lock-in to high-carbon assets and failure to make sufficient progress with decarbonisation by 2030, unnecessarily high system costs/prices, and loss of any security of supply benefits associated with generation from low-carbon sources rather than imported gas (Figure 4.29).

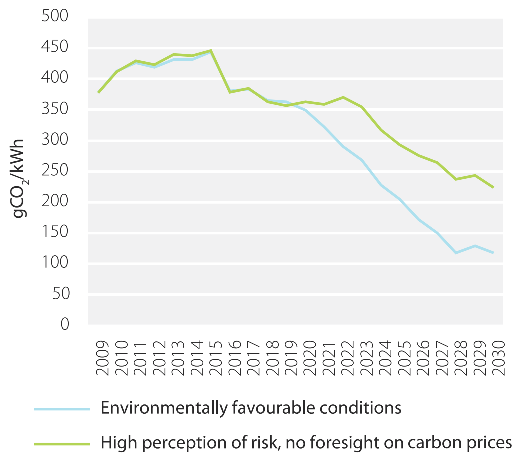
In addition to commissioning the Redpoint modelling, we joined a multi-client study by Pöyry Energy Consulting which simulated investment scenarios using a different power sector model. In line with the Redpoint analysis, Pöyry analysis suggests that with high levels of wind generation, returns for investors will become far less certain under current market arrangements and investment incentives will be undermined, particularly for low-carbon technologies (Box 4.14).

Figure 4.28 Wholesale cost to consumers under alternative scenarios



Source: Redpoint (2009), *Decarbonising the GB power sector.*
Note: These prices exclude VAT, transmission and distribution costs, and the costs of energy efficiency policies.

Figure 4.29 CO_2 intensity of generation under alternative scenarios



Source: Redpoint (2009), *Decarbonising the GB power sector.*
Note: Emissions intensity is not adjusted for losses during transmission and distribution.

Box 4.13 Summary of Redpoint modelling results

The key results of the Redpoint modelling for decarbonisation, security of supply and prices are[13]:

- **Decarbonisation:** In the core scenario emissions intensity falls to around 120 gCO_2/kWh by 2030. However, if the carbon price only reaches €45/tonne (rather than €120/tonne) then intensity only falls to 260 gCO_2/kWh. Even with a higher carbon price, if this is not foreseen by investors and they have a high perception of risk then only 220 gCO_2/kWh is achieved. High risk perception is especially damaging as it biases against (capital intensive) nuclear and CCS.

- **Security of supply:** Capacity margins are lowest where decisions are based on the current (not future) carbon price, and where the perception of risk is high, delaying investment and resulting in unserved energy peaking at around 30 GWh per year. Even in this scenario, levels of unserved energy are not much higher than those typically experienced today as a result of transmission and distribution outages.

- **Prices:** Even in scenarios where over 60% of generation is coming from low-marginal cost plant by 2030, CCGT plant continues to set the price most of the time. As such, rising commodity and EUA prices lead to very high consumer prices in 2030 (and large rents to low-carbon generators) in all scenarios. Prices are highest where the perception of risk is higher, and where there is a lack of foresight on the EUA price, as investment is made in high-carbon assets which then prove very expensive to run.

Table B4.13 Key results of Redpoint modelling

	Standard perception of risk, foresight on EUA price	**Higher perception of risk, investment based on current EUA price**
Decarbonisation by 2030	~120 gCO_2/kWh in 2030	~220 gCO_2/kWh in 2030
Security of supply	Annual unserved energy peaks at 0.001% of demand	Annual unserved energy peaks at around 0.003% of demand
Wholesale cost to consumers	11p/kWh in 2030	15p/kWh in 2030

13 Full results available in the supporting research paper: Redpoint (2009) *Decarbonising the GB power sector*

Box 4.14 Summary of Pöyry Energy Consulting analysis

The CCC joined several key players in the power sector (including National Grid and three of the 'big six' energy companies) in funding Pöyry Energy Consulting's investigation into the challenges large-scale investment in wind might pose for the electricity market to 2030[14].

Pöyry's study examined historical wind patterns, taking hourly data for eight years from 36 different locations across the UK and Ireland. These data were used to generate forecasts of wind power output and to estimate the resulting impact on the electricity market for a number of scenarios to 2030. A core scenario was based on a very high assumed level of wind investment (33 GW installed by 2020 and 43 GW by 2030) alongside modest demand growth and significant investment in new nuclear. Additional scenarios varied other factors such as the level of interconnection.

Key findings of the study were as follows:

- While thermal plant and interconnectors appear able to deal with the dynamic requirements of a significant level of wind output, the running regime of thermal plant is likely to change dramatically, with much more irregular output patterns and lower average load factors. Frequent fluctuations in load may mean greater maintenance requirements or shorter lifetimes for thermal plant.
- Wholesale electricity prices fall but become much more volatile with high levels of wind generation. The distribution of prices becomes more extreme with some periods of negative prices and some periods of very high prices. By 2030, many plants earn a significant part of their annual return over a few periods per year. Meanwhile, average prices fall.
- More interconnection can help the physical management of the system, but is not a sufficient solution of itself.

Pöyry conclude that power stations built now will face a future of far lower and more uncertain load factors and dramatically increased uncertainty of revenues. They argue that the price spikes needed to reward the risks for investment in peaking plant are likely to stretch the market design to the utmost. Investors are unlikely to believe that price spikes will be allowed to occur and volatile prices greatly increase the risks of operation and dampen economic signals to new investors.

(iii) Conclusions and next steps

Risks under current arrangements

Power sector decarbonisation by the early 2030s is central to cutting emissions more generally (e.g. through the application of low-carbon electricity to cars and vans, etc.). Given the importance of moving to a low-carbon electricity system at affordable cost, the Committee believes that we should not accept the significant risks and costs associated with the current market arrangements.

We therefore strongly recommend that a range of options for power market intervention are seriously considered. New arrangements would replace current interim support for selected technologies. They should cover the full range of low-carbon generation technologies for the 2020s, and be designed to increase confidence about power sector decarbonisation, cut the costs of achieving this, and address any concerns about security of supply.

Options for market intervention

The options which we believe could potentially improve on the current market arrangements in delivering low-cost, low-carbon generation investment include (Box 4.15):

- Measures to strengthen the carbon price signal (e.g. underpinning the carbon price at the EU or UK level, extending the Climate Change Levy exemption to all new low-carbon sources)

14 Pöyry Energy Consulting (2009) *Impact of Intermittency*

- Measures to provide confidence over the price received by low-carbon generation (e.g. feed-in tariffs for low-carbon generation, tendering for low-carbon capacity)
- Measures to ensure investment in low-carbon capacity (e.g. a low-carbon obligation, possibly as part of a wider capacity obligation, or an emissions performance standard).

These options have not previously been assessed in the UK. The Committee recommends that they should now be seriously considered given the new context, in which the UK has committed to cut emissions by 80% in 2050, and where decarbonisation of the power sector in the period to 2030 is vital in achieving this goal.

Transitioning from current arrangements

Our analysis shows that we require significant investment in low-carbon generation from now over the next 20 years and beyond to 2050. We expect that this investment will initially be mainly in wind generation (over 20 GW), with investment in up to around 3 GW of new nuclear plant and 2 GW of CCS coal by 2020, and around an additional 20 GW of low-carbon generation capacity in the period 2020-2030.

The risks that we have identified adversely impact cost and viability of investment in nuclear and CCS, and may increase the costs of wind investment required to meet EU targets. In assessing the appropriate timing of possible interventions, we have considered the timing of decisions to invest, the time likely to be required to introduce any intervention, and the need for near term investment in gas-fired generation:

- Working back from when investments should ideally come on line, and given long project lead times, decisions to proceed with investment in low-carbon generation for the 2020s will have to be made in the relatively near term (e.g. during the second carbon budget period).
- Detailed design of a market intervention could require a lengthy process. We note that it took several years each to move from the old power pool to the New Electricity Trading Arrangements (NETA), and from NETA to the current British Electricity Trading and Transmission Arrangements (BETTA).
- Our extensive discussions with a wide range of industry stakeholders – energy companies, analysts, academics – suggest a strong consensus that current arrangements will not deliver a low-carbon power generation system through the 2020s, and that changes to the current arrangements are both required and inevitable. In these circumstances, a failure to review current arrangements may be perceived as creating more uncertainty by postponing introduction of inevitable change.
- A new global agreement to reduce emissions and the EU response could have implications for the carbon price which in turn could change the power sector investment climate for the period to 2020 and beyond.
- There is a significant amount of gas-fired generation currently in the pipeline that we expect to move forward and replace coal-fired capacity that will come off the system before 2016 and therefore maintain near-term system security (Table 4.2). These investments will be required whatever new mechanisms are introduced, and should be provided with appropriate comfort in the context of any review.

The Committee's judgement in balancing these concerns is that a comprehensive review of the current market arrangements should be carried out in the near term. This should reflect any implications of Copenhagen for EU targets, the carbon price and UK carbon budgets. It should be designed to address adequately concerns for current investment in gas-fired generation. Any delay in moving forward with a review as soon as is practical following Copenhagen will jeopardise prospects for successfully decarbonising the power sector in the 2020s.

Box 4.15 Potential power market interventions

The below table briefly describes a set of market interventions which could help support investment in low-carbon generation capacity. These range from measures which could be introduced relatively quickly, and would entail minimal change over the current system (such as extending the exemption for renewables from the Climate Change Levy to other new build low-carbon generation) to measures which would mean a much greater level of government intervention (such as introducing a system of tendering for low-carbon capacity). The measures listed here are not necessarily mutually exclusive or exhaustive.

The CCC does not yet have a view on which measure would best tackle the risks posed by the current market structure, but believes that all should be seriously considered in the near term.

Table B4.15 Potential power market interventions

Measures	Description
Measures to strengthen the carbon price signal	
Extend exemption from Climate Change Levy (CCL) to all new low-carbon generators	The CCL is a 0.4p/kWh levy on the supply of electricity to industry, commerce, agriculture, public administration and other services. Renewable generation is already largely exempt. This exemption could be extended to new nuclear and new CCS.
Carbon price underpin	The carbon price faced by the power sector could be prevented from falling below a certain level, for example by setting an auction reserve price at the EU level or using a carbon tax or contracts for difference to set a minimum carbon price for the UK.
Measures to provide confidence over the price received by low-carbon generation	
Feed-in tariffs for low-carbon technologies	Feed-in tariffs would guarantee a price for a fixed period for electricity generated by new low-carbon generators.
Tenders for low-carbon capacity	An agency could competitively tender for investment in low-carbon capacity, offering successful bidders long-term contracts free of commodity price risks.
Measures to ensure investment in low-carbon capacity	
Emissions performance standard	An emissions performance standard would entail regulation to specify a maximum emissions intensity (g/kWh) of generation. This could be introduced at firm or installation level.
Low-carbon obligation	An obligation could be placed on UK suppliers to source an increasing proportion of their electricity from low-carbon sources to ensure the required investment in low-carbon generation is undertaken. It could also be set to up to require that generators have sufficient installed capacity to meet the peak load of the customers they serve, plus a reserve margin.

Table 4.2 Current power sector projects in the pipeline

	Under construction	With planning consent (all have TEC), but not yet under construction	Total
Fuel type	**GW**	**GW**	**GW**
Coal	0	0	0
Gas	5.1	7.5*	12.6
Nuclear	0	0	0
Wind	2.1	6.9	9.0
Other renews	0.1	0.4	0.5
CHP	0	0	0
Interconnector	1.2	0	1.2
Total	**8.5**	**14.8**	**23.3**

* Includes 0.8 GW Hatfield project whose turbines will operate initially on natural gas, switching to coal IGCC with CCS as and when that part of the plant is operational.
Source: CCC calculations based on DECC, BWEA (September 2009) http://www.bwea.com/statistics/
Note: Transmission Entry Capacity (TEC) is a Connection and Use of System Code term that defines a generator's maximum allowed export capacity onto the transmission system. Wind data is measured on an installed capacity basis.

7. Summary of power sector indicators

Our indicators of progress for the power sector include (Table 4.3):

- Power sector emissions and emissions intensity
- Low-carbon capacity deployment (e.g. trajectories for adding onshore and offshore wind generation)
- Forward indicators to assess progress delivering capacity (e.g. amounts of onshore and offshore wind capacity entering and completing planning and under construction)
- Underpinning indicators required to deliver progress (e.g. planning approval rates and times, supply chain capability)
- Policy milestones for required enabling frameworks (e.g. early decisions on transmission network access and investment).

Table 4.3 Power sector indicators

Power		Budget 1	Budget 2	Budget 3
Headline indicators				
Emissions intensity (g/kWh)		509	390	236
Total emissions (% change from 2007)		-15%	-39%	-64%
Generation (TWh)	*Wind*	21	50	98
	Nuclear	58	30	48
	CCS	0	5	11
Supporting indicators				
Transmission				
Agreement on incentives for anticipatory investment for Stage 1 reinforcements		2010		
Implementation of enduring regime for accessing grid		2010		
Transitional OFTO regime in place		2009		
Enduring OFTO regime in place		2010		
Grid reinforcement planning approval		2011: Scotland Stage 1, Wales Stage 1 (Central), South East	2013: Wales Stage 1 (North), English East Coast Stage 1, South West 2014: Scotland Stage 2	
Grid reinforcement construction begins		2012: Scotland Stage 1, Wales Stage 1 (Central), South East	2014: Wales Stage 1 (North), English East Coast Stage 1, South West 2015: Scotland Stage 2	
Grid reinforcements operational			2015: Scotland Stage 1, Wales Stage 1 (Central), South East 2017: Wales Stage 1 (North), English East Coast Stage 1, South West	2018: Scotland Stage 2

Table 4.3 continued

Power		Budget 1	Budget 2	Budget 3
Transmission continued				
Tendering for first offshore connections under enduring OFTO regime		2010		
Construction of first offshore connections under enduring OFTO regime begins		2011		
First offshore connections under enduring OFTO regime operational		2012		
Planning				
IPC set up and ready to receive applications		2010		
Market				
Review of current market arrangements and interventions to support low-cost, low-carbon generation investment		to begin in first budget period		
Wind				
Generation (TWh)	*Onshore*	13	26	44
	Offshore	8	24	54
Total capacity (GW)	*Onshore*	5.7	10.8	18.0
	Offshore	2.5	7.4	16.6
Capacity entering construction (GW)	*Onshore*	0.9	1.3	1.5
	Offshore	0.9	1.6	2.6
Capacity entering planning	*Onshore*	New planning applications will be required from the end of the second budget period at the latest to maintain flow into construction		
	Offshore	New planning applications will be expected in line with site leasing		
Average planning period (months)		<12	<12	<12

Note: Numbers indicate amount in last year of budget period i.e. 2012, 2017, 2022

Key

Headline indicators Implementation indicators Forward indicators Milestones Other drivers

Table 4.3 continued

Power	Budget 1	Budget 2	Budget 3
Nuclear			
Regulatory Justification process	2010		
Generic Design Assessment	2011		
National Policy Statement for nuclear (including Strategic Siting Assessment)	2010		
Regulations for a Funded Decommissioning Programme in place	2010		
Entering planning	first planning application in 2010	subsequent applications at 18 month intervals	
Planning approval; site development and preliminary works begin	first approval and site development and preliminary works begin in 2011	subsequent application approvals, site development and preliminary works at 18 month intervals	
Construction begins		first plant in 2013, subsequent plants at 18 month intervals	
Plant begins operation			first plant in 2018, with subsequent plants at 18 month intervals*
CCS			
Front-End Engineering and Design (FEED) studies for competition contenders completed	2010		
Announce competition winner	2010		
Second demonstration competition	launch 2010, announce winners 2011		
Quantification of saline aquifer CO_2 storage potential		no later than 2015	
Review of technology and decision on framework for future support		no later than 2016	
Strategic plan for infrastructure development		no later than 2016	

Table 4.3 continued			
Power	**Budget 1**	**Budget 2**	**Budget 3**
CCS continued			
Planning and authorisation approval, land acquisition, and storage site testing completed, construction commences	first demo in 2011	subsequent demos 2012/13	
Demonstrations operational		first demo in 2014, subsequent demos 2015/16†	
First new full CCS plants supported via the 2016 mechanism			2022
Other drivers			
Total demand (TWh), coal and gas prices, nuclear outages *Average wind load factors, availability of offshore installation vessels, access to turbines* *Nuclear supply chain, availability of skilled staff* *International progress on CCS demonstration and deployment* *Planning approval rates and frequency of public inquiries to decisions of Infrastructure Planning Commission*			

Note: Numbers indicate amount in last year of budget period i.e. 2012, 2017, 2022
* Up to 3 nuclear plants by 2022.
† Up to 4 CCS demonstration plants by 2020.

Key:
Headline indicators Implementation indicators Forward indicators Milestones Other drivers