Committee on Climate Change

Power sector scenarios for the fifth carbon budget

October 2015

Acknowledgements

The Committee would like to thank:

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A wide range of stakeholders who attended our expert workshops, responded to our Call for Evidence, engaged with us, including through our public dialogue, or met with the Committee bilaterally.

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The Committee

The Rt. Hon John Gummer, Lord Deben, Chairman

The Rt. Hon John Gummer, Lord Deben, was the Minister for Agriculture, Fisheries and Food between 1989 and 1993 and was the longest serving Secretary of State for the Environment the UK has ever had. His sixteen years of top-level ministerial experience also include Minister for London, Employment Minister and Paymaster General in HM Treasury.

He has consistently championed an identity between environmental concerns and business sense. To that end, he set up and now runs Sancroft, a corporate responsibility consultancy working with blue-chip companies around the world on environmental, social and ethical issues. Lord Deben is Chairman of Valpak Limited and the Association of Professional Financial Advisors.

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Professor Sir Brian Hoskins, CBE, FRS is the Chair of the Grantham Institute for Climate Change and the Environment at Imperial College London and Professor of Meteorology at the University of Reading. His research expertise is in weather and climate processes. He is a member of the scientific academies of the UK, USA, and China.

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Paul Johnson has been director of the Institute for Fiscal Studies since January 2011. He is a visiting professor at UCL. Paul has published and broadcast extensively on the economics of public policy including tax, welfare, inequality and poverty, pensions, education, climate change and public finances. He is author of major books on pensions, tax and inequality. He is one of the authors of the “Mirrlees review” of tax system design. Paul has previously worked at the FSA and has been chief economist at the Department for Education and director of public spending in HM Treasury as well as deputy head of the UK Government Economic Service.

Paul is currently a member of the council and executive committee of the Royal Economic Society, a member of the banking standards board and has just completed an independent review of consumer price inflation statistics for the UK Statistics Authority. He has previously served on the council of the Economic and Social Research Council. He was a founder council member of the Pensions Policy Institute and in 2010 he led a review of the policy of auto-enrolment into pensions for the new government.

Professor Dame Julia King

Professor Dame Julia King is a Fellow of the Royal Academy of Engineering (FREng) and was made a CBE for ‘Services to Materials Engineering’ in 1999. She was appointed by the Chancellor of the Exchequer in March 2007 to lead the ‘King Review’ to examine the vehicle and fuel technologies that, over the next 25 years, could help to reduce carbon emissions from road transport.

She is currently Vice-Chancellor of Aston University, and is one of the UK’s Business Ambassadors, supporting UK companies in the areas of low carbon and transport. Following on from a career as an academic researcher and lecturer in materials engineering at the Universities of Cambridge and Nottingham, Julia King joined Rolls-Royce PLC in 1994. At Rolls-Royce, she held a number of senior executive appointments, including Director of Advanced Engineering for the Industrial Power Group and Engineering Director for the Marine Business. Julia returned to academia in 2004 as Principal of the Engineering Faculty at Imperial College, London, moving to Aston in 2006.

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Professor Lord Krebs Kt FRS FMedSci ML is Emeritus Professor of Zoology at Oxford University. He was Principal of Jesus College, Oxford between 2005 and 2015. Previously, he held posts at the University of British Columbia, the University of Wales, and Oxford, where he was lecturer in Zoology, 1976-88, and Royal Society Research Professor, 1988-2005. From 1994-1999, he was Chief Executive of the Natural Environment Research Council and, from 2000-2005, Chairman of the Food Standards Agency. He is a member of the U.S. National Academy of Sciences.

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Professor Jim Skea has research interests in energy, climate change and technological innovation. He has been RCUK Energy Strategy Fellow since April 2012 and a Professor of Sustainable Energy at Imperial College since 2009. He was Research Director of the UK Energy Research Centre 2004-12 and Director of the Policy Studies Institute 1998-2004.

He has operated at the interface between research, policy-making and business throughout his career. He is President of the Energy Institute and was elected co-Chair of IPCC Working Group III in 2015. He was awarded a CBE for services to sustainable energy in 2013 and an OBE for services to sustainable transport in 2004.

Executive summary

This report sets out scenarios for the power sector in 2030 as an input to our advice on the fifth carbon budget, which we will publish in November. The fifth carbon budget will set a limit on UK emissions of greenhouse gases over the period 2028 to 2032. It marks the halfway point from the first carbon budget (2008-12) to the UK's statutory target for 2050 to reduce emissions by at least 80% across the economy relative to 1990, as set out in the Climate Change Act.

We are publishing these scenarios ahead of our November advice given the importance of the power sector to meeting the economy-wide emissions targets. It has been a common finding of our previous work that meeting the 2050 target will require that emissions from energy use – power, heat and transport – are almost eliminated. To achieve this it is important to have low-carbon sources of energy that are low cost, secure, acceptable to the public and attractive to investors. A decarbonised power sector can provide that low-carbon energy source.

Our scenarios set out possible futures for the UK power sector. They are not intended to set out a prescriptive path. The scenarios provide a tool for the Committee to verify that its advice can be achieved with manageable impacts for the criteria in the Climate Change Act, including competitiveness, affordability and energy security. We welcome comments and input on this analysis.

Our key messages are as follows, leading to the policy implications in Box 1:

- **New investment will be needed in the 2020s.** Up to 200 TWh of new generation will be needed in the 2020s to replace generation from retiring coal and nuclear capacity and to meet possible increases in demand (total annual generation is expected to be around 310 TWh in 2020 and 380 TWh in 2030). The 2020s are therefore a crucial decade for the future of the power sector.
- **Low-carbon options are likely to be cost-competitive.**
  - Several low-carbon options should reach maturity by or during the 2020s. If unabated gas-fired generation faces the full cost of its carbon emissions (i.e. a 'target-consistent' carbon

price, estimated at £78/tonne in 2030, see Box 3), these options could be delivered without further subsidy, even when intermittent generation faces the full system costs it imposes.

  – These options represent good value investments for a society committed to climate targets and are included in our scenarios: onshore wind and ground-mounted solar from the first half of the decade, and nuclear, offshore wind and potentially carbon capture and storage (CCS) in the second half of the decade.

- **A portfolio approach is appropriate and justifies continued support for less mature technologies, which should fall until subsidies can be removed.**
  – Our scenarios also include investments in less mature options – principally offshore wind and CCS – in the first half of the 2020s, when these will still need subsidies. These are required to drive down costs for competitive deployment from the second half of the decade.
  – CCS is very important for reducing emissions across the economy and could almost halve the cost of meeting the 2050 target in the Climate Change Act.
  – Offshore wind is demonstrating cost reduction and has the potential to meet a large share of total electricity demand. The majority of required development costs have already been committed as part of efforts to meet the UK's 2020 renewables target.
- **Flexibility is important.** To maximise the value of these investments and ensure security of supply it will be important to improve the flexibility of the power sector. That will require investment in flexible gas-fired generating capacity alongside expansion of international interconnection, flexible demand response and potentially electricity storage. The costs of these measures are included in our assessment of intermittency and system costs.
- **Scenarios for the fifth carbon budget.**
  – Investments that are already committed to 2020, along with the closure of coal capacity, will reduce emissions intensity of the UK power sector from around 450 gCO_2/kWh to 200-250 gCO_2/kWh.
  – Our new scenarios for 2030 are towards the upper end of the 50-100 gCO_2/kWh range that we have previously identified as suitable for 2030. That reflects delays to new nuclear and CCS projects alongside good progress for renewable technologies. Emissions in 2030 are around 55 $MtCO_2$ lower in these scenarios than if investment in the 2020s was in gas-fired rather than low-carbon generation.
- **Impact on consumer bills.**
  – In 2020, a typical household will be paying around £105 through their annual electricity bill of around £500 to support investment in low-carbon generation, including the market carbon price. Those costs are already committed through investments that are underway and contracts that have been awarded.
  – In our scenarios, support will increase to £120 per household in 2030 and then fall as support for earlier investment expires.
  – Costs to households would be around £20 higher in 2025 and £40 higher in 2030 in our scenarios than if investment in the 2020s was focused on gas-fired generation facing a market carbon price (which we expect to rise to £42/tonne in 2030, lower than the target-consistent carbon price, see Box 3).

- **Policy implications.** The key tools are in place to deliver this low-carbon investment – long-term contracts with price discovery through competitive auctions. However, to deliver at lowest cost, the Government must urgently clarify the direction for future policy (Box 1).

Box 1: Policy implications

- Extend funding for low-carbon generation under the Levy Control Framework to at least 2025. This is required to provide a clear long-term signal to investors that there will be a future market for low-carbon contracts, which are auctioned at the Government's discretion.
  - Total available funding should increase from £8 billion in 2020 to around £9 billion in 2025 under central assumptions, including that the Government keeps to its target trajectory for carbon prices (i.e. £42/tonne in 2025, on the path to £78/tonne in 2030).
  - For this to be an effective signal of the funding available for new projects the Government must set out how the total will be adjusted if circumstances do not turn out as assumed. For example, funding should increase to £9.8 billion if the market carbon price reaches only half the level the Government has targeted for the carbon price floor (e.g. £21/tonne instead of £42/tonne in 2025).
- Set out the timetable and funding pots for the next auction round for low-carbon contracts. A separate funding pot should be reserved for emerging technologies, including offshore wind and CCS until the mid-2020s. These important technologies would be unlikely to secure contracts if they were to compete openly with other low-carbon technologies to provide new generation before 2025.
- Set auction reserve prices for low-carbon options that have reached maturity based on the expected lifetime costs of new gas capacity facing its full carbon cost, allowing for intermittency costs and consistent with potential cost reduction. For example, that would imply a maximum price for onshore wind and ground-mounted solar of £80/MWh from 2020, and for offshore wind of £90/MWh from around 2025, with the expectation that competitive auctions could deliver lower prices.
- Set out an approach to commercialise CCS through the planned clusters: including a strategic approach to transport and storage infrastructure, completing the two proposed projects and contracting for at least two further 'capture' projects this Parliament.
- Work with Ofgem and National Grid to ensure that flexibility options (e.g. flexible demand response, interconnection with other parts of Europe, storage) are able to capture their full value and low-carbon investments face their full system integration costs.
- Develop approaches to securing low-cost generation at the end of contract life and from repowering (i.e. re-using existing sites by installing new equipment but taking advantage of the existing grid connections and other existing infrastructure to reduce costs).
- Consider further routes to reduce the cost of capital alongside the increased policy certainty that would accompany carrying out the above actions (e.g. infrastructure guarantees, risk-sharing ahead of auctions).

We set out our full summary in seven sections:

a) The power sector today and the challenge in the 2020s

b) Our approach to building power sector scenarios

c) The opportunity for low-cost deployment of low-carbon options

d) Offshore wind and CCS beyond 2020

e) Scenarios for the power sector in 2030

f) Costs of low-carbon support and implications for electricity bills

g) Policy to deliver the scenarios at lowest cost

(a) The power sector today and the challenge in the 2020s

Power sector emissions were 121 $MtCO_2$ in 2014, around a quarter of total UK greenhouse gases (Box 2). The majority of these emissions are from coal (71% of emissions, whilst providing 32% of generation) followed by gas (27% of emissions, 29% of generation). There are no direct emissions from the 19% of generation from nuclear or 20% of generation from renewables.

In developing our scenarios for 2030, we reflect the current capacity mix, investments that are already underway and existing Government policy:

- The Government has offered low-carbon contracts that will increase the share of renewable generation to 30-35% in 2020 and support at least one new nuclear plant in the 2020s whilst aiming to support two plants fitted with carbon capture and storage (CCS).
- The UK's remaining coal plants are expected to either close or convert to biomass during the 2020s, in line with the cross-party leaders' pledge and the Government's manifesto commitment. A clear signal that the Government will intervene if necessary to ensure this happens may be required to strengthen confidence for investors in replacement capacity.
- Taken together these measures would reduce carbon intensity of UK electricity from around 450 gCO_2/kWh in 2014 to around 250 gCO_2/kWh by 2020 and 200 gCO_2/kWh by 2030.

Alongside coal closures, most existing nuclear capacity is expected to close by 2030, even if plants are granted further life extensions by the regulator. Our scenarios for decarbonising the rest of the economy imply an increased demand for electricity via electric vehicles and electric heat pumps in buildings in the 2020s, alongside increasing demand with income growth, partially offset by a continuing improvement in energy efficiency in the 2020s (e.g. greater uptake of LED lighting and efficient appliances).

The combination of plant closures and new demand means that new generation (up to 200 TWh per year) and capacity (at least 20 GW) will be needed in the 2020s.

Box 2: The power sector in 2014

- Total generation of 298 TWh (298 billion kWh), met mainly from: coal (32%), gas (29%), renewables (20%) and nuclear (19%).
- Responsible for 121 $MtCO_2$, 23% of total UK greenhouse gas emissions. This was down 18% on 2013 as coal closures led to the biggest reduction in emissions since reporting began in 1990.
- Most carbon-intense source is coal (900 gCO_2/kWh); gas ran at an average of 365 gCO_2/kWh in 2014.
- Peak electricity demand in 2014 was 51 GW, between 5pm and 6pm on Thursday December 4rd.
- At the end of 2014 there was 102 GW of capacity on the system (68 GW of *de-rated* capacity, which adjusts for how often capacity is actually available).
- A typical gas-heated household consumes 3,000 kWh of electricity at an annual cost of around £415. Around a third of the bill is the cost of generating electricity, one quarter is for the network connecting power plants to homes and a fifth is levies and taxes, including around £20 for supporting energy efficiency and £35 for supporting low-carbon generation and paying for the costs of intermittency. The remaining quarter consists of additional costs related to managing the system and supplier costs and margins.

Table B2: Estimated lifecycle emissions of selected generation technologies

Power Sector Technology	Capacity in 2014 (GW)	Generation in 2014 (TWh)	Emissions in 2014 ($MtCO_2$)	Emissions Intensity of generation in 2014 (gCO_2/kWh)	Lifecycle emissions (gCO_2/kWh)
Coal	19.9	95	86	900	785 - 990
Gas	39.1	87	32	365	380 - 500
Other fossil	2.6	5	3	660	-
Nuclear	9.9	58	-	-	5 - 55
Onshore wind	8.5	18	-	-	7 - 20
Offshore wind	4.5	13	-	-	5 - 24
Biomass	4.5	20	-	-	-20 to +800
Solar PV	5.5	4	-	-	40 - 85
Hydro	1.7	6	-	-	2 - 13
TOTAL	**95.0**	**298**	**121**	**442**	-
Pumped storage	*2.7*	*-1.0*	-	-	-
Interconnection	*4.0*	*20.5*	-	-	-

Source: DECC (2015) *Digest of UK Energy Statistics.* Available at: www.gov.uk
Notes: Nuclear power, renewables, pumped storage and interconnection do not produce emissions directly as a result of electricity generation, but have embedded lifecycle emissions. Estimates of lifecycle emissions are based on new build technologies and included, where available, from: CCC (2013) *Reducing the UK's Carbon Footprint* and POST (2011) *Carbon Footprint of Electricity Generation.* We monitor emissions from UK demand; emissions from generation imported through interconnection are accounted for in exporting countries, and are covered by the EU ETS. Our scenarios for the 2020s assume no net imports to or from the UK.

(b) Our approach to building power sector scenarios

Investments to 2020 and related costs are largely committed already by investor decisions and existing Government policy. This report therefore focuses on the additional investments that can be made in the 2020s.

Our scenarios for providing new generation in the 2020s reflect the need to prepare for 2050, the need to minimise costs and the challenges in securely integrating intermittent renewables into the electricity system:

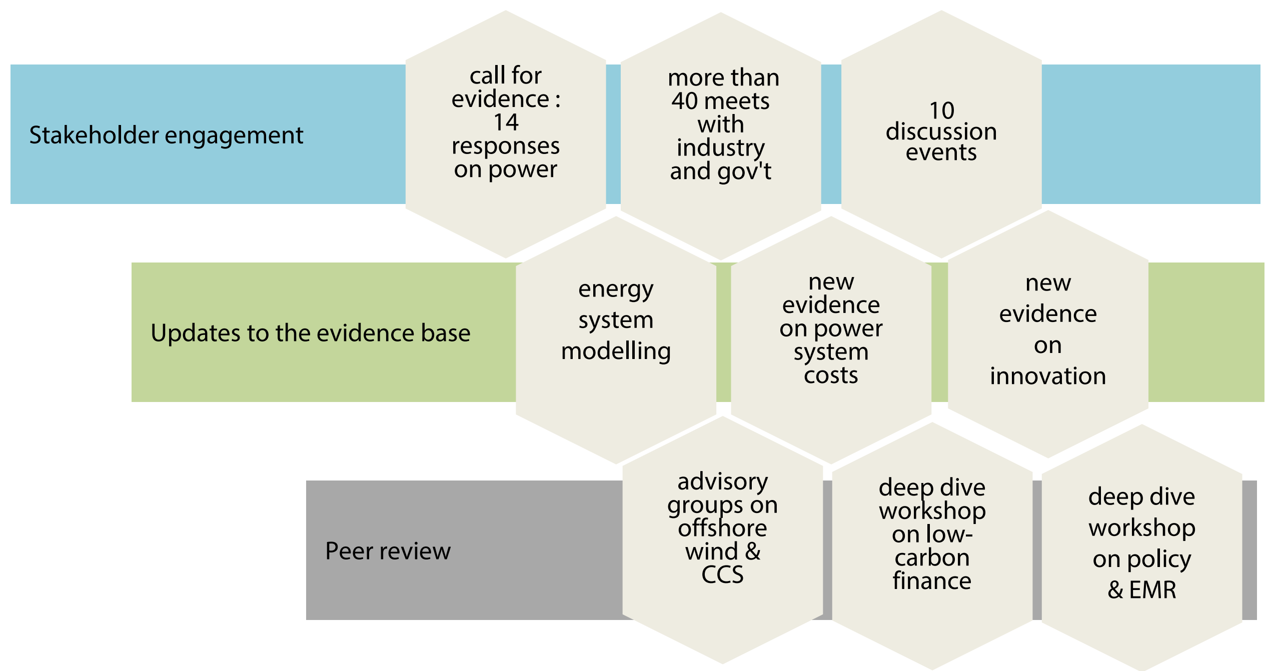
- **Preparing for 2050.** Offshore wind and carbon capture and storage are currently higher cost, but are likely to be needed in the long run to meet the UK's 2050 target. As in our previous scenarios we include a minimum rate of deployment for these technologies. We have reduced that rate based on an improved understanding of the relationship between deployment and cost reduction and because of delays to CCS projects in the UK and internationally.
- **Minimising cost.** Onshore wind and ground-mounted solar, in the first-half of the 2020s, and nuclear and offshore wind, in the second half, are likely to be deployable without subsidy provided gas generation faces the full costs of its carbon emissions (see Boxes 3 and 4 below). This is still true when wind and solar generators face the full cost of intermittency. We have reduced the total deployment of these technologies compared to our previous scenarios to ensure that there can be strong competition for contracts with deployment focused on the best sites and projects and to reflect delays to new nuclear build.
- **Intermittency and flexibility.** We have commissioned new work looking at the system costs of integrating large levels of intermittent, variable and inflexible generation. This finds that many combinations of technologies are consistent with providing a secure supply provided flexibility is also increased by adding technologies such as demand-response, interconnection and fast-responding generation. However, the analysis also demonstrates that the challenge increases as the share of low-carbon technologies increases beyond 75% and could result in higher system costs .

Our approach is based on an explicit recognition that the optimal final mix of generation is uncertain. Our scenarios are built based on the best understanding we have currently as to the costs and compatibility of different options, but we do not know exactly how these will develop in future. We present scenarios with different mixes of low-carbon generation, different demand and different success with deploying low-carbon options. The statutory 2050 target implies that the direction of travel must be towards reduced carbon emissions. Clarity is needed about how policy will adjust as areas of uncertainty are resolved.

For this report we have commissioned work and undertaken peer reviews with expert steering panels on innovation and system costs, as well as gathering a range of views through workshops, meetings and a call for evidence (Figure 1).

Throughout this report we present costs in real terms, in a 2014 price base.

Figure 1: Evidence and engagement for this report



(c) The opportunity for low-cost deployment of low-carbon options

Low-carbon technologies are, and in the 2020s will continue to be, a more expensive way to generate electricity than burning gas and allowing the emissions to enter the atmosphere for free. However, in a carbon-constrained world this is not an option.

A carbon price that reflects the full cost of emissions would increase the cost of gas-fired generation to a level at or above the cost of some low-carbon options. The Government's carbon values are designed to be consistent with action required under the Climate Change Act (Box 3). They reach £78/tonne in 2030 and would be enough to push the costs of gas-fired generation up above the level of mature low-carbon options in the 2020s (Figure 2).

- In a central scenario for gas prices and with a value attached to carbon that is consistent with meeting the UK's 2050 target, the full cost of new gas generation would be £85/MWh for new plants coming on line in 2020 and £95/MWh for 2025. That assumes a gas price that increases from 46 p/therm in 2015 to 66 p/therm by 2025;[1] if gas prices remain at 46 p/therm, the full costs for gas generation would be £70/MWh in 2020 and £85/MWh in 2025.
- Mature renewables are already demonstrating that they can provide electricity at a lower lifetime cost, implying they will effectively be subsidy-free by 2020 (Box 4):
  - Onshore wind and ground-mounted solar projects have signed contracts to deliver electricity at £83/MWh from 2016/17.[2]
  - These generators have a lower capacity value as their output is variable – that implies an

[1] The Government's most recent published scenarios for gas prices had a central case of 72 p/therm in 2025. We have reduced that to 66 p/therm for this report given sustained low gas prices since that publication and pending new scenarios, which DECC are due to publish shortly.

[2] Original contracts at £80/MWh in £2011/12 prices, adjusted to £2014 prices.

intermittency cost, which we estimate at around £10/MWh for both wind and solar for the deployment levels in our scenarios.

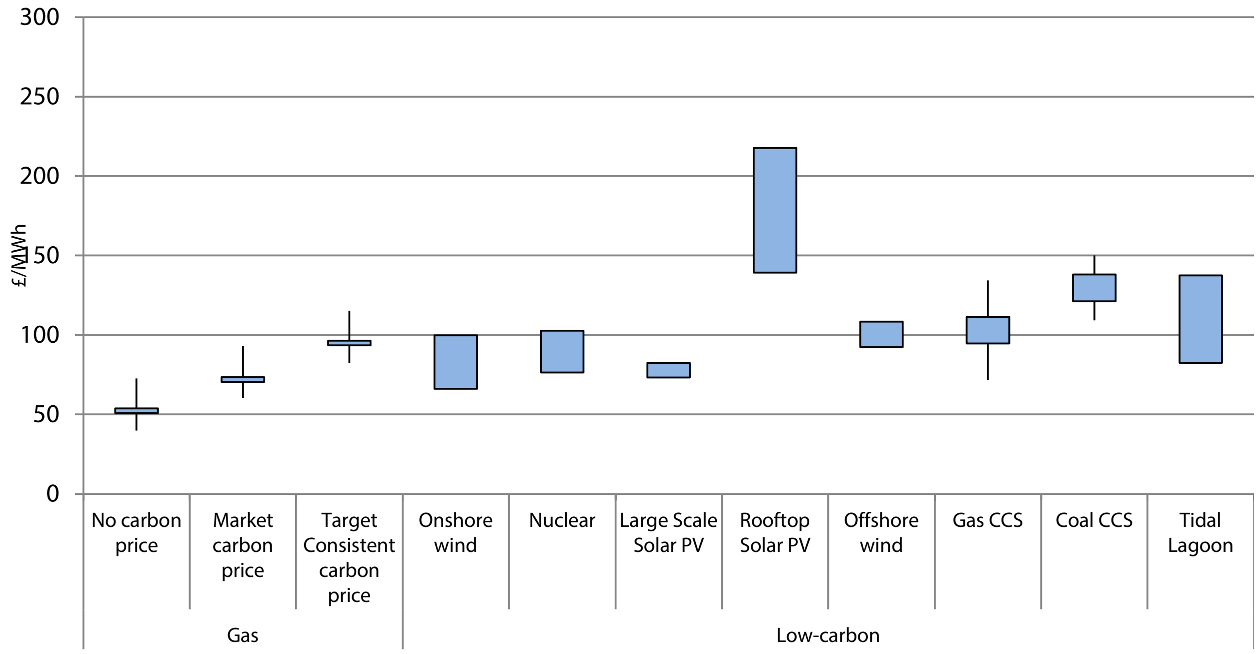
  – Offsetting this, contracts only cover around two-thirds of the plants' life expectancies, after which they can continue to produce power at low cost. This value is worth around £5/MWh.
  – Taken together these imply a full cost of onshore wind and ground-mounted solar projects similar to that of gas generation in 2020 (i.e. £85/MWh). In practice some of the best sites/projects should be able to deliver at lower cost, potentially below the costs of gas generation at current gas prices, especially if technology costs fall further over time.

- Although new nuclear has suffered delays and has been offered a higher contract price than mature renewables (i.e. £93-96/MWh offered to Hinkley Point C[3]), delivery at this price would still be valuable given limits to available sites for onshore wind and solar and given nuclear is not intermittent:
  – The contract price is in line with the expected full cost of gas generation in 2025.
  – There may also be scope for later plants to deliver at lower costs, for example if the current price reflects a premium for the first plant to be built under the UK's regulatory regime.
  – However, if costs escalate or the benefits of a programme do not translate into lower costs than for the first plant, then the value of a nuclear programme could be called into question, particularly if other low-carbon options are making good progress.
- As we set out below, there is also scope for offshore wind and possibly CCS to provide electricity at similar cost in the second half of the 2020s, provided they are suitably supported in the first half. Other options, such as tidal stream or tidal lagoons, could also have a role.

Current projections are for lower market carbon prices in the 2020s than the Government's values. In this case contracts for low-carbon generation are likely to imply extra support above the carbon price even for mature options if these are to contribute to UK emissions reductions in a cost-effective way. We quantify the total size of the necessary support and the impact on consumer bills in section (e).

[3] Figures adjusted to £2014 prices.

Figure 2: Projected lifetime costs for low-carbon technologies compared to gas generation facing different costs for its carbon emissions (2025)



Source: Calculations based on: DECC (December 2013) *Electricity Generation Costs*. Available at: www.gov.uk; BVG Associates (2015) *Approaches to cost reduction in offshore wind*. Available at: www.theccc.org.uk; Pöyry/Element Energy (2015) *Potential CCS Cost Reduction Mechanisms*. Available at: www.theccc.org.uk.
Notes: Lifetime costs for new build plants. CCS refers to carbon capture and storage. We assume the following ranges for gas prices: 30-76p/therm in 2020, 38-99p/therm in 2025 and 46-99p/therm in 2030. Target consistent carbon price: rises in line with Carbon Price Floor, to £32/t in 2020 and £78/t in 2030; Market carbon price: based on EU ETS projection from Thomson Reuters Point Carbon (June 2015), including carbon price support, rising to £30/t in 2020 and £42/t in 2030. Solid boxes represent range for technology costs; whiskers represent range for fuel costs (where appropriate). Costs are estimated for technology specific load factors for average projects (projects at the best sites could be cheaper): 95% for Gas, nuclear and CCS, 28% for onshore wind, 46% for offshore wind, 11% for solar PV and 22% for tidal lagoons.

Box 3: A target-consistent price of carbon and market expectations for carbon prices

Target-consistent carbon price

- The Government's carbon values for policy appraisal are designed to be consistent with action required under the Climate Change Act. They reflect estimates in the literature and modelled scenarios. The values are peer reviewed by an expert panel. The modelling work includes a top-down global sectoral model for the world energy system under low, central and high projections for global technology costs, fossil fuel prices and global energy demand. The model is used to calculate carbon costs consistent with international action to limit the average increase in global surface temperatures to 2°C above pre-industrial levels.
- In a central case the carbon values reach £78/tonne in 2030, growing steadily to £220/tonne in 2050. Low and high values are 50% below and above the central level. We have previously concluded that these values are in line with estimates in the wider literature for the costs of limiting warming to 2°C, where these do not rely on over-optimistic assumptions for the availability of sustainable bioenergy.
- The UK's 2050 target is aligned to this level of effort globally, and is likely to require actions at the margin that have a similar carbon cost[1].
- The annual rate of increase in the Government carbon values is around 5%. Using this trajectory for carbon values as a guide to low-carbon investment would therefore support a steady increase in effort over time.

We use the target-consistent carbon price to assess whether low-carbon investments represent good value compared to gas-fired generation and can be deployed without further subsidy.

Expected market carbon price

- The actual carbon price in the market is expected to be lower. Independent forecasters project a carbon price in the EU Emissions Trading Scheme of £24/tonne in 2030. Although this will be topped up in the UK, with the Government's carbon values as the formal target trajectory, the additional UK carbon price support has been frozen at £18/tonne. That implies a total market price of £42/tonne in 2030.
- If the world were to agree action to reduce emissions consistent with a 2°C target and deliver this through an efficient carbon market, then in theory market carbon prices would rise to a level in line with the target-consistent carbon price.

We use the market carbon price in our calculations of household bills.

Source: DECC (2009) *Carbon Valuation in UK Policy Appraisal: A Revised Approach*; DECC (2014) *Updated short term carbon values for UK policy appraisal*; CCC (2012) *The 2050 target*; Thomson Reuters Point Carbon (June 2015) and Aurora Energy Research (2015) each project a price of £24/tonne in 2030.
Notes: 1) For example, a carbon price at this level was needed to construct scenarios that could meet the 2050 target in CCC (2012) *The 2050 target*.

Box 4: How we define 'subsidy-free'

We define the point at which a low-carbon technology should be considered to be deployable without subsidy based on the definition of 'full costs' set out in our 2015 Progress Report:

- This should include any intermittency costs, for example reflecting that variable renewable capacity will generally need to be backed up by flexible capacity that can operate on demand.
- The appropriate comparator is the alternative means of providing additional generation with costs judged across its lifetime.
- The cost of carbon emissions should reflect the value of these under the UK's domestic emissions targets (see Box 3).
- We do not factor in the costs of other fossil fuel-related externalities, such as air pollution, or landscape impacts of renewables. These are separately covered by air quality regulations and the planning system.

This implies, for example, that under a central scenario for gas prices, low-carbon technologies should be considered subsidy-free if they can provide power at £85/MWh or less in 2020.

(d) Offshore wind and CCS beyond 2020

In our 2015 Progress Report to Parliament we set out the need to continue support for carbon capture and storage (CCS) and offshore wind beyond 2020:

- Both have the potential to provide power in the second half of the 2020s below the full cost of gas generation (i.e. £95/MWh in a central case). There is more uncertainty over CCS: although the first "at scale" CCS plant commenced generation in Canada in 2014, CCS is yet to be demonstrated in the UK. Offshore wind is demonstrating cost reduction: latest contracts have been signed at around £120/MWh, compared to costs in 2011 estimated at around £150/MWh.
- **CCS** has the potential to fill several roles in a low-carbon economy where alternatives are limited. CCS could be used in heavy industry, in the power sector offering flexible low-carbon generation and to open up other routes to reduce emissions (e.g. based on hydrogen, using CCS in combination with bioenergy to offset emissions elsewhere). Estimates by the Energy Technologies Institute (ETI) and the Committee[4] suggest that the cost of meeting the UK's 2050 emissions target would be up to twice as high in the absence of CCS deployment.
- **Offshore wind** has a potential resource of over 400 TWh, greater than total UK electricity demand in 2014. Although offshore wind currently has high costs, it has fewer barriers and risks to its roll-out than other options. For example, onshore wind and new nuclear face site restrictions and potential public opposition. Development of offshore wind therefore hedges against the risk that other options are constrained.

The near-term goal should be development of these options, rather than deployment per se. However, analysis published alongside our progress report demonstrated the importance of UK deployment in driving down the costs of both offshore wind and CCS:[5]

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[4] The CCC's *The 2050 Target* (2012) report found that the cost of meeting the 2050 target increased from 0.5% to 0.9% of GDP without CCS. ETI (2015) *Carbon capture and storage - Building the UK carbon capture and storage sector by 2030* found that a "complete failure to deploy CCS would imply close to a doubling of the annual cost of carbon abatement to the UK economy" in 2050.

[5] BVG (2015) *Approaches to cost reduction in offshore wind*; Pöyry/Element (2015) *Potential CCS Cost Reduction Mechanisms.*

- **CCS.** The key opportunity for delivering cost reduction is through economies of scale delivered by shared infrastructure for transporting and storing CO_2. This implies a minimum level of roll-out will be required in the UK which, if signalled in advance, can also support a competitive pool of projects and increase interest from the financial community. Projects in the power sector are vital to provide 'anchor loads' for smaller industrial sites.
- **Offshore wind.** A sufficient scale of market, signalled in advance, is required to drive private sector investment in innovation (e.g. to create bigger turbines), to support a competitive project pipeline and supply chain, and to encourage a falling cost of capital through mature financial sector involvement. The UK is a key part of the wider European market that will drive technology development. Deployment in the 2020s would build on development of offshore wind in the 2010s; we estimate that around 75% of the total cost of commercialising offshore wind has already been committed to 2020.

Based on those assessments we identified a minimum level for UK deployment of 4-7 GW of CCS by 2030 and 1-2 GW per year of offshore wind in the 2020s. We build these levels into our scenarios in this report, with the possibility of more deployment in the second half of the 2020s if they are able to out-compete other low-carbon options.

(e) Scenarios for the power sector in 2030

Our scenarios include a continuing role for unabated gas generation at around its 2014 level (i.e. around 100 TWh), with new nuclear, CCS and renewables replacing retiring nuclear and coal generation and meeting increases in demand. These low-carbon options represent good value investments in the 2020s for a society committed to climate targets.

The scenarios imply an emissions intensity at the upper end of the range of 50-100 gCO_2/kWh that the Committee have previously suggested would be appropriate for 2030 (Figure 3). Low-carbon sources would provide around 75% of generation, including around 45-55% from renewable sources. The scenarios would position the UK power sector appropriately to meet the 2050 target at lowest cost. They would develop a portfolio of options and leave enough undeveloped potential to meet further increases in demand as electrification is extended.

Scenarios delivering 50 gCO_2/kWh could be appropriate if several low-carbon technologies perform particularly well in the 2020s or if demand growth is slow. We will also consider these scenarios in our fifth budget advice, along with scenarios where nuclear and CCS projects do not go ahead (Figure 4).

As part of the evidence base for this report we commissioned a detailed analysis of how the different low-carbon options could be effectively integrated to the electricity network. System management is likely to be more challenging than at present as many of the low-carbon options are inflexible (nuclear) or intermittent (wind and solar).

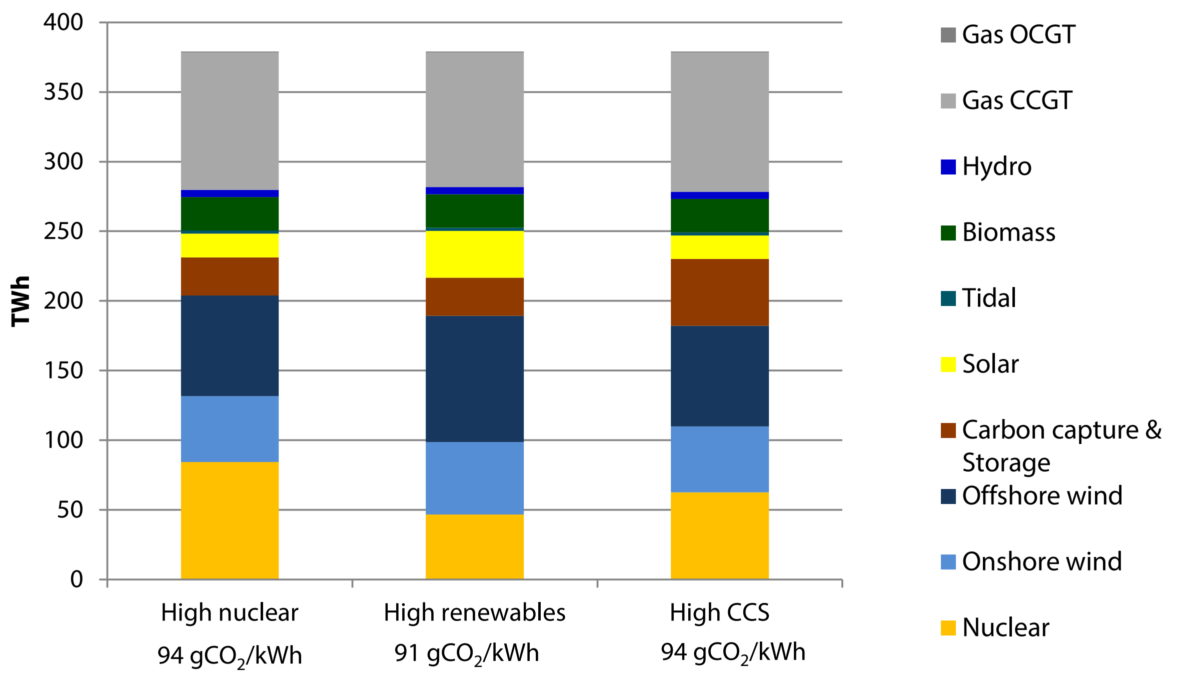
Our new analysis confirms:

- It is possible to ensure security of supply in a decarbonised system with high levels of intermittent and inflexible generation.

- Increasing the flexibility of the power sector can significantly reduce overall costs. That includes: greater interconnection to systems beyond the UK; enabling demand to respond more to short-term price signals; increased electricity storage; and ensuring that back-up capacity is flexible enough to increase generation without having to run part-loaded. The cost of providing this flexibility is significantly less than its benefit to the system in reduced running costs, which is of the order of several billion pounds per year.
- There is a cost associated with intermittent options, largely reflecting the need to provide additional back-up capacity. We estimate this to be around £10/MWh of intermittent generation for levels of deployment assumed in our scenarios (based on a range in our estimates of £6-13/MWh). These costs would be likely to increase at much higher penetrations of intermittent renewables (e.g. to around £25/MWh for solar if capacity exceeds 40 GW or to around £15/MWh for wind if capacity exceeds 50 GW, each within a power system reaching 50 gCO_2/kWh).
- In deeper decarbonisation scenarios (i.e. 50 gCO_2/kWh rather than 100 gCO_2/kWh) there would be an increasing value to CCS generation relative to nuclear generation, worth around £5/MWh. That reflects the fuel costs that CCS can save when running at lower load factors and potentially higher flexibility, dependent on how CCS technologies develop.

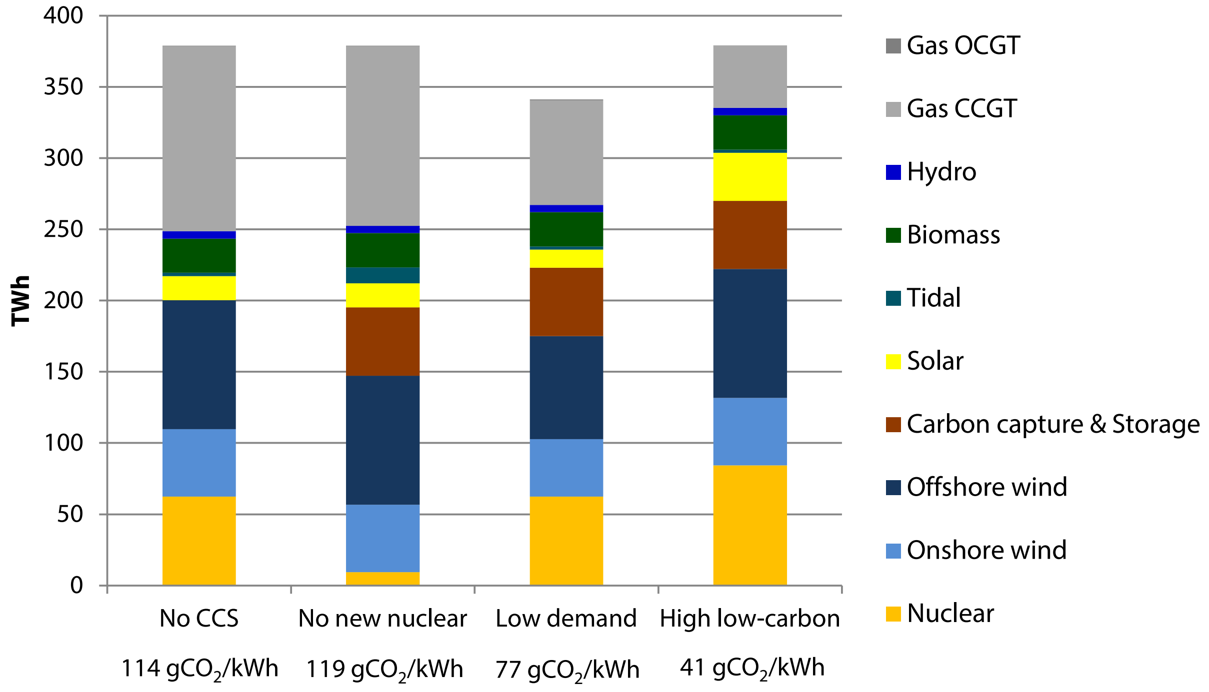
Our scenarios involve an increase in system flexibility alongside the expansion of low-carbon capacity. We include the costs of intermittency in our assessment.

Figure 3: Power sector scenarios for 2030



Source: CCC modelling.

Figure 4: Alternative power sector scenarios for 2030



Source: CCC modelling.

(f) Costs of low-carbon support and implications for electricity bills

In assessing the costs of our scenarios we distinguish between the total social costs and the private costs to bill-payers. The former includes the full social cost of carbon (i.e. the target-consistent carbon price), whilst the latter includes only costs that would appear on a typical electricity bill (e.g. the market carbon price). To determine the additional cost or benefit in the "social" or "private" case, we compare our scenarios to an alternative where investment in the 2020s is solely in gas-fired generation: all new demand is met by gas-fired generation and all retiring plant is replaced by gas-fired generation where required.

Costs and bills to 2020

Support for low-carbon (primarily renewable) generation deployed in the period up to 2020 is expected to total around £8 billion per year by 2020 over and above the market carbon price (projected to be £23/tonne in 2020). Support is capped at this level under the Levy Control Framework (LCF) and is spread across all electricity consumers through the Renewables Obligation, Small-scale Feed-in Tariff and Contract for Difference schemes.

Annual electricity bills for the average household in 2020 will be around £105 higher as a result of the market carbon price and support under the Levy Control Framework. This compares to a total electricity bill projected to be around £500 in 2020. Businesses will similarly see higher electricity costs as a result of this support for low-carbon investment. These costs are already committed and they will largely continue into the 2020s.

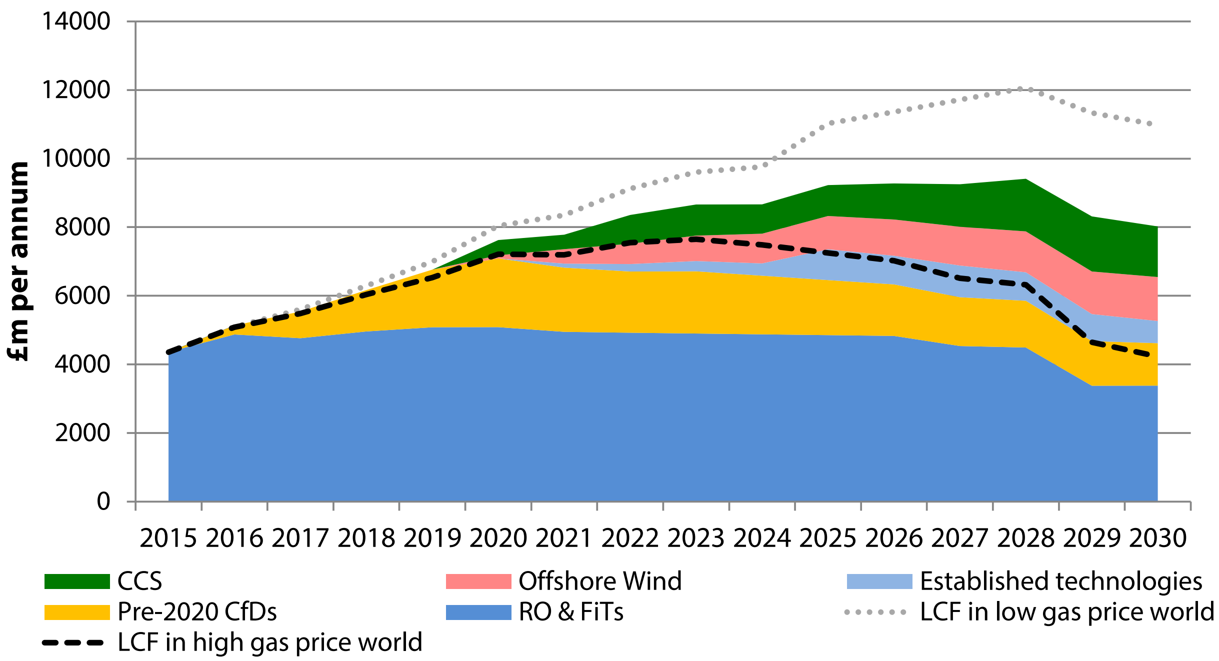
Additional cost of low-carbon investment in the 2020s

If more low-carbon capacity is to be deployed in the 2020s, as in our scenarios, the total support will initially need to increase beyond £8 billion per year.

- Offshore wind and CCS projects will be more expensive than the alternative of gas generation across their lifetimes, even if the full carbon value is reflected in the market. These create the main need for additional funding to 2025.
- Onshore wind, solar and nuclear are expected to be cheaper than gas generation across their lifetimes. However, they are likely to be more expensive in early years because contracts do not cover full project lifetimes, gas generation costs will rise over time with carbon prices and the market carbon price is likely to be below the full carbon value.

Taken together, and in a central scenario for gas prices, our scenarios require a support level of £9.2 billion per year in 2025 if carbon prices rise to the Government's target carbon value of £42/tonne (Figure 5). Support will need to be higher, at £9.4 billion if market carbon prices rise as currently projected to £37/tonne in 2025. A similar level of support would be needed in 2030, falling thereafter.

Figure 5: Funding required under the Levy Control Framework for our scenarios (2015-2030)



Source: CCC modelling.
Notes: All years are calendar years. All money is in £2014. The Levy Control Framework cap for 2020/21 is £7.9bn in the calendar year 2020. We assume the following ranges for gas prices: 30-76p/therm in 2020, 38-99p/therm in 2025 and 46-99p/therm in 2030. Target consistent carbon price: rises in line with Carbon Price Floor, to £23/t in 2020 and £78/t in 2030.

This increased support will feed through to consumer bills, along with increases in the market carbon price and costs associated with intermittent renewables.

Electricity bills in the 2020s

Offsetting this, investment in new low-carbon generation avoids some of the increase in bills that could result if all new generation is provided by unabated gas (the so-called 'merit order effect'):

- If new generation is provided by gas-fired plant, then it will set the price in the wholesale market, which will rise with the market carbon price. This would increase returns to operators of the existing nuclear fleet and renewables supported through the Renewables Obligation.
- If new generation is provided by low-carbon generation then wholesale prices will rise less quickly. That reflects that, once constructed, the cost of producing electricity for low-carbon capacity tends to be low, and this will be reflected in lower market prices as the low-carbon share increases.
- Compared to a scenario with investment in gas-fired generation that implies a saving to consumers, who would otherwise have to pay higher returns to existing low-carbon generators.
- We estimate that this "merit order effect" would reduce annual costs to the typical household by up to £10 in 2025 and 2030 in our scenarios.

We report bill impacts in Table 1 below under central assumptions for gas prices (66 p/therm in 2025). Bills would be £20 higher in 2025 and £35 higher in 2030 and 2035 than in a scenario focused on gas-fired generation (£25 and £45 higher ignoring the merit order effect).

However, from a "social" point of view there would be an additional value to the carbon saved, worth £25 per household in 2030 and £50 per household by 2035. The more positive outcome from a "social" point of view reflects the fact that the market price for carbon, beyond 2020, is not projected to fully incorporate the costs that greenhouse gas emissions impose on the UK or the world.

If gas prices remain at current low levels (i.e. 46 p/therm) then the costs of investing in low-carbon generation would be higher by up to £20 per household per year. However, lower gas prices mean that total electricity bills would be lower for customers (by about £40 per household per year if gas is at 46 p/therm). Low-carbon investment also reduces the risk of very high increases in bills, which could otherwise occur if European gas or carbon prices were to rise sharply over the next decade.

Where there are increased costs imposed in the short term, and if these are not replicated in other countries, it will be important for the Government to continue schemes providing exemptions or compensation to affected industries that would otherwise be at risk of losing competitiveness.

Table 1: Impact of low-carbon investment relative to investment in gas generation for the annual electricity bill of a typical dual-fuel household					
£/household annual bill (central gas price = 66 p/therm in 2025)	**2014**	**2020**	**2025**	**2030**	**2035**
(A) BASELINE BILL *– if new generation in the 2020s is provided by unabated gas generation with no carbon price and no support for low-carbon generation*	365	380	415	415	415
TOTAL BILL IN OUR SCENARIOS	415	485	530	535	520
Of which:					
(A) Market carbon price	10	30	40	45	50
(B) Support for low-carbon investment already committed (pre-2020), including intermittency cost	35	70	55	40	20
(C) Additional support for low-carbon investment in the 2020s	-	5	25	40	40
(D) Intermittency cost of low-carbon investments in 2020s	-	-	0 to 5	5	5
(E) Merit order effect	-	-	-(5 to 10)	-10	-10
TOTAL IMPACT of low-carbon investment in the 2020s (relative to investment in gas-fired generation) = C+D+E	-	-	20	35	35
TOTAL IMPACT of carbon price and support for all low-carbon investment = A+B+C+D+E	45	105	115	120	105

Source: CCC modelling.
Notes: Base bill includes wholesale costs of energy, network costs, supplier margins and VAT. Numbers may not sum due to rounding. Market carbon price: based on EU ETS projection from Thomson Reuters Point Carbon (June 2015), including carbon price support, rising to £30/t in 2020 and £42/t in 2030.

The wider value of low-carbon investment in the 2020s

While low-carbon deployment could imply higher costs and bills in the early years of their contracts, especially if gas and carbon prices remain low, steady deployment in the 2020s is likely to reduce costs overall and in the long run:

- **Learning and stability.** Deployment in the 2020s can reduce costs of future projects. That is clearest for less mature technologies, but may also be the case for others, such as nuclear, where the first plant in a new build programme could require a premium in cost of capital and in proving the regulatory regime. More generally, a stable market for low-carbon generation will keep supply chains and investors engaged and risks low.

- **Life beyond contracts.** Low-carbon capacity can continue to provide power, at low cost, after the initial contract period. For example, offshore wind farms are expected to generate power for around 10 years beyond their 15-year contracts.
- **Repowering.** At the end of their lifetimes, renewable projects can be replaced at lower cost. That reflects that some costs, such as development and transmission, do not need to be incurred again, as well as the scope for technological improvement.

There are other benefits to low-carbon investment in the 2020s not quantified in our analysis. These include improved air quality and spillovers to other sectors (e.g. from development of CCS and increased availability of low-carbon electricity as a route to reducing emissions in heat and transport).

(g) Policy to deliver the scenarios at lowest cost

Investments in the power sector have long lead-times, with planning cycles stretching well beyond the current 2020 policy window. Large offshore wind farms, CCS plants and nuclear plants have a project lead-time of up to 10 years or more, with supporting investments in the supply chain stretching even further.

If investors are exposed to policy risk in this timescale then they will apply risk premia to projects and costs will be unnecessarily increased. Potential projects in the pipeline could also be discarded, which would reduce the number of competitors in the auctions.

We therefore recommended in our 2015 progress report that the Government extend the Levy Control Framework to 2025 to provide investors with increased confidence over the future low-carbon market and to signal a commitment to continuing decarbonisation of the power sector through a portfolio of options. This remains an urgent priority.

For this to be an effective signal of the funding available for new projects the Government must set out how the total will be adjusted if circumstances do not turn out as anticipated:

- For example, funding of £9.2 billion in 2025 would be appropriate if carbon prices increase in line with the full carbon value (i.e. to £42/tonne) and if wholesale electricity prices reflect the full costs of new gas generation.
- Funding of £9.8 billion would be needed if the market carbon price reaches half the level assumed in the Government's carbon values (i.e. £21/tonne instead of £42/tonne in 2025).
- Higher funding would be needed to the extent that the merit order effect and/or the capacity market lead to a lower wholesale electricity price. In this case and the case of lower carbon prices, total electricity bills would be lower but low-carbon funding would make up a greater proportion of the bill.

Alongside or following extension of funding, the Government should set out the timetable and funding pots for the next auction round for low-carbon contracts. A separate funding pot should be reserved for emerging technologies, including offshore wind and CCS until the mid-2020s.

In setting reserve prices for the next auctions the Government can limit the levels of subsidy provided. We would consider options to be subsidy-free where they provide power at or below the expected lifetime costs of new gas generation facing its full carbon cost, allowing for intermittency costs. For example, that would imply a maximum price for mature intermittent renewables of £80/MWh in 2020, £90/MWh in 2025, with the expectation that competitive auctions would deliver lower prices.

To ensure that low costs are delivered in practice our analysis further suggests that the government should:

- **Set out an approach to commercialise CCS through the planned clusters.** That should include a strategic approach to transport and storage infrastructure, completing the two proposed projects and contracting for at least two further ‘capture’ projects this Parliament.
- **Ensure consumers benefit from lower generation costs as existing projects reach the end of their contracted lives.** The Government should develop its approach to procuring generation from low-carbon projects after their contracts have expired and an approach to procuring generation from repowered sites. These both offer opportunities for lower cost generation, but currently there is no clear route to procuring it at low cost.
- **Ensure investment decisions reflect their full cost.** The Government should work with the regulator and System Operator to ensure that flexibility options are able to capture their full value and decisions on low-carbon investments reflect their full system integration costs.
- **Explore ways to further reduce cost of capital.** A 1% reduction in the cost of capital for low-carbon projects procured in the 2020s would save around £1 billion per year by 2030. The Government should therefore continue to explore ways to reduce the cost of capital. The actions set out above are intended to be an important contribution to this reduction alongside extending the Levy Control Framework. Further options could include extending use of infrastructure guarantees and considering the case for an increased public role in some areas, for example on initial offshore site development.

Chapter 1: The power sector - challenges for the 2020s

Introduction and key messages

In November the Committee will publish its advice on the fifth carbon budget. This will cover the limit on UK emissions of greenhouse gases over the period 2028-32. It marks the halfway point from the first budget (2008-12) to the UK's statutory target for 2050 to reduce emissions by at least 80% relative to 1990, as set out in the Climate Change Act.

In advising on carbon budgets, the Committee is required to consider the implications of meeting carbon budgets across a range of criteria, including: economic impacts, fuel poverty, security of supply, fiscal position of the Government and competitiveness. We do this by assessing a set of scenarios across all sectors of the economy. This report sets out those scenarios for the power sector.

The power sector scenarios are particularly important because of the link between the power sector and the rest of the economy. Low-carbon power can be used as a fuel to decarbonise surface transport, heating and parts of industry. The costs of providing low-carbon power also have potential impacts for UK competitiveness and fuel poverty via the impact on electricity bills.

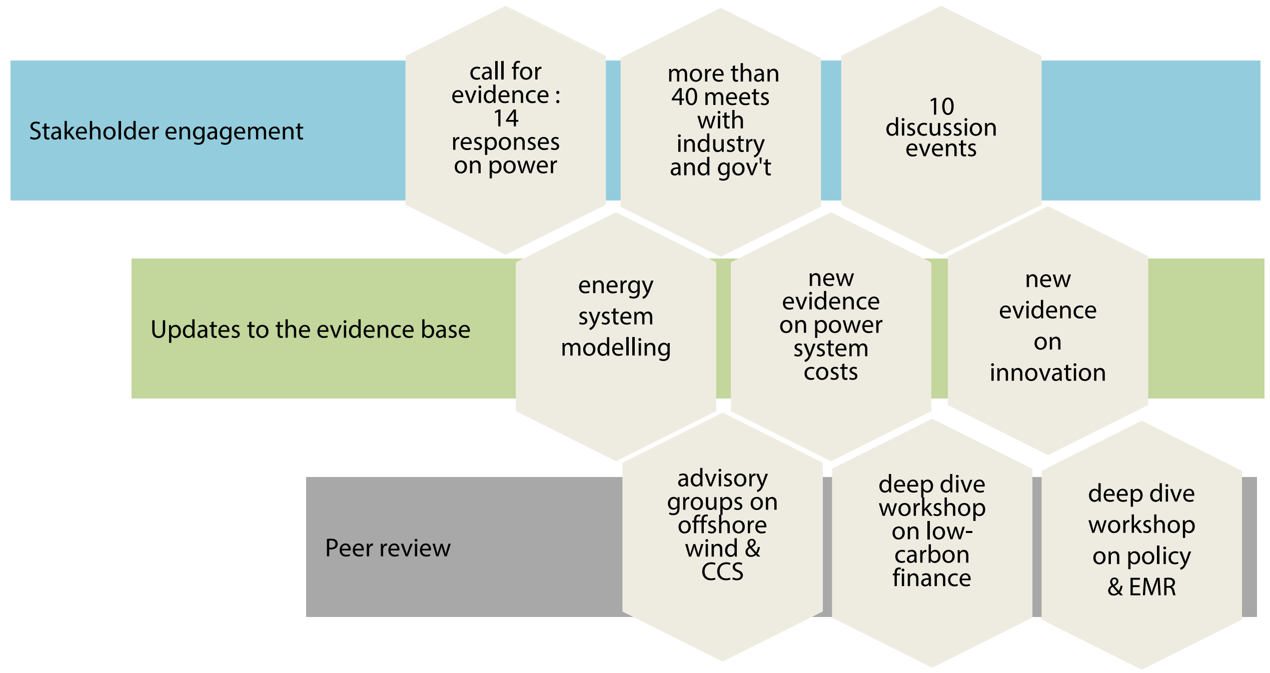
Our scenarios to 2030 are underpinned by a detailed evidence base, building on work compiled for previous advice (e.g. the 2010 *Fourth Carbon Budget*, 2011 *The Renewable Energy Review* and 2013 *Next Steps on Electricity Market Reform*). For this report we have updated our evidence base and refreshed our deployment scenarios accordingly. For example, ongoing delays to the programme of new nuclear and CCS are reflected in lower ambition for these technologies, whilst falling costs of renewables imply reduced affordability impacts.

We have also commissioned work and undertaken peer reviews with expert steering panels on innovation and system costs, as well as gathering a range of views through workshops, meetings and a call for evidence (Figure 1.1).

In this chapter we set out the expected development of the UK power sector to 2020 and the challenge facing the sector in the 2020s. We identify a generation and capacity gap, requiring new capacity to be built during the 2020s that is capable of generating up to 200 TWh/year and providing at least around 20 GW of de-rated capacity.

In Chapters 2 and 3 we set out our evidence base on the costs of different options for filling this gap and for integrating technologies together while maintaining security of supply. Chapter 4 presents our scenarios for the power sector, which would ensure value for society as a whole and bill-payers while reducing greenhouse gas emissions.

Figure 1.1: Evidence and engagement for this report



The key messages in this chapter are:

- The power sector was responsible for emissions of 121 $MtCO_2$ in 2014, around a quarter of total UK greenhouse gases.
- In line with the Government projections, we expect both retirements and new investment to 2020. The majority of these changes to 2020 are already planned or contracted, leaving a relatively narrow band of uncertainty in this period.
- In the 2020s a large amount of new generation (up to 200 TWh/year, compared to expected generation in 2020 of around 310 TWh) will be required to replace generation from retiring coal and nuclear capacity and to meet possible increases in demand. The 2020s are therefore a crucial decade for the future of the power sector.

This chapter is set out in four sections:

1. The power sector today and recent developments
2. Expectations to 2020
3. The challenge for the 2020s: meeting the capacity and generation gap
4. Our approach to building scenarios for the 2020s

1. The power sector and recent developments

Generation and capacity

From 1990 to 2005, electricity generation increased in line with demand, which rose at around 1.6% annually. More recently, generation has fallen by an average 1.9% annually from 2006-2014 due to a mix of energy efficiency, changing economic structure and slower output growth. In 2014, the most recent year for which data are available, generation was 298 TWh to meet 290 TWh of demand alongside 21 TWh imports and 28 TWh of losses.

Since 1990 the generation mix has shifted away from coal and towards gas and renewable generation:

- The share of coal has reduced from a large share of generation in 1990 (around 80%) to 35% in 2007 and 30% in 2014. The recent reductions reflect the EU Large Combustion Plant Directive, which has restricted the use of coal on air quality grounds, as well as changing economics (e.g. lower gas price and carbon prices).
- The dash for gas led to an increase in CCGT penetration from 1990 to 1999, (from zero to 34%). In recent years the penetration of gas has fluctuated and in 2014 was 30%.
- Since 2007 low-carbon generation has increased from 21% generation to 38% in 2014. That reflects a similar share of nuclear (19%) and an expanded contribution from renewables (19%).

Total de-rated capacity[6] in 2014 was around 68 GW, the largest share of which was provided by gas (20 GW), followed by coal (18 GW) and nuclear (8 GW) (Figure 1.2).

Emissions and bills

The power sector is a major source of emissions, despite reductions since 1990:

- Greenhouse gas emissions from the power sector were 121 $MtCO_2$ in 2014, accounting for 23% of the UK total. This implies an emissions intensity of 442 gCO_2/kWh of electricity supplied.
- Despite producing only 30% of all electricity, generation from coal is by far the largest source of emissions, accounting for 86 $MtCO_2$ (71%). Most of the remainder (30$MtCO_2$, 29%) is from gas generation.
- Emissions in 2014 were 41% lower than 1990 mainly as a result of the reduced burning of coal – coal emissions intensity averaged around 900 gCO_2/kWh in 2014, whereas gas was around 365 gCO_2/kWh.

Emissions are a result of the type of capacity on the system and how it is used. Emissions from the current plant mix could be reduced by 48 $MtCO_2$, to an average of 250 gCO_2/kWh by dispatching gas generation before coal, alongside the low-carbon capacity. Almost all of demand in 2014 could have been met without using coal generation. This 'achievable emissions intensity' has fallen 46% since 2007 (from over 450 gCO_2/kWh) as a result of falling demand and increased low-carbon capacity.

Electricity prices have increased for households and businesses in the last ten years, from 8.1

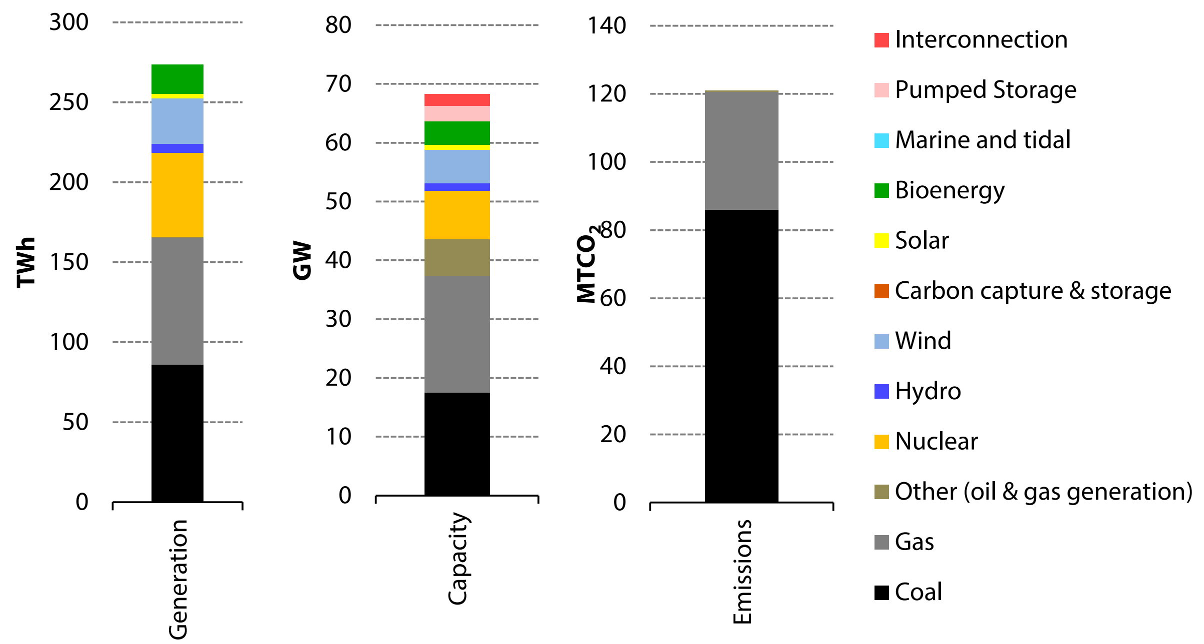
[6] 'De-rated' capacity is the metric used to standardise capacity across technologies with different availabilities. It reflects the probable proportion of a source of electricity which is likely to be technically available to generate (even though a company may choose not to utilise this capacity for commercial reasons). We adopt de-rating factors consistent with the Governments' Capacity Market and the Digest of UK Energy Statistics.

p/kWh in 2004 to 16.7 p/kWh in 2014 (a 106% increase over a period in which there was 26% inflation). The price of electricity in 2014 is comprised of the price paid to cover the cost of wholesale electricity (4.4 p/kWh), supplier cost and margin (2.1 p/kWh), costs of maintaining and upgrading the network (3.4 p/kWh) and policy costs (3.0 p/kWh). Policy costs include 0.5 p/kWh from the carbon price, 1.2 p/kWh to further support investment in low-carbon electricity, 1.4 p/kWh to fund energy efficiency programmes and 5% VAT.

The increase in electricity prices after 2004 was driven by a combination of increasing fossil fuel prices (38% of the increase), network charges (45%) and environmental levies (15%).

Higher prices translated to higher electricity bills overall. Data on the average bill for household electricity indicates that annual bills have risen from around £250 in 2004 to around £415 in 2014[7].

Figure 1.2: The UK power sector in 2014 — capacity, generation and emissions



Source: DECC (2015) *Energy Trends*; DECC (2015) *Digest of UK Energy Statistics*; CCC calculations.
Notes: Generation is before accounting for losses and imports. Capacity is de-rated.

2. Expectations to 2020

Based on the Government's 2014 projections, our scenarios include a small increase in demand to 2020 due to increasing demands for energy services as the economy grows, offset to some extent by energy efficiency.

In line with the Government projections, we assume this demand will be met by a different generation mix, reflecting both retirements and new investment. The majority of these changes are already planned or contracted, leaving a relatively narrow band of uncertainty in the period to 2020:

[7] For a 'typical' household using around 3000 kWh electricity per annum for lighting and appliances.

- **Coal retirements.** There is potential for a further 10 GW of coal to close in the period to 2020 due to EU directives and unfavourable market conditions (i.e. due to the carbon price).
- **New renewables.** A significant amount of new renewable electricity is likely to 2020. Most of the new capacity is already under construction, has been contracted or is expected to connect within the grace period for the Renewables Obligation. In terms of installed capacity, we assume a further 3.8 GW (9 TWh/year) of onshore wind, 5.7 GW (21 TWh/year) of offshore wind and 2.2 GW (2 TWh/year) of large scale solar. Alongside existing capacity, we assume renewable generation rises to around 100 TWh in 2020.
- **Carbon capture and storage (CCS).** We assume that two CCS projects go ahead as planned under the Government's commercialisation competition. This is around 0.6 GW of capacity and 5 TWh/year of generation.
- **The capacity market.** Some new capacity has been contracted through the capacity market. Although it appears unlikely that this will all proceed, the auction results imply up to 1.7 GW of new gas capacity and 2.5 GW of small diesel generators could come on by 2020, with the latter only expected to run at very low load factors given their high running cost.

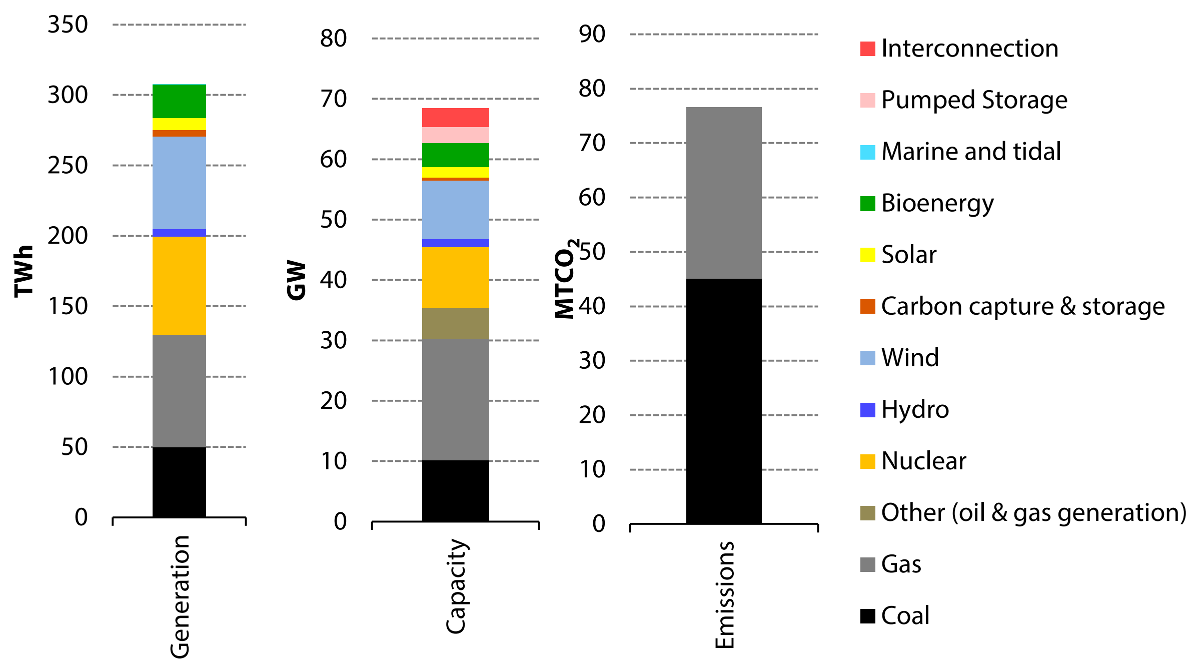
The retirements and new additions identified above imply that de-rated capacity remains broadly flat to 2020, at 68 GW (Figure 1.3).

The share of low-carbon generation would increase to around 58% in 2020 (of which 23% is nuclear, 34% renewables and 1% CCS).

Actual emissions will depend on the relative shares of coal and gas, which in turn depend on prevailing prices of input fuels and carbon in 2020. Assuming around 10 GW of coal remains in 2020 (in line with latest available Government projections[8]), and generates around 50 TWh (16% of generation), this would result in emissions of around 45 $MtCO_2$ in 2020 and a carbon intensity of around 250 g/kWh.

[8] DECC (2014) *Updated energy and emissions projections*. Available at: www.gov.uk

Figure 1.3: The UK power sector in 2020 — capacity, generation and emissions



Source: DECC (2015) *Energy Trends;* DECC (2015) *Digest of UK Energy Statistics*; CCC calculations.
Notes: Generation is before accounting for losses and imports. Capacity is de-rated.

The expansion of renewable generation to 2020 is supported through the Renewables Obligation, Contracts for Difference and small-scale Feed-in Tariff schemes. Along with the market carbon price these added around £45 within a typical dual-fuel household's annual electricity bill of £415 in 2014, and will add around £105 in 2020. As set out in our 2014 report Energy Prices and Bills, there is potential for most households to offset this cost through improved energy efficiency of their lights and appliances.

3. The challenge for the 2020s: meeting the capacity and generation gap

Beyond 2020 the possible path for the power sector is more open: a large amount of capacity is expected to retire, demand could increase and the longer lead-time means that more generation technologies are available for its replacement.

In our November fifth carbon budget advice covering the whole economy we will update our scenario for demand based on the latest projections and the latest evidence on electrification of heat and transport. For this report we have used the scenario for electricity demand from our 2013 Fourth Carbon Budget Review. This has electricity demand increasing by 23% from 2020 to 379 TWh in 2030:

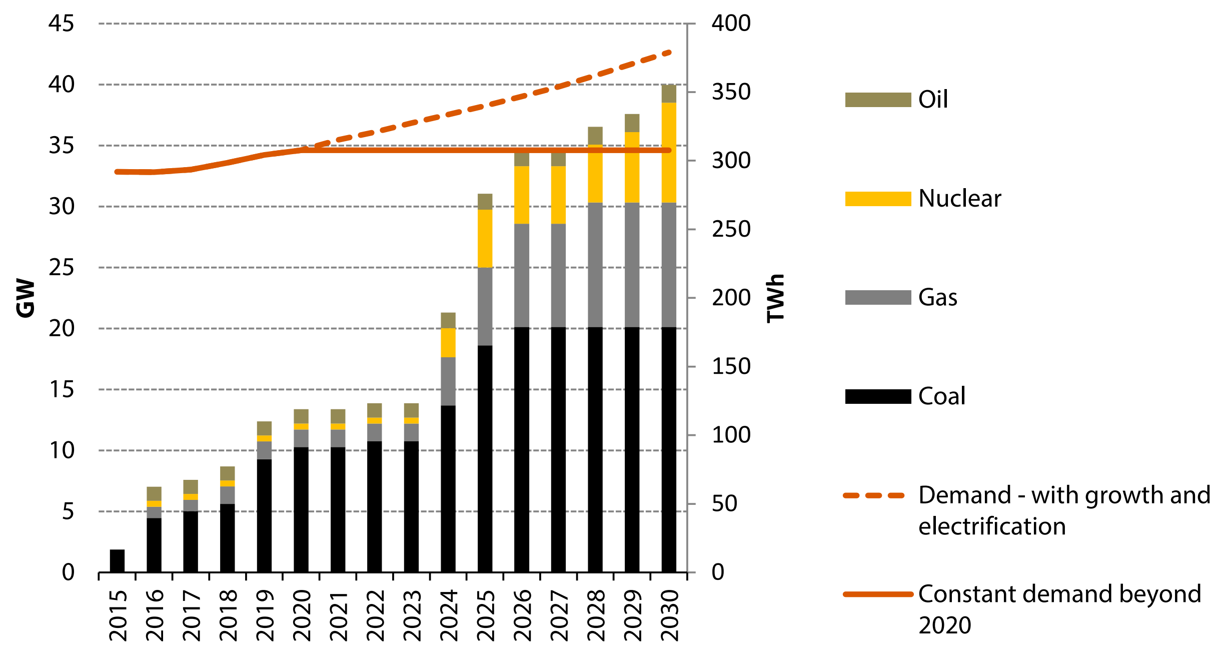
- This is based on the Government's official energy projections from 2013.
- As part of our scenarios for meeting carbon budgets, we include ongoing improvements in efficiency, such as the roll-out of LED lighting and increasing penetration of the most efficient appliances, reducing demand.

- We add extra demand to allow for electrification of transport (17 TWh) and heating (18 TWh), reflecting our scenarios for uptake of electric vehicles and heat pumps, which are needed to reduce emissions in those areas.
- There is general uncertainty when building scenarios for the future. We therefore also consider the implications of significantly more limited demand growth, given the recent downward trend and risk of under-delivery of electrification in heat and transport.

Alongside this potential demand increase, some plant will close during the 2020s (Figure 1.4):

- **Coal.** We and the Government assume that the remainder of the UK's coal capacity (11 GW) will cease unabated operation in the 2020s. These closures are due to age (the youngest plants were built in the 1970s and 1980s), tightening requirements under European air quality directives, assumed increasing costs as a result of rising carbon prices and potentially conversion to burn biomass instead of coal.
- **Nuclear.** The majority of the UK's nuclear power plants will be over 40 years old in the 2020s and are expected to close. Of the current 9 GW of nuclear power plants, we assume only Sizewell B (1.2 GW) remains on the system by 2030. There may be scope for some further life extensions, subject to regulatory approval, which could leave more existing nuclear capacity operating in 2030.
- **Gas.** Of around 33 GW of gas-fired capacity expected to be on the system in 2020, some may become uneconomic, depending on wholesale and capacity prices. We assume 9 GW retire through the 2020s.
- **Renewables.** Some older plant contracted under the Renewables Obligation will begin to reach the end of its life during this period (around 3.5 GW by 2030).

Figure 1.4: Retirements by technology to 2030



Source: DECC (2014) *Updated energy projections*; CCC calculations based on analysis by Redpoint (2013) for the *Fourth Carbon Budget Review*.

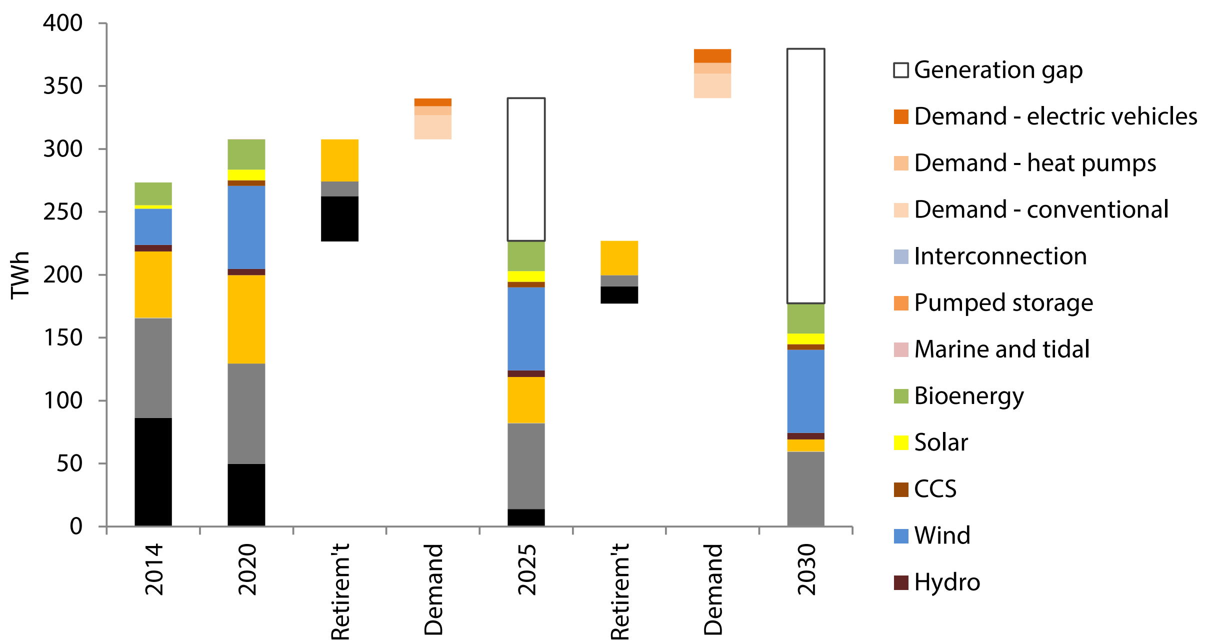
The closure of the UK coal plants is particularly important in the context of decarbonisation, since these plants account for over 70% of remaining emissions in 2020. Some analysis has suggested that there are scenarios in which the coal plants could economically run beyond 2030, yet the cost implications of their closure is small.

All our scenarios assume that the remaining coal closes by 2030 (or converts to biomass or CCS), mostly by 2025, with reducing running hours over the decade. This is in line with the cross-party leaders' pledge and the Government's manifesto commitment. A clear signal that the Government will intervene if necessary to ensure this happens may be needed to strengthen confidence for investors in replacement capacity.

Together, increasing demand and plant retirements imply a generation gap for the 2020s (Figure 1.5). Based on the retirement and demand assumptions set out above, we estimate a generation gap of up to 200 TWh/year.

With no growth in demand during the 2020s, around 25 GW of new capacity would be needed to replace retiring firm capacity and maintain system security. More capacity will be needed to the extent that demand also grows. For example, if demand grows by 23% as in our central scenario for demand growth, a total of 40 GW of de-rated capacity would be needed, possibly more if demand growth is concentrated in the winter peak periods.

Figure 1.5: The generation gap in the 2020s



Source: DECC (2015) *Energy Trends*; DECC (2015) *Digest of UK Energy Statistics*; DECC (2014) *Updated Energy Projections*; CCC calculations.

4. Our approach to building scenarios for the 2020s

In building scenarios we consider the range of options available for the power sector, including both low-carbon and gas-fired generation, the options for integrating low-carbon technologies with secure supply and at minimal cost. Our suggested deployment scenarios in Chapter 4 are consistent with deploying at least cost on the path to the 2050 target and meeting security of supply.

The importance of keeping costs low

The goal in meeting the generation and capacity gap in the 2020s should be for the power sector to make its contribution to meeting carbon targets while minimising costs and ensuring security of supply. Secure low-cost electricity is vital to effectively reducing emissions across the economy given the importance of electrification.

A full analysis must consider not only costs during the 2020s, but also costs in later periods, given that power plants have lifetimes of 20 to 60 years. In Chapter 2 we present lifetime cost estimates for the different generation and capacity options that could be deployed in the 2020s. In Chapter 4 we present the implications of our scenarios for energy bills in the 2020s and beyond.

Including the full costs of providing generation and capacity

Throughout our analysis we require that the Government's standard for security of supply is met. In Chapter 3 we examine the different challenges posed by a low-carbon electricity system and assess the full system costs of low-carbon options, including the need to back up intermittent renewables.

In comparing the cost of low-carbon options with generation from unabated gas we assume a cost for the emitted carbon. We distinguish in our analysis between the likely market carbon price (i.e. the cost of each carbon allowance in the EU Emissions Trading System and the UK's carbon price underpin) and a carbon price that is consistent with meeting the UK's 2050 target. The latter is the appropriate basis for decision-making for a country committed to long-term carbon targets and international efforts to tackle climate change (Box 1.1).

There are other potential costs attached to different generating options, but we do not include those in our analysis. For example, we do not quantify air quality impacts, which are greatest for coal. Generators face some cost of limiting air quality impacts under air quality regulations but are not required to reduce these to zero. Nor do we quantify visual amenity, which is covered by planning rules and community payments.

Box 1.1: Carbon values

Target-consistent carbon price

The Government's carbon values for policy appraisal are designed to be consistent with action required under the Climate Change Act. They reflect estimates in the literature and modelled scenarios. The values are peer reviewed by an expert panel. The modelling work includes a top-down global sectoral model for the world energy system under low, central and high projections for global technology costs, fossil fuel prices and global energy demand. The model is used to calculate carbon costs consistent with international action to limit the average increase in global surface temperatures to 2°C above pre-industrial levels.

In a central case the carbon values reach £78/tonne in 2030, growing steadily to £220/tonne in 2050. Low and high values are 50% below and above the central level. We have previously concluded that these values are in line with estimates in the wider literature for the costs of limiting warming to 2°C, where these are based on suitably cautious assumptions over the availability of sustainable bioenergy.

The UK's 2050 target is aligned to this level of effort globally, and is likely to require actions at the margin that have a similar carbon cost.[9]

The annual rate of increase in the Government carbon values is around 5%. Using this trajectory for carbon values as a guide to low-carbon investment would therefore support steady increase in effort over time.

Expected market carbon price

The actual carbon price in the market is expected to be lower. Independent forecasters project a carbon price in the EU Emissions Trading Scheme of £24/tonne in 2030. Although this will be topped up in the UK, with the Government's carbon values as the formal target trajectory, the additional UK carbon price support has been frozen at £18/tonne out to 2019/2020. If held at this level through the 2020s, this would imply a total market price of around £42/tonne in 2030, which is unlikely to be high enough to encourage investment in low-carbon generation in the 2020s.

If the world were to agree action to reduce emissions consistent with a 2°C target and deliver this through an efficient carbon market, then in theory market carbon prices would rise to a level in line with the target-consistent carbon price.

Our previous analysis has set out how pursuing a back-ended path for decarbonisation would be likely to raise the costs and risks of meeting the 2050 target.[10] It is therefore important that the UK develops policies and makes investments that prepare for a higher carbon price, rather than assuming that lower prices will persist in the long term. That implies allowing for steady rather than back-loaded low-carbon investment.

In designing our scenarios in this report we therefore continue to use carbon values consistent with UK actions to meet the 2050 target to support investment in low-carbon generation through the 2020s and estimate whole system costs of decarbonisation. We also report the impact of low-carbon investment on consumer bills relative to the expected market carbon price.

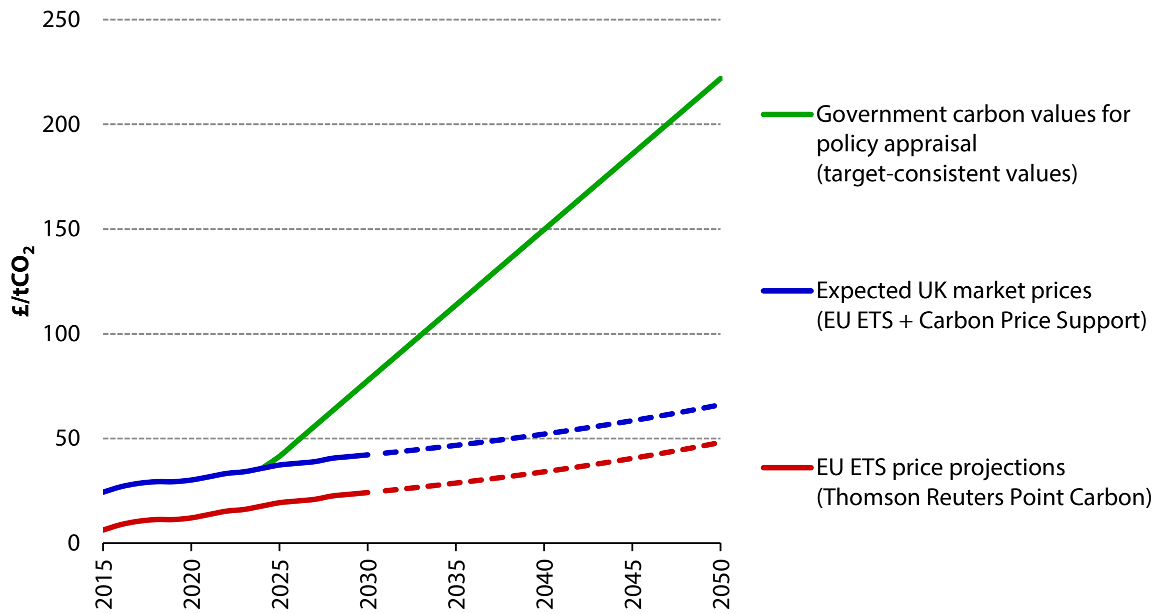
Figure B1.1 shows the trajectory of carbon values we consider out to 2050.

[9] For example, a carbon price at this level was needed to construct scenarios that could meet the 2050 target in CCC (2012) *The 2050 target*. Available at: www.theccc.org.uk

[10] See CCC (2013) Fourth Carbon Budget Review – part 2, *The cost-effective path to the 2050 target.* Available at: www.theccc.org.uk

Box 1.1: Carbon values

Figure B1.1: Target-consistent carbon values and market prices (2015-2050)



Source: DECC (2009) *Carbon Valuation in UK Policy Appraisal*; DECC (Oct 2014) *Updated short-term traded carbon values used for UK policy appraisal*, PointCarbon Thomson Reuters (2015), projected beyond 2030 at 3.5% p.a.
Notes: To determine the additional cost or benefit in the "social" or "private" case, we compare our scenarios to an alternative where investment in the 2020s is solely in gas-fired generation: all new demand is met by building gas-fired generation and all retiring plant is replaced by gas-fired generation where required. Expected market prices projected in 2020s and beyond assuming CPS frozen at £18.

Reflecting uncertainty in the analysis

A key feature of our approach is a recognition of the inherent uncertainties in constructing scenarios for the future. Fossil fuel prices, technology costs, deployability of different options, the size and shape of demand are all impossible to predict with confidence. This is reflected when we set out the latest evidence base in Chapters 2 and 3, including ranges for estimates of future generating costs, and our scenarios in Chapter 4, which include several potential generation mixes.

Uncertainty does not imply that nothing can or should be done. The statutory 2050 target implies that the direction of travel must be towards sharply reduced carbon emissions. However, it is not possible to say in advance exactly what the mix of options should be, and there are likely to be limits to generation potential of some technologies. To keep down costs of delivery, clarity is needed about how policy will adjust as areas of uncertainty are resolved.

In Chapter 4 therefore we emphasise the need to deploy those technologies that the market can deliver at lowest cost, while developing a wider portfolio of options to ensure cost competition between technologies and that other options are available should circumstances change. A narrow focus solely on the current lowest cost options in the short term is not an appropriate strategy given the different risks and the importance of low-carbon power, and could increase costs in the longer term.

Chapter 2: Evidence base on costs and potential for different generation technologies

Introduction and key messages

In Chapter 1 we set out the likely development of the power sector to 2020 and identified a need for more generation and capacity in the 2020s as existing capacity retires and as new demands for electricity grow.

How best to meet those needs depends primarily on the relative costs of the different available options and the opportunities to deploy them.

This chapter sets out the latest evidence on generating costs, deployability and developer interest for the main technology options. We assess potential system costs (e.g. to take account of the intermittency of some technologies) in Chapter 3.

Our assessment in this chapter includes both engineering estimates based on bottom-up assessments and revealed information based on market decisions and agreed contracts. We do not include an assessment of unabated coal, since new coal plants without CCS would be inconsistent with carbon objectives and have been ruled out by the Energy Act 2013

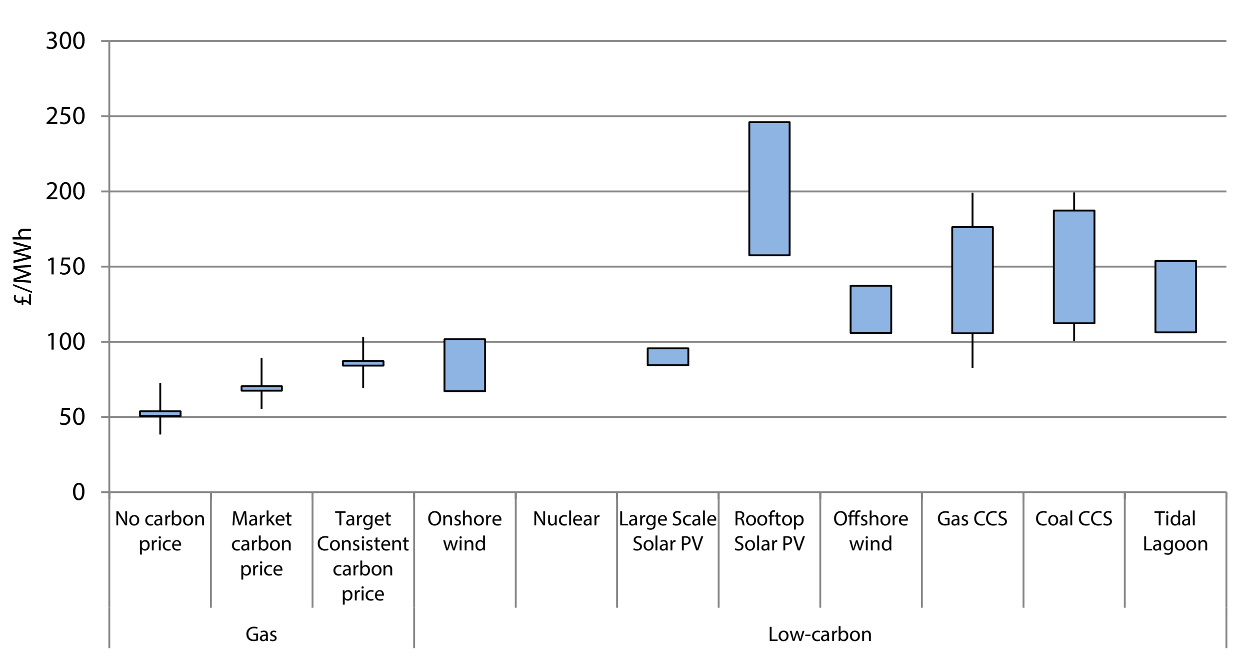
The evidence is summarised in Table 2.1, Figure 2.1 (2020 costs), Figure 2.2 (2030 costs), and Figure 2.3 (2030 costs at a reduced cost of capital).

Our key findings are:

- Low-carbon technologies are, and will continue to be, a more expensive way to generate electricity than burning gas and allowing the emissions to enter the atmosphere for free. However, in a carbon-constrained world, this is not an option.

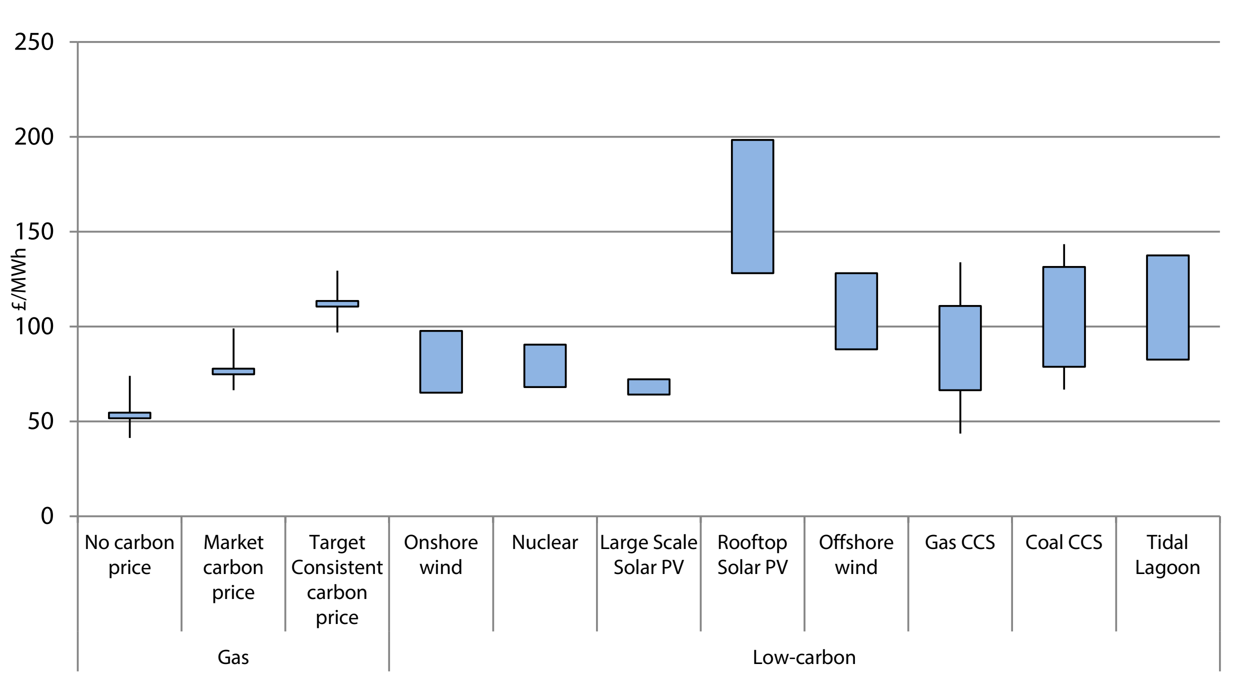
- The Government's carbon values are designed to be consistent with action required under the Climate Change Act. They reach £78/tCO_2 in 2030. Carbon values at this level would be enough to increase the cost of gas-fired generation to a level at or above the cost of low-carbon options in the 2020s. Extra support may be needed above the carbon price if market prices reach a lower level.
- A new gas-fired plant facing this target-consistent carbon cost could provide power at £70-105/MWh from 2020 or £95-130/MWh from 2030, with the range reflecting scenarios for future wholesale gas prices.
- Within the set of low-carbon options, some are already competitive with the 2020 cost of gas-fired generation, whilst others would need continued support beyond 2020 but could compete before 2030. For example:
  - Onshore wind and ground-mounted solar are already proving they can deliver electricity at £80/MWh.
  - Offshore wind is showing cost reduction, but still requires progress to reduce costs towards £90/MWh in the mid-2020s.
  - New nuclear projects may be deliverable at these costs, based on engineering estimates and has negotiated a contract at around £90-95/MWh for the mid-2020s. Nuclear plants have been delivered to cost internationally (e.g. in China and Korea) but have suffered delays and cost overruns in Europe and the United States.
  - The development of carbon capture and storage (CCS) has been delayed and remains at the demonstration phase in the UK. It is currently expected to have higher costs than other low-carbon technologies until at least the mid-2020s.
  - A programme of tidal lagoon development offers an opportunity for near base-load power, but currently appears to have higher costs than the alternatives.
- Costs of low-carbon generation options are sensitive to the return required on capital investment. If this can be lowered, then generation costs would fall significantly.

Figure 2.1: Expected costs of generation by technology (2020)



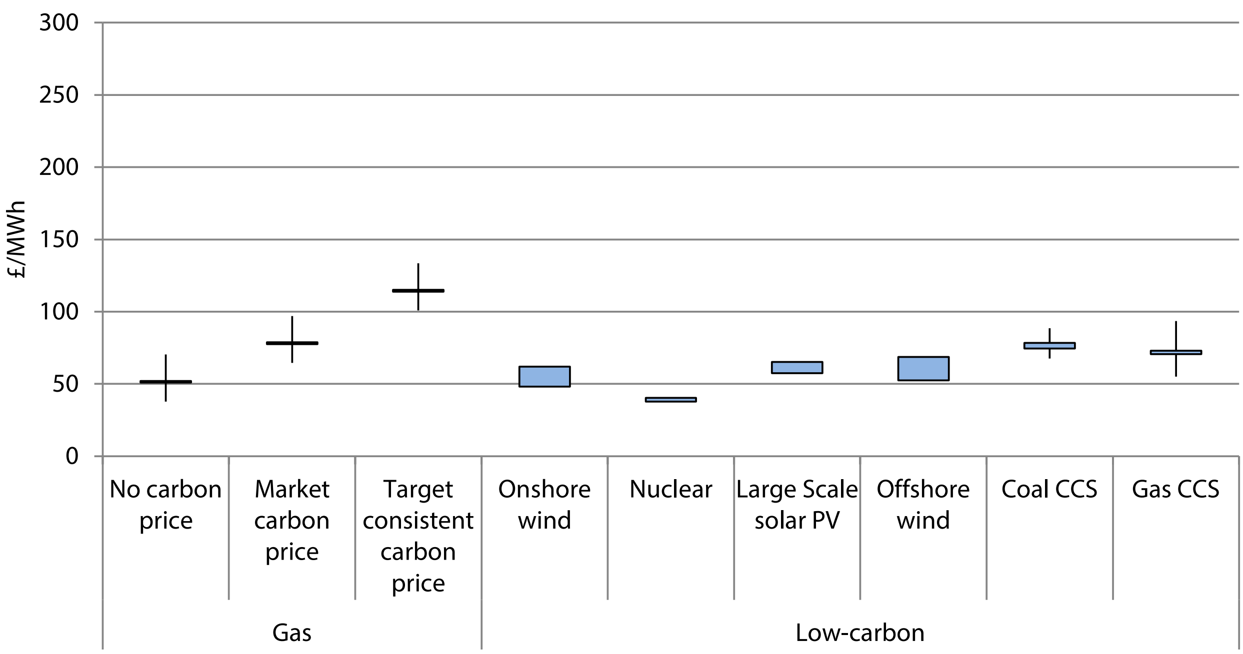
Source/notes: See Figure 2.3
Note: New nuclear is not available in 2020, so no costs are reported here.

Figure 2.2: Expected costs of generation by technology (2030)



Source/notes: See Figure 2.3

Figure 2.3: Levelised costs for selected technologies in 2030, at a HMT Green Book discount rate (3.5%)



Source: Calculations based on: DECC (December 2013) *Electricity Generation Costs*. Available at: www.gov.uk; BVG Associates (2015) *Approaches to cost reduction in offshore wind*. Available at: www.theccc.org.uk; Pöyry/Element Energy (2015) *Potential CCS Cost Reduction Mechanisms*. Available at: www.theccc.org.uk.

Notes: CCS refers to carbon capture and storage. We assume the following ranges for gas prices: 30-76p/therm in 2020, 38-99p/therm in 2025 and 46-99p/therm in 2030. Target consistent carbon price: carbon price rises in line with Carbon Price Floor, to £23/t in 2020 and £78/t in 2030; Market carbon price: based on EU ETS projection from Thomson Reuters Point Carbon (June 2015), including carbon price support, rising to £37/t in 2025 and £42/t in 2030. Solid boxes represent range for technology costs; whiskers represent range for fuel costs (where appropriate). Costs are estimated for technology specific load factors: 95% for CCGT, nuclear and CCS, 28% for onshore wind, 46% for offshore wind, 11% for solar PV and 22% for tidal lagoons. Costs in Figures 2.1 and 2.2 reflect technology specific pre-tax real rate of return (7.5% for unabated gas, 7.1% for onshore wind, 9.5% for nuclear, 5.3% for large-scale solar PV and 10% for coal/gas CCS).

Table 2.1: Key statistics for power sector generation technologies

Key technologies	*Cost 2020*	*Cost 2030*	*Cost 2030 (3.5%)*	*Capacity in 2014 (GW)*	*Generation in 2014 (% of total)*	*UK practical resource*	*Load Factors (%)*
Unabated gas	£55-89/MWh (market carbon price); £69-103/MWh (target consistent carbon price)	£64-97/MWh (market carbon price); £97-129/MWh (target consistent carbon price)	£57-89/MWh (market carbon price); £101-133/MWh (target consistent carbon price)	32 GW	87 TWh (30%)	Limited by emissions constraint.	Up to 100%
Onshore wind	£67-102/MWh	£65-98/MWh	£48-62/MWh	8.5 GW	18 TWh (6%)	Around 80 TWh per year, depending on planning constraints	26-30%
New nuclear power	-	£76-103/MWh	£38-40/MWh	New: - Existing: 9 GW	New: - Existing: 58 TWh (19%)	In theory could be very large. In practice may be limited by sites – 8 currently approved sites could provide over 20 GW (e.g. 175 TWh per year). Including small nuclear reactors this could reach up to 50 GW (e.g. over 400 TWh per year)	Up to 95%
Biomass	£107-117/MWh	-	-	3.4 GW	20 TWh	Limited by land use and sustainability concerns.	Up to 95%
Offshore wind	£106-137/MWh	£88-128/MWh	£51-67/MWh	4.5 GW	13 TWh	Very large – over 400 TWh per year.	38-45%
Carbon capture and storage	£150-170/MWh	£89-130/MWh	£55-94/MWh	-		Likely to be large - storage unlikely to be a limiting factor.	Up to 95%
Tidal range	£107-154/MWh	£83-138/MWh	-	-		Up to 40 TWh.	22%
Tidal stream	£100-200/MWh	£70-100/MWh	-	< 1 GW	<1 TWh	Potentially large – 18 to 200 TWh per year.	31%
Solar PV	£84-96/MWh (large-scale ground-mounted); £158-246/MWh (rooftop)	£64-72/MWh (large-scale ground-mounted); £128-198/MWh (rooftop)	£57-65/MWh (large-scale ground-mounted);	8.0 GW	4 TWh	Large – around 140 TWh per year (on the basis of current technology) with more possible with technology breakthroughs.	11%

Source: CCC Calculations, based on Mott MacDonald (2011) *Costs of low-carbon generation technologies*. Available at: www.theccc.org.uk. Other information from DECC (2015) *Energy Trends*, DECC (2015) *Digest of UK Energy Statistics* and DECC (2015) *Public Attitudes Tracker*. Available at: www.gov.uk

Table 2.1: Key statistics for power sector generation technologies

Estimated deployment rate in 2010s	*Potential deployment rate in 2020s*	*Assumed generation lifetime*	*Public Acceptability*	*Importance of UK deployment for reducing costs*	*Other considerations*
-	-	40 years	-	-	High levels of capacity could have low emissions through lower load factors.
0.8 GW per annum	*1 GW per annum*	25 years	66%	Technology is already well-established and is being deployed globally. UK impact on costs likely to be limited.	Variability of generation output. Possible local resistance.
-	*Up to 1.5 GW per annum from 2024/25*	60 years	38%	Equipment costs likely to be driven by global deployment, with some potential for local learning-by-doing and reduction in cost of capital.	Mature technology, globally deployed. Waste disposal and proliferation concerns. Public acceptability risk.
< 0.5 GW per annum	-	May be limited by feedstock availability or age of base plant (if converted).	49%	Limited cost reduction expected.	Sustainability concerns about use of wood pellets in biomass generation. Competition from other sectors for use of scarce bioenergy, where low-carbon alternatives may be limited.
1.0 GW per annum	*1-2 GW per annum*	25 years	74%	UK deployment likely to be important to reducing costs, given significant capabilities already established and a large share of the global market.	Variability of generation output. Lower visual impact (less local resistance).
-	*0.5-1 GW per annum*	40 years	55%	UK deployment important alongside global cost reduction efforts. UK has existing strengths (e.g. in CO2 storage and transportation, subsurface evaluation & geotechnical engineering, and power plant efficiency & clean coal technologies), likely an early deployer internationally.	Dispatchable. Exposed to fossil fuel price risk. Higher lifecycle emissions, including direct residual emissions.
-	*Depends on individual projects*	120 years	-	Limited cost reduction expected, though arguments have been made for benefits of a programme of tidal lagoons.	Predictable output, though intermittent. Possibility for baseload equivalent generation if multiple projects paired together. Environmental concerns.
< 0.1 GW per annum	*Uncertain*	25 years	74%	UK has an important role. UK companies have significant marine design/engineering experience and already have a sizable share of device developers and patents. UK resource also a large share of the global market.	Predictable output, though intermittent.
1.0 GW per annum	*Multiple GW per annum*	25 years	82%	Limited learning from deployment though UK does have research strength. Technology development likely to be driven by international deployment or by research in the UK that is not dependent on UK deployment.	Variability and intermittency of generation output, which is highest in summer when demand for electricity is lower.

Notes: For reference, peak demand in 2014 was 51 GW, and total capacity was 95 GW, producing 298 TWh of generation. Wholesale electricity prices in 2014 were around £45/MWh.

(a) Unabated gas as an alternative to investment in low-carbon technologies

Power generation from natural gas is produced from Combined Cycle and Open Cycle Gas Turbines (CCGTs and OCGTs), with emissions of around 350 gCO_2/kWh and 650 gCO_2/kWh respectively (compared to emissions of over 900 gCO_2/kWh from existing UK coal generation – see Table 2.2).

There is already 32 GW of gas-fired CCGT capacity on the power system, mainly built during the 'dash for gas' in the 1990s. It is unlikely that much of this capacity will be retired before 2020 as plants can run for about 40 years. The most recent plant to be commissioned was a 2.2 GW plant that came online in 2012 after a four-year construction period.

Deployment potential. The practical resource for gas generation depends on the cost and availability of natural gas for use in the power sector, and emissions constraints. Natural gas in the UK is largely imported (62% in 2014)[11], and is expected to remain so at the margin even if decarbonisation is successful and even with a large increase in domestic onshore supply[12].

Project pipeline. There is currently 22 GW of new build gas capacity in the planning process, with 18 GW approved and awaiting construction, and 0.9 GW under construction.

Current and future costs: CCGT is currently the lowest cost way to meet a need for new electricity generation. Future costs are uncertain, reflecting uncertainty in the future wholesale fuel cost, but will have to rise in a carbon-constrained world, reflecting the increasing value attached to carbon (see Box 1.1 in Chapter 1). The levelised cost of an unabated gas plant includes estimates of both future gas and carbon prices. We consider current costs of new build CCGT against both a market price and a 'target-consistent' carbon value:

- Current costs are around £45-64/MWh, using a market carbon price (rising to £42/tCO_2 in 2030), or £57-72/MWh at a target-consistent carbon price (rising to £78/tCO_2 in 2030).[13]
- Gas prices are volatile, and historically have been linked to changes in the global oil price, though that link is increasingly being broken. The Government is in the process of updating their fossil fuel price assumptions. In advance of that concluding, we have used working assumptions, which reflect decreases in UK System Average Price of around 6p/therm between 2014 and 2015[14]. We assume the following ranges: 30-76p/therm in 2020, 38-99p/therm in 2025 and 46-99p/therm in 2030 (Figure 2.4).
- The carbon prices that we use to assess the levelised cost of gas generation are consistent with the 'carbon values' described in Chapter 1 (i.e. the Government's carbon values for policy appraisal, which rise to £23/tCO_2 in 2020, £42/tCO_2 in 2025 and £78/tCO_2 by 2030).
- However, the price faced by plants in the market is unlikely to reach these levels for some

[11] DECC (2015) Digest of UK Energy Statistics: Natural Gas Commodity Balances. Available at: www.gov.uk
[12] National Grid's *Future Energy Scenarios* (2015) consider four scenarios where UK shale gas is exploited. In the most ambitious scenario, 'Consumer Power', import dependency falls to 32% in the mid-2020s, before rising to 39% in 2035. In early 2016 we will publish a report assessing the impact of shale gas extraction in the UK on carbon budgets.
[13] Here and throughout this chapter we assess technologies based on their levelised costs of generation over plant lifetimes, at technology specific discount rates. Technology costs are based on DECC (2013) *Levelised Cost of Electricity Generation*, available at: www.gov.uk, and due to updated in the near future. We have used more recent evidence for offshore wind, CCS, tidal lagoons and tidal range technologies – see sources in relevant sections. And we consider contract prices that have been offered or agreed following the 2014/15 low-carbon auctions throughout.
[14] National Grid (2015) *Data explorer: SAP*. Available at: www2.nationalgrid.com/uk

time. We therefore also report CCGT costs at a projected market price, including carbon price support[15], rising from £24/tCO_2 in 2015 to £37/tCO_2 in 2025 and £42/tCO_2 in 2030.

- There are costs associated with air quality, from NOx (Nitrous Oxides), SOx (Sulphur Oxides) and particulate emissions. The costs of meeting existing regulation concerning these pollutants is included in the levelised cost estimates of CCGT; we do not add any additional costs relating to these pollutants.

This implies a range of technology costs for CCGT facing its full carbon costs rising to £69-103/MWh in 2020 and £97-111/MWh in 2030, due to the increasing value attached to carbon emissions[16]. At market carbon prices, costs would rise to £54-88/MWh in 2020 and £63-96/MWh in 2030.

Cost structure: Gas power plants have relatively low capital costs (10-15% of total costs for CCGT, 20% for OCGT – see Figure 2.5) and the ability to switch on and off. As a result they face a relatively low cost penalty for operating at a restricted load factor.

Conclusion: CCGT facing a carbon cost is the relevant comparator for considering the cost of low-carbon alternatives. CCGTs and OCGTs also provide a low-cost route to providing capacity that is able to run at low load factors and provide flexibility to complement intermittent low-carbon generation.

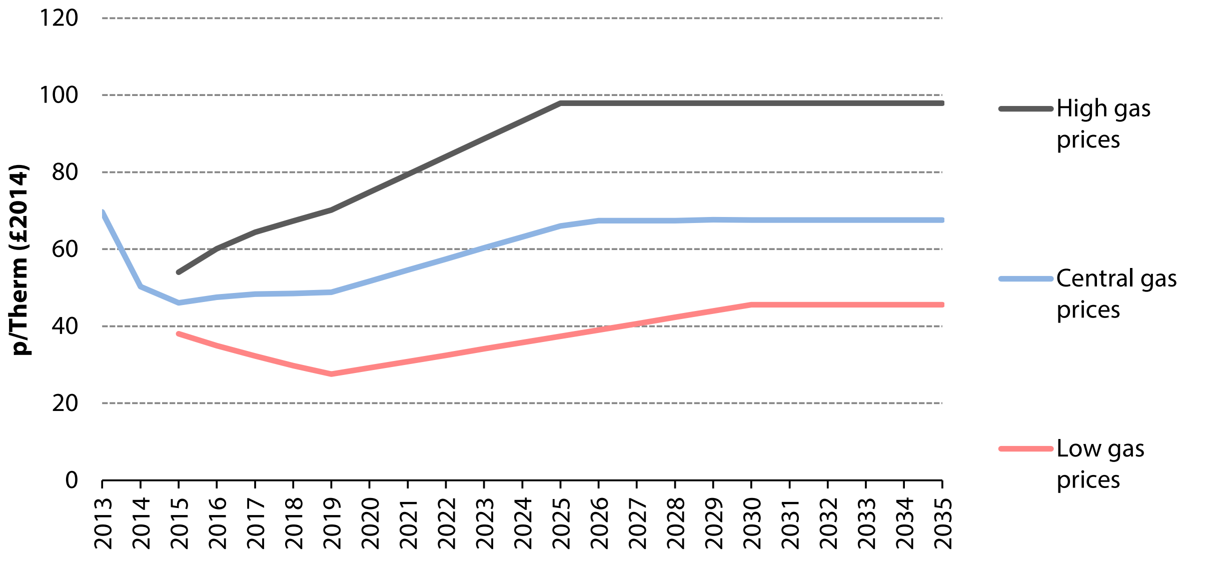
Table 2.2: Carbon emissions intensities of fossil fuel technologies

Technology	2014 Average (gCO_2/kWh)	New Build (gCO_2/kWh)	With CCS (gCO_2/kWh)
Coal	907	775-820	~120
Gas CCGT	365	345	~50
Gas OCGT	-	640-660	-
Oil	-	800-1000	-

Source: DECC (2015) *Digest of UK Energy Statistics*. Available at: www.gov.uk; Pöyry (2013) *Technology Supply Curves for low-carbon generation.* Available at: www.theccc.org.uk.

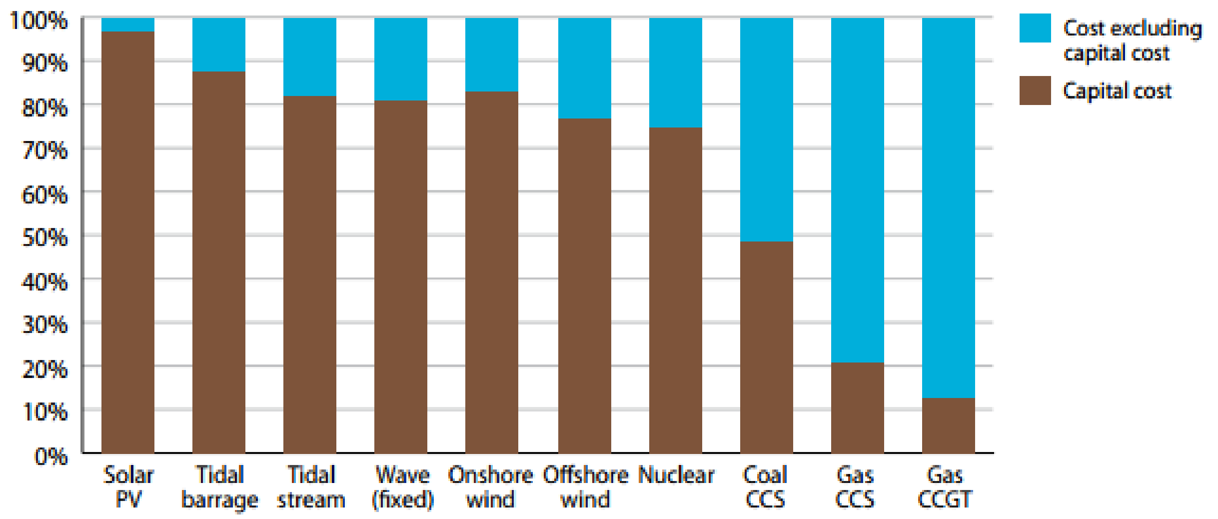
[15] Carbon Price Support frozen at £18/tCO_2. Market price projection from Point Carbon Thomson Reuters (June 2015). Available at: www.financial.thomsonreuters.com

Figure 2.4: Gas price projections



Notes: The Government is in process of updating their fossil fuel price assumptions. In advance of that concluding, we have used working assumptions, which reflect decreases in UK System Average price of around 6p/therm between 2014 and 2015. We have incorporated this into the fossil fuel price assumptions we use, based on DECC (2014) *Fossil Fuel Price Projections*. For example, where DECC used a 72 p/therm central case for 2025, we use 66 p/therm. Available at: www.gov.uk, and National Grid (2015) *Data Explorer: SAP*. Available at: www2.nationalgrid.com/uk.

Figure 2.5: Share of capital costs in long-run marginal costs



Source: CCC Calculations, based on Mott MacDonald (2011) *Costs of low-carbon generation technologies.* Available at: www.theccc.org.uk
Notes: Based on projects starting in 2011, using 10% discount rate and central scenario for capital costs and fuel prices. Non-renewable plants operating at baseload (i.e. a load factor of 90%); the proportion of capital costs would be higher for operation at mid-merit (e.g. 50%). Capital cost category excludes the costs of CO2 transportation and storage, which are around 3% for gas CCS and 6% for coal CCS.

(b) Nuclear

Nuclear power has been deployed in the UK since the 1950s. There is currently 9 GW of nuclear power on the system, with the last new nuclear power station connecting in 1995. The majority of existing nuclear power (8 GW) is set to come offline by 2030, but there are currently plans to develop up to 12.6 GW of projects over the next 15 years. Nuclear power is a baseload low-carbon generation technology with inflexible output, and is capable of running at high load factors (e.g. up to 90%).

Deployment potential. Our 2011 report, *The Renewable Energy Review,* suggested that around 175 TWh of generation could be achievable towards 2050 through a new build nuclear program in the UK, equivalent to around 21-25 GW of capacity. A recent report from ETI suggested that this figure could be much higher, towards 50 GW, including smaller modular nuclear reactors (SMRs) which could provide heat as well as power[17]. This capacity could be deployed across the existing nuclear sites that were approved in the National Policy Statement for Nuclear (2009)[18]. The only existing nuclear plant that is currently expected to remain online beyond 2030 is Sizewell B (1.2 GW), though plant life extensions for existing nuclear plants could see 3-4 GW of plant remaining online until the late 2020s.

Project pipeline. Three developers are currently looking to bring forward projects totalling 12.6 GW of capacity by 2035, across five different sites, which could both replace and add to the existing nuclear power capacity:

- **EdF.** Hinkley Point C (3.2 GW), the first new nuclear plant is now not scheduled to commence generation until 2025. The project was recently offered a £2 billion infrastructure guarantee, though a Final Investment Decision is yet to be taken. The reactor for the project, the EPR, passed its Generic Design Assessment (GDA) in 2012. Original estimates for Hinkley Point C suggested the project could come online as early as 2017 at an overnight cost[19] of £17 billion; the current cost estimate for the project remains the same. The connection date has since been put back to 2025, reflecting delays to projects building EPRs in France and Finland (see Box 2.1) and negotiations over contracts and financing for Hinkley Point C. Assuming Hinkley Point C goes ahead, EdF has plans to develop another 3.2 GW site at Sizewell in the late 2020s.
- **Horizon.** Horizon are aiming to submit a planning application next year for a 2.6 GW plant at Wylfa ahead of commencement of major on-site work in 2018. This is with a view to being online in the mid-2020s. Development is also continuing at another Horizon-owned site at Oldbury (2.6 GW), although this may not begin operation until after 2030. This venture is using the UK version of GE Hitachi's Advanced Boiling Water Reactor (AWBR) which is currently being assessed under the GDA process, expected to complete by January 2018.
- **NuGen.** The NuGen (3.6 GW) venture at Sellafield expects to enter planning in 2015/16, with the intention of being operational in the mid-2020s. The GDA process was paused for this reactor (Westinghouse AP1000), but resumed in mid-2014 and is now expected to be completed before 2017.
- **Other projects.** Other developers could potentially also join the pipeline, for example at the approved sites at Bradwell, Heysham and Hartlepool. Whilst there is a possibility of small modular reactors, these are unlikely to make a major contribution by 2030. We do not include them in our scenarios but will keep them under-review as new evidence emerges.

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[17] ETI (2015) *The role for nuclear within a low-carbon energy system.* Available at: www.eti.co.uk.

[18] DECC (2011) *National Policy Statement for Nuclear Power Generation*. Available at: www.gov.uk

[19] The cost excluding interest during the construction period

Current and future costs. Nuclear is expected to be cost-competitive with new gas CCGT plant facing a target-consistent carbon price when the first new plant commissions in the mid-2020s.

- The first new build nuclear plant in the UK is expected to be commissioned around 2025. Following negotiations wih EdF, the Government has offered a strike price of £93-96/MWh for 35 years (compared to an expected lifespan of 60 years).
- Some technological learning can be expected through both UK and international deployment, but we anticipate this to have a limited impact on costs before 2030. Given that the last new build nuclear project in the UK was connected in 1995, new nuclear power will also require significant supply chain development. Future projects should benefit from experience and supply chain development in earlier projects. The presence of multiple developers and competitive pressure from other low-carbon technologies delivering at lower cost could lead to lower strike prices in the future, especially if development of the first project is seen to reduce regulatory risk.
- Costs include an allowance for future decommissioning costs. They would also have to cover regular payments from developers to the Treasury in return for infrastructure guarantees.
- Nuclear power plants are highly capital intensive (see Figure 2.5), with around 75% of the overall costs being incurred during the construction phase.

Conclusion: Nuclear can play a role as a part of a low-carbon portfolio of technologies provided it can deliver on costs. Given delays in signing the contract for Hinkley Point C, we have revised downward potential ambition for new nuclear power projects to a maximum of 12.6 GW by 2030 (from 16 GW in earlier estimates), representing projects from three separate developers. Most of our scenarios limit deployment to two or three plants and we consider scenarios for meeting demand in 2030 with no new nuclear build.

Box 2.1: International nuclear power deployment

In recent years, nuclear plants have been delivered to cost and on time in Asia, but have experienced delays, and cost overruns in both Europe and the US. Several different reactor technologies are in use.

- **Asia:** Recent estimates of costs in South Korea are between £22-35/MWh with an average build time of around 50 months, and £22-37/MWh in China (70 months). GE Hitachi's Advanced Boiling Water Reactors (ABWRs) have previously been constructed in Japan in around 50 months, at an estimated cost of £48-73/MWh.
- **Europe:** Two nuclear projects in Europe have experienced delays and cost overruns in building Areva's European Pressurised Reactors (EPRs) in Finland and France. In Finland, construction on an EPR started at Olkiluotu in 2005, though an initial connection date of 2009 has been pushed back to 2018. At Flamanville in France an initial connection date has been pushed back to 2018, from 2012.
- **US:** Five nuclear projects in the US are under construction, of which four are using Westinghouse's AP1000 reactor. These have been delayed by an average of three years.

Source: IEA (2015) *Projected Costs of Generating Electricity: 2015 Edition.* Available at: www.iea.org
IAEA (2015) *Nuclear Power Reactors in the World: 2015 Edition.* Available at: www-pub.iaea.org

(c) Onshore Wind

Onshore wind is an established low-carbon generation technology with intermittent output (e.g. generation is dependent on weather conditions). There is currently 8.7 GW of onshore wind on the system, which provided 6% (18 TWh) of generation in 2014.

Deployment potential. There is an estimated resource of up to 80 TWh of onshore wind in the UK[20] (Table 2.1), although this is ultimately limited by long-term site availability and concerns around landscape impacts. Public acceptability is fairly high overall (Box 2.2), however the technology is less popular in some areas because of local impacts. Wind patterns in the UK are positively correlated with seasonal demand.

Project pipeline. There is 2.1 GW of onshore wind under construction, with an additional 4.5 GW of projects with planning permission and awaiting construction, and Contracts for Difference (CfDs) have been signed for an additional 0.75 GW to come online by 2020. The Government has signalled its intention to curtail support for onshore wind, limiting deployment to a total of 12.3 GW of capacity by 2020/21[21]. However, a strong pipeline of projects could continue to deploy beyond 2020, as well as the opportunity to repower existing sites at lower cost before 2030:

- Analysis by Pöyry[22] for our 2013 report *Next steps on Electricity Market Reform* suggested that a potential of 15 GW of capacity could exist beyond 2020.
- Additionally, 3.5 GW of onshore wind was installed before 2010, with a 20-year contract under the Renewables Obligation, and is therefore set to come offline before 2030. It is likely that these sites can be repowered at low cost as they begin to reach the end of their lifetime in the second half of the 2020s (Box 2.4).

Current and future costs. Onshore wind is one of the most cost-competitive low carbon technologies, with potential for further cost reduction in the UK:

- In the Government's recent CfD auction, contracts were signed at under £83/MWh (£2014 prices).
- Under the Government's central scenarios for carbon and gas prices, onshore wind could be considered subsidy-free from around 2020
- There is potential for further cost reduction. For example, onshore wind costs in Germany and the US are £50-70/MWh and £30-50/MWh respectively[23], due to a combination of enhanced technology (e.g. larger blades, taller turbines, which are currently restricted due to UK planning regulations) and lower cost of capital (e.g. as low as 5% compared with an estimated 7.1% in the UK).

Conclusion: Onshore wind is a cost-effective low-carbon technology, with a pipeline for up to 25 GW of total capacity (incl. repowering) available at low cost before 2030. In practice it is unclear how much of this can be developed. Our scenarios consider a range of options.

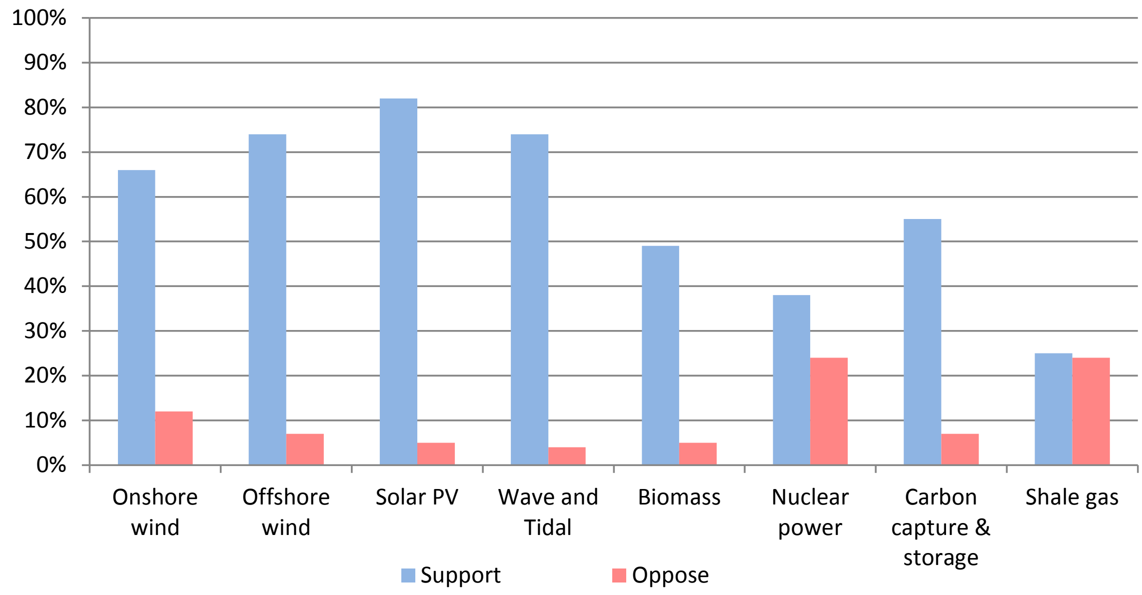
[20] CCC (2011) *The Renewable Energy Review.* www.theccc.org.uk
[21] DECC (2015) *Estimated capacity of selected renewable technologies in 2020/21.* Available at: www.gov.uk
[22] Pöyry (2013) *Technology supply curves for low-carbon generation.* Available at: www.theccc.org.uk
[23] IEA (2015) *Projected Costs of Generating Electricity: 2015 Edition.* Available at: www.iea.org

Box 2.2: Public attitudes tracking survey for low-carbon electricity sources

Figure B2.2 presents the findings from DECC's Public attitudes tracking surveys for key low-carbon electricity sources, conducted between March 2012 and June 2015. The results represent averages across the United Kingdom, and may be different in specific local areas.

Wind, solar and tidal energy consistently receive strong support. Support for biomass electricity, nuclear power and carbon capture and storage is lower, but with higher support than opposition. Shale gas receives lower support than all low-carbon technologies, but otherwise conventional sources of power generation, such as coal and gas, are not included.

Figure B2.2 Public attitudes tracking survey for low-carbon electricity sources (UK)



Source: DECC (2015) *Public Attitudes Tracker: Waves 1-14.* Available at: www.gov.uk
Notes: Data presented is the averages of Waves 1-14 for questions 13, 14ai, 15ai and 15B.. 'Support' encompasses the responses 'support' and 'strongly support'; 'Opposed' is 'oppose' or 'strongly oppose'.

Box 2.3: Repowering of existing low-carbon plant

Under the Feed-in-Tariff and Renewable Obligation schemes, contracts were signed for 20-25[24] and 20 years of generation, respectively. As these projects come to the end of their lifetimes, there may be opportunities to repower these sites with greater capacity and/or enhanced efficiency, resulting in an increase in output. Towards 2030 this is particularly important for onshore wind, where there could be opportunities to repower 3.5 GW of onshore wind capacity:

- Projects are expected to begin retiring from FiTs and the RO from 2022: up to 3.5 GW of onshore wind projects came up under RO between 2001-2010 and are set to be retired by the mid to late 2020s.
- The average turbine size for these projects is 1.8 MW. Onshore wind turbines are currently being developed internationally at over 4 MW, with potential for further cost reduction.
- The cost of repowering an existing site should be lower than building new, since development costs are already sunk, infrastructure (such as roads, substations) exists, and it may be possible to repower end-of-life turbines without replacing the foundations and tower.
- Between 2008 and 2014, onshore wind projects were deployed at 0.9 GW per annum suggesting a repowering market of up to the same size from 2027. Similarly, large-scale solar projects were constructed at 0.7 GW per annum between 2012 and 2014.

Towards the end of the 2020s similar opportunities may exist for offshore wind and large-scale solar projects.

(d) Ground-mounted and rooftop solar PV

Solar Photovoltaic (PV) technology is the main solar power technology in the UK and is deployed on residential and commercial rooftops, as well as in larger ground-mounted arrays. Its output is intermittent and variable. Solar PV capacity in the UK has expanded rapidly from less than 0.1 GW of capacity in 2010, to around 8 GW today (generating 4 TWh, or just over 1% of electricity in 2014), of which 5 GW has been added since the end of 2013. Of the current installed capacity, 2.7 GW is small-scale (<50kW capacity) and on domestic and commercial rooftops and 5.1 GW is larger-scale ground-mounted installations.

Deployment potential. We have previously identified a UK resource potential of up to 160 TWh per annum[25]. As solar generates most in summer when UK demand is lower, deployment could ultimately be limited by electricity system constraints (see Chapter 3).

Project pipeline. Currently 0.2 GW of solar PV over 1 MW is in construction. A further 2.9 GW with planning permission is awaiting construction. Additionally, 0.04 GW of large scale solar PV has been contracted under CfDs to be deployed by 2020. The Government has signalled its intention to curtail support for solar PV, limiting deployment of large-scale solar PV to 5.7 GW by 2020/21[26].

Current and future costs. Globally, the costs of solar panels have fallen by more than 80% since 2006, enabling ground-mounted solar PV to become one of the most cost-effective low-carbon generation technologies in the UK. However costs for rooftop solar PV remain high.

[24] 25 years for initial solar FiTs only
[25] CCC (2011) *The Renewable Energy Review*. Available at: www.theccc.org.uk
[26] DECC (2015) *Estimated capacity of selected renewable technologies in 2020/21*. Available at: www.gov.uk

- In the recent Government CfD auctions, costs for large-scale ground mounted solar PV generating in 2016/17 were around £80/MWh, comparable to onshore wind.
- Costs of smaller rooftop installations are as high as £140/MWh, due to higher installation costs per unit of capacity, but have also fallen significantly (from £400/MWh in 2010).
- Further cost reduction is possible through efficiency improvements, reduction in cost of solar cells on the global market, as well as reduced installation costs for rooftop solar.

Conclusion: Ground-mounted solar is a relatively low-cost renewable technology that can be deployed rapidly, subject to availability of publicly acceptable sites. Rooftop solar has lower barriers to acceptability, but higher costs. Our scenarios include cost-competitive roll-out into the 2020s within limits that can be accommodated on the grid (see Chapter 3).

(e) Biomass

Electricity from bioenergy is currently produced through a variety of different sources, including energy from waste, anaerobic digestion, advanced gasification and advanced conversion technologies, biomass conversion and dedicated biomass plant.

Power generation from biomass has risen from 8.7 TWh in 2008 (around 3% of electricity supply) to 20.1 TWh (7% of electricity supply) in 2014, with power generated from 2.2 GW of biomass conversion and dedicated biomass plant on the system, and 1.2 GW of capacity from other biomass generation technologies.

There are concerns around the sustainability of the feedstocks of large scale biomass combustion, such as dedicated biomass and biomass conversion plant (Box 2.4)

Deployment potential. We previously identified in our 2011 *Bioenergy Review* potential for up to 100 TWh of generation from biomass in the power sector to 2020 on an energy supply basis.

Project pipeline. We expect up to 3.4 GW of bioenergy capacity to be online by 2020, producing 24 TWh of electricity, approximately 8% of the UK's electricity supply. This includes 2.2 GW of biomass conversion capacity in 2020/21 (equivalent to around 15 TWh).

- CfDs have been signed for a total of 1.5 GW of bioenergy capacity to come online by 2020.
- Biomass conversion plans include a potential 3rd unit at DRAX converting to biomass in 2015/16 as well as the closure of an existing biomass conversion plant, Ironbridge (0.7 GW), expected in 2015/16.
- Beyond 2020 the Government has indicated that it will limit support for biomass deployment, by removing contract grandfathering under the RO.

Current and future costs. Current biomass costs range between £30/MWh for energy from waste to over £100/MWh for biomass conversion and dedicated biomass technologies. In all cases the potential for costs to fall in the future is limited, primarily because these technologies rely on existing combustion techniques that are already achieving high efficiencies.

There are costs associated with air quality, from NOx, SOx and particulate emissions, which we do not include directly in our cost estimates of biomass.

Conclusions: Expansion of biomass conversion and dedicated biomass plants should be contingent on guaranteeing that the biomass used is within sustainability standards. Our scenarios do not include an increase in biomass capacity beyond 2020 due to concerns around sustainability, and the value of bioenergy in other sectors in the economy.

Box 2.4: Life-cycle carbon emissions

The lifecycle emissions or carbon footprint of a product refers to the total greenhouse gas (GHG) emissions caused directly and indirectly at each stage of its life, from the extraction of raw materials and manufacturing right through to its use and final re-use, recycling or disposal. It includes the GHG emissions resulting from any material inputs to, or outputs from, this lifecycle, such as energy use, transportation fuel and direct gas emissions such as refrigerant losses and waste. Estimates of the lifecycle emissions for key power sector technologies in the UK are presented in Table B2.4.

Lifecycle emissions for bioenergy vary significantly depending on the source of the bioenergy feedstock. We have previously recommended to Government that the use of biomass in power generation in the UK should be contingent on its lifecycle emissions being lower than 200 gCO_2e/kWh.

Lifecycle emissions for low-carbon technologies are lower than for conventional fossil fuel generation. Furthermore, as manufacturing becomes more energy efficient, and electricity systems reduce their carbon intensity around the world, lifecycle emissions of the key components (e.g. steel, concrete, silicon) used in these technologies will decrease.

Table B2.4: Estimated lifecycle emissions of selected generation technologies

Technology	**Estimated lifecycle emissions (gCO_2e/kWh)**
Nuclear power	5 – 55 gCO_2e/kWh
Onshore wind	7 – 20 gCO_2e/kWh
Offshore wind	5 – 24 gCO_2e/kWh
Gas CCS	90 – 245 gCO_2e/kWh (of which 50 gCO_2e/kWh is from combustion)
Coal CCS	80 – 310 gCO_2e/kWh (of which 120 gCO2e/kWh is from combustion)
Solar PV	40 – 85 gCO_2e/kWh
Biomass	-20 to +800 gCO_2e/kWh
Gas CCGT	380 - 500 gCO_2e/kWh

Source: CCC (2013) *Reducing the UK's Carbon Footprint.* Available at: www.theccc.org.uk.
DECC (2014) *Bioenergy Emissions and Counterfactual Calculator.* Available at: www.gov.uk.

(f) Offshore wind

Offshore wind is a large-scale renewable electricity technology with variable output, with a large potential wind resource in UK coastal waters. The UK is currently the market leader in offshore wind, with 5 GW installed, generating 13 TWh in 2014 (4% of UK generation). Other countries are also deploying offshore wind programmes (5 GW is currently operational elsewhere in Europe).

Deployment potential. Estimates of the UK offshore wind resource suggest that up to 400 TWh of offshore wind generation is available around the UK. Public support for offshore wind is strong, and the visual impact of the technology is significantly lower than other low-carbon technologies, such as onshore wind. Wind patterns in the UK are positively correlated with seasonal demand.

Project pipeline. Deployment of offshore wind is on track to reach over 10 GW installed capacity by 2020:

- 5 GW is already installed.
- CfD and Final Investment Decision Enabling Regime (FIDER) contracts have been signed for 1.2 GW and 3.2 GW respectively of capacity to come online by 2020. Additionally, up to 1.5 GW is anticipated to come online through the RO grace period for offshore wind.
- There is an additional 9 GW of projects with planning permission and up to 13 GW with site licences from The Crown Estate.

Current and future costs. Costs for offshore wind are higher than other low-carbon technologies, though costs are on a downward trajectory to 2020. Post-2020, opportunities exist for further cost reduction such that offshore wind could be cost competitive with unabated gas plants in the second half of the 2020s, provided deployment continues through the first half of the decade (Box 2.5):

- Costs have reduced from around £146/MWh in 2011 to around £121/MWh currently[27]. Internationally, costs range from £88/MWh in Denmark (7% discount rate) to £212/MWh in Korea (10% discount rate). However, these costs are not directly comparable due to different support structures for the industry (such as site licensing, infrastructure support)[28].
- Industry ambition is to reduce costs towards £100/MWh, for projects commissioning in 2020. In the recent CfD auction round, contracts were signed at around £120/MWh for projects commencing generation between 2017/18 and 2018/19. The levelised costs of energy from these projects will be lower (around £110/MWh), as the projects will generate for longer than the 15 year CfD lifetime.
- Potential for significant cost reduction has been identified, which can be unlocked via both R&D and UK and European deployment in the 2020s.
- Costs for floating offshore wind installations are not considered here, but the technology has potential to reduce costs in the long-term, by removing the need for fixed foundations.

Conclusion: Given the large potential contribution to UK power sector decarbonisation, the importance of the UK market and the emerging record of cost reduction, offshore investment beyond 2020 is important to ensure cost reductions continue. We include a minimum level of deployment in our scenarios consistent with driving costs down.

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[27] Offshore Renewable Energy Catapult (2015) *Cost Reduction Monitoring Framework.* Available at: www.ore.catapult.org.uk

[28] IEA (2015) *Projected Costs of Generating Electricity: 2015 Edition.* Available at: www.iea.org

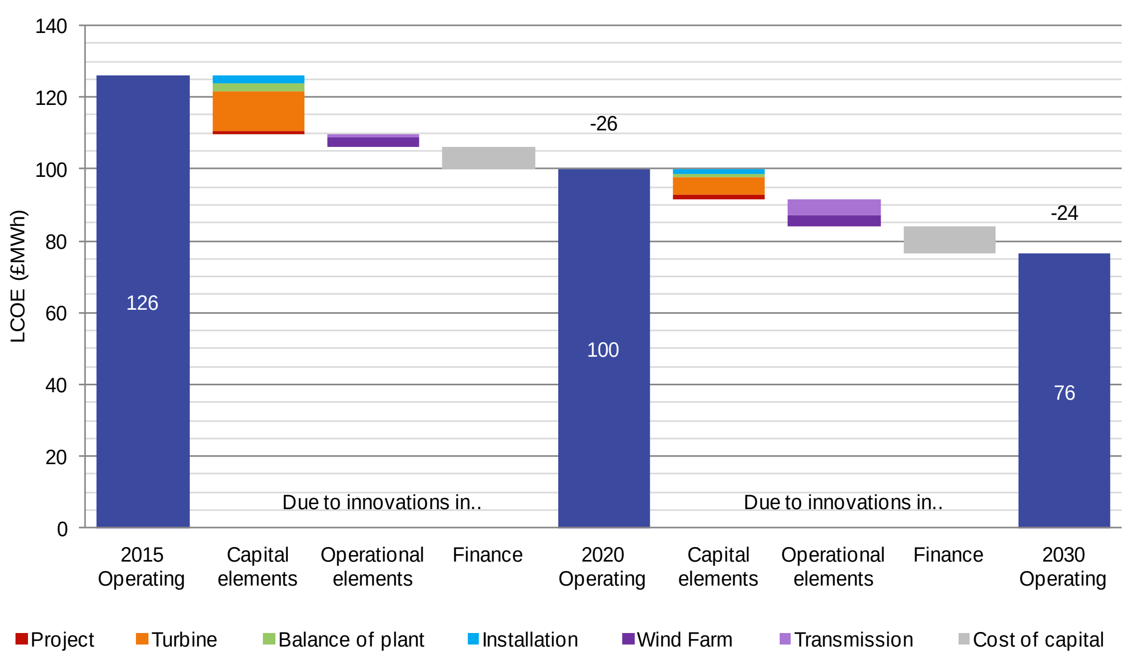
Box 2.5: Accessible cost reductions in offshore wind

Recent research undertaken for the Committee looked at the potential for cost reductions in the UK for offshore wind and carbon capture and storage technologies in the power sector. This research was based on detailed engineering estimates, and concluded that through a combination of both project deployment and technological research and development, there are opportunities to reduce costs.

Offshore wind

- In 2012, The Offshore Wind Cost Reduction Task Force identified potential for cost reduction from £155-200/MWh to £100/MWh in 2020.
- In 2015, the CCC commissioned BVG Associates to update this work and extend it to 2030.
- Latest data on the costs of offshore wind from auction results and levelised cost information indicate that costs have already fallen by 11%, between 2010 and 2014, to around £121MWh, based on actual project data. Evidence from CfD auction results and engineering cost estimates suggest that these costs are anticipated to fall further towards £106/MWh in 2017/18 and £100/MWh in 2020,
- A key factor explaining this projected fall in cost is the increase in the size of turbines, from an average of 3.6 MW today, towards larger 6-8 MW turbines in projects being installed towards 2020. Additionally, BVG identified potential cost of capital reductions of up to 1% and improved operation and maintenance as key cost reduction drivers to 2020 (Figure).
- BVG identified up to a further £26/MWh of cost reduction potential in the 2020s (Figure B2.5), as a result of another step up in turbine size (e.g from 8 MW to 10 MW), cost of capital reductions of 1%, improvements in installation and operation of the turbines, as well as supply chain development.

Figure B2.5 Opportunities for cost reduction in offshore wind



Source: BVG (2015) *Approaches to cost reduction in offshore wind.* Available at: www.theccc.org.uk ; DECC (2012) *Offshore wind cost reduction task force report*, DECC (2015) *Renewable Energy Planning Database.* Available at: www.gov.uk.

(g) Tidal range

Both tidal barrage and tidal lagoon technologies[29] are established low-carbon technologies that capture energy from tidal surges via turbines in artificially constructed sea walls. The technology is similar to that in hydrological dams.

The output of tidal range technologies is predictable and uncorrelated with other variable renewables. Projects have long lifetimes (e.g. over 100 years). There is potential for future projects to be paired to provide a larger source of baseload low-carbon generation (i.e. individual projects with different generation profiles). However, concerns around the environmental impact of tidal barrage projects have previously prevented development.

Tidal Barrage

Deployment potential. Estimates suggest that deployment potential for tidal barrages in the UK could be up to 40 TWh, up to half of which would be for the Severn Barrage project.

Project pipeline. There are no current proposals to develop tidal barrage projects in the UK. The Government last considered the case for the Severn Barrage in 2010, but did not see a strategic case for building the Severn barrage at that time[30].

Current and future costs. Estimates for the Severn Barrage suggested costs of around £75-110/MWh at a social discount rate. Cost estimates are significantly higher at a commercial discount rate (e.g. 10%), at around £210-400/MWh[31].

Tidal Lagoons

Deployment potential. Up to 30 TWh (or around 10%) of generation could be harnessed from UK coastal waters via a series of tidal lagoons around the UK.

Project pipeline. Currently, one developer, Tidal Lagoon Power, is actively developing three tidal lagoon sites (3.6 GW, 7 TWh) that could be operational by 2021. A further three sites have been considered that could be developed to provide a total of 16 GW of capacity by 2030.

Current and future costs. Costs for tidal lagoons are higher than alternative low-carbon technologies, though there remains potential to reduce the costs of the technology by realising economies of scale.

- Tidal lagoons are capital intensive and the first and second projects are likely to be more expensive at around £130-170/MWh (at a 6.5% discount rate).
- Plans for further, larger scale projects could realise significant economies of scale, reducing weighted average levelised costs to £100/MWh for the first three plants. There is limited scope for cost reduction through technological learning.

Conclusion: A programme of tidal lagoon development offers an opportunity for near base-load power, but currently appears to have higher costs than the alternatives. In our scenarios, we consider tidal lagoons as an alternative technology that could be deployed if other options, like nuclear, fail to deliver, or if they can compete with other low-carbon options on cost.

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[29] A tidal barrage operates by damming a river or estuary, whereas a tidal lagoon would create an artificial lagoon in a section of a river, estuary or sea.

[30] DECC (2010) *Severn Tidal Power: Feasibility Study Conclusions and Summary Report.* Available at: www.gov.uk

[31] CCC (2011) *The Renewable Energy Review*. Available at: www.theccc.org.uk

(h) Carbon capture and storage

Coal and gas-fired power plant with carbon capture and storage (CCS) is expected to be a low-carbon and relatively flexible form of power generation. CCS technology involves generating power from fossil fuel sources, capturing and then safely storing the carbon dioxide. CCS technology also has potential to play an important role in decarbonising heavy industry where there are limited alternative options for emissions reduction. Moreover, it has potential for negative emissions if used in conjunction with biofuels, and can open up other decarbonisation pathways (e.g. based on hydrogen).

CCS has taken positive steps towards being proven globally, with the first "at scale" CCS power demonstration project (a 110 MW post-combustion coal plant retrofit) commencing operation at Boundary Dam in Canada in 2014. There has also been an increase in the number of active projects, with 22 CCS projects now in construction or operation, a 50% increase since 2010[32]. CCS is yet to be deployed in the UK, and has been delayed since the Government's first competition in 2010; the first projects are now aiming to commence operation by 2020.

Deployment potential. Estimates of CO_2 storage potential in the UK Continental Shelf (UKCS) suggest that availability of CO_2 storage is not a limiting factor for CCS deployment in the power sector[33].

Project pipeline. Front End Engineering and Design (FEED) studies, are currently being undertaken for two CCS demonstration projects in the UK: 'White Rose' a 300 MW oxy-fuel project, and a 340 MW post-combustion CCGT project in Peterhead. Although DRAX, part of the Capture Power consortium has recently pulled out of the White Rose project, the remaining project partners have signalled their intention to move forward with the project. The results of these studies are due to be published towards the beginning of 2016. The Government has promised £1 billion of capital funding between these projects, which will also require CfD contracts. Subsequent projects in the UK will have the opportunity to share transport and storage infrastructure, as well as learn from the development of the technology.

Current and future costs. Projected costs for the first CCS demonstration projects in the UK are higher than alternative low-carbon technologies. Technological development and the sharing of transport and storage infrastructure can reduce the costs of CCS towards 2030:

- Current deployment costs of CCS projects in the UK remain highly uncertain, pending the results of FEED studies and funding decisions. Current cost estimates for the two initial CCS demonstration projects in the UK are £150-170/MWh.
- Work we commissioned for our 2015 progress report identified potential for cost reduction to below £100/MWh in the 2020s, both through technological learning from global CCS deployment, and through the development and sharing of transport and storage infrastructure in the UK (Box 2.6).
- CCS costs are also sensitive to the costs of the input fuel. For example, our range of scenarios for wholesale gas prices imply an additional uncertainty for gas CCCS costs of +/-£25/MWh.

There are costs associated with air quality, from NOx, SOx and particulate emissions, which we do not include our cost estimates of CCS. Life-cycle emissions are also higher than other low-carbon options, but its lower capital intensity makes it more suited to a mid-merit role (i.e. operating at reduced load factors).

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[32] Pöyry/Element (2015) *Approaches to cost reduction in CCS*. Available at: www.theccc.org.uk

[33] ETI (2014) *A picture of CO_2 storage in the UK.* Available at: www.eti.co.uk

Conclusion: CCS could be a competitive option by 2030, especially if fuel prices turn out low and for generation at reduced load factors. However, it is still facing significant uncertainty. We include a minimum level of roll-out in our scenarios to 2030, as needed to further develop the technology, given its importance across the economy (see Chapter 4).

Box 2.6: Accessible cost reductions in carbon capture and storage

Recent research undertaken for the Committee looked at the potential for cost reductions in the UK for offshore wind and carbon capture and storage technologies in the power sector. This research was based on detailed engineering estimates for both technologies, and concluded that through a combination of both project deployment and technological research and development, there are opportunities to reduce costs.

Carbon capture and storage

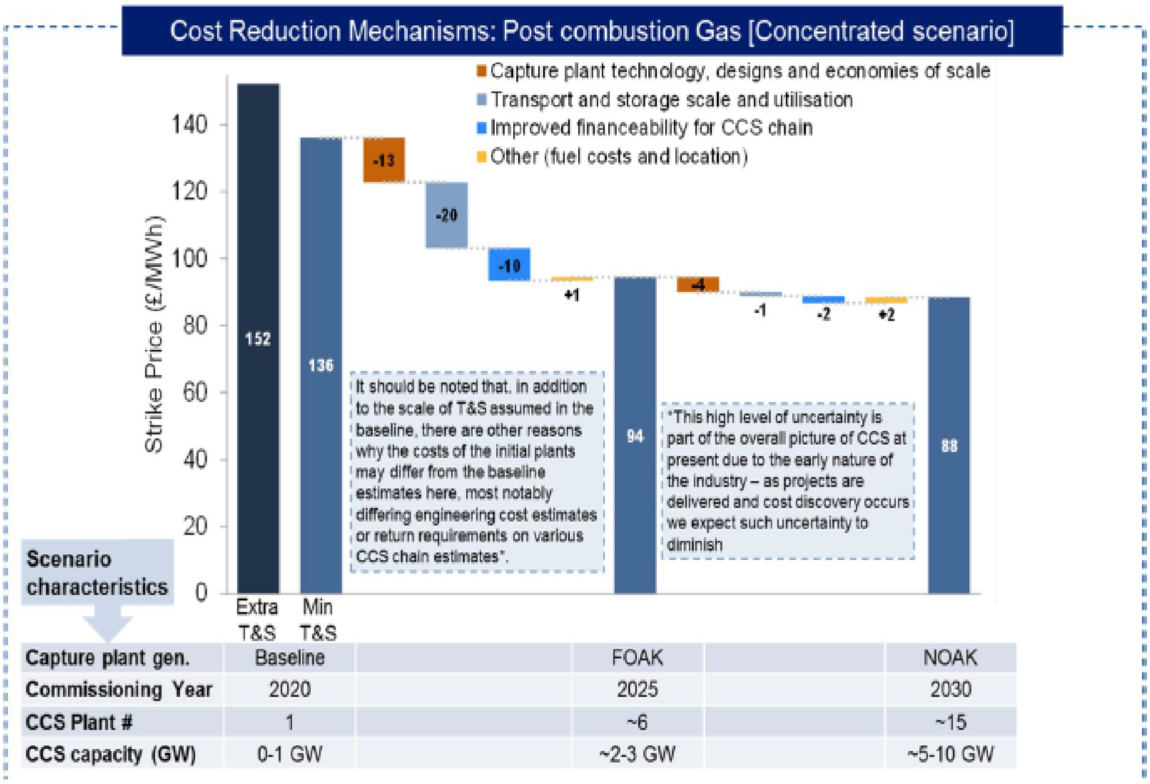
- Carbon Capture and Storage technology is yet to be demonstrated in the UK power sector; therefore cost estimates are based solely on engineering estimates.
- In 2013, the CCS Cost Reduction Task Force concluded that UK gas and coal power stations equipped with carbon capture and storage have clear potential to be cost competitive with other forms of low-carbon power generation, delivering electricity at a levelised cost approaching £100/MWh by the early 2020s.
- Latest estimates, from work we commissioned for our 2015 progress report suggest costs for initial projects at around £150-170/MWh, for the first CCS demonstration projects in the UK, which are expected to come online by 2020. The costs of these 'first of a kind' projects include the initial cost of developing transportation infrastructure. These costs could be reduced over their lifetime by around £20/MWh, by other CCS projects using the same transportation infrastructure, as part of a CCS cluster.
- Beyond 2020, Pöyry/Element Energy (2015) suggested that costs could be reduced towards £100/MWh by 2030 by a combination of technological learning and infrastructure development (Figure B2.6). Accessible cost reductions included up to £16/MWh from improvements to capture plant technology. A further £25/MWh was identified through the efficient development and sharing of infrastructure. Reducing the cost of capital to 10% could reduce this by a further £12/MWh (compared to an estimated 15% cost of capital for a FOAK plant).
- An important distinction between this and the offshore work is that these are not per unit cost reductions, but lower costs associated with a program of deployment due to the sharing of infrastructure.

In order to unlock these cost reduction opportunities, the Government needs to continue to provide support – via both research & development, and deployment – into the 2020s (see Chapter 4).

Figure B2.6 summarises cost reduction pathways identified by Pöyry/Element.

Box 2.6: Accessible cost reductions in carbon capture and storage

Figure B2.6: Accessible cost reductions in carbon capture and storage



Source: Pöyry/Element Energy (2015) *Potential CCS Cost Reduction Mechanisms*. Available at: www.theccc.org.uk DECC(2013) *CCS cost reduction task force report*. Available at: www.gov.uk.
Note: Figure reports costs based on DECC's 2014 central scenario for gas prices of 72 p/therm. Costs in this report are updated for a central gas price of 66 p/therm, reflecting continued low prices since 2014.

(i) Tidal stream

Tidal stream technology generates electricity through underwater turbines, either on the seabed or just below the water's surface. Deployment of tidal stream technologies could make a contribution to power sector decarbonisation towards 2030 and beyond.

Tidal stream deployment in the UK is at the demonstration phase, though the industry is largely harmonised around the horizontal axis turbine technology, for which opportunities have been identified to reduce costs towards 2030.

Deployment Potential. Estimates of the potential UK resource for tidal stream technology range between 18-200 TWh per annum.

Project Pipeline. Early commercial arrays totalling 5 MW (generating less than 3 GWh in 2014) are deployed in UK waters. Another 3 MW are under construction, and further projects are under development.

Current and future costs. Currently technology costs remain significantly higher than alternative low-carbon technologies, at around £200/MWh. However the industry has the potential to progress beyond the demonstration phase over the next few years. A recent ETI study suggested the horizontal axis turbine technology could cost between £100-200/MWh by 2020, and between £70-100/MWh by 2030[34].

Conclusion: Tidal stream could have a role in the longer-term if costs come down. Currently a focus on technology development rather than deployment remains appropriate. We consider increased deployment in a sensitivity to our scenarios.

(j) Other technologies

There are a number of other power technologies that could provide more generation in the 2020s in theory, either in the UK or imported from other countries. However, given the lack of development of these options to date we do not include them in our scenarios.

Wave Power

Wave power spans several different technology types and is currently in the pre-demonstration phase. Although wave power has an estimated UK resource potential of up to 40 TWh per year, there is just 3 MW of capacity currently deployed in UK waters across four different technology types, (equivalent to around 8 GWh)[35].

The industry is yet to agree on a uniform approach to generating electricity from wave power Therefore there is an uncertain path to deployment and cost reduction out to 2030.

Geothermal

Geothermal technology generates power by producing steam to run a generator from heat below the earth's surface. Estimates suggest up to 35 TWh of potential power could be accessed from geothermal sources in the UK[36]. Importing geothermal power via an interconnector to Iceland, where the technology is widespread, is currently being considered.

Geothermal power generation is not currently deployed in the UK and its costs are therefore highly uncertain. Recent cost estimates by DECC suggest that current technology costs are between £130-340/MWh in the UK, though potentially lower when used as a Combined Heat & Power (CHP) source. Potentially it could be competitive with new gas and with other low-carbon options, depending on success demonstrating this technology in the UK.

Hydropower

Hydropower generates electricity via dams, and run-of-the-river turbines. There is currently 1.7 GW of capacity in the UK which generated 5.9 TWh in 2014. Estimates suggest that the technical potential for hydropower in the UK is limited, to 8 TWh.

Other solar technologies

Several alternative solar technologies are also in development and deployment around the world, including perovskites, thin film PV and Concentrated Solar Power (CSP).

[34] Energy Technologies Institute (2015) *Insights into tidal stream energy.* Available at: www.eti.co.uk
[35] Renewable UK (2015) *UK Marine Energy Database.* Available at: www.renewableuk.com
[36] CCC (2011). *The Renewable Energy Review.* Available at: www.theccc.org.uk

Chapter 3: Moving to a low-carbon grid: system flexibility and integration

Introduction and key messages

In Chapter 2 we set out the costs at which different technologies could generate electricity.

In this chapter we explore the costs of managing the electricity system as a whole to provide a secure supply of electricity.

The transition to a low-carbon electricity system brings new challenges in grid management, due to higher levels of intermittent and variable renewable generation (e.g. wind and solar), less flexible generation technologies such as nuclear, and higher demand from other sectors via electrification of heat and transport.

These system challenges include the need for back-up firm capacity for wind and solar generation, the risk of excess generation at times of low demand, and the need for additional infrastructure to transmit power generated in more remote locations. Managing this transition at lowest cost will require investment in flexible gas-fired generating capacity alongside expansion of international interconnection, flexible demand response and electricity storage.

There is also a policy challenge in that current market arrangements may not lead to sufficient investment in these options for flexibility, and developers of intermittent generation may not face the full costs they impose on the system.

We consider the role of increased system flexibility to better accommodate low-carbon technologies at higher penetrations while maintaining security and quality of supply. We then examine the potential costs associated with integrating different low-carbon technologies into the electricity grid, and how these challenges can be better addressed in policy decisions and through markets.

Our conclusions are:

- It is possible to manage a deeply decarbonised UK power system in 2030 with high levels of intermittent renewables (e.g. 40% of total generation) while maintaining security of supply.
- This will require a significant increase in system flexibility (e.g. demand-side response, interconnection, storage, and more efficient and flexible thermal capacity), to maintain system stability and security without imposing unnecessary cost.
  – Smart technologies and increased uptake of electric vehicles to 2030 can help to meet this need.
  – System flexibility is likely to bring down the costs of decarbonising the UK's power sector, for example by allowing demand to be met with less capacity (both low-carbon and unabated fossil-fuel plant).
  – Our new analysis suggests that a more flexible power system that reaches an average emissions intensity of 100 gCO_2/kWh in 2030 can offer annual savings of around £3-3.5 billion relative to a less flexible system.
- While all generation technologies have associated system costs, wind and solar generally impose higher costs on running the system than less intermittent low-carbon options like nuclear and more flexible options like CCS. Provided that flexibility options are rolled out, our new analysis is in line with previous findings that in a power sector reaching 100g/kWh with 35-40% renewables penetration, wind and solar intermittency can be managed at a cost of around £10 per MWh that they generate.
- However in a more decarbonised power system reaching 50 gCO_2/kWh in 2030, with higher levels of intermittent renewables penetration (50%), the marginal integration costs could be £20/MWh or above. Effectively integrating much higher levels of wind and solar without significant additional cost may require additional flexibility, for example, much greater uptake of electricity storage.
- We take into account the new evidence on potential system impacts of individual low-carbon technologies in developing our power sector scenarios. For example, we constrain deployment of wind and solar to no more than 50 GW and 40 GW respectively in our 2030 scenarios, and most of the scenarios reach an emissions intensity of around 100 gCO_2/kWh rather than 50 gCO_2/kWh (see Chapter 4).
- Under current market rules developers face some, but not all, of the integration costs they impose on the system. The Government should work with the regulator and the system operator to find ways to better reflect these costs without imposing unnecessary risks on developers.

We set out the analysis that underpins these conclusions in the following sections:

1. Challenges to integrating low-carbon technologies
2. Options for and the importance of system flexibility
3. System integration costs for low-carbon technologies
4. Policy implications

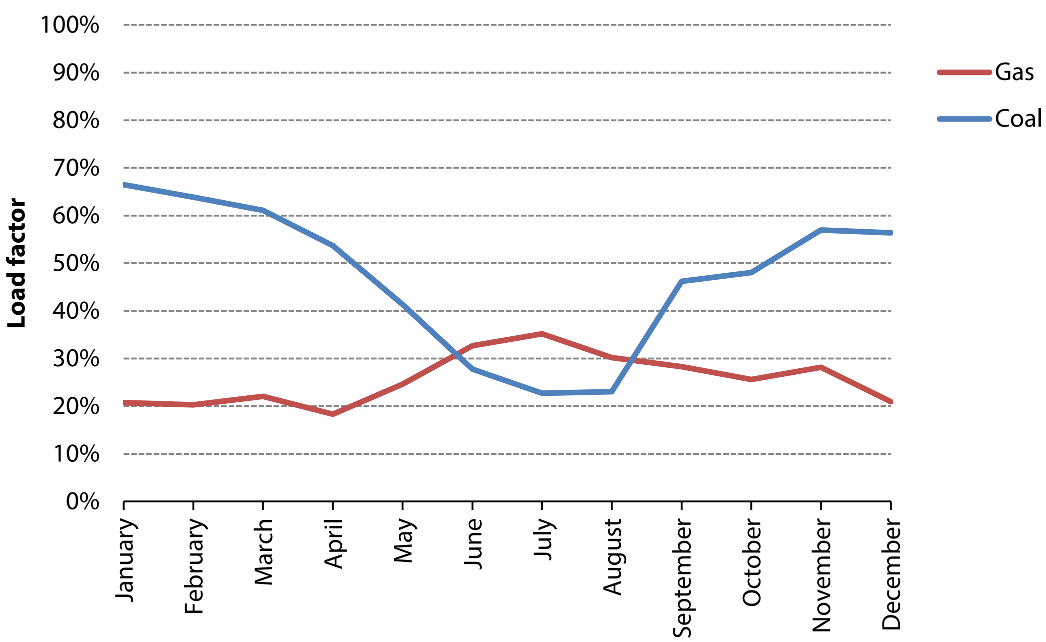
1. Challenges to integrating low-carbon technologies

An effective electricity system provides electricity where it is needed, when it is needed.

The UK's electricity system is currently managed largely by turning thermal plants up and down to match demand. For example, plants operate more during the day and in winter when demand is higher (Figure 3.1). In 2014 the average annual load factor for gas was 26% and for coal was 47%[37]. National Grid, the UK's system operator, currently procures a number of balancing and other services from various providers, mainly large conventional plant to ensure that the electricity system is both stable and secure at all times (Box 3.1).

Grid management can be more challenging for a low-carbon system where the output of generation is dictated by the location and timing of the resource (e.g. wind and sun). Furthermore, while thermal plant saves fuel and cost when running at lower load factors, nuclear and renewable generators do not and so it is not efficient for them to turn down when demand is lower (Figure 3.2).

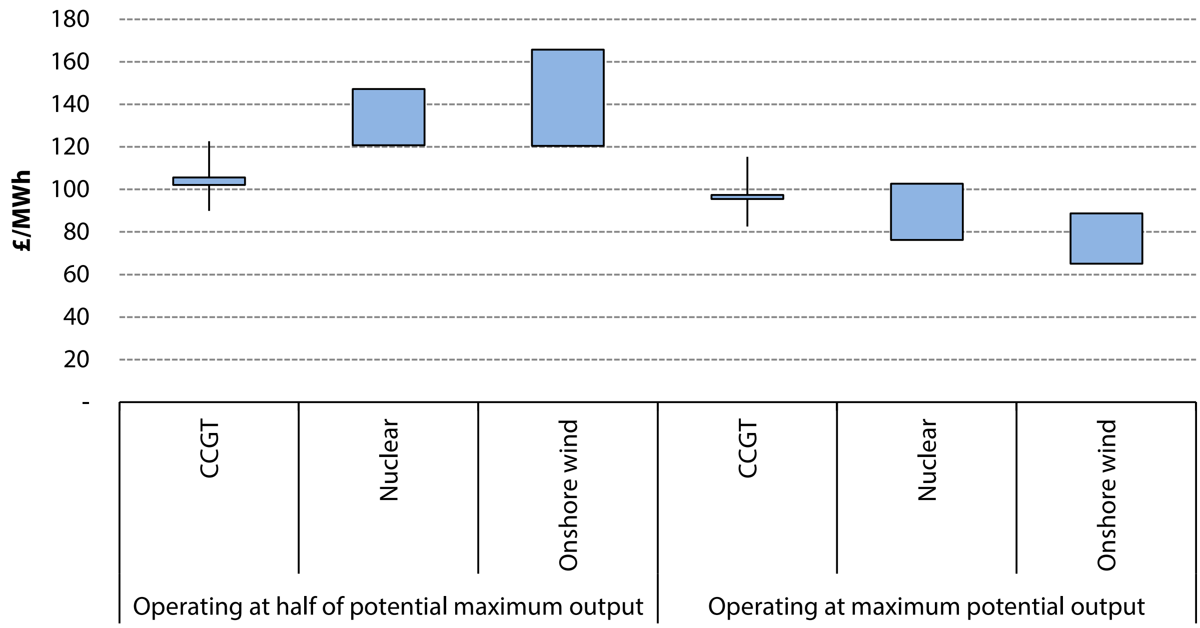
Figure 3.1: Average monthly load factors for coal and gas in 2014



Source: Aurora Energy Research, EOS Data Analytics Platform (2015).
Notes: Chart shows balancing role of gas and coal plant with coal ramping up output in the winter when demand is highest. Gas generation increases in summer due to lower gas prices. Gas load factors includes CCGT, Gas CHP-CCGT and OCGT.

[37] Load factor measures the ratio of a plant or technology's actual output over a period of time (e.g. a year), to its potential output if it operated at its full technical capacity continuously over the same period.

Figure 3.2: Costs of unabated gas generation technologies compared to low-carbon technologies at different load factors (2025)



Source: CCC calculations based on DECC (2013) *Levelised Cost of Electricity Generation Technologies*, updated with latest DECC projections for fuel prices and carbon values for policy appraisal (October 2014).
Notes: Estimates for lifetime costs for projects commissioning in 2025 assuming carbon price rises to £42/t in 2025. Pre-tax real rate of return of 7.5% assumed for unabated gas, 9.5% nuclear, and 7.1% onshore. Solid boxes show range for high/low technology costs and central fuel prices; whiskers show sensitivity to low and high gas prices. Half and full capacity factors for gas and nuclear assumed to be 50%/95% and for wind, 14%/29%.

A decarbonised power sector that is not properly managed could put security of supply at risk and/or prevent the system from accommodating renewables, with associated costs.

In 2014, with 13 GW of wind and 5.4 GW of solar capacity, wind and solar provided 12% of generation and there were no periods in the year where low-carbon generation exceeded demand (Figure 3.3).

However as deployment increases (consistent with reducing carbon intensity to 100 gCO_2/kWh) there would be challenges in using the available generation fully, in meeting peak demand at certain times, and in meeting other system balancing requirements such as reserve and response:

- **Using available generation.** With 35% intermittent renewables penetration alongside 20% of nuclear, there would be periods where output is in excess of demand (Figure 3.4, e.g. at night when demand is low and both wind and nuclear are generating or during the summer when solar output is highest but demand is low). This output would effectively be wasted and have no value.

- **Meeting peak demand.** There would also be many periods where demand is greater than nuclear and renewables generation, requiring alternative capacity to be available. In particular there may be periods where demand is high, but intermittent renewables make a limited contribution to meeting it (e.g. at the left-hand side of Figure 3.4). To ensure the system is secure and reliable there needs to be enough firm capacity to meet peak demand with low potential contribution from intermittent sources.
- **Balancing requirements (e.g. reserve and response).** There would also be challenges to balance the system and maintain grid frequency. That could require additional 'part-loaded' running of gas-fired capacity that is not needed to meet demand (Box 3.1).

Previous work from the Committee and from others has demonstrated that these challenges can be met but will impose costs on the system.[38]

We discuss those costs in section 3, based on existing studies and new analysis we have commissioned by Imperial College London and Nera Economic Consulting[39]. This new analysis extends the evidence base on overall costs of managing intermittency. In particular it looks at the different impacts that individual generation options have on system costs in the context of a largely decarbonised grid.

[38] UKERC (2006) *The Costs and Impacts of Intermittency*; Pöyry (2011) *Analysing technical constraints on renewable generation to 2050.*
[39]Imperial College London (2015) *Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies***;** Nera Economic Consulting (2015) *System Integration Costs for Alternative Low Carbon Generation Technologies – Policy Implications.* Available at: www.theccc.org.uk

Box 3.1: Current approaches to grid management and future challenges

The UK electricity grid is currently managed to maintain security of supply[40] and stability through procurement of various ancillary (balancing) services by the system operator, including:

- **Reserve to keep system in balance.** National Grid pays for the option to access extra sources of power in the form of either generation or demand reduction, to be able to deal with unforeseen demand increase and/or generation unavailability. Reserve is procured at different timescales (e.g. faster reserve within minutes, where plants increase their output or demand decreases, to within hours to days where plants that would otherwise be offline, switch on).
- **Response to maintain grid frequency and deal with unexpected loss of load.** The UK grid is run at a frequency of ~ 50 Hz and system inertia, provided by rotating turbines in conventional thermal plant, helps regulate this frequency. When a large plant shuts down, grid frequency is maintained in the first few seconds through stored system inertia. In the next tens of seconds, plants are requested to increase their output to stop frequency decline and stabilise the system at a certain level. National Grid mandates that all thermal plant provide some frequency response if generating and pays to keep some plants part-loaded to provide frequency response.

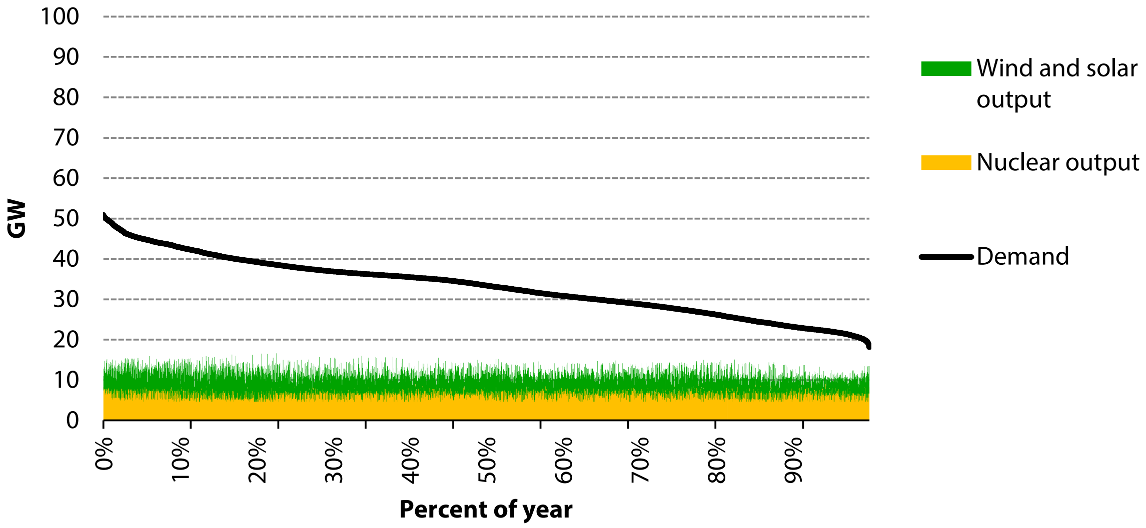
The need for these services could increase with higher penetration of intermittent sources of generation. That particularly reflects the possibility of rapid increases and decreases in output that are generally less predictable than changes in conventional generation. Meeting that requirement could result in more use of gas-fired capacity than required to meet demand:

- System inertia and frequency response services cannot currently be provided by intermittent renewable sources. There are also questions over the extent to which some types of CCS plant can provide frequency response.
- There will be less conventional plant to provide this system stability in a decarbonised system. For example, while in the current system the output from gas and coal plants is rarely below 10 GW, in scenarios with carbon intensity of around100 gCO_2/kWh, output would be below 5 GW for much of the year. That reflects that most of demand will often be met by low-carbon sources.
- If that is not enough to provide sufficient reserve and response, then additional plant may need to run part-loaded than is required to meet demand.

Our work with Imperial College/Nera suggests that without additional system flexibility, this could add 20 $MtCO_2$ to power sector emissions, which would increase grid intensity from100 gCO_2/kWh to150 gCO_2/kWh.

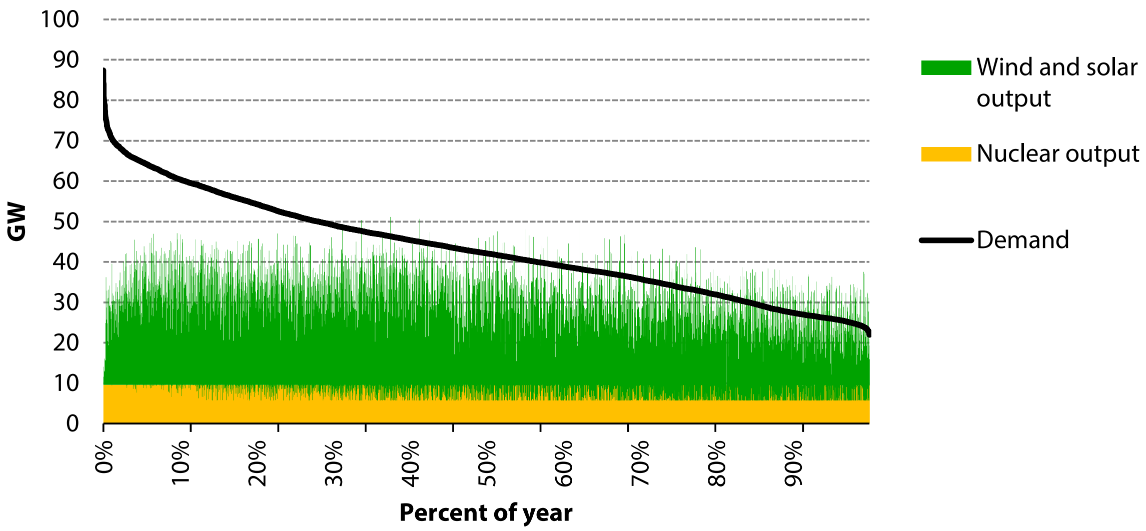
[40] The UK's electricity system must be managed to meet the Government's reliability standard, which targets a loss-of-load expectation of no more than three hours per year. This represents the number of hours per year in which, over the long term, it is statistically expected that supply will not meet demand.

Figure 3.3: In 2014 demand was always higher than the combined output of nuclear, wind and solar



Source: CCC calculations based on Gridwatch (2015) Elexon BM Report data for 2014 and Aurora Energy Research, EOS Data Analytics Platform (2015) data.
Notes: Figure shows hourly demand data in 2014 sorted high to low against nuclear, wind and grid-connected solar PV output in that hour. In 2014, there were no periods in the year with excess generation from low-carbon sources.

Figure 3.4: With higher deployment of nuclear, wind and solar (consistent with 100 gCO_2/kWh) combined output could often exceed hourly demand



Source: Imperial College London modelling (2015).
Notes: Figure shows hourly demand data in hypothetical 2030 scenario reaching 100 gCO_2/kWh sorted high to low against nuclear, wind and solar PV output in that hour.

2. Options for and the importance of system flexibility

Flexibility can help to meet the challenges of integrating low-carbon technologies. Flexibility can provide low-carbon sources of system reserve and response to minimise the need for part-loaded unabated gas plant, with associated emissions savings. Flexible systems also allow renewables and nuclear output to better match demand by shifting demand (demand-side response), supply (storage), or both (interconnection).

Options for flexibility

There are four main options to increase the flexibility of the system:

- **Flexible unabated gas plant.** There is currently 32 GW of unabated gas on the UK's system. More efficient and flexible generation technologies are available that can operate stably at lower levels of output, provide faster frequency response than at current levels, and consume less fuel when part-loaded to provide system reserve. Greater use of these would require less overall thermal plant to be built to stabilise the system, be less likely to curtail renewables output, and reduce overall emissions.
- **Interconnection.** Interconnection already provides a valuable source of flexibility to the UK with 4 GW of capacity linked to Ireland, France and the Netherlands. Increased interconnection to these or other electricity markets (e.g. Norway) can improve security of supply and operating efficiency through sharing of back-up capacity as well as ancillary services, and better accommodate intermittent generation by taking advantage of geographical diversity of renewable output and demand profiles. Although there are concerns regarding the reliability of interconnection (e.g. whether generation will be available in other markets when wind output is low in the UK), studies have shown that greater levels of interconnection are generally associated with better security of supply.[41]
- **Demand-side response.** Shifting electricity demand away from 'peak' time periods, such as on a winter evening and towards periods when demand is lower, is known as Demand-Side Response (DSR). DSR can help to manage large volumes of intermittent renewable generation and can significantly reduce the overall cost of a decarbonised system by shifting demand to off-peak periods with higher renewable output or by reducing the requirements for capacity during peak periods. New electricity demand from electric vehicles can provide further potential for DSR as could heat pumps where they are rolled out in thermally efficient buildings or with storage. Widespread deployment and use of smart technologies (such as smart meters) will facilitate increases in demand-side response given sufficient consumer engagement.
- **Energy storage technologies.** There is currently around 3 GW of pumped hydro storage in the UK. Further deployment of bulk and distributed energy storage (e.g. battery technologies) can reduce the need for additional back-up capacity and infrastructure, by storing electricity when demand is low and discharging when demand is high. Deployment of storage solutions is in the early stage, with around 200 MW of battery devices currently being trialled across the UK. Further deployment of batteries could face barriers due to costs (and uncertain cost reduction pathways), choice of technology (several technologies are being developed and trialled) and a lack of clear regulatory frameworks.

With increased flexibility, the UK's power system would be better able to cope under periods of

[41] See for example Redpoint/Baringa (2013) *Impacts of further electricity interconnection on Great Britain* for DECC.

stress or unexpected circumstances, and better able to accommodate a much larger share of intermittent generation:

- During periods of high demand and low output of wind and/or solar, demand-side response can be activated to shift demand to periods when demand is lower, interconnectors can import and storage devices can discharge fully into the grid.
- During period of low demand and high renewables output, demand can be increased (e.g. electric cars and heat pumps are charged), storage devices can charge, and interconnectors can export.

Rolling out these options for flexibility is important to decarbonise the power system at lowest cost while maintaining security of supply.

The value of flexibility

The Government, the regulator and the system operator have recognised the importance of increased system flexibility, from both traditional and new sources, in a decarbonised power system:

- A recent Ofgem paper[42], sets out how flexibility can bring down the costs of decarbonisation by reducing the need for expensive and carbon-intensive peaking plant, reducing transmission and distribution costs, and avoiding curtailment of renewable energy (Box 3.2).
- Several National Grid initiatives are underway to explore more sustainable and cost-effective ways to provide balancing and frequency response services and how to encourage providers of these services to participate in markets (e.g. the SMART Frequency Control project is looking at how wind farms, solar PV, energy storage and demand-side response can play a larger role in maintaining system frequency and bring down overall costs) (see Box 3.2).
- The newly established National Infrastructure Commission is looking at how to optimise solutions to matching demand and supply in an increasingly decarbonised grid and avoid redundant generation on the system, through large-scale power storage, demand management and interconnection.[43]

The new analysis we commissioned from Imperial/Nera tested the impact of deploying various flexibility options (Box 3.3). Together, the flexibility options allow more intermittent renewables to be accommodated and bring down overall system costs:

- In a scenario reaching an average grid intensity of 100 gCO_2/kWh in 2030 increased flexibility reduces potential curtailment of excess renewables output to less than 1%.
- Security of supply[44] is maintained in part from demand-side response, energy storage, and interconnection, plus some renewable plant, in addition to conventional thermal plant.
- Overall system costs are reduced by around £3 billion per year in 2030 (equivalent to around £25 on the average household's annual electricity bill) relative to a less flexible system, due to a reduced need for low-carbon capacity (as less generation is wasted) and a reduced need to build and run unabated gas capacity to secure and balance the system (Figure 3.5). Therefore, the cost of providing this flexibility is significantly less than its benefit to the system in reduced running costs.

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[42] Ofgem (2015) *Making the electricity system more flexible and delivering the benefits for consumers*
[43] https://www.gov.uk/government/news/chancellor-announces-major-plan-to-get-britain-building
[44] See Box 3.1

- Even if decarbonisation proceeds more slowly, increased flexibility is a low-regrets option. For example, in a power sector that achieves an average grid intensity of around 200 gCO_2/kWh, increased system flexibility can save £2.2 to 2.9 billion per year in 2030.

We therefore include improved system flexibility when modelling our scenarios for Chapter 4. A failure to deliver a significant improvement in flexibility would undermine efforts to reduce emissions and significantly increase costs. In section 4 we set out some of the policy challenges involved in increasing flexibility.

Box 3.2: Ofgem on benefits of power sector flexibility

Ofgem's recent paper *Making the electricity system more flexible and delivering the benefits for consumers* looks at the role and benefits of increased system flexibility, focusing on demand-side response (DSR), storage and distributed generation (e.g. rooftop solar with storage) but also recognising the role of interconnection.

Ofgem concludes a number of benefits from increased system flexibility including driving down overall costs of decarbonising the UK's power sector, reduced bills, reduced environmental impacts and improved reliability of the electricity system.

They note a number of actions currently underway including National Grid's 'Demand Turn Up' project which is exploring how to reduce barriers for DSR providers to provide firm frequency response; the Electricity Balancing Significant Code Review to address barriers to revealing value of flexible resources in the wholesale market; and funding for networks to develop/trial network solutions.

They also list planned actions for the coming years and made recommendations for further changes:

Planned actions

- Encourage DNOs to take a more active role in network management
- Clarify the role and responsibilities of demand aggregators
- Clarify the legal and commercial status of storage
- Explore how industrial and commercial customers can better participate in providing flexibility
- Increase participation of industrial and commercial consumers in providing flexibility

Recommendations

- Regulations should allow for and encourage new entry and new business models.
- Regulations should be reviewed to ensure they clearly set out roles and responsibilities and adequately reward efficient use of electricity system infrastructure.

Box 3.3: System flexibility assumptions in Imperial/Nera analysis

The new Imperial/Nera analysis considers the following key options to increase the flexibility of the UK's power system in 2030. These assumptions take into account the realistic technical potential for deploying options in the 2030 to 2050 horizon, reflecting the latest evidence and industry consensus.

- **Flexible plant.** Thermal plant is still required to balance the system, of which new plant (in addition to the 20 GW existing capacity likely to stay online until 2030) is assumed to have more flexible characteristics than the current fleet. These plants are commercially available but are estimated to cost slightly more (~10%) than the standard less flexible versions and there are therefore limited incentives for UK-based generators to invest in these more efficient plants.
- **Interconnection**. A minimum of 3.4 GW of additional interconnection is assumed by 2030 for a total of 7.4 GW. This reflects confirmed plans for interconnectors with contracts from Ofgem. The potential could be greater (e.g. we consider scenarios for our annual progress reports with up to 18 GW of interconnection).
- **Demand-side response (DSR).** At full potential the following loads are assumed movable in a given day: 80% of EV demand (representing 15 TWh of annual demand); 35% of heat pumps (9.4 TWh), 100% of smart appliances (25.4 TWh); and 19 TWh of industrial/commercial loads. These are assumed to provide both system reserve (e.g. back-up) and response (maintain grid frequency).
- **Energy storage.** Up to 10 GW of distributed storage is assumed by 2030, providing both reserve and frequency response, in addition to the 2.7 GW of pumped storage currently. This assumption is based on a 2012 Carbon Trust study, which concluded that up to 15 GW of storage could be added to the UK system if costs fall, as well as the recent surge in trialling of energy storage solutions in the UK, supported by innovation funding. Further deployment of energy storage solutions is contingent upon successful trials, cost reduction and stronger regulatory support.
- **Renewable generators providing system reserve.** In theory, wind farms can provide downward response by constraining their output. Imperial assume that renewable plants can contribute to reserve services when curtailed (lowering the amount of reserve procured from other sources).

Imperial/Nera also considered other flexibility options, including renewable plant contributing 'synthetic inertia' to maintain frequency response and breakthroughs in seasonal storage. These were not included in the scenarios, but could become available in future. Improved wind forecasting could also help by reducing unexpected shortfalls or excesses of generation. Demand reduction through energy efficiency could also reduce overall system costs by reducing peak demand requirements

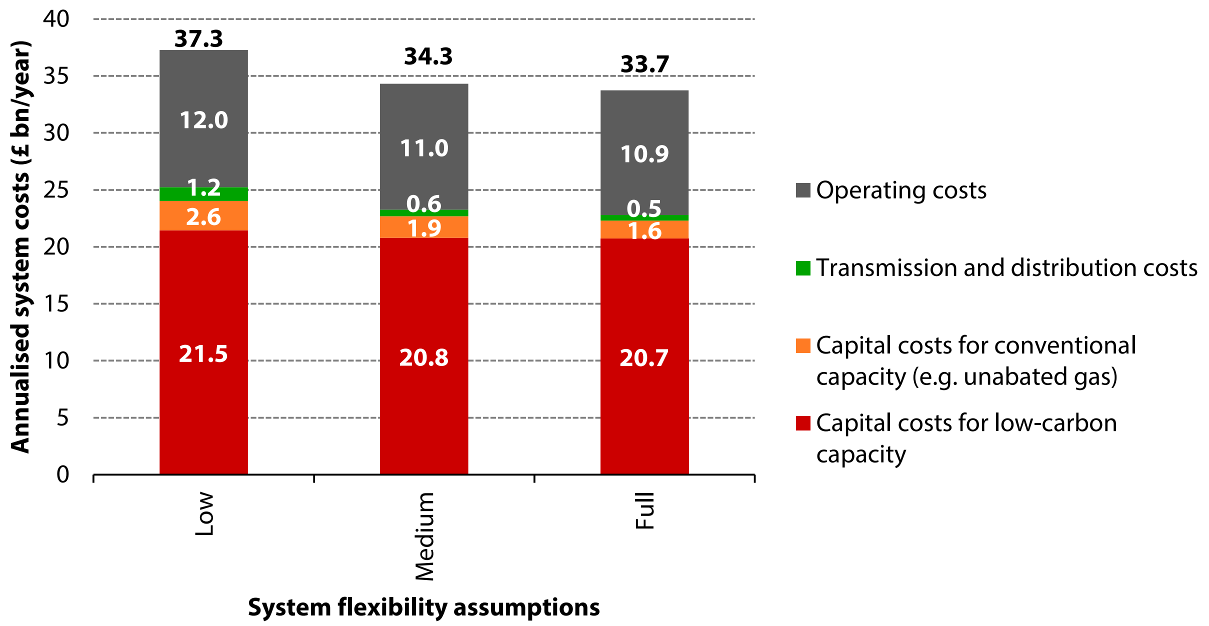
Table B3.3 summarises the key flexibility assumptions examined. Imperial deployed 'medium flexibility' assumptions in the main scenarios examined.

Table B3.3: Flexibility deployment in Imperial/Nera scenarios

	No additional flexibility	Low flexibility	Medium flexibility	Full flexibility
Flexible plant	None	All new plant to have more flexible/efficient characteristics		
Interconnection	Current (4 GW)	Minimum of additional 3.4 GW (7.4 GW total)		
DSR	None	0% potential	50% potential	100% potential
Energy storage	Current (2.7 GW)	No additional	Additional 5 GW	Additional 10 GW

Source: Imperial College (2015) *Value of Flexibility in a Decarbonised Grid and System Externalities of Low Carbon Generation* Technologies; Imperial (2012) *Role/Value of Energy Storage Systems in the UK Low Carbon Energy Future.*

Figure 3.5: Role of flexibility in bringing down costs of running the UK power sector with an average grid intensity of 100 gCO_2/kWh in 2030



Source: Imperial College London modelling (2015).
Notes: See Table B3.3 for assumptions regarding flexibility deployed in each scenario. Whole system costs fall due to less low-carbon (and associated transmission and distribution investments) and back-up conventional capacity required to reach an average grid intensity of 100 gCO_2/kWh while maintaining security of supply. Operating costs also fall, mainly due to less unabated gas facing a carbon price running. On a cost per unit of output basis, medium flexibility brings down system costs by £7.80/MWh and high flexibility by £9.30/MWh.

3. System integration costs for low-carbon technologies

System or grid integration costs account for the additional costs (or benefits) that a given technology imposes on the grid beyond their levelised cost of electricity.

The existing evidence base

Previous studies from the Committee and others have focused on the costs of integrating intermittent renewables:

- A 2006 UKERC study estimated the costs of managing intermittent renewable output to be up to around £8/MWh, at 20% penetration.
- The CCC's 2011 *Renewable Energy Review*, based on analysis we commissioned from Pöyry Management Consulting, concluded that high shares of intermittent renewable capacity (e.g. 50% or more) could be managed, provided options for flexibility are appropriately deployed. We estimated a cost of integrating intermittent renewables of around £10/MWh.

- The International Energy Agency has investigated the economic aspects of integrating intermittent and variable renewables, concluding that the costs of managing a system with large shares of intermittent generation (over 45% on a system) can be minimised with deployment of additional flexibility options, particularly in a future where low-carbon generation costs are likely to be lower and the cost of CO_2 emissions higher[45].
- In the UK, a recent study[46] by the Energy Research Partnership looked at the contribution of generation technologies to system costs. It concluded that integration costs are highly dependent on the technology mix on the system and that firm low-carbon capacity would be needed alongside intermittent renewables if the power sector is to decarbonise to 50-100 gCO_2/kWh.

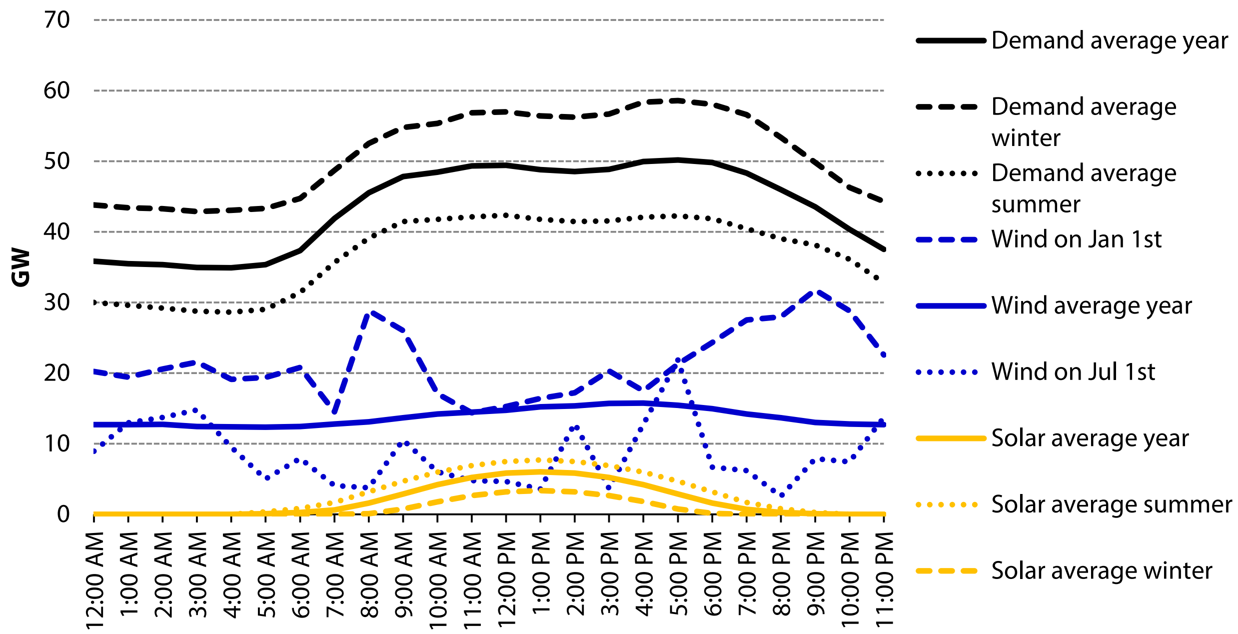
The focus on intermittent renewables reflects that challenges posed by wind and solar generation are likely to be the hardest to meet:

- **Onshore and offshore wind.** Wind generation is weather dependent (e.g. variable and less predictable) and therefore not dispatchable and subject to potentially large swings in output. That implies a relatively low capacity value. The profile of wind generation differs from day to day, whilst generating most during winter months when demand tends to be highest (Figures 3.6 and 3.7).
- **Solar PV.** Solar output is dependent primarily on the time of day and year, and is affected by weather conditions. Generation is highest in the early afternoon and in summer months (Figures 3.6 and 3.7). This implies a potential complementarity with wind, and very limited capacity value since output will be zero during the annual peaks in demand which occur during the hours of darkness in winter.
- **Nuclear.** Nuclear plant provides base-load generation but is inflexible (i.e. it cannot easily be switched on or off, or be ramped up and down). The large size of nuclear plant also requires procurement of sufficient reserve (back-up) in case of outages.
- **CCS.** CCS has yet to be demonstrated in the UK and therefore its characteristics are uncertain, and will depend on the type of plant deployed. It could reduce output and save fuel costs if there are extended periods of low demand, and may be able to switch on and off on a daily timescale to provide mid-merit generation[47].
- **Biomass.** Biomass generation is dispatchable and could operate in a mid-merit role.

DECC has also recognised the importance of grid integration costs and is currently engaging in efforts to quantify whole system costs of all generating technologies.

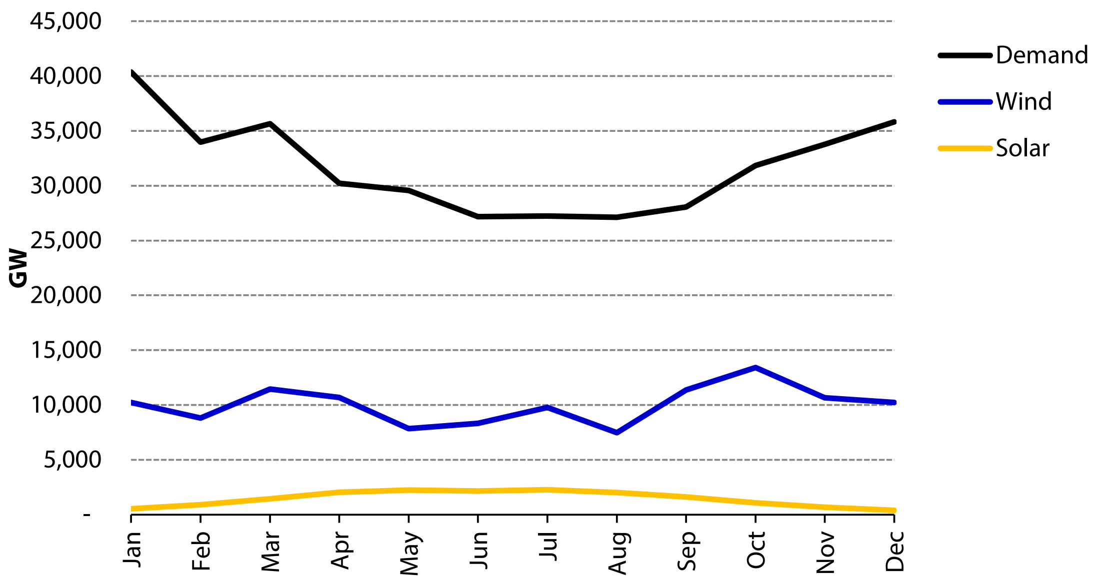
[45] IEA (2014) *The Power of Transformation: Wind, Sun and the Economics of Flexible Power Systems.*
[46] ERP (2015) *Managing Flexibility Whilst Decarbonising the GB Electricity System.*
[47] Mid-merit power plants fill the gap between base-load and peak-load generation (e.g. adjust output as demand fluctuates throughout a given day).

Figure 3.6: Daily hourly generation patterns for wind and solar compared to demand in a power sector reaching 100 gCO_2/kWh (2030)



Source: Imperial College London modelling (2015).
Notes: Average demand and output shown in given hour over year/winter/summer for solar. The average profile is representative for a typical solar day but for wind it will be uncommon for individual days to follow its average pattern. Therefore the chart shows actual wind output on a given day in the modelled year (Jan 1st, Jul 1st).

Figure 3.7: Monthly generation for wind and solar compared to demand in a power sector reaching 100 gCO_2/kWh (2030)



Source: Imperial College London modelling (2015).

The system integration costs for moving from a high-carbon to a low-carbon system

Our new work with Imperial/Nera analysed the system integration costs of moving from a scenario with a carbon intensity around 200 gCO_2/kWh to a scenario at 100 gCO_2/kWh in 2030. The scenario involved a reduction in the share of generation provided by gas-fired capacity from 60% to just under 30%, offset by increases in solar and wind (up from 22% to 35%) and nuclear and CCS (10% to 35%).

The average system integration cost of the increased low-carbon generation was estimated at around £2/MWh. If attributed to the increase in intermittent renewables, the average cost would be £6/MWh (Box 3.4).

Even at increased penetrations in this 100 gCO_2/kWh scenario, wind and solar generation make a useful contribution to meeting demand across the year. Given the flexibility provided by demand shifting, storage and interconnection, the total output from wind, solar and nuclear would rarely be in excess of final demand in any individual hour during the year (Figure 3.8).

Box 3.4: System integration costs of moving from a 200 gCO_2/kWh to a 100 gCO_2/kWh power sector

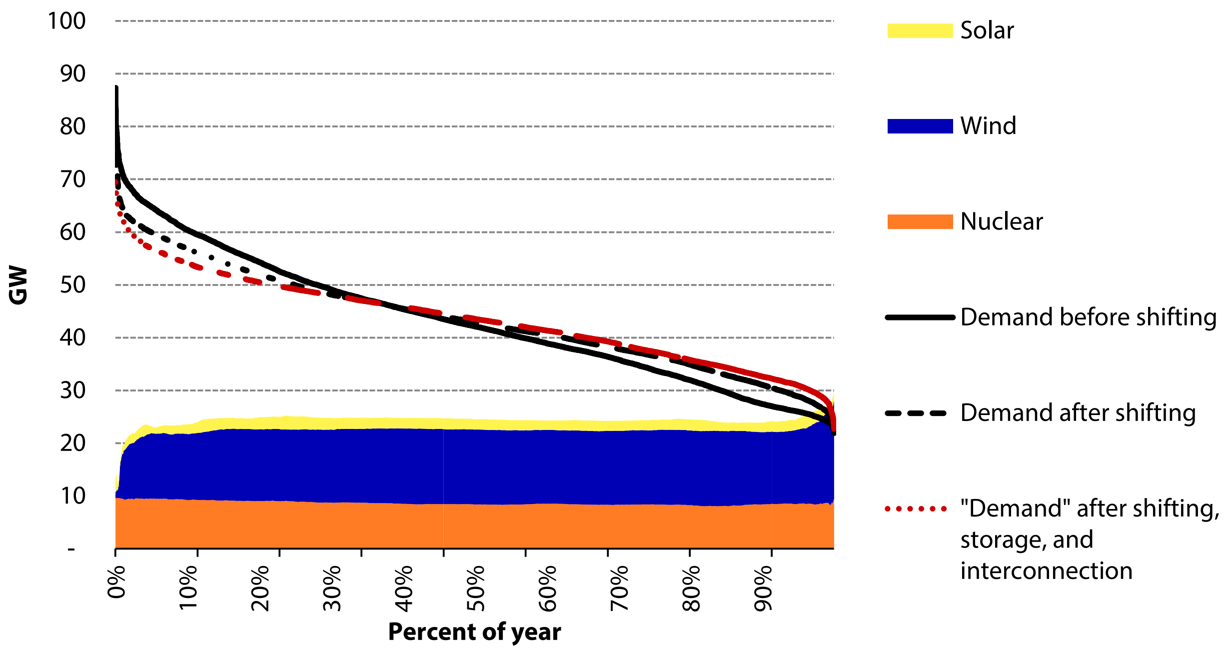
The system integration cost of moving from the 200g to the 100g scenario is largely attributable to back-up costs for the intermittent renewables:

- Increased flexibility including demand-side response and storage is able to provide most of the necessary reserve and response in both scenarios.
- Two-thirds of the increased low-carbon generation is from nuclear and CCS plants. These do not require additional back-up capacity or impose other significant costs on the system (noting that both the 200g and 100g scenario include at least one large nuclear unit).
- The extra system integration cost for the 100g scenario is the result of the need for additional back-up capacity to ensure that demand can be met when wind and solar output is low.

Since intermittent renewables made up around one-third of the increase in low-carbon generation that implies a cost per unit of intermittent generation of up to £6/MWh (i.e. £2 divided by a third). That is lower than our previous estimate (a £10/MWh intermittency cost), but likely to be within the margin of error of the analyses.

Source: Imperial College London (2015) *Value of Flexibility in a Decarbonised Grid and the System Externalities of Low Carbon Generation Technologies*.

Figure 3.8: Contribution of wind and solar to meeting demand in hypothetical 2030 scenario (reaching 100 gCO_2/kWh) with system flexibility deployed



Source: CCC estimates based on Imperial College London modelling (2015).
Notes: Figure shows hourly results in a hypothetical power sector scenario reaching 100 gCO_2/kWh in 2030 of the contribution of nuclear, wind and solar output to meeting demand, stacked from low to high against hourly demand, stacked from high to low. The role of demand-side response, storage and interconnector flows are also shown in the dotted lines (bringing down peak demand during periods on the left and increasing demand at periods of higher low-carbon output to reduce potential curtailment). The implication is that gaps between low-carbon output and demand on left side of chart must be met by coal/gas CCS as well as conventional thermal plant (e.g. unabated gas).

Marginal costs of integrating additional low-carbon technologies in a power system that is largely decarbonised

Imperial/Nera also examined the marginal costs of integrating additional wind, solar or CCS capacity starting from a 100g CO_2/kWh system, adjusting for differences in levelised costs to determine the system integration cost (Box 3.5).

Integration costs were estimated relative to nuclear by replacing nuclear capacity with wind, solar or CCS and calculating the net costs as the system adjusts to integrate the new capacity (Box 3.5). Nuclear was selected as the comparator as it is a low-carbon baseload technology but we also estimate the integration costs of wind and solar relative to CCS.

These marginal costs are estimated at £6-9/MWh for wind and solar relative to nuclear and £6-13/MWh relative to CCS:

- The specific marginal costs for wind are £6-8/MWh relative to nuclear, £6-13/MWh relative to CCS. The bulk of costs are associated with the build and running costs of additional CCGT and OCGT plants (Figure 3.9). In this scenario very little of the additional wind output is curtailed, therefore spill costs (manifesting in the need to install additional CCS capacity to compensate for spilled low-carbon output while maintaining emissions intensity) are minimal.
- The marginal costs of adding additional solar capacity are £6-9/MWh relative to nuclear, £8-13 relative to CCS. As for wind, the bulk of the costs are associated with the build and running costs of additional CCGT and OCGT plants (Figure 3.9).

At a deeper level of decarbonisation, the marginal cost of integrating wind and solar is likely to rise, particularly when the wind or solar share is higher itself. That reflects that marginal sites are likely to have output that is correlated with existing sites and that as the total low-carbon share increases there is a greater risk that low-carbon output will exceed demand during some hours of the year.

Imperial/Nera estimate that in scenarios reaching 50 gCO_2/kWh in 2030, the costs of integrating additional wind capacity would increase to £9-16/MWh relative to nuclear and the integration costs for solar would increase to £12-27/MWh (Table 3.1). Costs relative to CCS could be an additional £3-8/MWh.

- The high end of these ranges reflects scenarios with particularly high penetration of wind (53 GW) or solar (50 GW).
- As in a 100g scenario, there are costs associated with building and running additional back-up fossil fuel plant.
- The higher costs compared to a 100g scenario reflect that not all of the marginal wind or solar generation that is added can be used. That requires additional capacity to deliver the same level of decarbonisation.
- Solar integration costs are also increased by around £10/MWh as Imperial/Nera's modelling indicates that at this level of penetration (i.e. 50 GW) significant strengthening of the distribution network would be needed to support more solar generation.
- At this deeper decarbonisation CCS has system benefits relative to nuclear in some but not all assessments given its extra flexibility and ability to save significantly on fuel costs when not running. That is more valuable in a 50g scenario as at that level of decarbonisation the combined output of wind, solar and nuclear could exceed demand more regularly.

This analysis implies a potential threshold for wind and solar deployment beyond which system integration costs are liable to escalate.

The exact level of this threshold will depend on several factors including: the level, shape and responsiveness of demand; the availability of system flexibility, including potential new options for seasonal storage; the location of new low-carbon generation assets, and the other generation options that have been deployed. Given the potential for changes in these areas, particularly with expansion of the electric vehicle market and potential developments in hydrogen and CCS options, the threshold values are likely to increase beyond 2030.

Imperial/Nera explored the likely level of this threshold by allowing their model to choose the optimal mix of low-carbon technologies to reduce carbon intensity to 100 gCO_2/kWh based on the cost assumptions set out in Chapter 2 and allowing for the system integration costs. Although wind and solar costs are below costs of nuclear and CCS in these assumptions, the model limited deployment to 44-51 GW of wind and 38-43 GW of solar.

We therefore restrict deployment of wind and solar capacity to 50 GW and 40 GW respectively in our scenarios and focus on scenarios closer to 100 gCO_2/kWh than 50 gCO_2/kWh. We do not rule out the latter given the uncertainties attached to this analysis and the potential for new breakthroughs to support effective system management at deeper levels of decarbonisation.

Box 3.5: Imperial approach for estimating the integration costs of different low-carbon options

Imperial examined three core 2030 power sector scenarios with sufficient low-carbon capacity and flexibility options deployed to achieve a grid intensity of 50 and 100 gCO_2/kWh. Scenarios contained a minimum rollout of CCS (7 GW) and offshore wind (18 GW) as well as 20 GW of solar and 10 GW of nuclear (Table B3.4). The model is used to optimise deployment of additional capacity (e.g. gas CCGT and OCGT) to balance the system and meet security of supply requirements while decarbonising.

Table B3.4: Low-carbon capacity in Imperial core 2030 power sector scenarios (GW)

	100 gCO_2/kWh	50 gCO_2/kWh (wind-dominated)	50 $gCO2_2$/kWh (solar-dominated)
Onshore/offshore wind	36	53	45
Solar	20	20	50
CCS	7.1	7.7	7.7
Nuclear	9.6	10.6	10.6

Imperial then estimated the grid integration costs, or 'marginal' costs, of individual low-carbon technologies by adopting a relative approach, increasing the capacity of one low-carbon generating technology and reducing the capacity of another, while maintaining security of supply and meeting a system-wide emissions target. This enables the whole-system costs of two technologies to be compared for a given scenario. Noting there is no consensus in the literature on a single method for defining system integration costs, Imperial adopted three approaches to calculate relative costs:

- **Method 1 (Predefined replacement).** A moderate amount of wind, PV or CCS capacity is added to the system while at the same time the energy-equivalent nuclear capacity is removed.
- **Method 2 (Optimised replacement).** A moderate amount of nuclear capacity is removed from the system, but instead of adding a specified capacity of another low-carbon technology, the model is allowed to optimally increase the capacity of that technology.
- **Method 3 (Difference in marginal system benefits).** A moderate amount of nuclear, wind, PV or CCS capacity is added to the system, while allowing the system to readjust its CCS capacity (or nuclear if CCS is added) as well as any conventional capacity in a cost-optimal fashion.

The resulting costs reflect net savings or costs from removing capacity, additional back-up reserve and response, and transmission and distribution lines.

Imperial note that costs are sensitive to the level of system flexibility assumed and generation mix of the core scenario. For example, in a system that already has high deployment of a renewable technology, it will be challenging and costly to accommodate even higher penetrations of that technology.

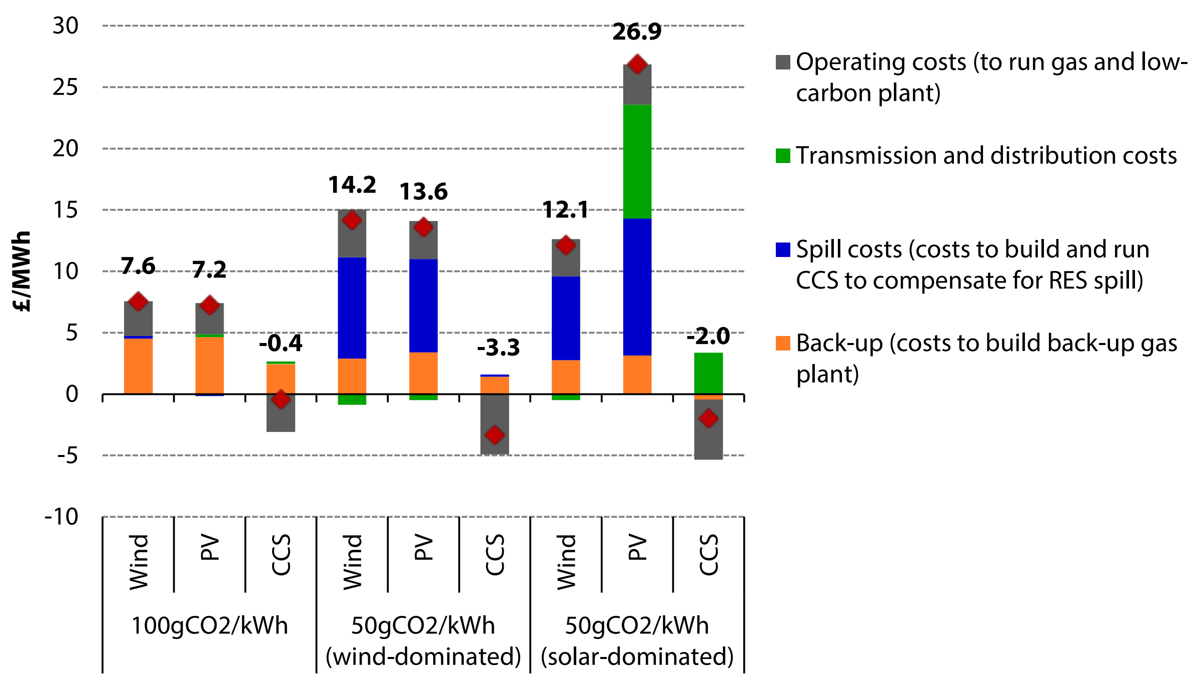
Source: Imperial College London (2015)

Table 3.1: Summary of integration costs of wind, PV and CCS relative to nuclear (in £/MWh) across different scenarios

2030 Scenario	100 gCO_2/kWh	50 gCO_2/kWh (wind-dominated)	50 gCO_2/kWh (solar-dominated)
Wind	6.2 to 7.6	12.5 to 15.6	9.5 to 14.3
Solar	6.1 to 9.2	12.1 to 17.1	26.2 to 27.6
CCS	-6.4 to +0.5	-7.9 to -3.3	-7.5 to -2.8

Source: Imperial College London modelling (2015).
Notes: Ranges reflect various methods adopted. Costs of wind/solar relative to CCS reported in the text are calculated on the basis of individual methods and not by adding the ranges in this table.

Figure 3.9: Integration costs of wind, solar and CCS relative to nuclear in power sector scenarios reaching 100 and 50 gCO_2/kWh (2030)



Source: Imperial College London (2015)
Notes: Grid integration costs shown for Method 1 (see Box 3.4) where a moderate amount of wind, solar or CCS capacity is added to the system while nuclear capacity is removed on an energy-equivalent basis, while maintaining grid intensity (CCS is added if there is a risk of renewables curtailment). Transmission costs could be up to £10/MWh higher for wind if it is in remote locations, but these will (in theory) be included in the direct costs faced by the generator through their Transmission Network Use of System (TNUoS) charge. Transmission costs for CCS are not included.

Uncertainties in system integration costs

The estimates of grid integration costs presented above are sensitive to underlying assumptions. Changes in these assumptions can impact the results. This reflects the fact that this flexibility modelling is still an emerging field. Further work will be needed to better understand the range of options and their costs. The results are sensitive to:

- **Capacity mix.** For example in a scenario with high amounts of nuclear and wind, the costs of integrating additional wind are higher than in a scenario with lower baseline wind and nuclear capacity.
- **System flexibility.** We include significant increases in system flexibility given the available opportunity and our assessment that improving flexibility is a low-regrets option. With less flexibility, grid integration costs of intermittent technologies would be higher.
- **Model and modelling approach.** Imperial/Nera considered a range of modelling approaches, but other models may find different results.
- **System constraints.** All our modelling assumes that the Government's security standard is met. However, detailed rules around grid codes and frequency response could also have a material impact on results.
- **Location of assets.** For example adding new wind capacity in the North has greater transmission cost implications than in the South.

Given these uncertainties we use a rounded estimate from the new analysis of £10/MWh for the system integration cost of intermittent renewables (both wind and solar) for scenarios with decarbonisation to around 100 gCO_2/kWh (based on a range in our estimates of £6-13/MWh). This is consistent with our previous assessment but is both an approximation and a generalisation. Costs for individual projects could differ significantly.

4. Policy implications

Our new analysis emphasises the value of system flexibility and demonstrates that different generation options affect system costs in different ways.

Policy to reflect system integration costs

The Imperial study demonstrates that the biggest system costs from intermittent renewables come from the need for back-up firm capacity, the risk of excess generation at times of low demand, and potentially from transmission and distribution costs when power is generated in more remote locations or local grids need strengthening. This raises a question of whether these costs are fully reflected under current market designs.

As part of our work with Imperial, Nera Economic Consulting examined this question. They found that low-carbon generators being contracted through low-carbon Contracts for Difference (CfDs) will face some, but not all, of the additional costs they impose on the system. In particular generators do not face the costs they impose on the system in respect to the capital and operational costs of other generation:

- **Back-up costs.** Low-carbon generators with CfDs are not eligible for the capacity market. Therefore their returns are not affected by the value of their capacity, and providers of firm capacity will have no source of revenue to allow them to bid lower prices in the low-carbon auctions.
- **Costs of excess generation (e.g. 'spill costs').** Generators face these costs in part as they will not receive CfD payments if electricity prices are consistently negative (e.g. at times of excess generation). However, mostly generators with low-carbon contracts will not see the value of their generation change significantly at different times.
- **Other ancillary costs including balancing.** Low-carbon generators displace conventional thermal 'spinning' plant, which reduces system inertia. National Grid will therefore need to schedule more frequency response, which will increase capital and operating costs for other plant. These costs are unlikely to be faced by low-carbon generators and are currently internalised in ancillary services procured by National Grid. Whilst low-carbon generators are responsible for their imbalances they are only exposed to changes from the day-ahead market and some costs are not reflected in half-hourly prices in any case.
- **Distribution and transmission costs.** Generators are likely to face higher transmission charges in more remote locations. Distribution and Transmission Network Use of System Charges (DUoS and TNUoS) seek to charge generators in different places and of different technologies a price for network access reflecting the marginal cost these assets impose on the networks. Therefore these costs may not require policy intervention, on the assumption that Ofgem keeps under review the extent to which these charges are cost reflective.

Therefore the fact that CfD contracts do not materially reflect the capacity value of contracted generation suggests that this should be additionally factored into project selection, alongside generation costs.

There are at least two main options for the Government to reflect system costs in policy design (more detailed options explored by Nera are set out in Box 3.5)

- **'Marketise' system costs.** Market rules could be changed to better reflect the system costs that different generators create. For example, low-carbon generators could be paid capacity payments that reflect their contribution to system security; the expectation in this case would be that developers able to secure returns in the capacity market would be able to bid lower costs in the CfD auction and therefore would be more likely to secure generation contracts. Other changes could go further, for example aligning CfD price indices, but should be weighed against the increased risks that they impose on developers.
- **Make strategic technology choices.** The most important differences in system costs are between intermittent renewables (i.e. wind and solar) and firm capacity (i.e. nuclear and CCS). Since the latter are due to be contracted through individual negotiations rather than low-carbon auctions, the Government could allow for the system advantages these offer when negotiating contract terms (e.g. our estimates suggest it would be worth paying up to £10/MWh more for firm low-carbon capacity than the prices awarded to intermittent renewable generators in contract auctions). Alternatively an independent agency could be tasked with assessing system costs for different technologies and proposing ways to use existing processes, such as maxima and minima in the auctions, to guide effective procurement.

Policy to reflect the value of flexibility

Nera further concluded that it is unlikely that most flexibility options will be able to capture the full value they bring to the system.

Again, changes could be made to existing markets and rules (e.g. to the capacity market, balancing market; and grid code requirements) to ensure a level playing field for flexibility and to incentivise an increase in provision, or specific approaches could be introduced to support individual options (e.g. as in existing policies for the roll-out of smart meters, the cap-and-floor scheme for interconnectors). See Box 3.6 for further proposals set out by Nera.

Another option that has been raised, reflecting the complexity and systemic nature of the challenges is creation of a System Architect[48], to ensure technical integration for a future UK electricity system that functions effectively to meet policy objectives (e.g. decarbonisation).

The Government should continue existing work with Ofgem and the System Operator to consider these challenges and how to account for them in policy design. In principle, options for flexibility, generation and capacity should be deployed so as to minimise overall system costs and therefore costs to consumers.

Box 3.6: Policy options to incentivise flexibility and account for grid integration costs

Nera identified multiple potential policy options for managing integration costs, subject to further assessment, including which components are currently priced into generator's levelised costs:

- Constraining allocation of subsidies to technologies with relatively high integration costs.
- Introducing maxima (or minima) to technologies that impose high (or low) system integration costs.
- Introducing handicaps to reflect differential system integration costs.
- Changing the reference price in CfD contracts to expose generators to price signals and incentivise them to be more responsive to system needs (e.g. wind farms could face a market reference price such as a year-ahead baseload price).
- Decoupling CfD subsidy payments from actual output to provide better incentives to low-carbon plants to turn up and down output in response to market signals.

Nera also recommended a number of further options for incentivising flexibility. Adopting some of these would require that the system operator adopts new techniques for balancing the system in real time, makes investments in new IT and control systems, and innovates.

- Transparent pricing of ancillary services to encourage investors to provide additional flexibility.
- Levelling the playing field for flexible options such as DSR and storage solutions to compete effectively with conventional sources (for example, shortening trading intervals from current lengths of 30 minutes to 5 minutes could help better reflect the value of flexibility in market prices).
- Exploring mechanisms through which storage and DSR can be offered additional support.
- Incentivising renewable generators to provide ancillary services (e.g. inertia, frequency response).
- Enabling CfD projects to participate in capacity-market auctions to provide system reserve (e.g. this would allow these generators to factor these revenues into their CfD auction bids).
- Ensuring new unabated gas plants can provide enhanced system flexibility (e.g. through pricing).

Source: Nera Economic Consulting (2015) *System Integration Costs for Alternative Low Carbon Generation*

[48] See for example IET (2014) *Britain's Power System: The Case for a System Architect.*

Chapter 4: Power sector scenarios, costs and policy implications in the 2020s

Introduction and key messages

Chapters 1 to 3 set out the need for up to 200 TWh/year of new generation in the 2020s and the costs of the various options to meet that challenge. This chapter sets out the scenarios we will use for the UK power sector in our fifth carbon budget advice based on that evidence base.

Our scenarios are designed to minimise costs whilst maintaining security of supply and ensuring that the statutory 2050 emissions target can be met.

- **Ensuring supply security.** All of our scenarios maintain system security (e.g. they meet the Reliability Standard set by Government) and involve a significant increase in deployment of flexibility options – demand-side response, interconnection, storage and flexible back-up gas capacity. We include the costs of the deployment of these options in each scenario.
- **Minimising cost.** Our scenarios include low-carbon investment when it is cheaper than gas facing the full costs of its carbon emissions, allowing for full system costs resulting from intermittent renewables.
- **Meeting the 2050 emissions target.** Our scenarios include minimum deployment levels for offshore wind and CCS consistent with fully commercialising these technologies in the 2020s.

The scenarios and costs set out below are also intended to be robust across plausible developments in technology, fossil fuel and carbon prices. Multiple scenarios illustrate the implications of different possibilities, for example if renewable costs turn out higher, if CCS does not come forward, or if public acceptability limits the availability of sites for onshore wind and/or nuclear power.

Our chapter conclusions are:

- Low-carbon options are likely to be cost competitive in the 2020s.
  - Several low-carbon options should reach maturity by or during the 2020s. If unabated gas-fired generation faces the full cost of its carbon emissions (estimated at £78/tonne in 2030), these options could be delivered without further subsidy, even when intermittent generation faces the full system costs it imposes.
  - These options represent good-value investments for a society committed to climate targets and are included in our scenarios: onshore wind and ground-mounted solar from the first half of the decade, and nuclear, offshore wind and potentially carbon capture and storage (CCS) in the second half of the decade.
- A portfolio approach is appropriate and justifies continued support for CCS and offshore wind beyond 2020. Support should fall until subsidies can be removed.
  - The costs of meeting the UK's statutory 2050 target for an 80% reduction in emissions relative to 1990 could double if CCS is not available. In order for this option to be available in the 2030s and 2040s, it is important to invest in CO_2 infrastructure in the 2020s that is connected to power sector projects providing large and reliable volumes of CO_2.
  - Offshore wind is demonstrating cost reduction and has the potential to meet a large share of total electricity demand. The majority of required development costs has already been committed as part of efforts to meet the UK's 2020 renewables target. Support should continue during the first half of the 2020s under the clear expectation that offshore wind will then compete with other low-carbon technologies.
- Our new scenarios for 2030 are towards the upper end of the 50-100 gCO_2/kWh range for carbon intensity that we have previously identified as suitable for 2030. That reflects delays to new nuclear and CCS projects alongside good progress for renewable technologies, as well as an improved understanding of the system costs of reaching 50 gCO_2/kWh by 2030. Emissions in 2030 would be around 55 $MtCO_2$ lower than if investment in the 2020s was on gas-fired rather than low-carbon generation.
- Scenarios achieving around 50 gCO_2/kWh may still be appropriate, for example if demand growth is slower or if CCS and/or offshore wind costs fall more quickly than expected.
- Impact on consumer bills.
  - In 2020, a typical household will be paying around £105 through their annual electricity bill of around £500 to support investment in low-carbon generation. Those costs are already committed through investments that are underway and contracts that have been awarded.
  - In our scenarios, support will increase to £120 per household in 2030 and then fall as earlier, higher cost renewables reach the end of their contracts.
  - Costs to households would be around £20 higher in 2025 and £40 higher in 2030 than if investment in the 2020s was focused on gas-fired generation facing a market carbon price (projected to rise to £42/tonne in 2030).
- For investment to proceed at low cost, investors need clarity over the future policy framework. This can be provided by extending the Levy Control Framework to 2025, accompanied by a clear statement of how the Levy Control Framework would be adjusted if carbon prices or gas prices turn out at the low end of expectations, and whether delays in nuclear or CCS will be managed with an initial underspend or a diversion of funds to other options.

This chapter is set out in four sections:

1. The role of emerging and established technologies in scenarios for the 2020s
2. Scenarios for the power sector to 2030
3. Alternative scenarios for investment in the 2020s
4. Costs and electricity bill impacts of low-carbon scenarios compared to investment in gas
5. Policy implications

1. The role of emerging and established technologies in scenarios for the 2020s

As we showed in Chapter 1, in the 2020s up to 200 TWh/year of new generation will be required to replace generation from retiring coal and nuclear capacity and to meet possible increases in demand.

Beyond 2030, more generation is likely to be needed as electricity provides a route to reduce emissions from heating, transport and parts of industry. That has been the repeated finding of a series of modelling exercises assessing how the UK's 2050 target to reduce emissions by at least 80% relative to 1990 can be met. These analyses also share a common finding that the lowest-cost path to the 2050 target will involve deep decarbonisation of the power sector by 2030 (e.g. to below 100 gCO_2/kWh).

Given uncertainty over the future costs of different options and potential limits to deployment (e.g. public acceptability and site restrictions for nuclear and onshore wind, see Chapter 2, and high system costs at high penetrations of intermittent renewables, see Chapter 3), there is value in having a portfolio of options available to provide low-carbon electricity.

- **Emerging technologies.** Offshore wind and carbon capture and storage (CCS) have costs that are currently higher than the alternatives, but there is potential for these to come down. While costs remain higher than alternatives, the goal is cost reduction rather than generation *per se*, with a focus on options with a large long-term resource and clear path to cost reduction. Our scenarios for the 2020s therefore include the minimum levels of deployment that we estimate are required to drive down costs of offshore wind and CCS.
- **Established technologies.** Further expansion of low-carbon generation in the 2020s should ensue if it is cheaper than the alternative of gas-fired generation. We include a mix of low-carbon options in our scenarios that are likely to be cheaper than gas when the full costs of carbon and intermittency are included (Box 4.1). These include onshore wind and ground-mounted solar in the first half of the decade and nuclear, offshore wind and potentially CCS and tidal lagoons in the second half of the decade (Figure 4.1).

Our scenarios therefore include development of emerging options alongside deployment of established options.

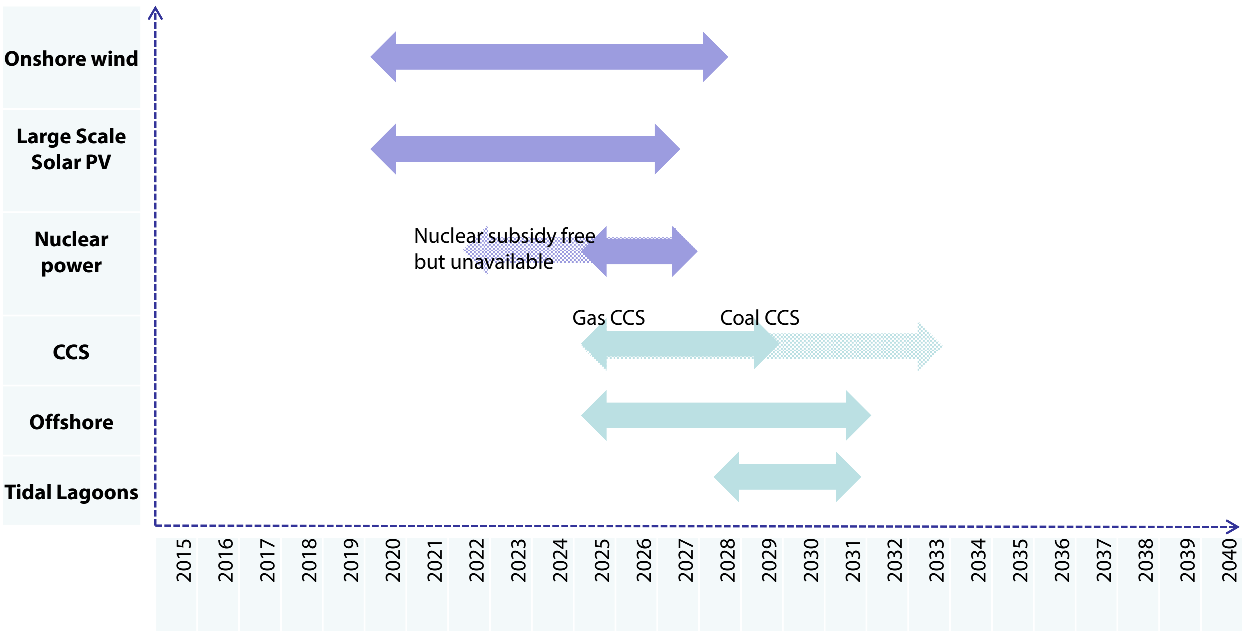
Box 4.1: How we define 'subsidy-free'

We define the point at which a low-carbon technology should be considered cheaper than gas-fired generation and deployable without subsidy based on the definition of 'full costs' set out in our 2015 Progress Report:

- The appropriate comparator is the alternative means of providing additional generation with costs judged across its lifetime.
- The cost assessment should include any intermittency costs, for example reflecting that variable renewable capacity will generally need to be backed up by flexible capacity that can operate on demand. As we set out in Chapter 3, this implies an additional cost of up to £10/MWh for wind and solar generation in a system with carbon intensity around 100 gCO_2/kWh.
- The cost of carbon emissions should reflect the value of these under the UK's domestic emissions targets. As set out in Box 1.1 in Chapter 1 this implies a carbon price of around £78/tonne in 2030.
- We do not factor in the costs of other fossil fuel-related externalities, such as air pollution, or landscape impacts of renewables. These are separately covered by air quality regulations and the planning system.

This implies, for example, that under a central scenario for gas prices (68 p/therm in 2030), low-carbon technologies should be considered subsidy-free if they can provide power at £85/MWh or less in 2020.

Figure 4.1: Year in which low-carbon options become cheaper than new CCGT facing the full costs of its emissions.



Source: Based on: DECC (December 2013) *Electricity Generation Costs*. BVG Associates (2015) *Approaches to cost reduction in offshore wind*. Pöyry/Element Energy (2015) *Potential CCS Cost Reduction Mechanisms*.
Notes: We assume the following ranges for gas prices: 30-76p/therm in 2020, 38-99p/therm in 2025 and 46-99p/therm in 2030. Target-consistent carbon price rises in line with Carbon Price Floor, to £23/t in 2020 and £78/t in 2030; Research by Pöyry (2013) *Technology supply curves for low-carbon generation*. suggests that best in class sites for onshore and offshore wind are around £10/MWh cheaper than average sites. Reflecting this, the ranges show when projects for different sites could start becoming subsidy-free across the range of gas prices.

(a) Emerging options

In our 2015 Progress Report to Parliament we identified carbon capture and storage (CCS) and offshore wind as the key emerging options requiring extra deployment support beyond 2020:

- Both have the potential to provide power in the second half of the 2020s below the full cost of gas generation (i.e. £95/MWh in a central case). There is more uncertainty over CCS: although the first 'at scale' CCS plant commenced generation in Canada in 2014, CCS is yet to be demonstrated in the UK. Offshore wind is demonstrating cost reduction: latest contracts have been signed at around £120/MWh, compared to costs in 2011 estimated at around £150/MWh (adjusted to 2014 prices).
- CCS has the potential to fill several roles in a low-carbon economy where alternatives are limited. CCS could be used in heavy industry, in the power sector offering flexible low-carbon generation and to open up other routes to reduce emissions (e.g. based on hydrogen or using CCS in combination with bioenergy to offset emissions elsewhere). Our previous estimates as well as those by the Energy Technologies Institute (ETI) suggest that the cost of meeting the UK's 2050 emissions target would be up to twice as high in the absence of CCS deployment[49].
- Offshore wind has a potential resource of over 400 TWh/year, greater than total UK electricity demand in 2014. Besides current high costs, it has fewer barriers and risks to its roll-out than other options. For example, onshore wind and new nuclear face site restrictions and potential public opposition. Development of offshore wind therefore hedges against the risk that other options are constrained. That is particularly important given ongoing delays to nuclear and CCS.

There are other emerging options (see Chapter 2), which are currently high cost but could have a significant future role and would benefit from innovation support. In the power sector, these include rooftop and distributed solar, where there is potential for UK-based cost reduction in installation but where the panel technology is likely to develop globally (supported by UK research), and wave and tidal stream technologies, for which the UK has a strong resource and which currently requires early-stage innovation and demonstration support. Innovation will also be important in supporting areas such as energy storage and smart grids.

We now consider the minimum levels of deployment of offshore wind and CCS required in the 2020s to support effective development of these options.

(i) Commercialising offshore wind in the early 2020s

We estimate that by 2020 annual support for offshore wind will be around £3 billion. That support has already been committed under efforts to meet the UK's share of the EU Renewable Energy Directive through the Renewables Obligation (RO), and low-carbon contracts that have already been offered. Under this support, subsidy costs have fallen from around £90/MWh in 2011 (when offshore wind projects received two certificates under the RO scheme) to around £60/MWh (i.e. the premium above the lifetime costs of gas-fired generation for the latest signed contracts, which are set to commission in 2017/18).

Alongside our 2015 Progress Report to Parliament we published work that we commissioned from BVG Associates (BVGA)[50] which suggests that there are opportunities for further cost

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[49] ETI (2015) *Carbon capture and storage: Building the UK carbon capture and storage sector by 2030.* Available at: www.eti.co.uk

[50] BVGA (2015) *Approaches to cost reduction in offshore wind.* Available at:www.theccc.org.uk

reduction that would allow offshore wind to compete with other low-carbon technologies in the 2020s. That work also assessed the potential mechanisms to unlock these cost reductions with minimal government support.

BVGA found that a sufficient scale of market, signalled in advance, is required to drive private-sector investment in innovation (e.g. to create reliable bigger turbines, which are the largest opportunity for cost reduction in the 2020s), to support a competitive project pipeline and supply chain, and to encourage cost of capital reductions. Our assessment suggests that a UK market of at least 1 GW per annum, complemented with targeted R&D and possibly further strategic actions would be appropriate:

- A 1-2 GW UK market is consistent with an EU market of 3-4 GW per annum, given expected programmes in France, Germany and Denmark. This size of market could support three to four players in the EU turbine market that are large enough to invest in major innovation programmes. While disruptive innovations may occur in markets beyond the EU (e.g. floating turbines), their progress is uncertain and they are unlikely to play a significant role in cost of energy reduction on UK projects in the period to 2030.
- At least 1 GW per annum could also support multiple developers in the UK, ensuring that auctions remain competitive. Higher deployment of up to 2 GW per annum could be pursued if cost reductions proceed more quickly.
- Private R&D should be complemented with targeted public R&D support, including in ways that de-risk and encourage collaboration within the industry and look ahead to new needs (e.g. to floating turbines).
- Other strategic actions may also enable cost reductions. For example, sharing of transmission infrastructure across multiple projects and taking a more active public role in site development.

Around three-quarters of the total cost of commercialising offshore wind has already been committed through the RO and early low-carbon contracts. We estimate that the annual cost of supporting new offshore wind from 2020 to 2025 is a further £0.9 billion (on top of the £3 billion already committed to 2020). This would support a programme of 1-2 GW per annum in the UK to 2025, after which offshore wind should be able to compete free from further subsidy.

A shift away from deployment as the main driver of cost reduction would introduce new risks and costs at a relatively late stage in the development of this technology:

- **Publicly funded R&D programme:** Large-scale R&D programmes (e.g. turbine innovation) can be delivered by large, commercial players given their existing skills and expertise. However, an R&D programme that is not accompanied by a market neglects important aspects of delivering a new offshore wind technology such as practical experience in operation, buy-in from existing customers and investment in new delivery capacity throughout the supply chain.
- **Delayed deployment:** The UK is currently half of the global market and expected to still be the largest player in 2020, with around one-third of the global market. Given this important role, lower investment in the UK would not necessarily be supplemented by growth elsewhere, and incentives for private R&D would be reduced.

Our scenarios therefore include continued roll-out of offshore wind during the first half of the 2020s. That would require continued support initially, with the presumption that support would be phased out by around 2025. In the minimum scenario outlined above (i.e. 1-2 GW of offshore wind added each year), offshore wind generation would increase by 20-40 TWh from 2020-2025.

(ii) Taking a strategic approach to CCS clusters

Carbon Capture and Storage (CCS) is likely to be a crucial part of a least-cost path to decarbonisation in the UK and globally. In the power sector, CCS can provide low-carbon generation as well as provide a back-up role for intermittent renewables and help to manage swings in demand. It also provides an opportunity to benefit from lower fuel prices should they transpire. More broadly, CCS has a crucial role in decarbonising energy-intensive industry where there are limited alternative options, and in the longer term would help to maximise the emissions reduction obtained from scarce supplies of sustainable bioenergy as well as opening up other decarbonisation pathways (e.g. based on hydrogen).

The development of carbon capture and storage (CCS) in the UK has been delayed, and remains at the demonstration phase (Chapter 2). Globally, CCS has taken positive steps towards being proven globally, with the first 'at scale' CCS power demonstration project (a 110 MW post-combustion coal plant retrofit) commencing operation at Boundary Dam in Canada in 2014.

While CCS is currently higher cost than other low-carbon alternatives, opportunities for reducing the cost of a CCS programme arise from sharing the costs of CO_2 transport and storage infrastructure. As set out in Chapter 2, this is the largest cost-reduction opportunity.

To unlock these reductions requires a strategic approach to roll-out that focuses on the development of hubs and clusters, and delivers anchor users in the power sector:

- **Hubs and clusters.** A common finding across our work and previous analysis by ETI is that there is value in onshore clusters and offshore hubs due to the potential to share infrastructure costs. The two projects in the current Commercialisation Programme (Peterhead and White Rose), if delivered, provide a good grounding for onshore clusters including both power and industry projects to develop around Grangemouth, Teesside and Humber.
- **Anchor users.** By providing large and reliable volumes of CO_2, projects in the power sector provide anchor loads for oversized transport and storage infrastructure. It is therefore important that these projects move forward to provide confidence that infrastructure will be sufficiently utilised once built.

As we set out in our 2015 Progress Report to Parliament, developing the approach to the CO_2 transport and storage infrastructure for CCS should be an important priority this Parliament (as is currently recognised in the National Infrastructure Plan).

Work we commissioned from Pöyry and Element Energy[51] suggests that the minimum share of effort in the power sector is 4-7 GW by 2030 to sufficiently anchor new infrastructure, support a competitive pool of projects and increase interest from the financial community:

- The 4-7 GW range reflects one to two fuels and/or capture technologies (e.g. post-combustion gas or oxyfuel coal) and could include new plants and retrofit of CCS to existing plants. Given the early stage of the technology and risk of failure from focusing too narrowly, the aim should be to develop two technologies and/or fuels, with the lower end representing constrained development of one technology due to challenges during the demonstration phase.

[51] Poyry/Element Energy (2015) *Potential CCS cost reduction mechanisms.* Available at: www.theccc.org.uk

- Deployment of 4-7 GW by 2030 allows for phased scale-up in plant size and the timeline allows for learning between projects while maintaining sufficient momentum to retain skills and expertise, to keep a pool of projects under development and to interest the financial community and drive cost of capital reductions.
- Developing projects around two clusters means multiple routes for the transport and storage of CO_2 are developed, which increases optionality for deployment beyond 2030.

Some cost reduction is expected through international efforts in technological learning (e.g. innovation in capture technology) to reduce costs of the technology before embarking on a deployment strategy. UK efforts should support and complement these efforts. However, international learning alone will not enable sufficient cost reductions. That is because around three-quarters of the cost reduction potential is attributable to UK-based actions, in particular the sharing of infrastructure costs or through improvements in the UK support structure for CCS occurring over time.

Our scenarios therefore include a strategic approach to the development of CO_2 transport and storage infrastructure in the 2020s, a roll-out in the power sector of at least 4-7 GW based around two clusters and maximising the opportunity for shared costs. This provides an additional 20 TWh of generation in the first half and a further 20 TWh in the second half of the 2020s.

(b) Established options

Given our set of assumptions regarding demand and schedule of retirements, the generation gap is around 115 TWh/year in 2020-2025 and 90 TWh/year in 2025-2030. Taken together, programmes for offshore wind and CCS leave a generation gap of up to around 50-70 TWh/year in 2020-2025 and 70 TWh/year in 2025-2030. To minimise costs, this remaining gap should be filled by the cheapest options, whether low-carbon or gas-fired generation facing its full emissions cost (estimated at £78/tCO_2 in 2030 – see Box 1.1 in Chapter 1).

Based on our assessments in Chapters 2 and 3, favourable sites for onshore and solar are likely to be as cheap as or cheaper than gas-fired generation by 2020, suggesting that these projects should proceed. New nuclear will at best be available by 2024/5, and if commercialisation is successful, offshore wind and possibly CCS could also be cost-competitive:

- **Gas-fired generation costs.** In a central scenario for gas prices and with a value attached to carbon that is consistent with meeting the UK's 2050 target, the full cost of new gas generation would be £85/MWh for new plants coming on line in 2020 and £95/MWh for 2025. That assumes a gas price that increases from 46 p/therm in 2015 to 66 p/therm by 2025. If gas prices remain at 46 p/therm, the full costs for gas generation would be £70/MWh in 2020 and £85/MWh in 2025.
- **Onshore wind and solar – low-cost sites are already demonstrating competitiveness.** Adding a £10/MWh system cost to reflect intermittency (see Chapter 3) to the cost estimates in Chapter 2 implies current onshore wind costs up to £85-90/MWh and similar for solar. The best sites could be considerably cheaper and costs should continue to fall. We assume that securing only the lowest-cost sites for onshore wind implies a slowdown in deployment compared to the 2010s. On that basis onshore wind and solar could provide 10-15 TWh/year of the new generation required in both the first and second half of the decade.

- **New nuclear – competitive and available from the mid-2020s.** The appropriate role for nuclear will depend on the costs that new projects can deliver and the cost of alternatives. The current development pipeline for new nuclear plants suggests that from 2025 it would be possible to contract for a new plant at least every two years (i.e. two to three new plants by 2030). At the strike price offered for the first plant at Hinkley Point C (£93-96/MWh) this would be cheaper than unabated gas facing its full carbon cost. This first project has been delayed until 2024/5, with the potential for at least one further project in the latter half of the decade. This implies around 20-25 TWh/year of new generation in each half of the decade, with the potential to go further (i.e. up to 60 TWh/year) in the period 2025-30 should additional projects deliver to time.
- **Offshore wind – competitive from the mid-2020s.** Assuming that offshore wind is successfully commercialised in the first half of the decade (i.e. levelised costs fall to below £90/MWh in 2025), it would then be cost competitive. Deployment could increase to up to 2 GW per annum. That would imply 20-40 TWh/year of generation from new offshore wind added in the second half of the decade. Whilst higher deployment would be plausible we do not include it in our scenarios as it could involve cost escalation as supply chains and the development pipeline are stretched.

Our scenarios therefore include more new low-carbon generation in the second half of the decade than the first, reflecting the greater availability of cost-competitive options from around 2025 (Table 4.1).

Other low-carbon options (e.g. sustainable biomass, tidal lagoons, tidal stream) could also provide more generation during the 2020s. It is less clear at this stage that these will provide a cost-effective alternative to unabated gas, so we only include a small amount of these in most of our illustrative scenarios. However, projects remain a possibility especially if alternatives fail to deliver and we include some generation from tidal technologies in our scenarios with no CCS and with no nuclear.

There will be an important role for new unabated gas-fired plant to fill any remaining generation gap and provide back-up capacity:

- **Generation.** We assume gas capacity fills the remaining gap in generation in the 2020s. That implies around 30 TWh/year in the period 2020-2025 and minimal additional contribution between 2025-2030.
- **Capacity and flexibility.** Even if low-carbon generation could cost-effectively meet the entire generation gap in the 2020s, it is likely to require supporting deployment of flexible gas plants (see Chapter 3). How much capacity is needed will depend on the shape of demand, the mix of low-carbon capacity and the success with expanding flexibility from demand-side response, interconnectors and storage.

Returns to gas-fired generation in the wholesale market will be uncertain and potentially limited. Continuation of a capacity market is therefore important to ensure that sufficient capacity comes forward to provide a secure system. That should provide a level playing field across technologies including demand-side response, interconnection and storage as well as new gas-fired capacity. A clearer path for future coal and nuclear retirements and for new build of low-carbon capacity would reduce the risks facing new developers of firm capacity and could reduce costs in the capacity market.

Given an effective capacity market, gas-fired capacity could then provide generation within an efficient wholesale market to fill the gap left after low-carbon investments.

Table 4.1: Potential contribution of low-carbon options to meeting generation gap, assuming central gas prices (TWh/year)		
	2020-2025	**2025-2030**
Generation gap	**Up to 115**	**Up to 90**
Onshore wind	10-15	10-15
Solar	5-15	5-15
Nuclear	0-25	20-60
Offshore wind	20-40	20-40
CCS	5-10	15-45
Other (e.g. tidal)	0-5	0-35
Potential low-carbon contribution	**65-110**	**70-205**
Source: CCC modelling. **Notes:** Numbers may not sum due to rounding.		

2. Scenarios for the power sector to 2030

We now set out our scenarios based on the approach set out in section 1. That includes minimum levels of investment in offshore wind and CCS consistent with developing those options in the first half of the 2020s. Beyond that the scenarios assume investment proceeds based on procurement of the lowest-cost options across plant lifetimes and allowing for the full value of carbon and the full cost of intermittency.

On our best estimates for future costs that implies the power system emissions intensity would fall to slightly below 100 gCO_2/kWh and have total emissions of around 40 $MtCO_2$ in 2030:

- Committed investments to 2020 imply a low-carbon share of around 60% and an emissions intensity of around 250 gCO_2/kWh.
- Emissions intensity would be reduced to 190 gCO_2/kWh with closure of the remaining coal capacity, even if replaced by gas-fired generation. However, if the closing nuclear was also replaced by gas, and if gas met all new demand, emissions intensity would rise to over 300 gCO_2/kWh by 2030.
- Commercialisation programmes for CCS and offshore wind alongside lowest-cost investments in the 2020s in a mix of new nuclear, onshore wind, solar and offshore wind rather than expanding gas generation would bring emissions intensity down to below 100 gCO_2/kWh.

In this scenario, unabated gas would continue to meet a similar share of demand in 2030 compared to 2014 (around 25-30%), with low-carbon generation replacing most of the generation previously provided by retiring nuclear plants and meeting any increase in demand.

Scenarios below 100 gCO_2/kWh are consistent with energy system modelling that we have updated for this report on the lowest cost path to meeting the 2050 target in the Climate Change Act (Box 4.2).

Overall these scenarios involve a reduced deployment rate for low-carbon technologies compared to our previous scenarios. That largely reflects delays to new nuclear projects and slow progress on CCS.

These deployment rates could also help to ensure that contracted projects are the lowest-cost projects available and that strong competition for contracts secures them at the lowest possible price. However, aiming for any slower rate of contracting low-carbon generation would risk parts of the project pool drying up, increased risks feeding through to higher costs, and/or an increased reliance on gas, which would imply higher carbon emissions and higher costs to consumers in the long run.

The scenarios involve the majority of new generation needs from 2020 being met by low-carbon sources, especially beyond 2025 (Figure 4.2). Figures 4.3, 4.4 and Table 4.2 detail three possible mixes for 2030:

- High renewables assumes that more acceptable sites are available for onshore wind and solar and that offshore wind can be deployed at low cost at 2 GW per year in the second half of the decade.
- High nuclear includes three new plants rather than the two included in the other scenarios.
- High CCS assumes that CCS progresses relatively well and expands to 7 GW by 2030. Higher deployment may be appropriate if costs fall below those of other low-carbon technologies.

The precise mix should reflect how costs develop, as revealed through mostly competitive procurement in the low-carbon auctions.

Box 4.2: Power sector decarbonisation to below 100g/kWh in 2030 on the path to 2050

The Committee has previously identified decarbonisation of the power sector reaching a carbon intensity of generation of around 50-100 gCO_2/kWh in 2030 as being on the cost-effective path to meeting the 2050 target[*]. Our new scenarios for 2030 are towards the upper end of this 50-100 g/kWh range, reflecting delays in nuclear and CCS projects as well as an improved understanding of the system costs of reaching 50 g/kWh by 2030.

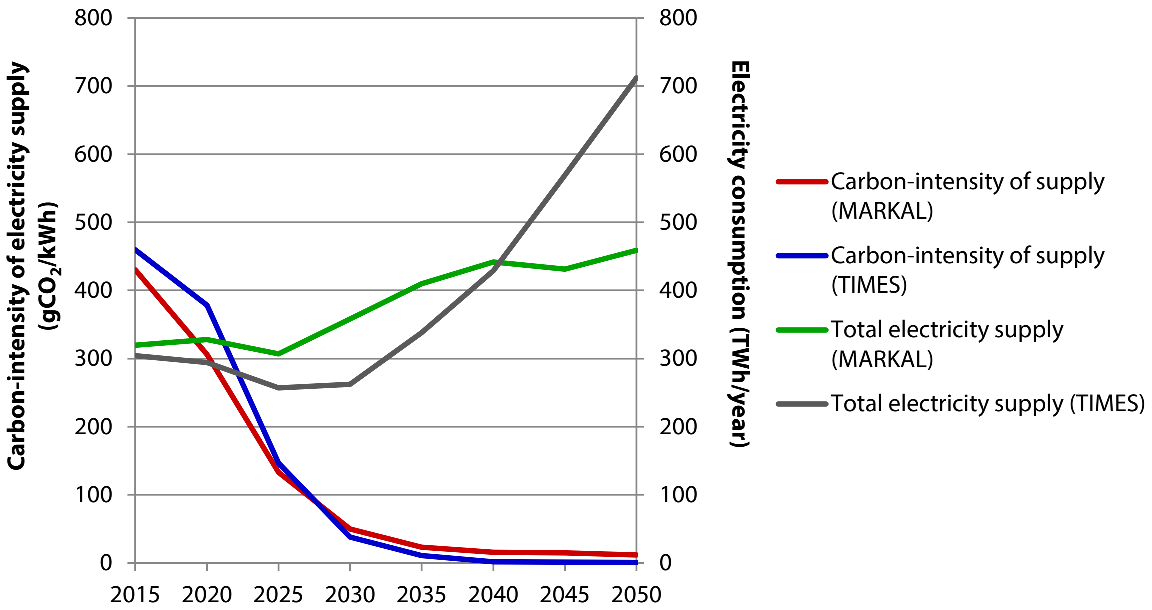
A very large degree of power sector decarbonisation by 2030 is a consistent result of energy system modelling in the UK.

- MARKAL and its successor TIMES are least-cost optimisation models of energy use, representing the entire energy system, from primary energy resources through to demands for energy services (e.g. passenger-kms driven).
- In runs of MARKAL conducted for the Committee in 2010 by UCL and in updated runs of TIMES in 2015 by DECC, carbon intensity falls to very low levels by 2030 (Figure 4.2). Electricity generation increases to 2050 due to increased electrification (e.g. roll-out of heat pumps and electric vehicles), although the extent of this depends on the balance between electrification and other abatement options in end-use sectors.
- While these models are rich in detail regarding technology options and costs, the power sector is characterised in less detail than in the modelling conducted by NERA and Imperial College London (Chapter 3). In particular, given the lower temporal resolution, the requirements for gas back-up (and therefore g/kWh) are likely to be underestimated.

Box 4.2: Power sector decarbonisation to below 100g/kWh in 2030 on the path to 2050

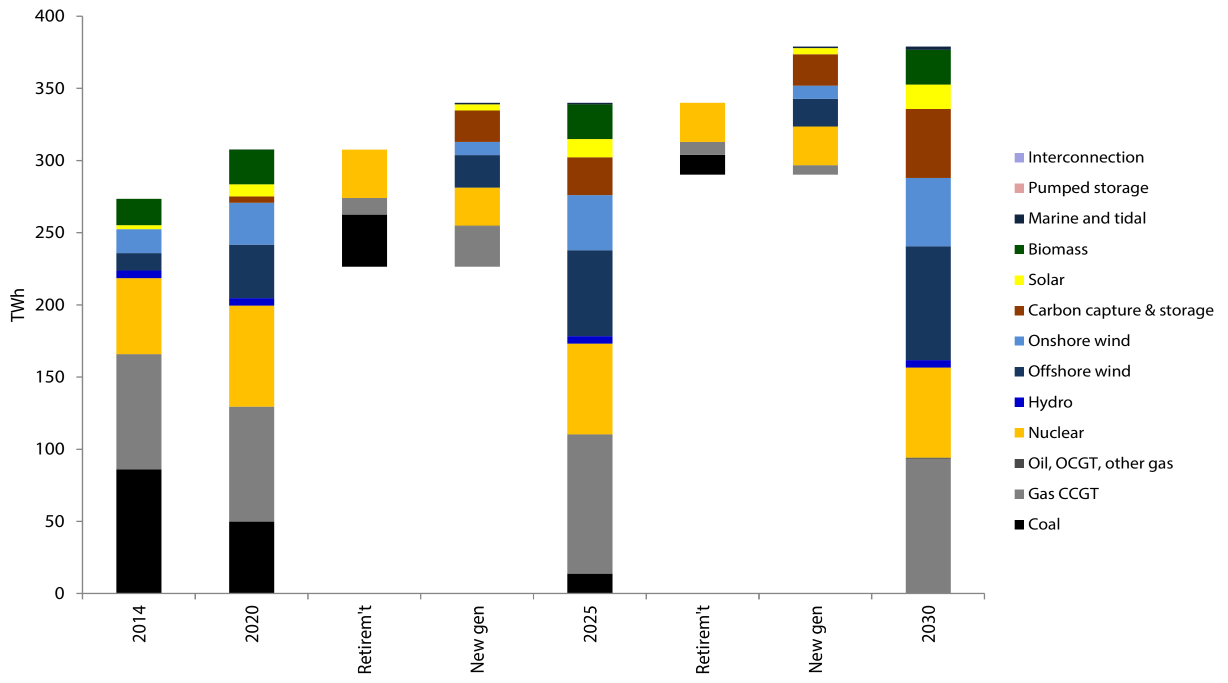
The models have indicated that the need for power sector decarbonisation is robust to a wide range of assumptions around fossil fuel prices (e.g. covering the full range of DECC's published scenarios) and technology costs, but that the precise mix of technologies used to achieve this is less certain.

Figure B4.2: Energy system model trajectories for the power sector (2015-2050)



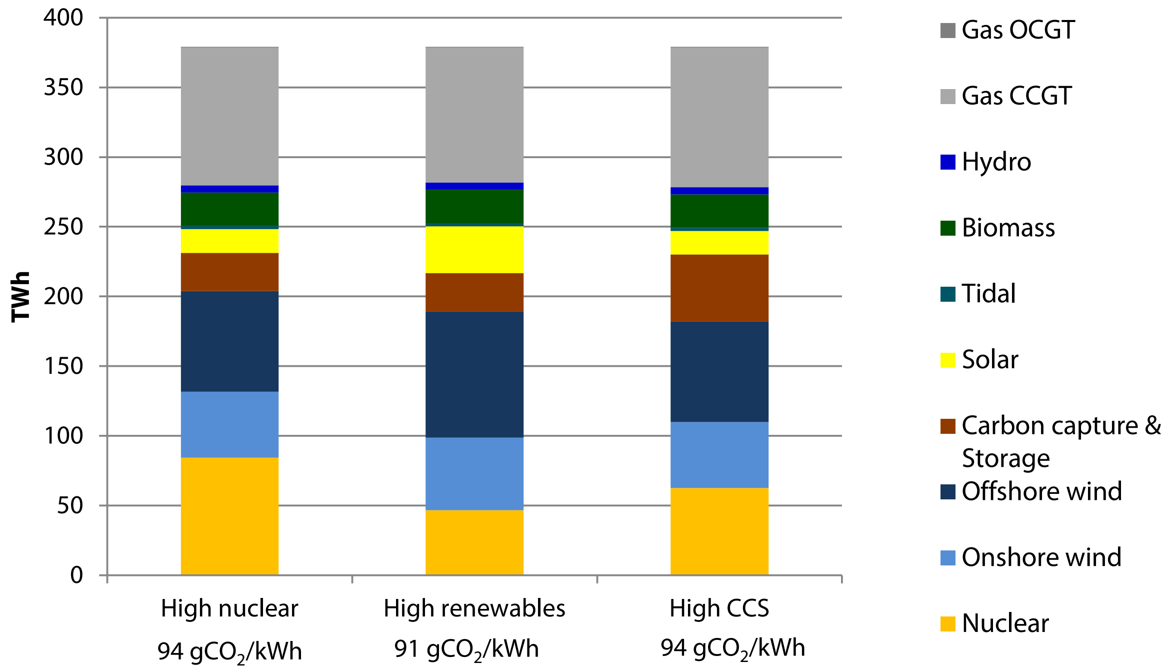
Source: MARKAL modelling by University College London for the CCC (2010); UK TIMES modelling for CCC by DECC (2015) CCC (2010) *Fourth Carbon Budget Review*; CCC (2013) *Next Steps on Electricity Market Reform*.
Notes: Carbon-intensity calculations exclude the 'negative emissions' benefits of using biomass in conjunction with CCS.

Figure 4.2: Potential contribution of low-carbon options to meeting generation gap at least cost (2020-2030) (TWh)



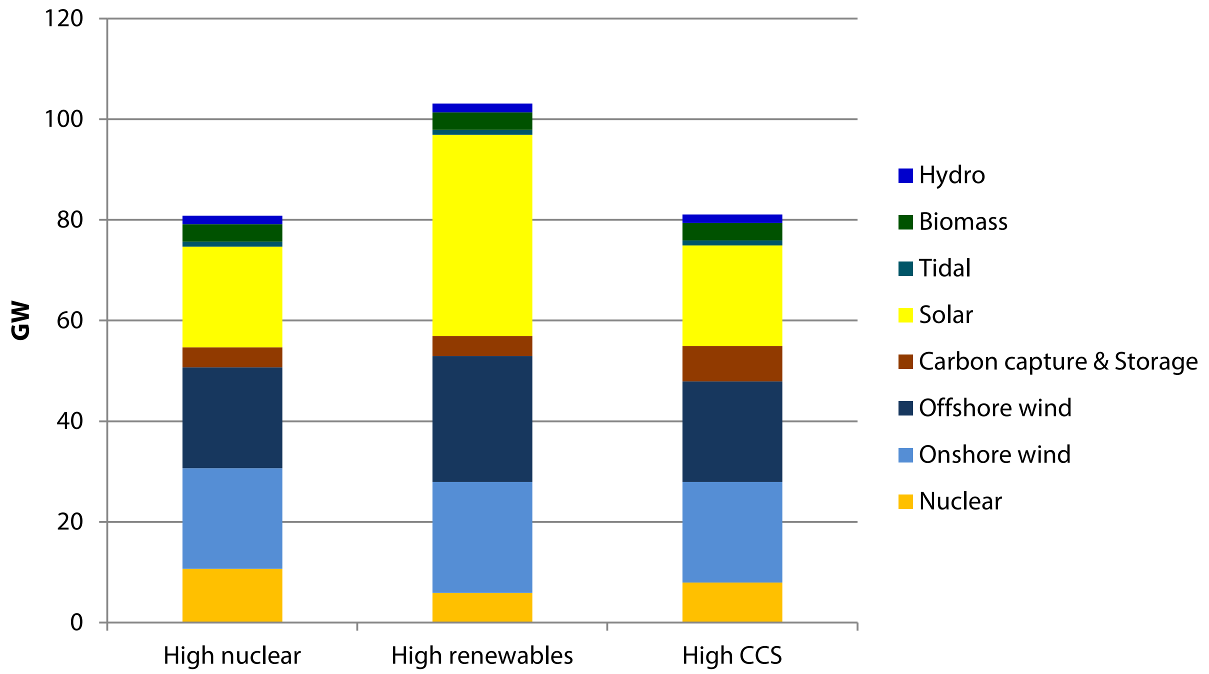
Source: CCC modelling.

Figure 4.3: Generation for scenarios with emissions intensity below 100 g/kWh in 2030 (TWh)



Source: CCC modelling.

Figure 4.4: Low-carbon capacity for scenarios with emissions intensity below 100 g/kWh in 2030 (GW)



Source: CCC modelling.
Notes: Additional gas-fired capacity will be required on top of this low-carbon capacity. The amount required will depend on the availability of system flexibility, the shape of demand, etc., so is not shown here.

Table 4.2: Key characteristics of scenarios reducing carbon intensity to below 100 g/kWh in 2030

	High nuclear	**High renewables**	**High CCS**
Total low-carbon TWh	280	282	278
Total TWh	379	379	379
g/kWh	93	91	94
Low-carbon %	74%	74%	73%
Intermittent renewables %	37%	47%	37%
Nuclear %	22%	12%	16%
Unabated fossil fuels %	26%	26%	27%
All renewables %	44%	55%	44%

Source: CCC modelling.

3. Alternative scenarios for investment in the 2020s, and uncertainties

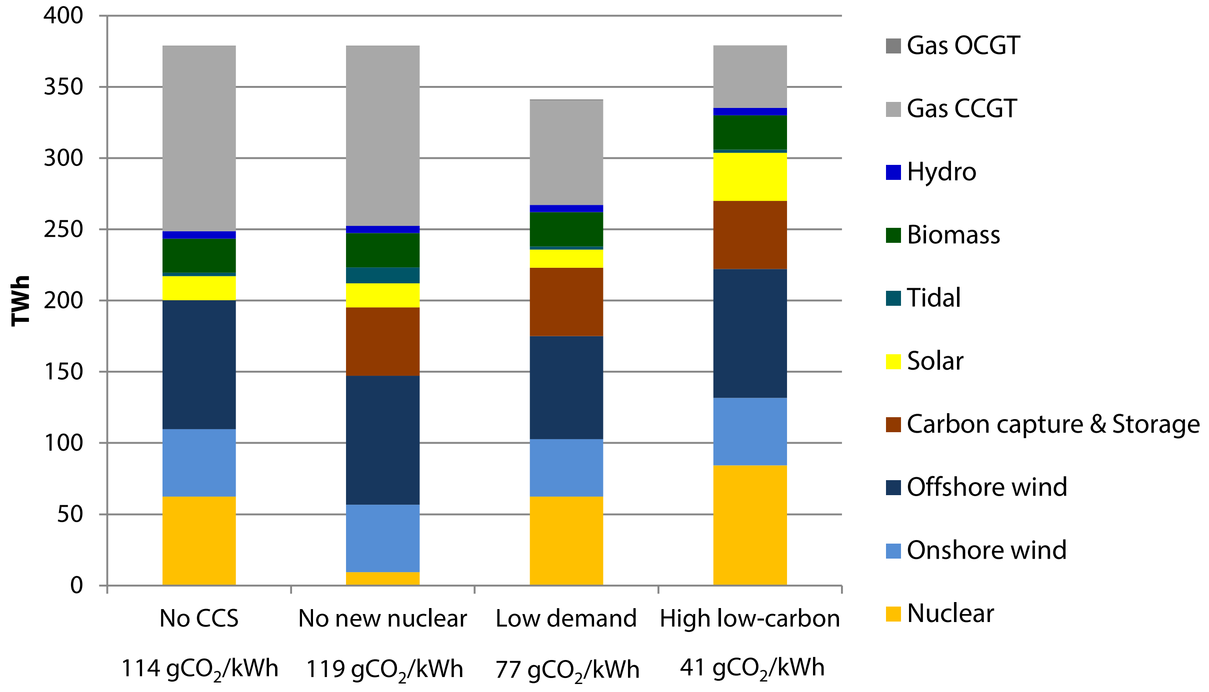
Alternative scenarios

In this section we assess alternative scenarios which entail more major deviations from our central assumptions, for example no new nuclear capacity or no CCS, to reflect current uncertainties about those programmes (Figures 4.5, 4.6, Table 4.3).

- **No CCS:** This scenario assumes no deployment of CCS beyond two initial projects (totalling 0.6 GW) selected in the Government's competition and a failure to demonstrate the technology effectively. It will be crucial that the other technologies deliver in this case, so the scenario builds in additional tidal lagoons and tidal stream as well as further offshore wind (leading to around 5 GW and 15 GW new build respectively in the 2020s). No CCS implies lower abatement in the industrial sector, which would need to consider higher cost options in place of CCS, and from the use of bioenergy. This is likely to lead to higher costs and greater risks for meeting the 2050 target.
- **No nuclear:** This scenario assumes no new nuclear, consistent with technical and/or financial difficulties with the new nuclear projects, pushing the programme back into the 2030s and raising questions over its long-term viability. Other technologies would need to compensate, at least in part, to stay on track to 2050. We therefore include higher offshore wind (15 GW new build in the 2020s) and tidal lagoons (given their potential to effectively provide baseload generation).
- **Low demand:** A lower level of electrification of heat and transport, or higher energy efficiency could mean lower demand than in our central projection. In this scenario we constrain the deployment of cost-effective technologies (onshore and solar) but maintain the minimum rates of investment in offshore wind and CCS. This scenario achieves a lower emissions intensity of around 75 g/kWh in 2030, and overall emissions of 26 $MtCO_2$.
- **Good performance across low-carbon technologies ('High low-carbon'):** Lower g/kWh (i.e. around 50 g/kWh) could still be appropriate if multiple low-carbon technologies perform particularly well in the 2020s. For example, that could be because the successful conditions for the three scenarios in section 2 all occur together. Successfully delivering this scenario would depend on effective integration of the different options in the grid, with improved system flexibility and the role of CCS likely to be particularly important.

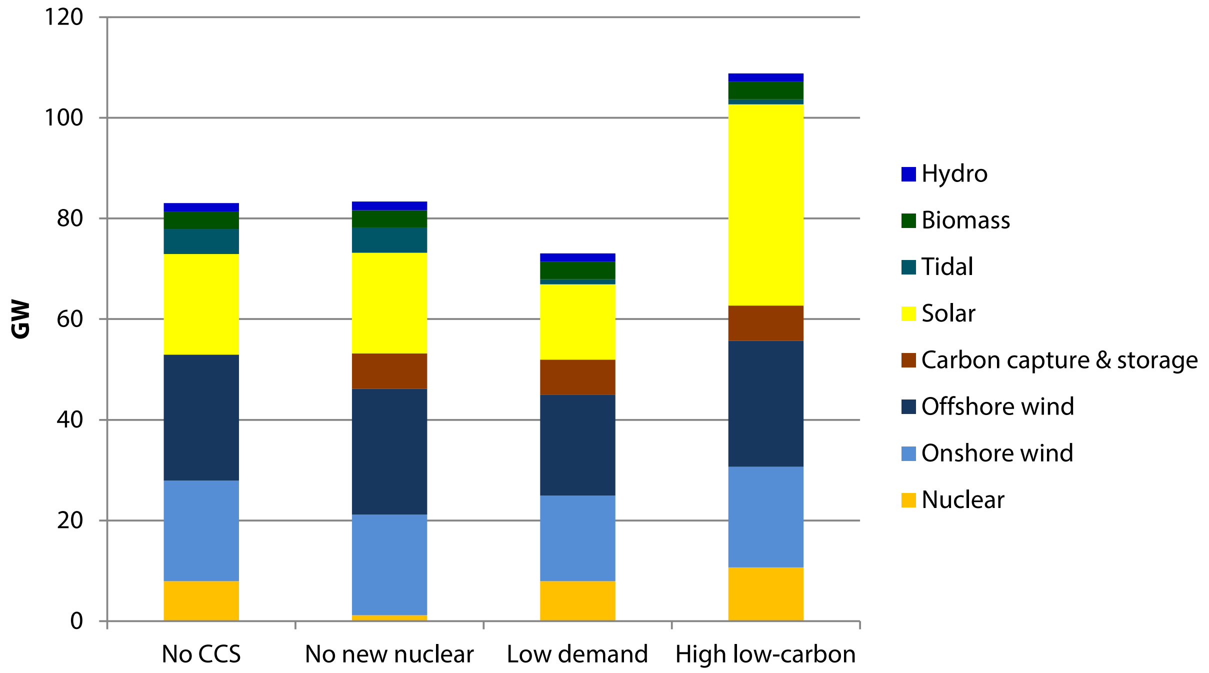
It is neither necessary nor appropriate to commit now to any one of these specific scenarios, given the various uncertainties. However, investors need to make decisions now about investments due to come on line in the 2020s. It is therefore important that the Government sets out its approach now and commit funding consistent with that. We discuss how best to do this in section 5 below, after setting out the implications of our scenarios for costs and affordability.

Figure 4.5: Generation for alternative scenarios in 2030 (TWh)



Source: CCC modelling.

Figure 4.6: Low-carbon capacity for alternative scenarios in 2030 (GW)



Source: CCC modelling.

Table 4.3: Key characteristics of alternative scenarios in 2030				
	No CCS	**No new nuclear**	**Low demand**	**High low-carbon**
Total low-carbon TWh	260	253	267	335
Total TWh	379	379	341	379
g/kWh	114	119	77	41
Low-carbon %	68%	67%	78%	88%
Intermittent renewables %	44%	44%	37%	46%
Nuclear %	16%	2%	18%	22%
Unabated fossil fuels %	32%	33%	22%	12%
All renewables %	51%	51%	46%	54%

Source: CCC modelling.

Uncertainties

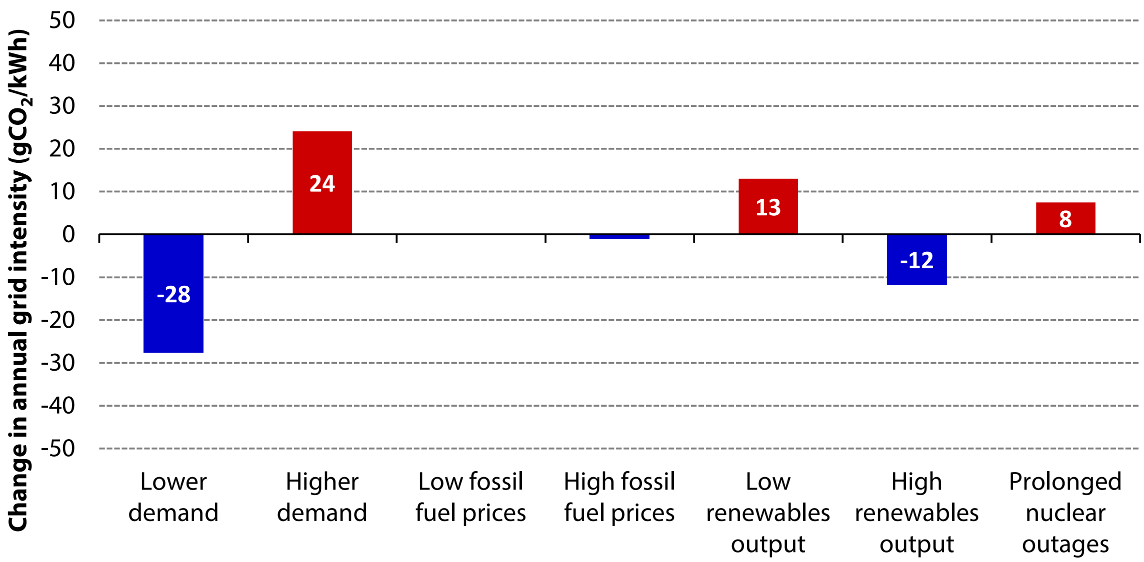
We have also assessed the impact of a range of specific sensitivities around a scenario reaching 100 gCO_2/kWh in 2030 (Figure 4.7). That includes different assumptions for demand, fossil fuel prices, renewables output and nuclear outages:

- **Demand.** The core scenario includes central projections for demand (based on our 2013 *Fourth Carbon Budget Review* analysis). High/low demand assumes demand is 10% higher or lower than central projections.
- **Fossil fuel prices.** High/low fossil fuel prices based on the range in DECC's fuel price projections published in 2014.
- **Expected output for renewables technologies.** High/low renewables output assumes wind/PV generation is 10% higher or lower than central assumptions, reflecting the possibility of years with particularly favourable or unfavourable weather conditions.
- **Nuclear outages.** Prolonged (6-month) outage of a nuclear plant.

The demand scenarios have the biggest impact; the expectation should be that if demand rises more/less quickly than projected then the rate at which new generation is procured from the low-carbon market should speed up or slow down accordingly. Fuel prices have a muted impact as by 2030 there is no coal capacity to switch to and low-carbon generation will dispatch before gas whether gas prices are high or low.

The sensitivities on renewables and nuclear demonstrate that there will be some sensitivity to conditions that can vary from year to year. Given that, it will continue to be important to track progress in terms of investment and capability as well as final emissions outcomes; we will reflect that in our monitoring approach.

Figure 4.7: Sensitivities around a 100 gCO_2/kWh scenario



Source: Imperial College modelling (2015).

4. Costs and electricity bill impacts of low-carbon scenarios compared to investment in gas

In this section we set out the costs associated with the scenarios set out in section 2 with carbon intensity slightly below 100 gCO_2/kWh in 2030. We base this assessment on a comparison to the alternative of a programme where new generation in the 2020s is provided by unabated gas-fired capacity.

First, we set out the cost premium associated with the scenarios set out above, which represents the level of required government support or subsidy. We then put these estimates together with other costs of electricity (e.g. network costs) to set out the results in two ways: total economic costs and electricity bill impacts.

- Total economic costs are the whole-of-society perspective and factor in a full assessment of costs including a value of carbon implied by the 2050 target (Box 1.1 in Chapter 1). Total economic costs are the appropriate basis to make decisions regarding the efficient allocation of resources by government.
- Bill impacts differ in that they depend upon how the programmes of low-carbon investment are financed – different public financing strategies imply a different allocation of costs between bill payers, power producers and the exchequer. Our assessment of bill impacts factors in a lower market carbon price rather than the 'target-consistent' value assumed in calculating total economic costs. We also include an assessment of the 'Merit Order Effect' (Box 4.3) that will reduce bills, and include other policy costs that are levied on bills.

The costs of integrating low-carbon technologies onto the grid (i.e. grid management and back-up costs) are included in both assessments.

(a) Support levels for low-carbon investment implied by our scenarios

To 2020, the Government has committed to a limited pot of funds to support low-carbon generation. That rises year on year to a level of £7.9 billion in 2020. That level is compatible with meeting carbon budgets: we estimate a cost of £7.6 billion in a central case for gas prices (52 p/therm in 2020) and £8.0 billion if gas prices are low (29 p/therm).

This funding is called the Levy Control Framework (LCF) and aims to protect consumers by placing a cap on total payments (above the electricity price) to low-carbon generation for each year until 2020.

The subsidy for low-carbon investment should in principle be defined as the premium above the alternative investment. In the 2020s the alternative is to build new unabated gas-fired generation (i.e. a combined cycle gas turbine – CCGT), which would require a price equal to its long-run marginal cost (LRMC, i.e. including the full cost of operation, including carbon costs, and payments to cover the investment cost). That should include the full ('target-consistent') value of carbon emissions, since any lower cost is effectively a subsidy to gas-fired generation.

The LCF should therefore ideally be indexed against the full costs of new gas plant, rather than the wholesale electricity price, which is likely to be lower. However at present the LCF is measured against the wholesale electricity price. Below we report costs against both the cost of new gas plant and the wholesale electricity price for transparency.

The cost of the existing commitment would fall in our central case, from £7.6 billion in 2020 to £7.0 billion in 2025. That reflects central assumptions that the gas price will rise (to 68 p/therm in 2030) and the increase in the full target-consistent carbon value (from £23/tCO_2 in 2020 to £78/tCO_2 in 2030). If reflected in market prices, those would reduce the top-up paid to low-carbon generation with a Contract for Difference.

Assuming central gas prices, our scenarios require around a further £2.2 billion of annual support for low-carbon investment to 2025, or £3.7 billion in the case of lower gas prices.

- The majority of this additional spend (£1.3 bn assuming central gas prices) is to develop the options of offshore wind (£0.9 bn) and CCS (£0.5 bn).
- The remaining cost is for investment in established technologies (e.g. onshore wind, solar and nuclear; £0.9 bn). These technologies require support in early years even though they are cost competitive when assessed over their full life. That reflects that their returns are front-loaded by low-carbon contracts that are shorter than expected asset lives and that the full costs of gas-fired generation are back-loaded under a rising trajectory for carbon values.
- In a scenario with low gas prices (falling to 46 p/therm in 2030) total further support required would increase to £3.7 billion (on top of the existing commitment, which would be £7.5 bn in 2025 if gas prices are low). That would have a similar split across emerging technologies (£1.3 bn for offshore wind, £0.7 bn for CCS) and established technologies (£1.6 bn). As we set out in our bills assessment below, whilst support costs would be higher, bills overall would be lower with low gas prices.

The total support required in 2025 is therefore £9.2 billion assuming central gas and full carbon costs and if the LCF is indexed against the LRMC of new gas plant (Figure 4.8).

If the LCF continues to be measured against the wholesale electricity price and market carbon prices are below the full value of carbon, required support will be higher (Table 4.4):

- If the carbon price support continues to be frozen at £18/tCO_2 above the EU ETS price, market carbon prices are expected to only reach £37/tCO_2 by 2025. In this case required funding would rise to £9.4 billion.
- If indexed against the wholesale electricity price, required LCF support for our scenarios could be higher. However, DECC have not yet revised their projections for the wholesale electricity price. The 2014 projections are for a price of £69/MWh in a central case, the same as the long-run cost of gas facing a market carbon price in our central assumptions for gas prices.
- In a world of low gas prices, the required LCF increases to £11.1 billion above the wholesale price. However in this scenario bills would be lower overall (see bills assessment below).

The support for low-carbon investment should fall towards 2030 given retirements of more expensive renewables and a rising value of carbon. However, required funding through the LCF may continue to increase if this is measured against a wholesale price that does not reflect the full costs of gas generation:

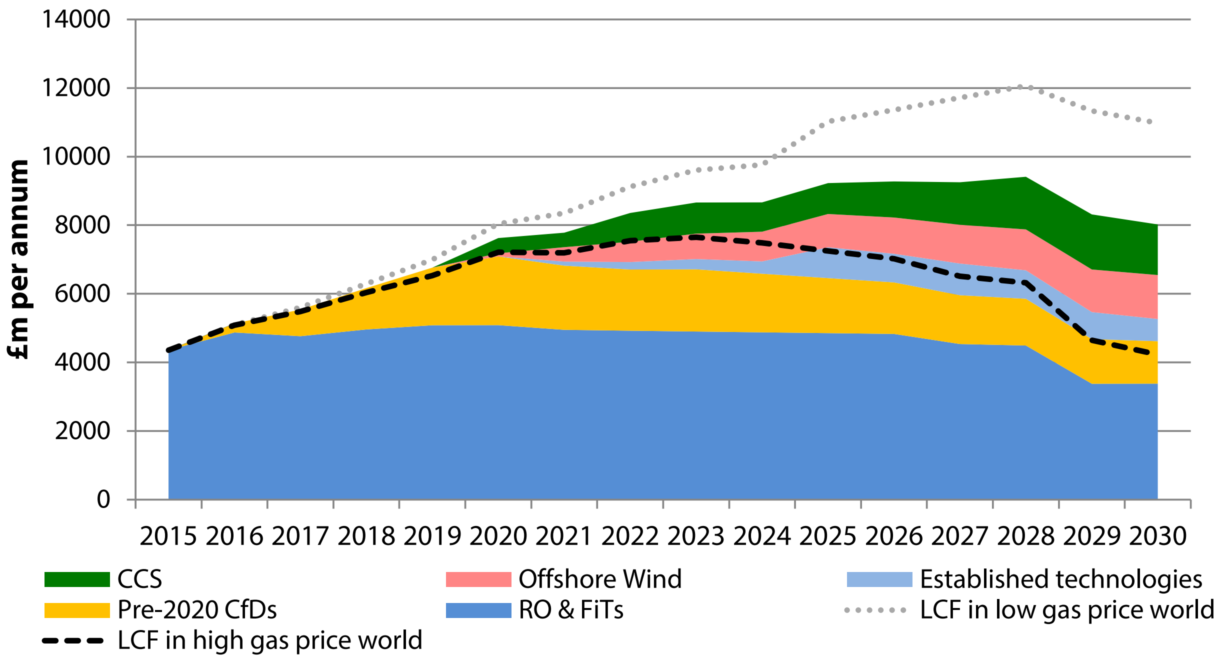
- If measured against the full cost of new gas plants facing a target-consistent carbon value, required support would fall from £9.2 billion in 2025 to £8.0 billion in 2030, in a central scenario for gas prices.
- If measured against DECC's 2014 wholesale price (i.e. comparable to the long-run costs of gas with a market carbon price), required support would continue to rise to 2030, to £9.9 billion from £9.4 billion in 2025.

These costs do not include the full costs of integrating low-carbon technologies onto the grid. We add these in the total economic cost and bills assessment below.

This level of support is indicative of costs across our scenarios, since all the scenarios include development spending on CCS and offshore wind and then allow focus on whichever technologies are able to provide generation at the lowest cost to the system.

A clear conclusion of this assessment is that with appropriate carbon pricing the additional support required for low-carbon investment in the 2020s is significantly smaller than the level of support committed in the 2010s (i.e. a £1.6 bn increase from 2020 to 2025 followed by a fall to 2030, compared with a £6.5 bn increase from 2010 to 2020). However, higher levels of support would be required to compensate for an insufficient carbon price and suppressed wholesale electricity prices.

Figure 4.8: The Levy Control Framework (LCF) in our power sector scenarios (2015-2030)



Source: We assume the following ranges for gas prices: 30-76p/therm in 2020, 38-99p/therm in 2025 and 46-99p/therm in 2030. Target-consistent carbon price rises in line with Carbon Price Floor, to £23/t in 2020 and £78/t in 2030.
Notes: Measured against the long-run marginal cost of gas. All years are calendar years. All money is in £2014. The LCF cap for 2020/21 is £7.9n in the calendar year 2020. CfD = Contract for Difference.

(b) Total economic costs of low-carbon scenarios compared to investment in gas

The full economic costs of our scenarios include generation costs, network costs, 'target-consistent' carbon values, costs of intermittency and other policy costs.

- **Generation costs.** The cost of gas generation is its long-run marginal cost (LRMC, i.e. including the full cost of operation and payments to cover the investment cost) at £55/MWh in 2030 in a central gas price scenario with no carbon cost. The cost of new low-carbon generation in the 2020s is the average strike price paid across the low-carbon contracts (£94/MWh in 2030 for generation contracted across the 2020s). The cost of existing low-carbon generation is the same in both scenarios.
- **'Target-consistent' carbon cost.** Gas generation additionally imposes a cost of its emissions. The full economic cost of those emissions is best measured by the target-consistent carbon values rising to £78/tCO_2 in 2030.[52] This adds £28/MWh to the gas generation cost in 2030. By 2035 it would add £40/MWh (based on a £114/tCO_2 carbon value), taking the cost of gas generation above the average cost of low-carbon generation added in the 2020s.
- **Cost of intermittency.** Intermittent renewables lead to increased grid management costs and increased requirements for back-up. As set out in Chapter 3, we estimate this to be around £10/MWh of intermittent renewables, or around £4/MWh on average for our 2030 scenarios, which include around a 40% share of intermittent renewables.

[52] Although part of this cost is paid to the Exchequer, that is a transfer and does not affect our calculations of economic cost.

- **Other system costs.** There are additional costs associated with delivering electricity to consumers, including costs of maintaining and upgrading the transmission and distribution network, supply costs and metering. Aside from the intermittency costs, we assume these are the same across scenarios.

Table 4.4: Levy Control Framework Estimates in 2020, 2025 and 2030, compared to the full costs of new gas generation and compared to the wholesale electricity price

		Subsidy cost (£bn per annum)	
Gas prices	**Year**	**Against in-year cost of new unabated gas plant facing target-consistent carbon price**	**Against wholesale electricity price with market carbon price**
Central	2020	7.6	7.6
	2025	9.2	9.4
	2030	8.0	9.9
Low	2020	8.0	8.0
	2025	11.0	11.2
	2030	11.0	12.8
High	2020	7.2	7.2
	2025	7.2	7.4
	2030	4.2	6.1

Source: We assume the following ranges for gas prices: 30-76p/therm in 2020, 38-99p/therm in 2025 and 46-99p/therm in 2030. Target-consistent carbon price: rises in line with Carbon Price Floor, to £23/t in 2020 and £78/t in 2030; Market carbon price: based on EU ETS projection from Thomson Reuters Point Carbon (June 2015), including carbon price support, rising to £37/t in 2025 and £42/t in 2030.
Notes: 1) All years are calendar years. 2) All money is in £2014. 3) The LCF cap for 2020/21 is £7.9bn in CY 2020. Figures for Low gas prices represent a worst case where there are no resulting reductions in costs of low-carbon generation, which there would be for gas CCS.

Table 4.5 sets out the implications for the economic costs of providing generation in our 'low-carbon' scenarios and the alternative where new generation in the 2020s is from gas generation. The low-carbon scenarios involve higher costs initially, reflecting that the extra generation cost for low-carbon investments is initially greater than the value of carbon saved. That largely reflects the extra costs of supporting offshore wind and CCS, as seen in the extra support costs in the LCF.

By 2035, the economic cost of the two scenarios will be similar as the rising value of carbon would bring the costs of gas generation in line with the average cost of low-carbon investments in the 2020s. Costs for gas generation would then continue to rise, whilst costs of low-carbon generation would be flat for the remainder of contracts and fall thereafter. Moreover, under the low-carbon scenarios the UK would have a portfolio of active low-carbon options available for further deployment at low cost in the 2030s, whereas the scenarios with investment solely in gas generation in the 2020s would not.

Our scenarios therefore represent good-value investments for a society committed to climate targets.

Table 4.5: Total economic costs of a programme of low-carbon and gas investment in the 2020s

£/MWh	**2020**		**2025**		**2030**		**2035**	
Investment profile	*Low-carbon*	*Gas*	*Low-carbon*	*Gas*	*Low-carbon*	*Gas*	*Low-carbon*	*Gas*
Generation costs	70	68	90	81	94	76	85	65
'Target-consistent' carbon cost	5	6	5	8	7	21	17	38
Cost of intermittency	2	2	3	2	4	2	4	2
Network & other costs	38	38	38	38	38	38	38	38
Total cost	116	114	136	130	143	137	144	143

Source: We assume the following ranges for gas prices: 30-76p/therm in 2020, 38-99p/therm in 2025 and 46-99p/therm in 2030. Target-consistent carbon price: carbon price rises in line with Carbon Price Floor, to £32/t in 2020 and £78/t in 2030; Market carbon price: based on EU ETS projection from Thomson Reuters Point Carbon (June 2015), including carbon price support, rising to £37/t in 2025 and £42/t in 2030.
Notes: All money is in £2014.'Network and other costs' includes the estimated costs of maintaining the transmission and distribution networks, based on Ofgem's allowed revenues for electricity transmission and distribution operators.

(c) Electricity bill impacts

The economic costs of the low-carbon scenarios relative to providing new generation in the 2020s from gas-fired generation will also feed through to consumers' electricity bills.

However, the impact on electricity bills will differ from the total economic cost in that bill-payers face the market price of carbon and wholesale prices may be lower than generation costs due to the so-called 'merit order effect'. Other policies and taxes are also levied on the electricity price.

- **Market carbon price.** We assume that the carbon price support remains frozen at £18/tCO_2, on top of central projections for the carbon price in the EU ETS (around £24/tCO_2). That would result in generators paying £42/tCO_2 for their emissions in 2030, rather than the target-consistent carbon value of £78/tCO_2 in 2030. This translates to a1.5 p/kWh uplift on the electricity price under the market carbon price.
- **Merit order effect.** Bills will be slightly reduced as new low-carbon generation in our scenarios exerts downward pressure on the wholesale electricity price (Box 4.3). We estimate that this 'merit order effect' could reduce electricity prices by 2 p/kWh in 2030.
  - Adding low-carbon generation reduces the average price of electricity in the wholesale

market because, once constructed, the cost of producing electricity for low-carbon capacity tends to be low, and this will be reflected in lower market prices as the low-carbon share increases.

  – That limits returns to existing nuclear plants and renewables supported under the Renewables Obligation, which would otherwise see their revenues increase as a result of the rising market carbon price. Compared to a scenario with investment in gas-fired generation (which would see higher returns to existing low-carbon generators) that implies a saving to consumers.
  – We estimate that this 'merit order effect' would reduce annual costs to the typical household by up to £10 in 2025 and 2030 in our scenarios.

- **Other policies and VAT.** There are various other policies that add to bills. These include the Energy Company Obligation, Warm Home Discount and smart meter support, which together are expected to add around 0.7 p/kWh through the 2020s. However these costs are not related to support for low-carbon investments, so do not change across our scenarios. There is also 5% VAT included in the total price.

We report bill impacts in Table 4.6 below under central assumptions for gas prices (66 p/therm in 2025).

- In 2020, a typical household will be paying around £105 through their annual electricity bill of around £500 to support investment in low-carbon generation. Those costs are already committed through investments that are underway and contracts that have been awarded.
- In our scenarios, support will increase to £120 per household in 2030 and then fall.
- Costs to households would be around £20 higher in 2025 and £35 higher in 2030 than if investment in the 2020s was focused on gas-fired generation facing a market carbon price (i.e. £42/tonne in 2030).

Our scenarios therefore imply an increased impact on consumer bills in the 2020s from support for low-carbon investment. However, this is comparatively less than increases during the 2010s and is a necessary investment to achieve good-value emissions reductions, to break the link with rising carbon prices and to ensure a portfolio of low-carbon options remain on the table in the late 2020s and beyond.

Our scenarios also imply potential savings in the longer term, which are not reflected in these cost estimates but could reduce consumer bills further beyond 2030. The low-carbon investments supported in our scenarios will be able to produce electricity beyond the end of their contracts at a much lower cost than unabated gas generation. At the end of their lifetimes, sites can also be 'repowered' at significantly lower cost than they were originally constructed. That reflects, for example, that in replacing an offshore wind farm at its existing sites some costs, such as development and transmission, do not need to be incurred again, as well as scope for technological improvement.

Box 4.3: The impact of the 'merit order effect' on costs

Once constructed, low-carbon generation generally has a lower cost for producing electricity than fossil-fired generation, since they have no or low fuel costs. For example, the *short-run marginal cost* for wind farms is close to zero, for nuclear plants is around £18/MWh, and for gas plants is around £40/MWh, with the latter projected to rise to £70/MWh by 2030 under a central scenario for gas prices and if the full value of carbon is reflected in the market.

The GB wholesale electricity market works such that the price at any time reflects the short-run marginal cost of whichever plant is most expensive and running at the time – the *system marginal price*. This price is then paid to all plants running at that time.

An increase in low-carbon generation will therefore lead to lower wholesale electricity prices.

- As low-carbon generation increases, there will be more periods when it is the marginal plant, resulting in very low or even negative system marginal prices.
- Even when low-carbon generation is not the marginal plant it will push out less efficient, higher-cost plant, and slightly reduce the system marginal price.

This will reduce the returns to plants that rely on the wholesale market for their income (Figure B4.3), and provide a saving to consumers:

- Existing nuclear plants and renewables that are not supported through Contracts for Difference will see lower returns through the wholesale market. Renewables with CfDs and new nuclear would see any reduction in their returns in the wholesale market made up through the CfD top-up.
- Coal and gas plants could also see their returns reduced, but will choose not to operate in times of very low prices.
- Lower returns in the wholesale market could increase returns necessary through the capacity market.

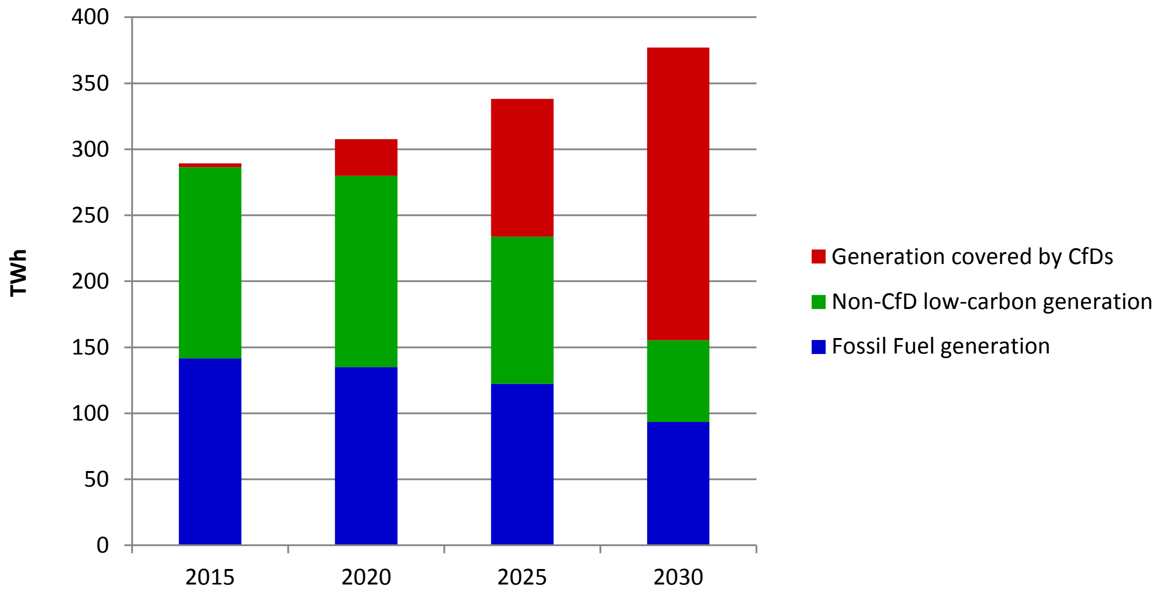
We have drawn on modelling from Aurora Energy Research to estimate the size of the merit order effect in our scenarios:

- Aurora model a scenario that reduces emissions to under 100 gCO2/kWh in 2030 in their *GB Power Market Forecast to 2040*.
- They find that this could lead to very low wholesale electricity prices (<£30/MWh) in around 15% of hours in 2030.
- They model the impact of reducing nuclear and wind output, finding that a 30 TWh reduction in each would lead to an average electricity price that is 0.7 p/kWh higher in 2030.

Scaling that up for the 168 TWh of low-carbon generation contracted in the 2020s in our scenarios implies a potential merit order effect of up to 2 p/kWh by 2030, 0.7 p/kWh in 2025. We assume this only affects low-carbon generators without a CfD. We note that these generators would still make strong returns given that without the merit order effect wholesale prices would be rising as a result of rising carbon prices.

Spread across all existing nuclear and renewable generation without CfDs, this implies a potential saving in 2025 of £0.8 billion and 2030 of £1.2 billion. That would translate to a saving of up to £9 on the annual electricity bill for a typical household.

Figure B4.3: Shares of generation with different exposures to the wholesale market



Source: DECC (2014) *Updated Emissions Projections: Annex M*. Available at: www.gov.uk; Aurora Energy Research (July 2015) *Quarterly Forecast*. Available at: www.auroraer.com

If gas prices remain at current low levels (i.e. 46 p/therm) then the bill impact of investing in low-carbon generation would be higher – by up to £20 per household per year. However, bills overall would be lower in this case – by around £40 per household per year compared to the central case, with additional savings for most households on their gas heating bills. Low-carbon investment also reduces the risk of very high increases in bills, which could otherwise occur if European gas or carbon prices were to rise sharply over the next decade.

Businesses will similarly see higher electricity costs as a result of support for low-carbon generation. Where there are increased costs imposed in the short term, and if these are not replicated in other countries, it will be important for the Government to continue schemes providing exemptions or compensation to affected industries that would otherwise be at risk of losing competitiveness.

Table 4.6: Residential bill outlook for investment programmes in low-carbon and gas					
£/household annual bill (central gas price = 66 p/therm in 2025)	**2014**	**2020**	**2025**	**2030**	**2035**
BASELINE BILL *– if new generation in the 2020s is provided by unabated gas generation with no carbon price and no support for low-carbon generation*	365	380	415	415	415
TOTAL BILL IN OUR SCENARIOS	415	485	530	535	520
Of which:					
(A) Market carbon price	10	30	40	45	50
(B) Support for low-carbon investment already committed (pre-2020), including intermittency costs	35	70	55	40	20
(C) Additional support for low-carbon investment in the 2020s	-	5	25	40	40
(D) Intermittency cost of low-carbon investments	-	-	0 to 5	5	5
(E) Merit order effect	-	-	-(5 to 10)	-10	-10
TOTAL IMPACT of low-carbon investment in the 2020s (relative to investment in gas-fired generation) = C+D+E	-	-	20	35	35
TOTAL IMPACT of carbon price and support for all low-carbon investment = A+B+C+D+E	45	105	115	120	105

Source: We assume the following ranges for gas prices: 30-76p/therm in 2020, 38-99p/therm in 2025 and 46-99p/therm in 2030. Market carbon price: based on EU ETS projection from Thomson Reuters Point Carbon (June 2015), including carbon price support, rising to £37/t in 2025 and £42/t in 2030.
Notes: 1) All years are calendar years. 2) All money is in £2014.

5. Policy implications

Our investment scenarios set out above imply that the low-cost strategy for meeting the needs of the power sector in the 2020s involves low-carbon generation as the primary source of new generation.

- Emissions in 2030 are 55 $MtCO_2$ lower than if new generation in the 2020s was all provided by unabated gas-fired generation.
- Our scenarios ensure that a portfolio of competitive options will be available from the late 2020s to meet growing demand for low-carbon electricity from other sectors (e.g. heating, transport) as they move away from fossil fuels.
- There is an initial cost to the scenarios, which we estimate would add £20 to annual household electricity bills in 2025 and £35 in 2030. However, this cost is lower than the full value of carbon saved from 2030.

The key tools are in place to deliver this low-carbon investment – long-term contracts with price discovery through competitive auctions. However, to deliver at lowest cost, the Government must urgently clarify the direction for future policy.

(d) Setting a Levy Control Framework that responds predictably to changing conditions

Investments in the power sector have long lead-times, with planning cycles stretching well beyond the current 2020 policy window. Large offshore wind farms, CCS plants and nuclear plants have a project lead-time of up to 10 years or more, with supporting investments in the supply chain stretching even further.

If investors are exposed to policy risk in this timescale then they will apply risk premia to projects and costs will be unnecessarily increased. Potential projects in the pipeline could also be discarded, which would reduce the number of competitors in the auctions.

We therefore recommended in our 2015 progress report that the Government extend the Levy Control Framework to 2025 to provide investors with increased confidence over the future low-carbon market and to signal a commitment to continuing decarbonisation of the power sector through a portfolio of options. This remains an urgent priority.

Although we estimate a central value for the LCF above (i.e. £9.2 billion in 2025), the spending cap can only be an estimate given it is set in advance and outturn spend depends on a set of factors that are difficult to predict with accuracy (e.g. wholesale electricity prices, the level of delivery under demand-led policies and outturn load factors). Recent assessments of projected LCF spend in 2020 suggested that the cap would be breached, although cost-control measures have now been introduced to mitigate potential overspend.

Setting the LCF beyond 2020 should include the overall level as well as provisions for how the Government intends to respond if circumstances turn out differently to those currently assumed.

- For example, funding of £9.2 billion in 2025 would be appropriate if carbon prices increase in line with the full carbon value as in the Government's published carbon values (i.e. to £42/tonne) and if wholesale electricity prices reflect the full costs of new gas generation.
- Funding of £9.8 billion would be needed if the market carbon price reaches half the level assumed in the Government's carbon values (i.e. £21/tonne instead of £42/tonne in 2025).
- Higher funding would be needed to the extent that the merit order effect and/or the capacity market lead to a lower wholesale electricity price. In this case and the case of lower carbon prices, total electricity bills would be lower but low-carbon funding would make up a greater proportion of the bill.
- If there are delays to expected projects (e.g. new nuclear), the presumption should be that funds will be freed up for other projects, rather than held back for future years.

Alongside or following extension of funding, the Government should set out the timetable and funding pots for the next auction round for low-carbon contracts. A separate funding pot should be reserved for emerging technologies, including offshore wind and CCS until the mid-2020s.

(e) Defining the Levy Control Framework to better reflect the level of subsidy and an approach to subsidy-free contracts

The cost to consumers is best measured by the full cost of low-carbon plant compared to the full cost of the alternative means of generation:

- As set out in chapter 3, low-carbon plant can lead to increased system costs from grid management and back-up capacity. These should be included in the costs of intermittent generators, either directly through changes to market rules, or indirectly in setting auction prices and calculating the LCF.
- The alternative investment is to build new unabated gas-fired generation (i.e. a combined cycle gas turbine – CCGT) which would require a price equal to its long-run marginal cost (LRMC). That should include the full cost of operation, the value of carbon emissions implied by targets in the Climate Change Act and payments to cover the investment cost.

Currently, the LCF is calculated against the wholesale electricity price, which is not consistent with the alternative investment and is likely to overstate the additional cost of low-carbon generation to consumers. The projected wholesale price is lower than the cost of CCGT because the market carbon price is below the target-consistent carbon price, because low-carbon generation with low marginal costs will reduce the wholesale price (the 'merit order effect' described above), and because part of the cost of gas-fired generation is paid under the capacity mechanism rather than the wholesale price.

Whatever the approach taken to measurement, the principles for setting the LCF should be:

- The LCF should provide enough support for established and emerging technologies on the basis on which it is measured (i.e. £9.2 billion in 2025 compared to the long-run cost of gas, £9.4 billion compared to the electricity wholesale price[53]).
- It should be set based on clearly communicated assumptions, for example for the level of the carbon price and the wholesale electricity price.
- The Government should clearly set out how deviations from central expectations will be handled. For example, if the LCF is set based on a 2025 carbon price of £42/tCO_2, funding should be increased by £0.6 billion if the 2025 carbon price turns out to be £21/tCO_2.

In setting reserve prices for the next auctions the Government can limit the levels of subsidy provided. We would consider options to be subsidy-free where they provide power at or below the expected lifetime costs of new gas generation facing its full carbon cost, allowing for intermittency costs (Box 4.1). For example, that would imply a maximum price for onshore wind and solar power of £80/MWh in 2020, with the expectation that competitive auctions would deliver lower prices.

(f) Funding for ongoing development of offshore wind, with stretching cost reduction goals

Our updated assessment (Chapter 2) finds that costs for offshore wind appear to be falling in line with industry goals and could continue to fall through the 2020s under a supportive policy environment. The most important enabler for these cost reductions is confidence that there will be a market for deployment provided costs continue to fall. A sufficient scale of market is required to drive private sector investment in innovation (e.g. to create bigger turbines), to support a competitive project pipeline and supply chain, and to encourage a falling cost of capital.

As set out in section 1, additional annual support of around £0.9 billion in 2025 would be consistent with delivering around 1 GW per annum (and possibly higher if costs fall faster). That

53 Based on DECC's 2014 projection, which is likely to be too high, implying that more funding would be needed if judged against the wholesale price.

would be in addition to continuing support for pre-2020 projects that is already committed and which falls from £3 billion in 2020 to around £2.7 billion in 2025 in DECC's central scenario for wholesale electricity prices.

In allocating funding, it should be made clear that while offshore wind is not expected to compete with established low-carbon technologies in the early 2020s, contracts will only be issued for projects that continue to demonstrate cost reduction and that the technology will have to compete without subsidy beyond this. That could be achieved by setting auction reserve prices on a falling trajectory in line with being subsidy-free in the mid-2020s, at a strike price of around £90-95/MWh.

(g) Funding for CCS with focus on shared infrastructure costs

The key opportunity for delivering CCS cost-effectively is through shared CO_2 infrastructure costs. This requires a minimum level of roll-out in the UK, which by 2030 we estimate to be 4-7 GW of power sector projects alongside further deployment in industry. If it is signalled in advance, this size of programme can also support a competitive pool of projects and increase interest from the financial community.

As set out in section 1, we estimate that an increase in annual support of around £0.9 billion in 2025 would be consistent with this level of ambition. Lower funding would be required for a 4 GW programme, but this would reduce the diversity of fuels, technologies and possibly the number of stores and pipelines available for future use. Going beyond 7 GW by 2030 would deliver limited further clear benefits in cost reduction so does not require dedicated support. It may be appropriate if CCS can deliver power more cheaply than the alternatives.

Funding should be accompanied by a strategic approach to infrastructure development. That could involve including working with industry to develop an effective business model for infrastructure sharing or a more regulatory approach to infrastructure build-out and pricing. It should also include consideration of the potential for Enhanced Oil Recovery.

The UK programme has been significantly delayed so far. Further delays should be avoided. The Government should ensure that the CCS competition delivers two projects as planned and that contracts are signed for at least two follow-on projects this Parliament, connecting into two clusters around the competition projects.

CCS will not be developed in the UK alone. The Government should work with industry and international partners to ensure that knowledge is shared across borders.

(h) Ensuring low-costs are delivered in practice

In addition to extending the LCF, there are some further policy implications to ensure low costs are delivered in practice.

- **Ensure low-cost opportunities are realised.** Available low-cost options should not be ruled out unnecessarily, for example onshore wind and ground-mounted solar projects where these are locally acceptable.
- **Develop the approach to life beyond contracts and repowering.**
  - Low-carbon capacity can continue to provide power, at low cost, after the initial contract period. For example, offshore wind farms are expected to generate power for 5-10 years beyond their 15-year contracts. However, currently their potential returns are uncertain given uncertainties over future wholesale costs.

- At the end of their lifetimes, renewable projects can be replaced at lower cost. That reflects that some costs, such as development and transmission, do not need to be incurred again, as well as the scope for technological improvement.
- That could create a perverse incentive for sites to close and repower earlier than needed. The Government should therefore develop an approach to repowering to ensure that consumers benefit from the potential low costs and that plant operators are incentivised to suitably maintain and refurbish plant beyond the life of their contract so that they can keep producing low-cost low-carbon power.
- Although the first contracts will not end for at least 15 years and the first major repowering will not begin until the 2020s, decisions on maintenance and refurbishment could be taken much sooner.

• **Explore ways to further reduce cost of capital.** The cost of capital is an important part of total project costs, and an important opportunity for cost reductions: a 1% reduction in the cost of capital for low-carbon projects procured in the 2020s would save around £1 billion per year by 2030. The Government should therefore continue to explore ways to reduce cost of capital that could include providing longer lead-times for policy, working with the finance community and considering the case for an increased public role, for example, on initial offshore site development.

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