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Future Electricity Series

Part 2: Power from Renewables

A report by Carbon Connect

‘This report guides people towards constructive debate about the future role of renewables at a time when it is dearly needed, as industry, technology and policy all undergo particularly rapid development.’

Baroness Worthington and Charles Hendry MP (September 2013)

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FOREWORD

This report is a guide to constructive debate about the future role of renewables in the power sector and is part of a series looking at the major technologies likely to supply us with electricity over the coming decades. It examines a very broad range of topics at a high level to inform strategic thinking about current and future policy, and was not written to reflect the full nuances of every area covered.

The story of renewables has been one of the most significant developments for the power sector in recent times, and it is clear that it has only just begun. The changes taking place in the power sector are rightly attracting discussion and debate, but only *constructive* debate will move us forward. This report guides people towards constructive debate about the future role of renewables at a time when it is dearly needed, as industry, technology and policy all undergo particularly rapid development.

Around 40 years ago, the Government began supporting a growing industry in overcoming extreme technology and engineering challenges to capitalise upon North Sea oil and gas. Today, Government is doing the same in helping industry to capitalise upon a different set of energy resources which the UK has in abundance and which are an everlasting national asset. These 'renewable' resources – such as wind, bioenergy, solar, hydro and marine – are being harnessed across our energy system and this report examines their prospects in the power sector.

Renewable electricity technologies have expanded steadily over the last ten years from a base of less than three per cent of power generation to over 11 per cent in 2012. This trend will continue through to 2020 when the UK hopes to generate at least 30 per cent of electricity from renewables, as part of efforts to meet the EU Renewable Energy Directive. Climate change and our statutory climate change target of reducing carbon emissions by 80 per cent by 2050 are also driving development of low carbon technologies, such as renewables, to meet our energy needs in an increasingly carbon constrained future. Research looking at the cheapest way to meet this carbon target has found that reducing carbon in the power sector is the first and most urgent action required. The Government's independent advisors on meeting carbon targets (the Committee on Climate Change) recommended that the Government begins by reducing carbon emissions from the power sector by around 90 per cent by 2030. Accomplishing this will entail generating more electricity from low carbon sources, such as renewables, nuclear and fossil fuels with carbon capture and storage. Throughout this transition to a sustainable energy system, electricity must remain affordable and secure.

A common mistake of debate around the role of renewables has been to focus too narrowly on the differing characteristics of individual technologies and not enough on the potential of the system to manage and adapt. Chapter 1 explains how security is a system property rather than a feature of particular technologies. It also shows that the challenges presented by an increasing share of varying renewable generation are not new in nature, only in scale, and can be managed using existing technologies, though new solutions are also likely to be developed.

Chapter 2 considers the carbon and wider environmental impacts of renewables technologies on a life cycle basis. Even on this basis, renewables remain amongst the lowest carbon forms of electricity generation alongside nuclear power and, if developed, fossil fuels or biomass with carbon capture and storage. Bioelectricity has been a particularly debated topic lately as Government developed its policies for managing sustainability risks. The focus of these plans on providing evidence and making transparent the actual practices of the industry and its supply chain will help move the debate forward.

Chapter 3 looks at affordability and shows that this is about more than just the costs of building and running power stations. System costs, carbon prices, risk and macro-economic impacts are also crucial components of affordability. The initial premium paid on reducing the costs of less mature renewables technologies and modest increases to system costs is counterbalanced by the particularly important role of renewables in reducing the UK's exposure to volatile fuel prices and other economic risks as well as helping to stimulate economic growth and improve trade balances.

The final chapter discusses the practicalities of eliciting an 'optimal' mix of technologies for the power sector, balancing our short, medium and long term needs. We find that there is broad support for Government going further to work with industry and academia in unlocking 'low regrets' power sector investments, such as supply chain investments, and that this approach is consistent with the Government's risk appetite and desire for technology neutrality.

Energy is a high stakes game, with consequences for every household, every business and every region in the UK. It is central to our economy, our security and our efforts to tackle climate change. For these reasons, Government will always hold the reins on energy, even when liberalised markets are charged with delivery. Energy will also remain a critical issue for politicians, who have been vocal on the topic throughout parliamentary scrutiny of the Energy Bill. Rhetoric has frequently sought to exploit political divides, often ignoring areas of consensus, which has created political uncertainty. This uncertainty has far-reaching consequences in a sector where infrastructure is built and operated by companies, often with international investment opportunities. Consensus amongst politicians and parties is therefore particularly important in keeping investment flowing and the costs of finance down. Coming as we do from two different parties, we want to highlight the value of acknowledging and building consensus, as the UK sits on the brink of a potentially game-changing period of intense investment in electricity infrastructure.

We are supporting the *Future Electricity Series* and Carbon Connect because they recognise this important point. *Power from Renewables* builds on the precedent set in *Power from Fossil Fuels* for timely and high quality research that makes a valuable contribution to these debates. This report will be followed by a similar report on nuclear power and we look forward to working with you on this over the remainder of 2013.

We would like to thank everyone who participated in this important inquiry, who generously gave their expertise during its course. We would also like to thank the esteemed steering group members for their hard work. Finally, we thank the Institution of Gas Engineers and Managers for their kind sponsorship of the *Future Electricity Series*, Siemens and Dong Energy, whose sponsorship also made this report possible, and Andrew Robertson and Fabrice Leveque at Carbon Connect for compiling the report.

Future Electricity Series Co-Chairs

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EXECUTIVE SUMMARY

Key findings

- Government could do more to narrow the scope of debate about technology mix beyond 2020 by working with industry and academia, first to establish 'low regrets' levels of technology deployment, and second to ensure that policies are in place to incentivise investments needed to deliver these low regrets actions.

- Debate should focus on security as a property of the whole electricity system and individual technologies should be considered in the context of how they add to or reduce system risks.

- Renewables are amongst the lowest carbon forms of electricity generation alongside nuclear power and, if developed, fossil fuels or bioelectricity with carbon capture and storage. This conclusion is consistent with existing evidence on life cycle carbon intensities, taking into account limitations and uncertainties.

- Although increasing support for renewables is likely to be a key driver of higher electricity bills to 2020, there are potentially significant benefits not reflected in bill impact analysis including improved bill predictability, future bill savings and macro-economic benefits.

Security

Chapter 1 discusses how security of supply is a property of the whole electricity system, including its fuel inputs, and individual technologies should be considered in the context of how they add to or reduce system risks. Considered like this, non fuel-based renewables reduce some risks, such as fuel supply risk, and add to others, such as system balancing risks. Expanding non fuel-based renewables can reduce the UK's overall exposure to fuel supply risks by displacing some fuel-based generation. This is also being achieved by diversifying fuels through bioelectricity and diversifying fuel import facilities. Bioelectricity, alongside hydroelectricity and potentially geothermal, offer flexibility similar to that of conventional thermal generation, which can help in system balancing.

New operational challenges arise from the varying output from some renewables. The availability of wind, solar, tidal and wave generation is dependent on prevailing environmental conditions, rather than readily available or storable fuel. However, all are predictable to the extent needed to manage any system imbalances they drive, provided the right system balancing tools are in place. The electricity system is designed to manage constant fluctuations in supply and demand, with a variety tools used to rectify imbalances, including flexible generation, storage, demand side response and generation in other countries via interconnection.

Whereas historically system imbalances were driven primarily by the demand side and resolved by actions on the supply side, increasingly imbalances will be driven and resolved by both the supply and the demand sides. Imbalances are also expected to be larger. The challenges of balancing an evolving electricity system are therefore ones of complexity and scale, but are not new in their nature.

The same system balancing tools used today (flexible generation, storage, demand side response and interconnection) are expected to be capable of managing much higher penetrations of varying renewables, providing their deployment is also increased. The principle challenges are therefore supporting technology development of newer and cheaper versions of existing tools and deploying the right mix of technologies. The best mix of tools is unknown and highly dependent on factors such as future technology costs and the relationship between electricity, heat and transport sectors. These factors are uncertain in the medium and, to a greater extent, the long term.

Sustainability

To achieve the UK's statutory 2050 carbon target, there is consensus that the amount of low carbon generation in the power sector will need to increase significantly, from 30 per cent today to between 72 and 90 per cent by 2030. Chapter 2 highlights that renewables are amongst the lowest carbon forms of electricity generation alongside nuclear power and, if proven, fossil fuels or bioelectricity with carbon capture and storage. This conclusion is consistent with existing evidence on life cycle carbon intensities, taking into account limitations and uncertainties. The carbon emissions saved from varying renewable generation, such as wind, displacing fossil fuel generation substantially outweigh the relatively small carbon penalties incurred in making available and deploying additional system balancing tools. This is likely to remain the case in the future.

Bioenergy has been a much debated topic recently, and provided sustainability risks can be managed, it could also make an important contribution to decarbonisation. Bioenergy could account for around ten per cent of total UK primary energy (currently around two per cent) and reduce the costs of decarbonisation by up to around £44 billion per year in 2050. However, where it is best deployed in the energy sector over the long term role is highly dependent on the availability of carbon capture and storage. Bioelectricity in particular has been debated intensely as Government develops its bioelectricity policy and it is an area where broader consensus would be particularly valuable. The Government's planned introduction of a cap on bioelectricity life cycle emissions is a pragmatic policy response that balances protecting the environment, building public confidence and enabling the sector to develop whilst increasing its contribution to the triple bottom line of energy policy. The introduction of sustainability criteria and plan to review their scope, in addition to reporting and assurance requirements, will help debate to focus on evidence of actual practices whilst building confidence in the emissions reductions and sustainability of bioelectricity.

Chapter 2 also examines the wider sustainability impacts of infrastructure, summarising some of the impacts that renewables infrastructure in particular can have. Environmental impacts are found to be very technology, site and scale specific, with renewables deployment leading to some impacts different in nature and location to other power sector technologies. We also consider the mitigating assessment, permitting and policy frameworks in place to protect the environment and the evolving evidence base that informs implementation of these frameworks.

Affordability

Ensuring that electricity remains affordable is both an economic and social priority. It will also be a crucial factor in determining the future role of renewables technologies, many of which are at an early stage of cost maturity. Affordability is, however, about more than the costs of building and running power stations. System costs, carbon costs, risk and macro-economic impacts are also crucial dimensions. Balanced assessments of costs and benefits are needed across all components of affordability and across different timescales.

Most renewables are currently higher cost than conventional fossil fuel generation. However, many are at an early stage of technology development, and offshore wind, wave, tidal and solar photovoltaic renewable technologies are thought to have a large cost reduction potential between now and 2030. Unabated fossil fuel generation will also become increasingly expensive in a carbon constrained world. Carbon pricing is intended to provide long term confidence to investors in high capital cost, low-carbon technologies. This will help to reduce the cost of investing in these technologies further, and is an important part of the UK's management of climate change risks.

Supporting less mature renewable technologies in the short term lowers the risk of high bills in the medium and long term, by diversifying future low carbon options. Increasing deployment of renewables can also reduce the exposure of UK electricity prices to fossil fuel price risk. This improves the predictability of average electricity prices which evidence shows is a valued component of affordability by consumers. The development and deployment of renewable technologies can also have macroeconomic benefits through employment, inward investment and export opportunities. These potential benefits are often difficult to assess and more evidence is needed to understand them better.

Recent historic energy bill increases were driven by higher gas prices, whereas forecast bill increases are expected to be substantially driven by support for renewables. These additional costs should be considered alongside benefits that include improved bill predictability, future bill savings and potential macro-economic benefits. The UK's electricity prices are also broadly competitive with other countries across Europe and the Government plans to mitigate the risk that forecast price increases reduce the UK's industrial competitiveness. In addition, forecast increases in energy efficiency savings could also more than offset the costs of support for low carbon generation, and carbon costs, between now and 2020. However, the evidence to support this assumption is currently limited.

Deployment

The UK has some of the world's best renewable energy resources, with excellent wind, wave and tidal potential. Evidence suggests that the UK has sufficient practical renewable resources to meet at least a substantial proportion of electricity demand volume, now and out to 2050.

There is a clear pathway to increase the share of renewable generation this decade, with agreed policy support, renewables targets and work being carried out to ensure the network and framework for its operation continue to be fit for purpose. The UK is currently on track to meet the 2020 targets, but this is most contingent on the following factors: planning consents for onshore wind, the success of biomass conversions for bioelectricity, and technology cost reductions for offshore wind and solar photovoltaic. Successful implementation of Electricity Market Reform is also critical.

The strategic direction for the UK power sector after 2020 is contested. Technology costs and carbon abatement ambition look likely to determine the direction of travel. The Government intends to move to competitive auctions between low carbon technologies during this decade, but has yet to provide clarity on what or if a carbon reduction ambition will be set specifically for the power sector for 2030. It has set economy wide carbon budgets up to 2027 and has indicated that existing and planned policies are likely to result in an electricity emissions intensity of around 100 gCO_2/kWh. Carbon budgets are the only near-term indicator, but as they cover the whole economy and have been made subject to a review in 2014, they leave open a wide range of possibilities for the power sector and for individual technologies within it. Consequently, debate about technology deployment in the decade to 2030 has been extremely wide in its scope.

Committing to a strategic direction early risks skewing deployment towards technologies that end up being more costly or setting an unhelpful precedent if commitments are not honoured. Committing to a strategic direction late, however, risks delaying commercialisation and deployment of less mature technologies, reducing the likelihood that these are available for deployment at scale when needed. This also risks forgoing the wider economic benefits of attracting supply chains to the UK, and could lead to higher finance costs for all technologies because of higher policy and political risk. This also runs counter to climate science that emphasises the need for early action due to the cumulative nature of greenhouse gas emissions.

Taking these risks into account, Government could be doing more to provide clarity of strategic direction for the power sector beyond 2020. In particular, more could be done to narrow the scope of debate about technology mix by working with industry and academia, first to establish 'low regrets' levels of technology deployment, and second to ensure that policies are in place to incentivise investments needed to deliver these low regrets actions. This approach is likely to result in earlier and lower cost supply chain investments which secure additional economic benefits and open up additional economic opportunities. The downside risk is limited by only committing to low regrets deployment, until better technology information is available.

A 'low regrets' approach would help provide the longer term clarity to the offshore wind industry that could secure supply chain investments. Without sufficient long term confidence over demand for offshore wind in the UK, it is unlikely that the UK will develop a strong domestic supply chain. Although offshore wind is not currently thought to be the lead contender for providing the bulk of low carbon supply required by 2030, such a policy would increase the likelihood that necessary cost reductions are achieved, and mitigate against the higher costs that would result in the delay or failure to deliver nuclear and carbon capture and storage as currently projected.

LIST OF FINDINGS

SECURITY

Finding 1

Bioelectricity, hydroelectricity and geothermal generation have flexibility properties, useful for responding to system imbalances, similar to conventional generation, such as coal and gas.

Finding 2

The output from wind, solar, wave and tidal generation varies according to different environmental conditions. All are predictable to the extent needed to manage any system imbalances they drive, provided the right system balancing tools are in place.

Finding 3

The electricity system is designed to manage constant fluctuations in supply and demand. The challenge of integrating varying renewables comes from the scale of future supply-side fluctuations, rather than their nature.

Finding 4

Diversifying fuels through bioelectricity and diversifying fuel import facilities both help to manage fuel supply risks. Expanding non fuel-based renewables can reduce the UK's overall exposure to fuel supply risks by displacing some fuel-based generation.

Finding 5

System security risks from wind, solar, wave and tidal technologies are manageable with existing technologies, including demand side response, storage, flexible generation and interconnection. These same system balancing tools are capable of managing much higher penetration of varying renewables, providing their deployment is also increased.

Finding 6

The optimal mix of system balancing tools is dependent on technology costs and deployability, and the nature of future system imbalances. All these factors are uncertain in both the medium and to a greater extent the long term. The principle challenge is therefore putting in place policy to support the development of a number of technologies and the deployment of the right technologies when it becomes more apparent what those are.

Finding 7

Debate should focus on security as a property of the whole electricity system. Individual technologies should be considered in the context of how they add to or reduce system risks. Considered like this, renewables reduce some risks, such as fuel supply risk, and add to others, such as system balancing risks. Overall, the additional risk is manageable using existing technologies, though new solutions are also likely to emerge.

SUSTAINABILITY

Finding 8

Renewables are amongst the lowest carbon forms of electricity generation alongside nuclear power and, if developed, fossil fuels or bioelectricity with carbon capture and storage. This conclusion is consistent with existing evidence on life cycle carbon intensities, taking into account limitations and uncertainties.

Finding 9

The carbon emissions saved from varying renewable generation, such as wind, displacing fossil fuel generation substantially outweigh the relatively small carbon penalties incurred in making available and deploying additional system balancing tools. This is likely to remain the case in the future.

Finding 10

Measuring and publishing the carbon emissions attributable to system balancing activities in the Government's annual Digest of UK Energy Statistics would help to monitor and communicate their relative significance as the system balancing challenge changes in coming decades.

Finding 11

As well as ensuring the UK Forestry Standard reflects the latest research on sustainability impacts of forestry practices, policy should ensure that imported woody biomass is derived only from forests that are managed to standards at least as robust as domestic standards.

Finding 12

The Government's planned introduction of sustainability criteria and requirements for reporting and assurance will help industry to demonstrate the sustainability of current and future biomass production practices more transparently and accessibly.

Finding 13

The introduction of a cap on bioelectricity life cycle emissions of 285 $gCO2/kWh$ in April 2015 (reducing to 180 $gCO2e/kWh$ by April 2025) will help ensure that emissions from bioelectricity are substantially lower than unabated fossil fuels. It is a pragmatic policy response that balances protecting the environment, building public confidence and enabling the sector to develop whilst increasing its contribution to policy objectives.

Finding 14

For some indirect risks, preventative policy may not be practical. If so, Government should consider identifying and monitoring indicators of indirect impacts such as land-use change or market dynamics.

Finding 15

The environmental impacts of renewable technologies are sometimes different in quality and location from other power sector technologies but existing frameworks for assessment and decision-making are adaptable to meet these novelties. New research is coming forward to evidence and explain where novel environmental impacts have been identified and mitigation strategies are being developed.

AFFORDABILITY

Finding 16

Offshore wind, wave, tidal and solar photovoltaic renewable technologies are thought to have a large cost reduction potential between now and 2030, however, recent experience and analysis have shown that the impacts of hard-to-predict and uncontrollable factors will always present significant risks to forecasts.

Finding 17

Varying renewables deployment, like other low carbon generation, will create additional network infrastructure costs, which are expected to contribute to some of the expected 20 per cent increase in overall network costs by 2020.

Finding 18

Increasing the share of varying renewable generation will add modestly to network balancing costs. The additional cost at 20 per cent penetration of wind is estimated to add between three and five per cent to electricity prices.

Finding 19

Increasing deployment of renewables can reduce the exposure of UK electricity prices to fossil fuel price risk. This improves predictability of average electricity prices which evidence shows is a valued component of affordability.

Finding 20

Part of the value in supporting less mature renewable technologies in the short term is that it lowers the risk of high bills in the medium and long term. This value is not reflected in levelised cost analysis or in analysing the electricity bill impacts of revenue support for low carbon technologies. It is nevertheless an important component of affordability.

Finding 21

The development and deployment of renewable technologies can have macroeconomic benefits through employment, inward investment and export opportunities. These benefits are difficult to assess and more evidence is needed to understand them better.

Finding 22

The UK's electricity prices are broadly competitive with other countries across Europe and the Government plans to mitigate the risk that forecast price increases, mainly driven by support for low carbon generation, reduce the UK's industrial competitiveness.

Finding 23

Recent historic energy bill increases were driven by higher gas prices, whereas forecast bill increases are expected to be substantially driven by support for renewables. However, increases to energy efficiency savings could more than offset increases in support for low carbon generation and carbon costs between now and 2020. Evidence to support assumed success of energy efficiency policies is, nevertheless, limited.

Finding 24

Although increasing support for renewables is likely to be a key driver of higher electricity bills to 2020, there are potentially significant benefits not reflected in bill impact analysis including improved bill predictability, future bill savings and macro-economic benefits.

DEPLOYMENT

Finding 25

Taking account of uncertainties, evidence suggest that the UK has sufficient practical renewable resources to meet at least a substantial proportion of electricity demand volume, now and out to 2050.

Finding 26

There is a clear pathway to increase the share of renewable generation this decade, with agreed policy support, renewables targets and work being carried out to ensure the network and framework for its operation are ready.

Finding 27

The UK is currently on track to meet the 2020 targets, but this is most contingent on the following factors: planning consents for onshore wind, the success of biomass conversions for bioelectricity, and technology cost reductions for offshore wind and solar photovoltaic.

Finding 28

The Government expects that nuclear power is likely to provide the majority of additional low carbon electricity between 2020 and 2030. However, should costs or deliverability prevent this from happening, more low carbon electricity from renewables or fossil fuels with carbon capture and storage will be needed to meet carbon objectives.

Finding 29

Should other low carbon technologies (nuclear, fossil fuels with carbon capture and storage) fail to be delivered as currently expected, renewables could provide between 45 and 55 per cent of total generation by 2030.

Finding 30

Government could do more to narrow the scope of debate about technology mix beyond 2020 by working with industry and academia, first to establish ‘low regrets’ levels of technology deployment, and second to ensure that policies are in place to incentivise investments needed to deliver these low regrets actions.

Finding 31

The best technology mix and size of the power sector beyond 2030 are highly uncertain, mainly due to unknown future technology costs and unknown future electricity demand, itself dependent on the extent to which heat and transport sectors are electrified.

Finding 32

If a high proportion of renewables transpires to be favourable beyond 2030, offshore wind, marine, solar and possibly bioelectricity are likely to be the technologies offering highest deployment potential.

Finding 33

Bioenergy across the energy sector could reduce the cost of meeting the 2050 carbon target by £44 billion per year by 2050 if a) carbon capture and storage technology is commercialised, giving the possibility of negative emissions, and b) adequate feedstocks can be sustainably sourced.

METHODOLOGY AND STEERING GROUP

Carbon Connect carried out this inquiry between May and September 2013. Evidence was gathered by a conference held in Westminster on 15 May 2013, interviews with those working in and around the sector, written submissions, desk-based research and input from our steering group of industry and academic experts. The views in this report are those of Carbon Connect. Whilst they were informed by the steering group and listed contributors, they do not necessarily reflect the opinions of individuals, organisations, steering group members or Carbon Connect members.

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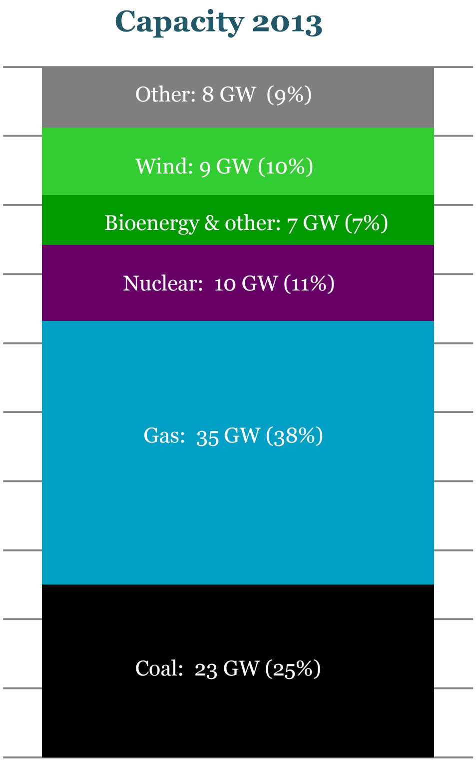
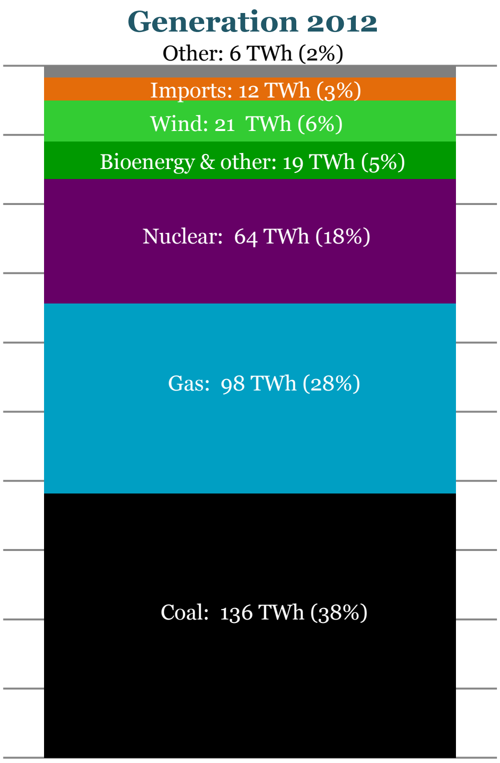
KEY NUMBERS



Total capacity:

92 GW

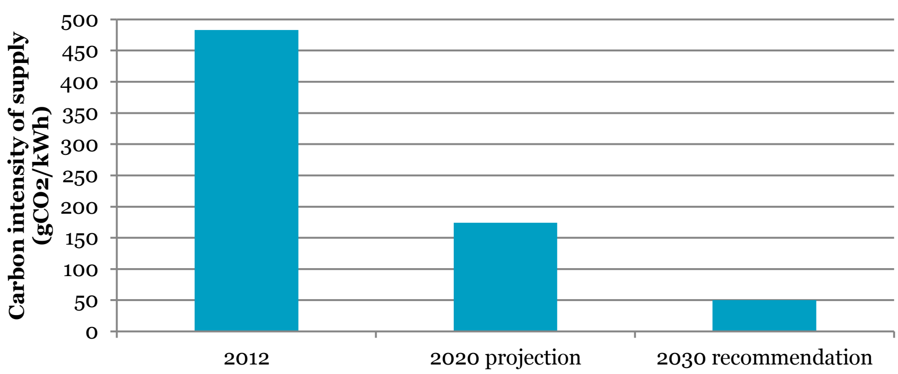


Total generation:

355 TWh

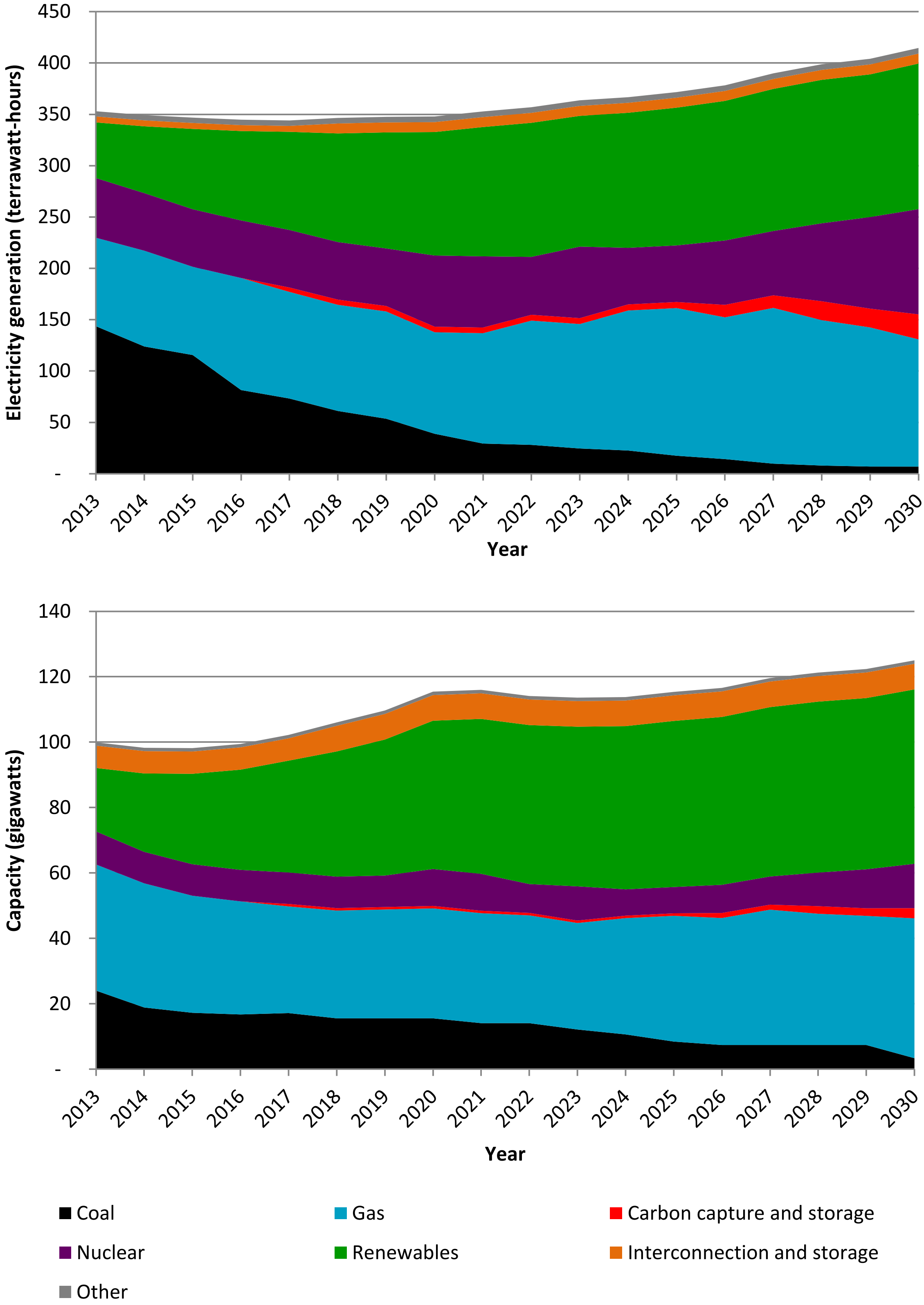
Notes:
1) GW is gigawatts
2) TWh is terawatt-hours
3) Bioenergy & Other: includes solar and marine
4) Other includes gas turbines, oil, and other thermal CHP
3) Capacity is Declared Net Capacity (not de-rated) and includes embedded generation
4) Generation is electricity supplied net of electricity used in generation (Source: DECC Energy Trends)

Carbon intensity of electricity supply 2012-2030



Notes:
1) 2012 (DECC) Digest of United Kingdom Energy Statistics
2) 2020: Carbon Connect projection based upon DECC Energy and Emissions Projections (central projection)
3) 2030 is the carbon intensity recommended by the Committee on Climate Change ('around 50 gCO2/kWh')

DECC central projection of electricity generation and capacity by source



Source: Department of Energy and Climate Change, Energy & Emissions Projections (October 2012)

Notes: 1) Electricity generation is gross generation less the amount of electricity used on station sites (own use)
2) Capacity is installed capacity of all electricity producers including combined heat and power and autogenerators
3) DECC is Department of Energy and Climate Change

1. SECURITY

We take for granted that power is always available and ready when we need it. A widespread interruption to supply can cause significant social and economic disruption. Security is provided by ensuring that risks to operational and fuel supply security are properly managed. Historically, electricity has not been easily storable at scale, and must therefore be generated as and when it is needed. The electricity system functions by keeping supply from power stations equal to demand as it varies throughout the day, week and seasons. In contrast to conventional power generation, many renewables will generate according to prevailing weather conditions, rather than demand. This chapter examines to what extent this novel nature of some renewables adds to or reduces these risks.

Characteristics of security

There are a variety of risks to the continued and stable operation of the electricity system, ranging from the physical (power station failure or weather events), price (volatility in the price of key inputs such as fuel) and geopolitical (external risks to fuel supply). These risks must be minimised and managed to ensure continued security of supply. Understanding individual risks related to technology or fuel is useful, but ultimately, it is the ability of the system to handle these risks that will determine how secure it is. Electricity supply is the result of the operation of the whole electricity system (markets, generation and networks), and therefore it is the effect of renewables on overall system performance that is of most relevance to an assessment of electricity supply security.

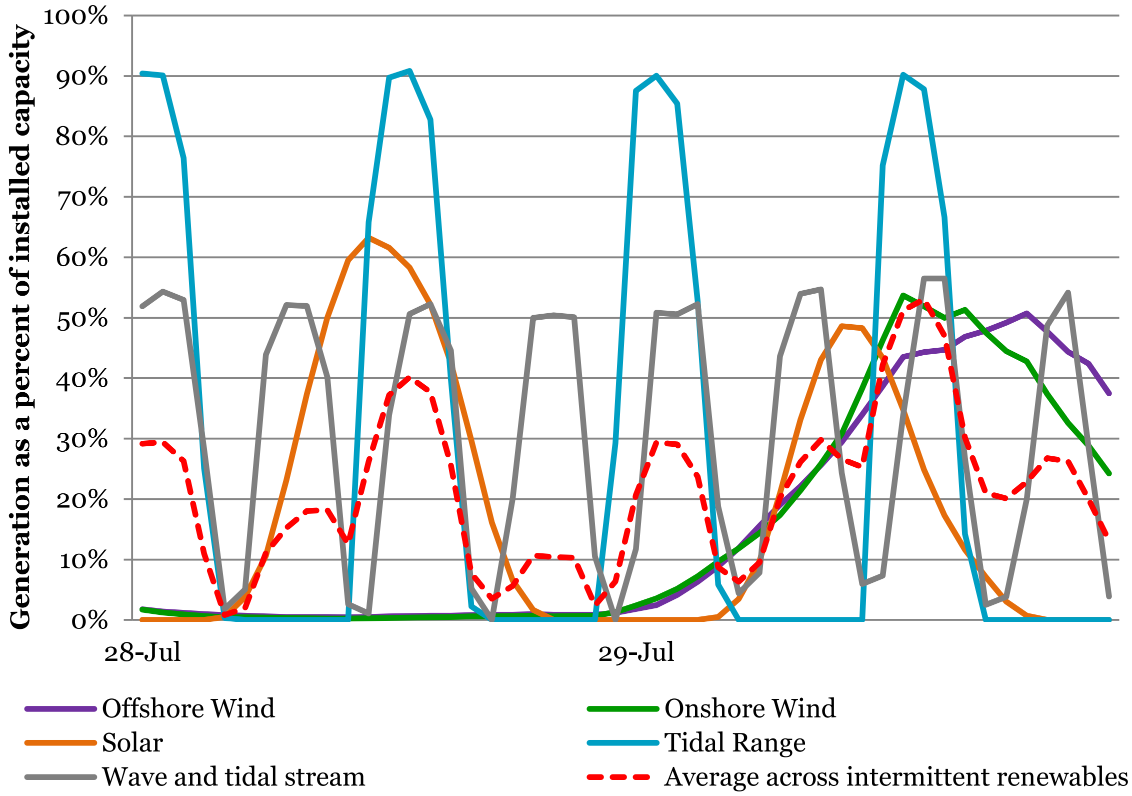
Perhaps the greatest challenge to system security posed by renewable generation is the varying nature of output from wind, solar and marine generators. This will have an impact on the operation of the network, markets and other generators. A crucial question is therefore whether, and to what extent, renewable generation can form part of a secure and reliable system. This chapter considers the security of renewables over three key operational timeframes: moment-to-moment, daily and seasonal variations. Fuel supply is also a key consideration, as fossil fuel and nuclear power stations, which today provide the majority of electricity supply, are reliant on a stable supply of fuel to operate.

What is the nature of power from renewables?

The availability of wind, solar, tidal and wave generation is dependent on prevailing environmental conditions, rather than readily available or storable fuel. The output of these varying generators is predictable to a certain degree, but is largely outside the control of power station owners or system operators. There are two key characteristics of note for integration to the electricity network. Varying output (determined by environmental conditions) impacts grid management over all timescales, as well as longer term system planning. Second, predictability is important as this will be used to manage varying supply onto the network. Predictability varies between technologies.

Wind energy can be predicted several days in advance, with accuracy improving as the timeframe draws nearer. Output from solar generation is dependent on the amount of solar radiation, which follows known daily and seasonal patterns, but will vary with predictable daily weather patterns (cloud cover, temperature). Tides are predictable, and the output from tidal range and tidal stream devices (usually underwater turbines mounted on the sea floor) is similarly so. Power generated from waves will be less predictable. Figure 1 illustrates the supply profile of different renewable generators over two days in summer.

Figure 1: Variation of renewables generation technologies (over two illustrative days for 2030 mix)



Source: Committee on Climate Change (2011) The Renewable Energy Review

Notes: 1) Committee on Climate Change Analysis based on modelling by Poyry
2) Based on observed patterns 28-29 July 2006, scaled up to 2030 levels. Chart shows the generation that would be produced by the different renewable technologies (as a percentage of installed capacity) in the Poyry Very High scenario over a two-day period.

The average output (shown in red) shows a lower degree of variation, and illustrates how overall variability can be reduced across a diverse portfolio of technologies. Average variability across many geographically dispersed sources will also be lower than intermittency at individual sites, as wind and cloud patterns will tend to vary by region. However, if technologies cluster in resource rich areas, variability over local networks may be increased[1]. Seasonal patterns of output can also be correlated to patterns of demand. Analysis indicates that average monthly wind speeds are highest in winter, coinciding with the period of highest electricity demand[2]. Output from hydroelectricity, which varies according to rainfall, is also higher during winter[3].

It is important to note that not all renewables have varying output. Bioelectricity and geothermal power stations have similar operational characteristics to conventional thermal plant, and can be operated in a similar flexible fashion. Coal power stations converted to burn biomass have a similar ability to provide flexible generation as

[1] UKERC (2006) UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network
[2] CCC (2011) Renewable Energy Review
[3] DECC (2010) Pathways to 2050

conventional coal plant, with plant combusting biogas (produced for example from anaerobic digestion) having similar capabilities to conventional gas power stations[4]. Some hydroelectric generators can also be operated flexibly.

Finding 1

Bioelectricity, hydroelectricity and geothermal generation have flexibility properties, useful for responding to system imbalances, similar to conventional generation, such as coal and gas.

The output profile of varying renewable generators (wind, solar, marine) contrasts to that of conventional thermal generation (coal, gas, bioelectricity), which is designed to provide supply when called upon, a characteristic around which the electricity system was designed. Upstream storage of coal, gas and biomass provides the means to control and vary these power stations and use them to follow changes in demand. In contrast, in the absence of low-cost bulk energy storage, power from non fuel-based renewables must be used when it is available. With no fuel costs, these have very low marginal costs, and therefore displace other forms of generation in the market when available. Flexible generation (coal, gas, bioelectricity) and other system balancing tools (storage, interconnection and demand side response – see Figure 2) will therefore be required to adapt to changing supply from varying renewables. This will create additional challenges in the electricity market, as well as system operation. As this chapter will later discuss, however, output from varying sources is predictable to the extent that will allow management of any system imbalances they drive.

Finding 2

The output from wind, solar, wave and tidal generation varies according to different environmental conditions. All are predictable to the extent needed to manage any system imbalances they drive, provided the right system balancing tools are in place.

Operational challenges, fuel security benefits

Varying renewables may create challenges to the secure operation of networks and markets, but their deployment will also displace fuel-dependent generation, reducing exposure to potential fuel supply risks. Fossil fuel power stations require a large throughput of fuel to operate, requiring adequate transport and storage infrastructure. Nuclear power stations require a relatively small quantity of uranium for fuel, although the nature of this material creates additional security concerns. Bioelectricity generators will also be dependent of the security of their fuel supplies. Fuel supply chains are complex, and subject to varying degrees of risk depending on the sources, routes and costs of the resources. Whilst the UK's domestic production of coal and gas has declined in recent years, the concomitant increase in import infrastructure has diversified potential import routes, helping to increase overall supply security. Storage of coal, gas and biomass at volume is also possible, and can provide an insurance against short term interruptions to supply.

Whilst the ability to store these fuels reduces short term risks, supply over the long term is increasingly dependent on the UK's ability to import coal by ship, and gas via pipelines or ship. Fuel to meet increasing bioelectricity production is also likely to rely predominantly on imports, due to limited current domestic feedstock production[5]. However, there remain geopolitical risks to regional and global supplies that fall largely outside the control of the

[4] DECC (2012) Electricity System: Assessment of Future Challenges - Annex
[5] DECC (2012) Bioenergy Strategy – Analytical Annex

UK Government, which can present an additional risk. These risks can be complex and will evolve over time with, for example, domestic production of unconventional (shale) gas potentially offsetting declines in conventional gas production.

Reducing dependence on complex fossil fuel supply chains will reduce exposure to potential fuel supply risks. These benefits may, however, be offset by the degree of additional operational risk created by integrating varying renewables on the network. Changes will need to be made to both systems and markets to maintain system security. As we show in the rest of this chapter, however, risks arise from the scale, rather than the unprecedented nature, of these challenges. Provided adequate measures are in place, system security can be maintained as the penetration of renewables increases, reducing exposure to fuel supply risk when this occurs. Exposure to fuel price volatility will also be reduced, which can be caused by disruptions to supplies. These benefits are assessed in chapter 3.

Finding 3

The electricity system is designed to manage constant fluctuations in supply and demand. The challenge of integrating varying renewables comes from the scale of future supply-side fluctuations, rather than their nature.

Finding 4

Diversifying fuels through bioelectricity and diversifying fuel import facilities both help to manage fuel supply risks. Expanding non fuel-based renewables can reduce the UK's overall exposure to fuel supply risks by displacing some fuel-based generation.

A renewables dominated system

Looking further ahead, an electricity system dominated by renewables (over 50 per cent supply) would require additional measures to shift supply (storage or interconnection) or demand (demand side response) to different times. This is because the peak output of most technologies may not necessarily correlate to peak demand, creating periods where demand exceeds supply (most likely in winter) and vice versa. Shortfalls in supply can be mitigated by alternative forms of generation, such as conventional power stations kept in reserve, whilst excess supply can be reduced by asking some generators to stop producing. However, costs will be incurred by keeping plant in reserve as well as the value of foregone generation. Many of the tools to maintain a balanced electricity supply are in use today, but would require significant expansion to manage the magnitude of supply variability in a renewables dominated system[6].

[6] Poyry (2011) Analysing Technical Constraints on Renewable Generation to 2050

Figure 2: Non-generation options for flexibility

Managing the electricity system requires a variety of tools to deal with different requirements across different timescales. As well as flexible thermal generation (coal, gas, bioelectricity), a variety of non-generation tools are also used:

Energy storage

Bulk storage in the form of pumped hydro is used to provide rapid response at times of system stress and peak demand, rather than output over prolonged periods of time. The UK currently has 2.7 gigawatts of capacity, although investment in additional capacity is currently thought to be unlikely. Other large scale technologies exist, but are at an early stage of technical development. These include grid-scale batteries, thermal storage, fly wheels, compressed air and conversion of electricity to hydrogen. These technologies could provide additional options to manage short term fluctuations as well as dispatchable supply. In the longer term, the storage ability of small appliances spread across the network, such as electric vehicle batteries and hot water storage combined with electric heat pumps could be cost effective[7], and help shift or smooth demand peaks, again over short to medium time periods.

Interconnection

The UK is connected to the electricity networks of France, the Netherlands, The Republic of Ireland and Northern Ireland, with a combined capacity of four gigawatts. These allow both the import of electricity at times of high demand, and export at periods of high supply. There is significant potential to expand interconnection, with estimates suggesting that the UK could have between 16 and 35 gigawatts by 2050[8,9]. Projects include additional links to the Republic of Ireland to import wind energy, and a North Sea 'supergrid' extending offshore wind farm connections between the UK, Scandinavia and Germany. Over shorter timescales interconnection is likely to provide system security benefits by providing a cost effective means of supplementing supply, or exporting surpluses. However, impacts on security during longer low output timeframes could be negative, as higher electricity prices in neighbouring countries could result in exports during these periods. Research suggests that a co-ordinated increase in integration and interconnection of electricity markets across Europe could be a key enabler in maintaining or improving overall electricity supply reliability[10]. The construction of dedicated interconnectors to wind power in Ireland, nuclear in Sweden or geothermal generation in Iceland could also mitigate reliability concerns.

Demand side response

Demand side response is the active reduction of electricity consumption, usually to shift demand from high cost periods to lower cost ones. This is currently contracted from large industrial and commercial users in the balancing mechanism, but could also be expanded to provide demand shifting on longer time scales. The Government plans to hold separate auctions alongside the capacity mechanism to contract additional services. In longer term, the roll out of smart meters and smart appliances could allow domestic demand side response to develop in the 2020s in conjunction with electric vehicles and heat pumps. The development of demand side response will provide many benefits beyond the simply the management of varying supply. Allowing consumers greater control over their consumption will provide greater means to control costs, as the use of certain appliances could be moved to lower cost periods.

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[7] Imperial / Nera (2012) Understanding the Balancing Challenge
[8] CCC (2011) Renewable Energy Review
[9] European Climate Foundation (2010) Roadmap 2050
[10] European Climate Foundation (2010) Roadmap 2050

Demand reduction

Investing in energy efficiency to achieve permanent reductions in demand can help reduce peak demand, which would help manage the risks arising from low renewables output coinciding with peak winter demand. Evidence suggests that it is cheaper, on a per unit basis, to invest in electrical efficiency, than to pay for additional generating capacity. Energy system models used to indicate the most cost effective pathways to reduce energy system carbon emissions consistently show that it is cheaper to achieve large reductions in energy demand through efficiency and conservation technologies than to provide an equivalent level of low carbon supply, across all scenarios[11]. The Government estimates that by 2030, there could be up to 32 terawatt hours of electricity demand reduction potential that is not incentivised by current policies, a reduction of nine per cent on predicted total demand, or the equivalent output of four large power stations. Government has proposed to run trial auctions for demand reduction alongside the capacity mechanism, which may help unlock some of this potential.

Short term alterations to the voltage of electricity (voltage optimisation) is currently used by National Grid at times of system stress to reduce demand. Voltage optimisation could also be used at the level of consumers, both commercial and domestic, to reduce demand. Experience has shown that savings of around five to ten per cent are possible depending on the characteristics of the consumer fitting the equipment[12].

System security

Increasing deployment of varying renewables (wind, solar, marine) will introduce greater supply-side variability. This has an impact across the three main timeframes over which the electricity system is operated and managed, which is analysed in the following section. The effects of renewable deployment in 2020 are considered, when 20 to 30 per cent of total capacity is likely to be varying generation (wind, solar, marine). The implications of greater deployment beyond 2020 are also considered.

The electricity system is operated by ensuring that supply matches demand at all times. Demand follows predictable daily, weekly and seasonal patterns, and power stations are contracted through the electricity market to provide supply to match. A variety of factors can cause an imbalance between supply and demand, ranging from market errors to power station outages, and must be managed to ensure a secure and stable supply to consumers.

- **Short term: one hour before delivery;** risks from anticipated and unexpected changes in supply and demand during the final hour before delivery are managed by keeping a proportion of capacity in reserve, which is able to adjust supply and demand rapidly (seconds to minutes) on request.
- **Medium term: commitment and dispatching;** electricity demand fluctuates significantly over the course of a day, and output from flexible generation and non-generation tools is adjusted to follow these changes.
- **Long term: system planning;** demand also varies over the seasons. Peak demand in winter can be up to 45 per cent higher than in summer[13]. A sufficient margin of generating capacity must be maintained over and above peak demand, to provide

[11] UKERC (2013) The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios
[12] https://www.ofgem.gov.uk/ofgem-publications/58457/energy-saving-trial-report-vphase-vx1.pdf
[13] National Grid (2011) NGETS Seven Year Statement

contingency should some power stations be unavailable (through maintenance or unexpected outages) when needed.

We now look at the effect of integrating varying renewables on each timeframe of system operation to consider their impact on overall system security.

Short term: one hour before delivery

Wind speeds can fluctuate, and solar output can dip and surge as clouds pass overhead. The precise output from wind, solar, wave and tidal generators can therefore be variable from moment to moment. The electricity system is well placed to manage these variations, however. Actual levels of supply and demand fluctuate continuously, and it is the job of the system operator, National Grid, to manage these. Although the electricity market will schedule generation to match forecast demand, reserves must be maintained to cover for unexpected variations in supply or demand as the moment of delivery draws closer. Differences occur through imperfect allocation by the markets, errors in predicting demand, and unexpected power station outages.

Unexpected changes during this final hour are managed through a variety of tools. Rapid adjustments to adjust supply up or down are provided by automatic controls on operating power stations that can respond in seconds, demand reduction from industrial and commercial users, and by fast responding 'peaking plant' such as open cycle gas turbines or back-up diesel generators that can be ready within 20 minutes. The amount of reserves contracted will depend on three principle risks: the capacity of the largest single generator that could fail, the expected availability (probability) of all conventional plant on the system and a given amount of demand prediction errors[14].

Increasing the volume of varying generation on the system will increase the size of differences between predicted and actual output, and will therefore require an expansion of the reserves held to manage these. The challenge from varying renewables in this timeframe is therefore quantifiable. For example, it is estimated that 0.3 megawatts of reserve is required for each additional megawatt of wind capacity added to the system[15]. Wind deployment is expected to reach around 25 gigawatts by 2020, and the amount of reserve required to manage this is expected to increase from 4.7 to 7.3 gigawatts between now and 2020/21[16]. Further improvements in wind forecasting will reduce forecast errors, reducing the proportion of capacity that is needed in reserve. There are a range of additional measures that could play a role in future. Newer wind turbines can reduce their output rapidly on demand and include in-turbine storage[17]. Megawatt-scale batteries are currently in testing, and will be able to fulfil many reserve requirements such as rapid delivery. Demand side response could also be expanded, potentially providing a lower carbon solution than the operation of peaking plant.

Medium term: commitment and dispatching

Electricity demand undergoes large swings over the course of a day, increasing rapidly in the morning, peaking in the early evening before falling away to an overnight low. Figure 3 below illustrates typical daily demand profiles across different seasons. Fluctuations are greatest in winter, when demand can increase by up to 35 per cent (approximately 13 gigawatts) over the course of several hours between early and late morning[18].

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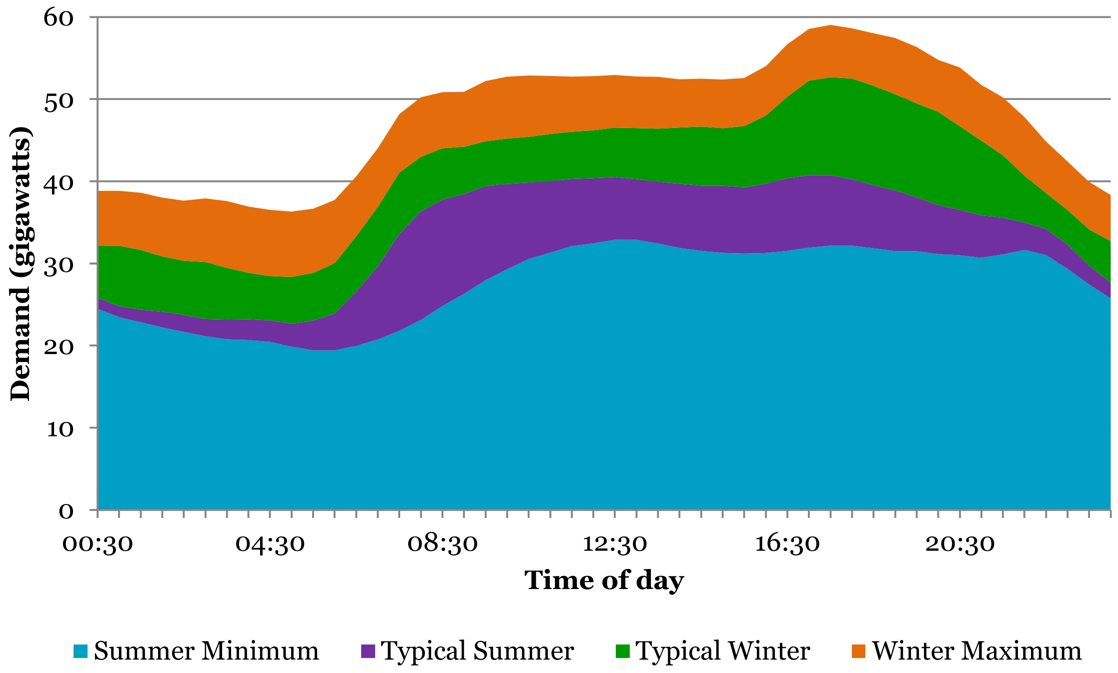
[14] UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network
[15] UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network
[16] National Grid (2011) Operating the Electricity Transmission Networks in 2020
[17] http://www.greentechmedia.com/articles/read/GE-Adds-Energy-Storage-To-Its-Brilliant-Wind-Turbine
[18] National Grid (2011) NGETS Seven Year Statement

Figure 3: Summer and winter daily demand profiles in 2010/11



Source: National Grid (2011) Seven Year Statement

How is this currently managed?

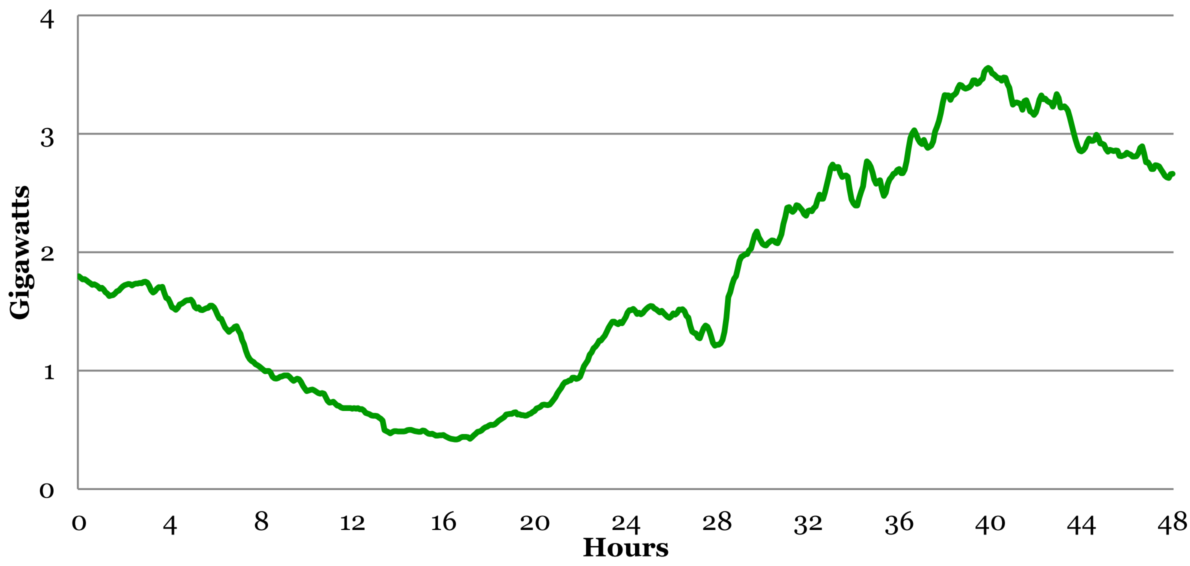
Supply in this timeframe is allocated by the market, with flexibility provided by power stations able to adjust their output over the course of a several hours. Generators will be brought on and offline to match demand, and must be able to vary their output as well as be able to start or stop operation according to need. These properties vary by type of generation. Some, such as nuclear, cannot start or stop easily, nor flex their output, and so are therefore committed to running constantly (baseload). Coal power stations can vary their output, although stop/start operation is avoided if possible[19]. Bioelectricity generators can also be operated flexibly. Unabated gas power stations are the most flexible of conventional technologies. These are able to start up rapidly as well as vary their output. Additional non-generation technologies are also used to manage demand requirements in this timeframe (see figure 2). Pumped hydro storage is often used to store energy from periods of low demand (and low prices) at night for release at peak demand in the evening[20]. Electricity is also imported or exported from neighbouring countries via electricity interconnectors. Shortfalls in contracted supply will be managed through the actions of the system operator ahead of delivery. In the longer term, the electricity market must ensure that there is sufficient flexible capacity to meet patterns of demand.

What effect do varying renewables have?

Power from varying renewable generators will fluctuate over the course of day, although the extent to which will vary by technology. The nature of output from wind generators over the course of two days is illustrated in Figure 4.

[19] UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network
[20] National Grid (2011) NGETS Seven Year Statement

Figure 4: Wind generation, 48 hour period



Source: Elexon (2013) http://www.gridwatch.templar.co.uk/download.php
Notes: Wind generation from 02/12/12 – 03/12/13

Output from varying generators, such as wind turbines, is used when it is available, and displaces conventional forms of generation due to the low marginal costs of these plants. As varying renewables are added to the system, existing flexible generation and non-generation tools will have to adjust their output in response. Today, flexible generators adjust their output mainly in relation to demand. In future, output from these power stations will need to be adjusted to both variations in demand *and* supply.

How can this be managed?

Supply from varying generators can be forecast in advance, allowing the market and system operator to commission flexible generation and other tools ahead of time[21]. Risks arising from varying supply in this timeframe will largely arise from errors in forecasting, which are being reduced as technology improves[22], and changing patterns of electricity flow across the network. As the share of varying renewables on the network increases, generation scheduling and network management will become more complex, whilst flexible generation and non-generation capacity will need to operate more flexibly[23]. Changes in both network and market operation will be required, but provided adequate reforms are made, there is no reason that electricity system operation over this timescale should be any less secure than it is today.

Wind generation currently accounts for approximately 12.5 per cent of total installed capacity, with no negative effects on operational reliability. By 2020, varying generation is likely to account for 20 to 30 per cent of total capacity. The increased magnitude of variations in supply will require that existing flexible generation[24], as well as interconnection and pumped hydro storage, operate more flexibly. Whilst this may have impacts on individual power station reliability (older coal and gas power stations are not designed for very flexible operation), risks arising from decreased power station reliability

[21] Poyry (2010) Options for low-carbon power flexibility to 2050
[22] National Grid (2011) Wind Power Forecasting; Presentation slides by David Lenaghan, Senior Forecasting Analyst
[23] DECC (2012) Electricity System: Assessment of Future Challenges - Annex
[24] DECC (2012) Gas Generation Strategy

will be managed using existing short term reserves. In future, domestic demand side response and distributed storage could allow the shifting of both supply and demand to facilitate grid balancing in this timescale. These solutions could be particularly cost effective should electricity demand rise due to the electrification of heating and transport, by reducing the need for additional network reinforcement[25].

Higher renewables deployment

As deployment increases, the capacity of options to provide flexibility will need to increase. This is likely to require that retiring coal and gas plant are replaced by newer, more flexible units. Increased interconnection will also provide capacity to manage both low and high output from varying renewables. The greatest challenge will be ensuring that the market incentivises sufficient flexible capacity, which is explored in the following section (system planning).

Further risks in a high deployment scenario are, as the share of varying capacity reaches over 50 per cent, instances where total supply from varying and inflexible (nuclear) supply exceeds demand. This risk is currently managed by requiring that some generators reduce, or curtail output. This is a cost, rather than a security risk, as foregone generation has a value. The volume of lost generation could be decreased by investing in measures to save excess energy for use at different times (storage), and tools to adjust demand (demand side response). Interconnection can help manage both these scenarios, by allowing exports at times of excess power, and imports when supply from varying renewables is low. The Committee on Climate Change has modelled an illustrative scenario of how these risks could be managed with a 50 per cent renewables mix in 2030. It projects that system security could be maintained with up to 15 per cent of demand made responsive, 16 gigawatts of interconnection, four gigawatts of bulk storage as well as backup capacity from flexible generation[26]. There are a variety of practical and economic barriers, however, that would need to be overcome in order to realise this scenario[27]

Long term: system planning

Deployment of varying renewables will also have a significant impact on the long term planning and operation of the electricity network and markets. Demand varies between seasons, with maximum peaks in winter typically double (60 gigawatts) of those in summer (30 gigawatts). As figure 4 above illustrates, absolute peak demand occurs in winter, during the early evening. To ensure reliable supply, a margin of system capacity must be maintained over and above peak demand. This provides contingency should plants be taken out of service, break down or when demand is higher than anticipated. This requires that electricity markets deliver enough capacity, and given the long lead time of energy infrastructure, requires planning several years in advance. So-called ‘capacity margins’ are monitored several years ahead by the System Operator, regulator and Government.

What effect do varying renewables have?

The size of the capacity margin is calculated as the excess of available generation capacity in relation to peak demand. The contribution of power stations to system capacity is now calculated according to the probability that they will be operating at times of peak demand. Varying generation provides a smaller contribution to the system’s capacity margin than conventional generation, as there is an increased likelihood that it is not operating during a period of peak demand. As a result, there must be more installed capacity on the network than there would otherwise be without varying generation. Whilst this is not an operational constraint, risk arises from the fact that current market

[25] Imperial / Nera (2012) Understanding the Balancing Challenge
[26] CCC (2011) Renewable Energy Review
[27] Energy Research Partnership (2012) Delivering Flexibility options for the energy system: priorities for innovation

arrangements may not incentivise enough capacity[28]. This is because some additional capacity will not be required to operate many hours, as it will mainly provide capacity for periods of system stress. Marginal plant may not generate enough revenue to cover their running costs, and as a result may close. A failure to provide sufficient capacity would increase the risks that peak demand cannot be met, should this coincide with a period of low output from varying generators.

How can this be managed?

This risk to system security arises from market arrangements rather than operational constraints. In theory it can be addressed by providing payments to reward the value of capacity 'services' provided by flexible generators. These payments can be considered an additional cost of integrating varying generators onto the network, an issue that is explored further in chapter 3. The Government has proposed to introduce a Capacity Market, which will incentivise supply and demand capacity to remain in operation, ready for periods of peak demand.

The risks that insufficient capacity is brought on by the market will increase as the share of varying generation on the network rises, and the Government currently expects to contract for capacity for delivery in 2018/19[29]. In theory, all types of flexible generation and non-generation tools such as energy storage, interconnection and demand side response will be able to provide capacity. A diverse set of options is likely to be needed according to the duration and speed of the response required, and the time of year that it occurs[30].

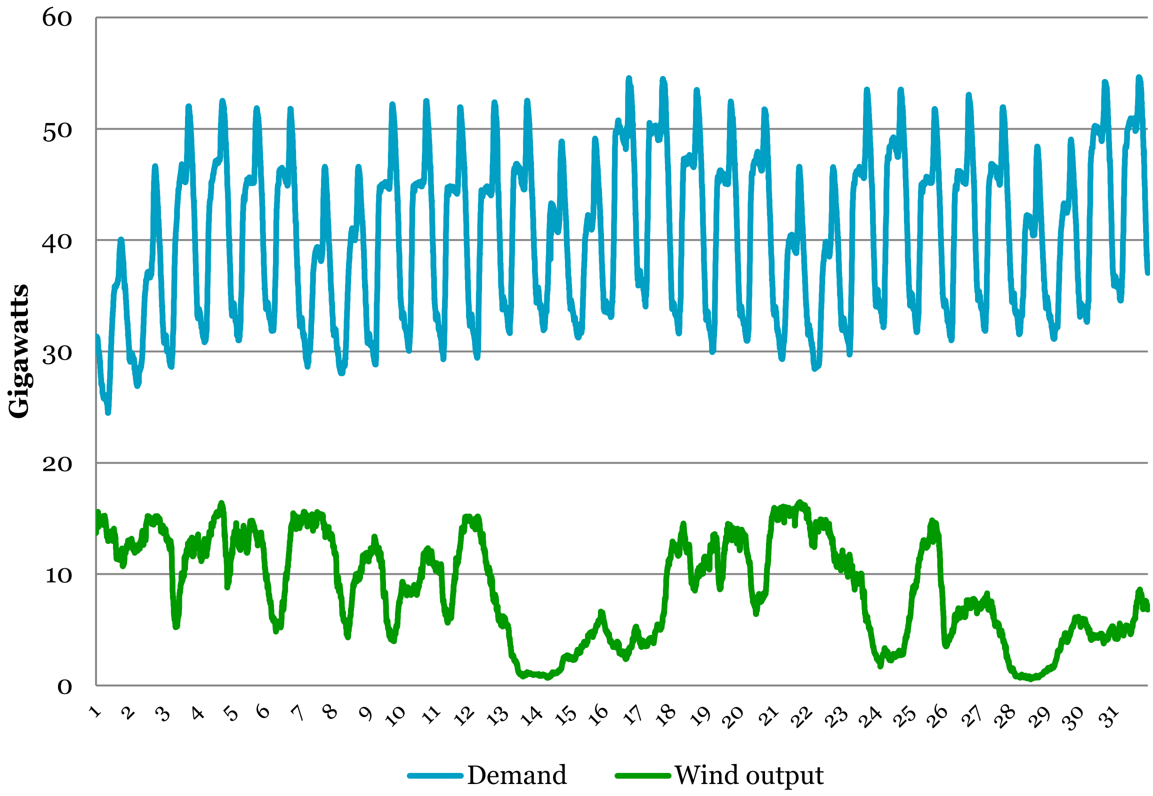
Investing in electrical efficiency could also be a cost effective way to reduce peak demand, and is thought to be cheaper than paying for equivalent generation capacity[31]. The Government estimates that by 2030, there could be up to 32 terawatt hours of electricity demand reduction potential that is not addressed by current policies, a reduction of nine per cent on predicted total demand, or the equivalent output of four large power stations[32]. As a result, it intends to run auctions for permanent electricity demand reduction, achieved through energy efficiency, alongside the Capacity Market. Separate auctions will also be held for demand side response, in both cases to encourage the technical and commercial development required before these solutions can compete at scale.

Peak demand, low output

The highest risk scenario likely to face the UK electricity system is likely to be anticyclonic weather occurring in winter, when wind speeds can be low for a number of days and demand is at its highest. Figure 5 below compares wind generation in January 2012 (roughly scaled to the level expected in 2020) to electricity demand. Two periods of low wind output can be seen, with the longest lasting four days.

[28] DECC (2011) Planning our electric future: a White Paper for secure, affordable and low☐carbon electricity
[29] DECC (2012) Electricity Market Reform: Policy Overview
[30] Poyry (2010) Options for low-carbon power flexibility to 2050
[31] Green Alliance (2011) Decarbonisation on the cheap
[32] DECC (2013) Electricity Demand Reduction – Amendment to Capacity Market Clauses; Impact Assessment

Figure 5: Wind generation (scaled for 2020) and electricity demand, January 2012



Source: Elexon (2013) http://www.gridwatch.templar.co.uk/download.php
Notes: 1) Wind output is scaled up fivefold to approximate possible 2020 capacity

As outlined in the previous section, short term lulls in output (several hours to a day) can be managed by using a combination of flexible generation, energy storage, interconnection and demand side response. However, it is currently uncertain to what extent these measures would provide adequate security in the event of a prolonged lull in output from varying renewables. The UK's pumped hydro storage facilities cannot provide supply over several days, and there is uncertainty regarding the reliability of interconnectors to import at times of system stress[33]. For example, electricity could be exported if prices are higher in neighbouring countries, and there may be insufficient generation available if the prevailing weather conditions affect neighbouring markets too. The contribution of non-generation tools to such a scenario will only become clearer once further technical and commercial development has taken place[34].

Flexible generation (gas, coal and bioelectricity) is currently the only solution deployed at scale to meet this challenge. With many coal power stations retiring or reducing their load factors to meet air quality standards over the coming decade, unabated gas and bioelectricity is likely to play an important role in balancing the increasing share of varying renewables. Analysis suggests that between 30 to 40 gigawatts of unabated gas capacity will be required by 2030, with some plant running few hours per year but

33 OFGEM (2013) Electricity Capacity Assessment Report 2013
34 Green Alliance (2012) The future of gas power Critical market and technology issues

maintained to ensure supply during times of system stress[35,36]. This figure is dependent on gas prices reducing and carbon prices increasing, disincentivising old coal from seeking life extensions. The risks of a high demand/low output scenario are not high this decade, due to the continued presence of large amounts of flexible capacity. Risks will increase during the 2020s under high renewable, low gas deployment scenarios, however[37].

Finding 5

System security risks from wind, solar, wave and tidal technologies are manageable with existing technologies, including demand side response, storage, flexible generation and interconnection. These same system balancing tools are capable of managing much higher penetration of varying renewables, providing their deployment is also increased.

Finding 6

The optimal mix of system balancing tools is dependent on technology costs and deployability, and the nature of future system imbalances. All these factors are uncertain in both the medium and to a greater extent the long term. The principle challenge is therefore putting in place policy to support the development of a number of technologies and the deployment of the right technologies when it becomes more apparent what those are.

Finding 7

Debate should focus on security as a property of the whole electricity system. Individual technologies should be considered in the context of how they add to or reduce system risks. Considered like this, renewables reduce some risks, such as fuel supply risk, and add to others, such as system balancing risks. Overall, the additional risk is manageable using existing technologies, though new solutions are also likely to emerge.

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35 CCC (2013) Next Steps on EMR Reform
36 DECC (2012) Gas Generation Strategy
37 Poyry (2010) Options for low-carbon power flexibility to 2050

2. SUSTAINABILITY

Environmental sustainability is considered in this chapter through carbon[38] impacts and wider, non-carbon, sustainability impacts. Social and economic sustainability are considered as they arise in this report's other chapters.

Carbon

In response to the threats of climate change arising from man-made greenhouse gases, the UK introduced a statutory target to reduce carbon emissions by 80 per cent on 1990 levels by 2050. Interim carbon budgets are set by Government and serve as a means of holding Government to account in the short and medium term for progress against delivery towards the long term target. Carbon budgets currently extend out to 2027 in five year periods. In 2012, electricity generation was responsible for 32 per cent of total UK carbon emissions[39] and by 2050 there is general consensus that power sector emissions should be virtually zero at most.

There is strong consensus that the power sector is the most practical and cost effective part of the economy to begin carbon reductions. Various models of the future energy system used by the Committee on Climate Change, the Energy Technologies Institute and the UK Energy Research Centre, suggest that expanding production of low carbon electricity, followed by substantial electrification of heating and transport is likely to be the most cost effective method of meeting the 2050 target[40,41,42]. The Committee on Climate Change, the official body tasked with advising the Government on how to achieve emissions reductions, has recommended that the carbon intensity of the sector be reduced from 531 grams of carbon dioxide per kilowatt hour (gCO2/kWh) in 2012 to around 50 gCO2/kWh by 2030[43,44]. These measures of carbon emissions are based upon emissions arising directly from combustion at power stations and are narrower in scope than life cycle analysis.

Life cycle analysis is examined below as the best means of assessing carbon impacts of different power sector technologies for the purposes of developing strategy and policy, although it is not without its challenges. Bioelectricity is considered in particular detail because it has many unique characteristics that distinguish it from other renewable technologies. Given recent debate and policy development, it is also an area that would benefit especially from constructive consensus building.

Although life cycle analysis is useful for understanding the full implications of strategy and policy, carbon emissions are measured on a UK production basis for the purpose of the UK's carbon budgets and target. This means that emissions arising outside of the UK, directly or through changes to carbon stocks, are not counted. Life cycle analysis nevertheless remains important and the Government acknowledges this for example in its Bioenergy Strategy[45].

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[38] Carbon is used as a proxy for all greenhouse gases throughout
[39] DECC (2013) UK greenhouse gas emissions, provisional figures
[40] CCC (2008) Building a Low Carbon Economy: The UK's Contribution to Tackling Climate Change
[41] ETI (2011) Modelling the UK energy system: practical insights for technology development and policy making
[42] UKERC (2013) The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios.
[43] CCC (2011) Fourth Carbon Budget
[44] CCC (2013) Next steps on Electricity Market Reform
[45] DECC, DfT, DEFRA (2012) Bioenergy Strategy

Wider sustainability

Whilst the environmental ambition of the Energy Bill focuses on carbon emissions, there are additional risks to the environment posed by energy production. Power sector infrastructure, like all infrastructure, can cause habitat loss, disturb or displace flora and fauna as well as create pollution risks. This chapter looks briefly at some examples of the impacts that renewables infrastructure can have and what frameworks are in place to manage environmental risks.

How low-carbon are renewables?

This question can be answered by measuring the amount of carbon emitted to the atmosphere per unit of electricity generated – a measure termed 'carbon intensity'. This measure allows for an important part of environmental sustainability to be quantified and compared across different technologies.

Life cycle analysis of carbon intensity

To make well-informed decisions about power sector decarbonisation, decision makers must consider all carbon emissions caused by the power sector. Changing the mix of technologies in the power sector can cause additional carbon emissions and savings directly in the UK power sector, but also in other sectors and other countries, potentially over several decades. A systematic way of making sure that all additional carbon emissions and savings are considered is to treat the deployment, operation and decommissioning of technologies as a 'life cycle' and to assess carbon impacts at all the stages of that life cycle.

Categorisation of life cycle stages is generally consistent. Some stages are applicable to one technology but not another, for example, sourcing of fuel is not relevant for offshore wind. The following table outlines all potential life cycle stages:

Figure 6: Typical life cycle stages

Sourcing of fuel	Sourcing of construction materials
Transport of fuel	Transport of construction materials
-	Construction of power station
Operation of power station	
Decommissioning of fuel	Decommissioning of power station

Carbon impacts can further be classified as direct or indirect, within each life cycle stage. For example, the planting of energy crops on UK arable land as a fuel for bioelectricity (sourcing of fuel) could hypothetically cause less food to be produced in the UK, resulting in higher indirect carbon emissions from importing replacement food. In another example to illustrate potential indirect carbon impacts, the deployment and operating of a wind farm (operation of power station) could cause changes to the way that existing unabated gas power stations are operated, resulting in decreases in the carbon efficiency of the power station as well as decreases to the volume of gas burned.

Life cycle analysis of carbon intensity informs better policy decisions because:

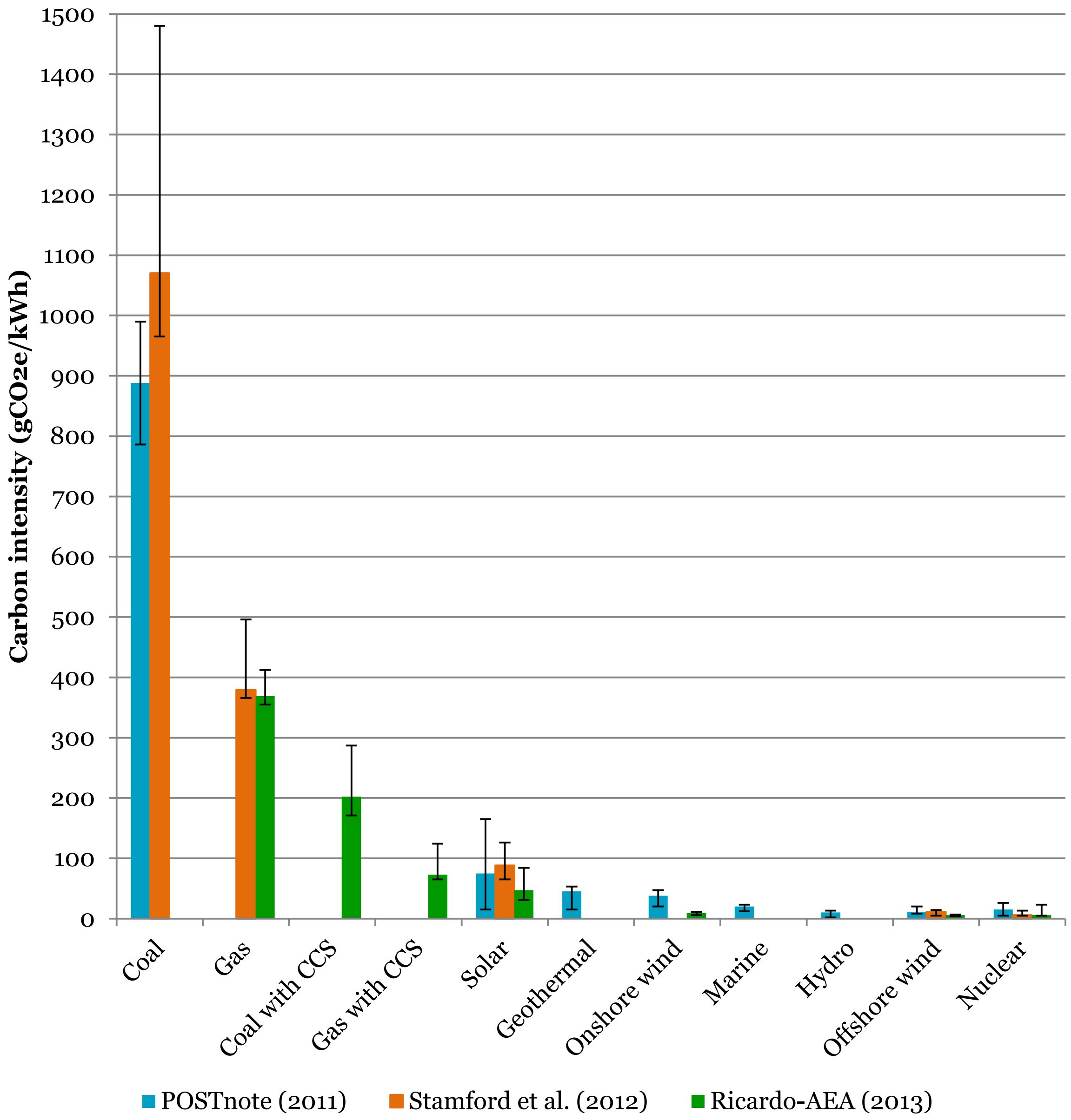
- it is a means of ensuring that policies to reduce carbon actually do so, by providing complete information;
- it can identify carbon savings, such as in bioelectricity, which can reduce the overall carbon impact and under some hypothetical scenarios result in net emissions savings and;
- it can help identify new carbon risks to manage and new ways of reducing carbon.

There are however a number of challenges presented by calculating and using life cycle carbon intensity information.

- Agreeing the scope of carbon emissions that should be measured.
- Applying the scope consistently across technologies.
- Attributing causality between power sector development and carbon emissions.
- Measuring (or estimating) actual carbon emissions of particular activities.
- Reaching general conclusions on carbon intensity for individual technologies where results can be very circumstance dependent.

For these reasons listed above, life cycle analysis of carbon intensity is difficult to do in practice and the literature varies widely because of inconsistencies and uncertainties in measurements, estimates, assumptions and counterfactuals. This can be seen in Figure 7 below where differences exist between sources and the ranges around central estimates are often wide. It is also notable that there are no single studies that assess a comprehensive range of technologies and adopt a common methodology. To attempt to combat this, three sources are drawn upon, each of which is an aggregation of data from a wide range of studies. The detailed assumptions made by each source and each of the studies that underlie them will vary because one single methodology of assessing life cycle carbon intensity is yet to emerge. Despite these limitations, useful conclusions can still be drawn.

Figure 7: Life cycle analyses of carbon intensity for different technologies



Sources: 1) POSTnote (2011): based upon 30 published peer-reviewed sources of the total life cycle carbon emissions for technologies deployed internationally.
2) Stamford et al. (2012): based upon the CML method, one of the most widely used life cycle impact assessment methods, adjusted for UK deployment. Impacts were assessed using global or European data.
3) Ricardo-AEA (2013): conducted for the Committee on Climate Change based on a review of existing literature. Life cycle assessments were made for deployment of technologies in the UK.

Notes: 1) All numbers are grams of carbon dioxide equivalent per kilowatt hour (gCO2e/kWh).
2) Gas is Combined Cycle Gas Turbine.
3) Coal with CCS includes pulverised coal and integrated gasification combined cycle. The central estimate is an average of the central estimates for each.
4) The Ricardo-AEA solar figures are the combined results of their analysis for poly-crystalline, mono-crytalline and CdTe solar. The central estimate is an average of central estimates for each.
5) Hydro is river hydro.
6) CCS is carbon capture and storage.
7) For detailed assumptions, refer to each source.

Figure 7 compares estimates of carbon intensity for different electricity generating technologies, based upon life cycle analyses. Bioelectricity has been omitted here because assessments of potential carbon intensity cover a very wide range – hypothetically, from negative emissions to emissions comparable with unabated coal. This is due to the particularly high diversity of feedstocks (fuel) and complexity of assessing their carbon impacts. For this reason, the carbon impact of bioelectricity is examined separately in more detail below. For the purpose of evaluation at this stage, we note that under the right policy regime, it should in principle be possible to only deploy low carbon bioelectricity with carbon intensities comparable to other renewables. The Government has published plans to introduce a cap on the life cycle emissions intensity of bioelectricity deployed in the UK, beginning at 285 gCO2e/kWh in April 2014 and falling to 180 gCO2e/kWh by 2025.

The majority of emissions recorded for non-thermal renewable technologies derive from infrastructure, whereas for thermal technologies the majority of emissions often derive from burning fuel. For example, turbine and foundation construction constitute approximately two thirds of onshore wind farm emissions, with solar photovoltaic cell and panel manufacture accounting for around three quarters of their total. For offshore wind, construction of extensive foundations makes up a significant proportion of its carbon impact; this is also the case for wave devices, with modules anchored to the sea floor. In contrast, for gas generation, fuel combustion accounts for 50 to 75 per cent of emissions[46]. With material and component manufacture often being the largest sources of emissions for non-thermal renewables, the carbon intensity of these processes, influenced by geographic location and factors such as local electricity carbon intensity, can lead to variation.

Figure 7 shows that renewables and nuclear power have significantly lower carbon intensities than unabated fossil fuels, even when assessed on a life cycle basis. Central estimates for solar photovoltaic place it as the highest carbon renewable (47 – 88 gCO2/kWh) and this is largely because of materials used in photovoltaic cells. Its carbon impact is estimated to be comparable to that expected from gas with carbon capture and storage.

Finding 8

Renewables are amongst the lowest carbon forms of electricity generation alongside nuclear power and, if developed, fossil fuels or bioelectricity with carbon capture and storage. This conclusion is consistent with existing evidence on life cycle carbon intensities, taking into account limitations and uncertainties.

In addition to the challenges in doing and using life cycle analyses for strategy and policy making, it is important to note that carbon intensities are expected to fall over time. The rates and real world limits to reductions are often technology specific and also highly uncertain. Nevertheless, the conclusion holds that carbon intensities are likely to fall substantially across renewable technologies over coming decades[47].

Carbon impacts of varying supply

It is often claimed that the integration of varying sources of power generation (such as wind and solar) to the electricity system can lead to higher overall carbon emissions due to the need to provide alternative supply during periods of low output[48]. Such indirect

[46] Ricardo-AEA (2013) Current and Future Lifecycle Emissions of Key "Low Carbon" Technologies and Alternatives
[47] Ricardo-AEA (2013) Current and Future Lifecycle Emissions of Key "Low Carbon" Technologies and Alternatives
[48] Global Warming Policy Foundation (2012) Why Is Wind Power So Expensive? An Economic Analysis

impacts are excluded from life cycle analyses of carbon intensity due to their system-specific nature. However, evidence suggests that emissions caused by additional grid balancing measures are not significant in comparison to the emissions savings achieved by renewables displacing fossil fuel generation[49].

Variations in supply from wind and solar generators can be managed in a number of ways (outlined in Chapter 1), depending on the rate, duration and scale of changes in output. Wind power, currently the most widely deployed varying generation technology in the UK, most often displaces gas power, which is usually the marginal plant in the power market. Output from wind can be predicted by the system operator (National Grid) accurately several hours in advance, allowing gas power station output to be scheduled accordingly. With life cycle carbon intensities for wind less than around ten per cent those of unabated gas and around four per cent those of unabated coal, displacement of fossil fuel power by wind will cause significant carbon savings. It is estimated that between April 2011 and April 2012, wind power avoided the release of 7.6 million tonnes of carbon dioxide[50].

Operating existing gas power stations more flexibly will lead, however, to some reduction in carbon savings, the effects of which are generally excluded from life cycle analyses. Operating gas and coal power stations more flexibly will reduce their efficiency, leading to an increase in carbon intensity. The efficiency of a gas power station can drop from 55 to 35 per cent when output is reduced to 50 per cent or less[51]. This lower efficiency will lead to higher emissions per unit generated whilst a plant is operated in this manner. These losses will only apply to power stations called upon to operate more flexibly, however. Research into these effects suggests that they are not large enough to undermine overall fuel and carbon dioxide savings, with efficiency losses (as a percentage of theoretical maximum fuel savings) ranging between a negligible level and seven per cent in scenarios with up to 20 per cent penetration of varying renewables[52] (the share of varying generation in 2020 is likely to be around 25 per cent[53]). It should also be noted that there are a variety of often lower carbon alternative options to provide such flexibility, including storage, demand reduction, demand side response and generation in other countries via interconnection. These tools are examined further in Chapter 1, and if developed and deployed, will lower the carbon footprint of managing variation in both supply and demand.

A more significant source of additional emissions can come from the increased operation of 'peaking' plant, used to make up for short term variations between predicted supply and demand. These plants are typically smaller gas or diesel generators, able to begin or increase generation rapidly, but at higher carbon intensities (700 gCO_2/kWh[54]). However, current evidence suggests that the effect is to reduce carbon savings from displacement of fossil fuel generation by only a very small percentage. National Grid has estimated that between April 2011 and April 2012, the additional carbon emissions resulting from peaking plant covering shortfalls between predicted and actual wind farm output to have reduced total carbon savings (7.6 million tonnes) by 0.1 per cent[55]. Given the forecast accuracy of supply, demand and wind generation, high carbon peaking power stations are required to run very few hours a year (in 2011, peaking gas plant ran for the equivalent of 16 hours at full load[56]).

[49] UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network
[50] IPPR (2012) Beyond the bluster: Why wind power is an effective technology [non life cycle emissions comparison]
[51] Eurelectric (2011) Flexible generation: Backing up renewables
[52] UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network
[53] CCC (2013) Next Steps on EMR Reform
[54] Green Alliance (2012) The future of gas power
[55] National Grid (2012) Submission to the Scottish Parliament - Appendix
[56] Gross & Heptonstall (2012) Supplementary evidence to the Energy and Climate Change Select Committee on the economics of wind energy

Based on current evidence, it appears that the additional demands on the electricity network of managing varying supply do not result in significant additional carbon emissions, compared with the savings achieved by the displacement of fossil fuels by renewables. Given the significant attention that this issue has received in the media, additional research on some of these impacts would provide more definitive analysis, and help evaluate the carbon benefits of different tools currently being developed to manage increased renewable deployment.

Finding 9

The carbon emissions saved from varying renewable generation, such as wind, displacing fossil fuel generation substantially outweigh the relatively small carbon penalties incurred in making available and deploying additional system balancing tools. This is likely to remain the case in the future.

Finding 10

Measuring and publishing the carbon emissions attributable to system balancing activities in the Government's annual Digest of UK Energy Statistics would help to monitor and communicate their relative significance as the system balancing challenge changes in coming decades.

Carbon impact of bioelectricity

After a short explanation of bioenergy and its importance for decarbonisation, this section examines the carbon impact of bioelectricity in the UK. The topic is discussed separately and in some detail because the nature of feedstocks for bioelectricity mean that it has many unique characteristics compared to other renewables technologies. Provided sustainability risks can be managed, bioenergy could make an important contribution to decarbonisation, with estimates indicating that it could provide ten per cent of energy in 2050[57] and reduce the costs of decarbonisation by £44 billion per annum in 2050[58]. The technology has been debated intensely recently as the Government develops bioelectricity policy and it is an area where broader consensus would be particularly valuable.

Background

Bioenergy refers to energy generated from solid, liquid or gaseous fuels (feedstocks) derived from biogenic matter[59]. Biogenic feedstocks can be used as substitutes for fossil fuels in heating, transport and power generation. The term biomass is generally used to describe solid fuels, biofuel for liquid fuels and biogas describes gaseous fuels. Biofuels are predominantly used in the transport sector, with solid biomass and biogas most commonly used in the power and heat sectors.

Electricity generated from biogenic matter is called bioelectricity. In the UK, bioelectricity is currently produced from the combustion of biomass (often solid wood in the form of pellets) or biogas (often from landfill gas, sewage gas or anaerobic digestion). Biogas can be combusted at source or via injection to the gas grid. There are broadly three types of feedstock for biomass and biogas used in the power sector: woody biomass from forests or woodlands; purpose grown energy crops, short rotation forestry or coppice; and waste

57 CCC (2011) Bioenergy Review
58 ETI, ESME Modelling
59 Matter derived from life processes

streams such as landfill gas, sewage gas, agricultural residues and municipal waste. Bioelectricity currently accounts for around three per cent (15 terawatt hours) of UK electricity generation, predominantly fuelled by biogas sourced from waste feedstocks such as landfill and sewage gas. A significant proportion also comes from solid biomass (often woody) combusted in dedicated, co-firing (with coal) or converted (from coal) power stations.

Future deployment of bioelectricity is discussed fully in Chapter 4, but key points are noted here for context.

- Bioenergy could account for around ten per cent of total UK primary energy (currently around two per cent) and reduce the costs of decarbonisation by up to around £44 billion per year in 2050[60]. However, its role is highly dependent on the availability of carbon capture and storage;
- By 2020, bioelectricity is anticipated to provide between five and eleven per cent (20 – 40 terawatt hours) of UK power generation[61];
- The majority of additional bioelectricity by 2020 is expected to come from the conversion of existing coal power stations modified to burn imported woody biomass. There will also be some growth in electricity from waste streams.

There are significant risks however that mean bioenergy is not automatically low carbon or sustainable. Evidence suggests that these risks are in principle manageable and the size of the potential opportunity justifies substantial efforts in risk management.

Measuring carbon impact

International guidelines for carbon accounting treat carbon emissions from bioelectricity as zero in the energy sector, because it is intended that instead they are accounted for in the Agriculture, Forestry and Other Land-Use (AFOLU) sector. There are however concerns that not all countries report emissions in this sector consistently and so significant emissions are not being counted. Additionally, emissions arising from cultivation, processing and transport of feedstocks are not attributed to bioelectricity. Guidelines are clear that bioelectricity is not treated as zero carbon because it is automatically assumed to be carbon neutral, but it is a methodological decision for providing internationally acceptable methodologies for calculating greenhouse gas inventories, upon which international climate negotiations are based.

Under current UK carbon accounting, used for carbon budgets and measuring progress towards the 2050 carbon target, only domestic carbon emissions are counted. For bioelectricity, the majority of feedstocks are likely to be imported with their carbon impact falling largely outside the UK. Recognising this, the Government has decided to base its strategy and policies for bioelectricity on a more complete measure of life cycle emissions than that used for national carbon accounting, following the principle that:

> *'policies that support bioenergy should deliver genuine carbon reductions that help meet UK carbon emissions objectives to 2050 and beyond. This assessment should look – to the best degree possible – at carbon impacts for the whole system, including indirect impacts such as indirect land-use change, where appropriate, and any changes to carbon stores.'*[62]

Adopting this principle helps industry to demonstrate the sustainability of feedstocks, for example by showing where, across the life cycle, carbon stocks are maintained or

[60] ETI, ESME Modelling
[61] DECC, DfT, DEFRA (2012) Bioenergy Strategy
[62] DECC, DfT, DEFRA (2012) Bioenergy Strategy

increased. We now explore the carbon savings that can arise from the use of three principle biomass feedstocks: waste, dedicated energy crops and woody feedstocks.

Waste feedstocks

Energy generated from waste typically has significantly lower emissions than fossil fuel power generation[63]. Carbon emissions from the combustion or anaerobic digestion of waste depend on the proportion of biogenic carbon (from plants) and fossil carbon (in fossil fuel derived materials like plastics) contained within the waste. Carbon released by the organic fraction of waste is deemed to be neutral, as carbon is likely to have been absorbed recently by growing such matter[64]. Exact emissions will vary with the proportion of organic and fossil carbon contained within a waste stream, and the efficiency of the power plant used to produce electricity.

The waste feedstocks used for bioelectricity would often result in greenhouse gas emissions through decomposition if not utilised for energy, such as is the case for landfill or sewage. The emissions resulting from bioelectricity in these instances are therefore usually offset by these foregone emissions earlier in the life cycle. The counterfactuals for waste feedstocks are therefore often less complex and easier to evidence than in the case of woody biomass. However, it would still aid wider understanding and sector development, if greater amount of data on national waste arisings and composition could be shared publicly.

Dedicated energy crop feedstocks

Recent discourse has largely focused on biomass from the residues of forestry because of the immediate prospect for significant growth in the use of these feedstocks for UK bioelectricity. But, dedicated energy crops, such as miscanthus, and willow grown in short rotation coppice, could offer another readily deployable option. These feedstocks could diversify agricultural holding whilst providing carbon savings. For example, evidence suggests that converting poor quality UK arable land to the cultivation to these growing dedicated crops can lead to a net increase in the amount of carbon subsequently stored in the soil and trees[65]. Further work in this area is needed to understand better the economic and carbon opportunities of for the UK, some of which is already underway, such as an Energy Technologies Institute's project collecting detailed data on the changes to soil carbon and greenhouse gas emissions associated with land use transitions to bioenergy in the UK.

Woody feedstocks

Depending on the scenario being looked at, bioelectricity from woody biomass can hypothetically have life cycle carbon impacts ranging from near zero (and even negative) to higher than coal[66]. In a study commissioned by the Government looking at several hundred UK woody biomass feedstock production scenarios, a small number where assessed as having very high carbon impacts, but the vast majority had very low or negative carbon impacts. Although challenging, in principle it is possible to develop policy that ensures only bioelectricity with satisfactorily low carbon impact is deployed. Following its Bioenergy Strategy, the Government recently announced its plans to put in place policy doing just this[67].

[63] CCC (2011) Bioenergy Review
[64] Defra (2013) Energy from waste; a guide to the debate
[65] CCC (2011) Bioenergy Review – Technical paper 1
[66] Forest Research (2012) Carbon impacts of using biomass in bioenergy and other sectors: forests
[67] DECC (2013) Government Response to the consultation on proposals to enhance the sustainability criteria for the use of biomass feedstocks under the Renewables Obligation

Carbon debt

Carbon is stored naturally in the soil, and within living and dead vegetation. Changes as a result of biomass feedstock production can hypothetically lead to an increase or decrease in these carbon stores and the Government is clear that, in principle, these changes must be taken into account when evaluating the carbon impact of bioelectricity.

The bioelectricity industry argues that internationally recognised forest certification schemes provide assurance that the overall level of carbon stored in certified forests is never reduced, and therefore that woody biomass derived from these forests does not incur carbon debt. The industry also argues that the vast majority of its woody biomass feedstocks are low financial value by-products of forestry and therefore are unlikely to drive changes to forestry practices that could lead to carbon debt.

Forestry practices that could lead to emissions releases are the subject of guidance within the UK Forestry Standard, and should thus avoid such risks for domestic feedstocks. However, it is anticipated that the UK bioelectricity sector will rely mostly on imports of woody biomass in the future and concern has been raised that forestry standards governing foreign imports of biomass may not always address carbon risks as robustly as the UK Forestry Standard:

The risk, therefore, is that biomass is imported from countries where frameworks to ensure sustainable forest management are less robust, in which case emissions benefits would be eroded'[68] Committee on Climate Change

Finding 11

As well as ensuring the UK Forestry Standard reflects the latest research on sustainability impacts of forestry practices, policy should ensure that imported woody biomass is derived only from forests that are managed to standards at least as robust as domestic standards.

Tightening sustainability requirements

The introduction of sustainability criteria for bioelectricity supported by the Renewables Obligation, (over one megawatt electrical) with mandatory reporting by April 2014 and mandatory compliance by April 2015, is a positive step towards ensuring that UK bioelectricity is sustainable. Another positive step is the recognition of and plan to review further concerns about sustainability criteria, such as criteria for the preservation of land carbon stocks, in a review scheduled for 2016/17. This is important for building public confidence in the significant contributions that the UK bioelectricity industry can make to meeting sustainability, security and affordability policy objectives[69].

Finding 12

The Government's planned introduction of sustainability criteria and requirements for reporting and assurance will help industry to demonstrate the sustainability of current and future biomass production practices more transparently and accessibly.

The Government will also introduce a gradually tightening cap on the annual average carbon intensity of bioelectricity, starting at 285 gCO2e/kWh in April 2014, falling to 200

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[68] CCC (2011) Bioenergy Review

[69] DECC (2013) Government Response to the consultation on proposals to enhance the sustainability criteria for the use of biomass feedstocks under the Renewables Obligation

gCO2e/kWh in April 2020 and to 180 gCO2e/kWh in April 2025 (for bioelectricity excluding new dedicated biomass power)[70]. The introduction of sustainability criteria and emissions caps and the planned tightening of sustainability requirements is a pragmatic policy response that balances protecting the environment, building public confidence and enabling the sector to develop whilst increasing its contribution to policy objectives.

Finding 13

The introduction of a cap on bioelectricity life cycle emissions of 285 gCO2/kWh in April 2015 (reducing to 180 gCO2e/kWh by April 2025) will help ensure that emissions from bioelectricity are substantially lower than unabated fossil fuels. It is a pragmatic policy response that balances protecting the environment, building public confidence and enabling the sector to develop whilst increasing its contribution to policy objectives.

Indirect impacts

Indirect carbon impacts could hypothetically arise if demand for biomass from the bioelectricity industry caused changes beyond feedstock supply chains that directly served the industry. One possible scenario is where demand for woody biomass causes some forestry products to be diverted from uses where carbon would remain stored to uses where carbon is released into the atmosphere. Another possible scenario is where increased competition for woody biomass from sustainable forestry, driven by the bioelectricity industry, causes other industries to source wood from unsustainable rather than sustainable forestry. The bioelectricity industry argues that both scenarios are unlikely to arise because the vast majority of feedstocks are low cost residues whereas other forestry products are much higher value timber used in industries such as construction and furniture. It argues therefore that the comparatively low value of the products it utilises is unlikely to significantly change the market dynamics which would lead to either scenario.

Whilst the economics of wood production do provide some assurance that indirect impacts are unlikely or might be limited, a precautionary policy response would be sensible. However, these examples highlight the complexity of calculating and attributing causality to indirect effects, which are consequently difficult to anticipate and prevent through policy. A policy approach in which indicators of indirect impacts are identified and monitored could be more practical and proportionate.

Finding 14

For some indirect risks, preventative policy may not be practical. If so, Government should consider identifying and monitoring indicators of indirect impacts such as land-use change or market dynamics.

[70] DECC (2013) Government Response to the consultation on proposals to enhance the sustainability criteria for the use of biomass feedstocks under the Renewables Obligation

Wider sustainability

Renewables, like any other infrastructure, have environmental and social impacts, such as visual, noise, air quality and biodiversity effects. The development and deployment of renewables technologies has led to new kinds of infrastructure, such as wind turbines and tidal turbines, located in sometimes more dispersed and novel locations such as hill tops and estuaries. Just as economics dictated that coal power stations be located near coal mines, economics is drawing wind farms and marine generation to be located in areas with large resources. Some renewables such as wind have lower power-area densities than coal, gas or nuclear power stations. This means that generating assets are spread over a wider area, although the addition of infrastructure does not always require a change in use of the entire area covered, for example where wind farms are sited across farmed land. The deployment of renewables is therefore a significant, but not exclusive, driver of change in the overall environmental impacts of the UK power sector. This change in quality and location of impacts is why in recent times the wider environmental impacts of renewables technologies have become frequently discussed and debated topics.

The following section discusses briefly some examples of the kinds of impacts that renewables infrastructure can have, although it should be noted that impacts are extremely technology, site and scale specific. The evidence base for environmental impacts and mitigation strategies is developing and planning, permitting and policy frameworks exist to manage the environmental risks that all infrastructure poses, a matter touched upon at the end of the chapter.

Environmental impacts are driven by a number of activities throughout a technology's life cycle. Impacts arise at the sites where generating and serving network infrastructure are located, as well as along the supply chain for construction materials and fuel. Local impacts call for careful assessment, consideration and planning by developers, network companies and local communities before infrastructure is built.

Impacts can arise from the sourcing and delivery of fuel, most commonly from the extraction of fossil fuels, but also as a result of feedstock production for bioelectricity. Although the inability to store wind, solar, wave and tidal energy upstream (before use for generation) presents a challenge to network management, the environmental impacts from fuel extraction, processing and transport are avoided. Construction can cause significant disruption and onsite pollution, although these effects last a relatively short time in comparison to the overall lifetime of a project. Once constructed, facilities must be operated and maintained. Providing access to onshore wind farms requires the construction of additional access roads, whilst offshore technologies (wind, wave and tidal stream) will require means of access, via ship or air, which may require additional facilities. Finally, it is important to consider how equipment is disposed of at the end of its life, and whether sites that host infrastructure can be put to alternative uses or can subsequently be returned to nature.

Visual and noise impacts

Infrastructure can have direct impacts on the site where it is located; which can be most acute during construction, where ground will be disturbed and in the case of large projects such as dams and barrages, a large volume of material will be transported to or from the site. Onshore technologies can have visual impacts lasting the lifetime of the infrastructure (around 20 years). The effect of wind farms on the character of surrounding countryside can be a contentious issue, as can commercial scale solar farms, albeit to a lesser extent due to their lower height and reduced visibility. Placing infrastructure offshore reduces visual impacts, provided these are located sufficiently far from coasts. Tidal stream and seabed mounted wave devices have the advantage of minimal visual impacts. Bioenergy power stations can be cited more flexibly, with access to road, rail or port facilities being the main constraints on location.

Noise arising from construction can disturb local animal populations for projects on and offshore[71]. Wind turbines produce sound by the aerodynamics of blades passing through air, with additional mechanical sound produced by the internal moving parts of the turbines themselves. Noise travels further underwater, and noise from marine devices may well disturb and displace marine species, although these risks are not yet fully understood[72]. Solar photovoltaic is noiseless during operation.

Air and water quality

It is also important to consider whether the placement of energy infrastructure has adverse effects on air and water quality. As with all construction projects, the use of materials and the generation of waste creates pollution risks. In the longer term, impacts on air quality are confined to bioenergy power stations. An advantage of wind, solar, tidal and wave generators is that no direct emissions are produced during operation. Waste to energy power stations present the greatest risks (albeit technically manageable), as waste combustion can release a variety of pollutants such as nitrogen dioxide, sulphur dioxide, and PM10[73] to the atmosphere, all of which have potentially serious health effects. However, modern, well managed incinerators, anaerobic digesters, and landfills do not contribute significantly to local air pollution, and are under tight regulations to control these emissions[74]. Power stations combusting wood are not generally covered by these standards (unless they are also combusting wood waste). In general, they emit less sulphur dioxide and mercury than coal power, but produce higher levels of particulates (soot and ash) and carbon monoxide[75]. Biomass plants will be subject to the same non-carbon dioxide emissions rules being introduced for coal and gas power generation under the EU Industrial Emissions Directive from 2016.

Risks to water quality include pollution, and changes to local water resources, through alterations to hydrology, or water extraction. Pollution risks are generally confined to the construction phase of projects, although geothermal energy presents a possible risk of contamination should water pumped below ground escape[76]. The UK has a very good track record of regulating similar practices from the oil and gas industry. The production of biomass feedstocks (from managed forests, or dedicated plantations) can create changes to local hydrology patterns and soil quality. For example, different types of vegetation intercept different amounts of rainwater, so changes in vegetation can lead to these impacts[77]. The construction of foundations and access roads, such as for onshore wind, can also affect site drainage.

Biodiversity

Biodiversity can be affected directly by new energy infrastructure, and indirectly through the cumulative effects of the factors described above. Direct impacts can include collision, barrier effects, displacement and disturbance and habitat loss, which can all lower biodiversity. There are some instances where changes will actually help increase local biodiversity.

Location and density of equipment can be the defining factors of risks, with the greatest threats arising where large scale transformation of the landscape occurs. This is perhaps

[71] Birdlife Europe (2011) Meeting Europe's Renewable Energy Targets in Harmony with Nature
[72] RSPB (2012) Birds and wave and tidal stream energy: an ecological review
[73] Particles less than 10 micrometres
[74] Health Protection Agency (2009) The Impact on Health of Emissions to Air from Municipal Waste Incinerators
[75] Union of Concerned Scientists; Environmental Impacts of Biomass for Electricity; accessed 20.07.13
[76] Union of Concerned Scientists; Environmental Impacts of Geothermal Energy; accessed 06.08.13
[77] Forest Research (2011) Short Rotation Forestry: Review of growth and environmental impacts

greatest with dams (for hydro-electric power) and where tidal energy technologies are located at the mouths of estuary systems, which could cause changes in hydrology and salinity, impacting animal and plant life[78]. Biomass feedstock production could hypothetically lead to biodiversity loss either directly or indirectly, but the application of robust forestry standards such as those in the UK are thought to effectively mitigate this risk. As discussed above, concerns have been voiced that not all countries where woody biomass is sourced from may have forestry standards as effective as mitigating this risk as the UK[79].

Location is a key determinant of biodiversity effects. There are generally low risks to biodiversity if previously developed, sealed or intensive arable or grassland is used for infrastructure, However, not all sensitive wildlife sites are protected from development and where infrastructure is built in close proximity to important habitats, disturbance and displacement can occur. The separation distance between wind turbines leaves intervening spaces that are available for other human and animal uses, and does allow for sites to be designed in a manner that reduces biodiversity impacts.

Some specific dangers to wildlife are increasingly understood and monitored. Wind turbines present a collision risk to birds and bats, with high wind sites typically found in upland and coastal areas (and offshore) which also attract birds who use these as important habitats for breeding, wintering and migrating. An environmental impact assessment can significantly reduce risks, for example by siting the wind farms away from key migration paths and large breeding and roosting areas. Technical solutions are also available to reduce the likelihood of bird fatalities[80]. Similarly, underwater turbines used for hydroelectric, tidal stream and range can create impact risks to marine animals. Wind turbines are not unique amongst power sector infrastructure for causing bird fatalities.

Some technologies could provide benefits to biodiversity. For example, the construction of foundations and barrages at sea could provide a stable substratum for marine invertebrates to colonise, which attract small fish and in-turn, larger organisms, increasing biodiversity in the local area. Similarly, the conversion of intensely farmed land in the UK to accommodating short rotation forestry or coppice, or commercial solar farms, could also lead to an increase in biodiversity by providing additional habitats. The overall impacts on biodiversity for many new technologies are yet to be fully understood, and the subject of much needed on-going research[81]. Where major risks have been identified, such as bird strikes, mitigation strategies have been developed.

Managing environmental risks

The novelty and change in impacts that many types of renewable generation present call for development and adaptation of:

- scientific understanding and the empirical evidence base;
- assessment and assurance tools and frameworks and;
- governance and decision making.

Many of these risks are already managed through existing frameworks such as environmental impact assessments and planning policy. Risks relating to more established technologies, such as onshore wind, are better understood, with changes made to existing legislation to incorporate risks (such as environmental impact assessments). Where impacts are more novel, such as the case of bird strikes, better knowledge is fostering the

[78] Union of Concerned Scientists; Environmental Impacts of Hydro-kinetic Energy; accessed 06.08.13
[79] CCC (2011) Bioenergy review
[80] Birdlife Europe (2011) Meeting Europe's Renewable Energy Targets In Harmony with Nature (eds. Scrase I. and Gove B.)
[81] Birdlife Europe (2011) Meeting Europe's Renewable Energy Targets in Harmony with Nature (eds. Scrase I. and Gove B.)

development, and promotion, of mitigation strategies[82]. For less developed technologies, such as wave and tidal devices and to an extent offshore wind, the focus is on developing scientific understanding in order to better understand the magnitude of risks and potential mitigation strategies. Assessing impacts can be challenging because there are diverse drivers and manifestations. These in turn are often project and site specific, and in many cases, scientific understanding and empirical evidence is still in development. Trade-offs arise in many cases between the need to develop new technologies, expand use (to ensure timely carbon reductions) and develop the evidence base for impacts.

Finding 15

The environmental impacts of renewable technologies are sometimes different in quality and location from other power sector technologies but existing frameworks for assessment and decision-making are adaptable to meet these novelties. New research is coming forward to evidence and explain where novel environmental impacts have been identified and mitigation strategies are being developed.

[82] Birdlife Europe (2011) Meeting Europe's Renewable Energy Targets In Harmony with Nature (eds. Scrase I. and Gove B.)

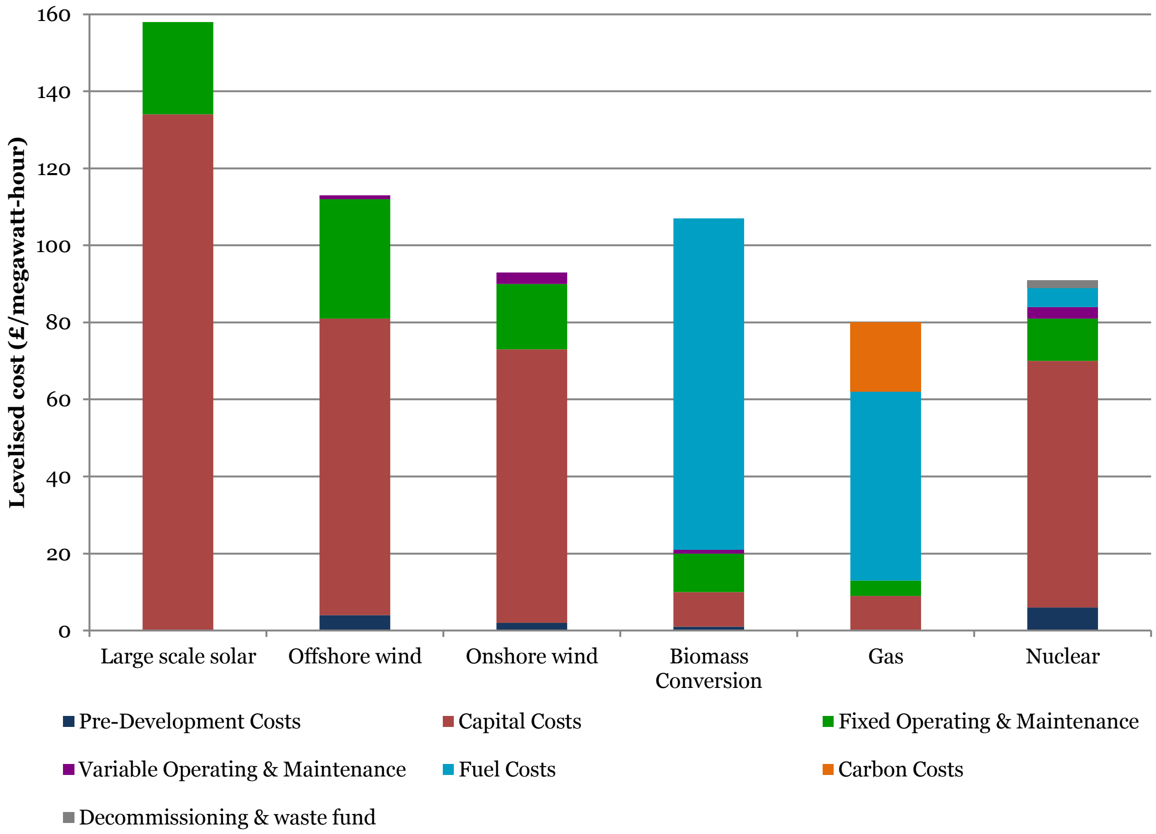
3. AFFORDABILITY

Ensuring that energy remains affordable is both an economic and social priority. It will also be a crucial factor in determining the future role of renewables technologies, many of which are at an early stage of cost maturity. Affordability is about more than the costs of building and running power stations. System costs, carbon costs, risk and macro-economic impacts are also crucial components of affordability. Balanced assessments of costs and benefits are needed across all components of affordability in the near term and long term. This chapter examines each of these components and looks at the impact that carbon costs and supporting renewables, amongst other forms of low carbon generation, could have on electricity bills in the short term.

The characteristics of affordability

Levelised costs

Figure 8: Levelised cost estimates for projects starting in 2013



Source: DECC (2013) Electricity Generation Costs July 2013

Notes:
1) Offshore wind is round two and onshore wind is UK and >5 megawatts
2) Nuclear is first of a kind
3) Gas is combined cycle gas turbine
4) Coal is not shown because no new coal can be built in the UK without full chain carbon capture and storage on at least 300 megawatts.
5) 2012 real prices assuming a 10 per cent discount rate

A standard method of comparing the output costs of different generation technologies is to use a levelised cost analysis. Lifetime costs of constructing and operating generating infrastructure (including fuel) are aggregated, and divided per megawatt-hour of electricity produced to give a per unit cost. This provides a metric that is relatively easy to calculate and clear in its outputs. Whilst a useful tool in these respects, levelised cost estimates have several limitations. Their results are highly dependent on input assumptions, including discount rates, and omit wider network impacts and costs. They are also a poor guide to real investment decision making and developers must factor in project-specific risk and the costs of obtaining finance, which will have a significant impact on investment decisions. Finally, they are subject to industry optimism bias.

Figure 8 shows non-thermal renewables and nuclear power have high capital costs, with relatively low operational costs. In contrast, bioelectricity and fossil fuelled generation have lower capital costs and higher operational fuel costs. The results in Figure 8 should be understood in the context of the underlying assumptions. The chosen discount rate (ten per cent) reflects the weight given to future costs, and is particularly significant given the different cost profiles between technologies with high upfront capital costs and technologies with higher operating costs spread over the lifetime of the infrastructure. High discount rates penalise those technologies with relatively higher upfront costs, whereas low discount rates penalise technologies with relatively higher operating costs. For example, moving from a ten to a seven-and-a-half per cent discount rate can reduce the levelised cost of wind power by up to 17 per cent, compared to a five per cent reduction for gas generation[83]. In diminishing the share of levelised costs deriving from fuels, higher discount rates may underplay the risk posed by fuel price volatility. It should be noted that levelised cost analysis does not reflect risk well.

A further limitation of this analysis is the exclusion of network costs, which can be an important consideration for integrating varying renewable generation or remote generating assets. The analysis above may also call into question the need to provide revenue support for more mature renewables. Again, the risks faced by developers of these technologies, arising from price volatility in the electricity market, are not reflected. These have a strong bearing on real world investment decisions, and can help explain why seemingly mature technologies continue to require support.

Future technology costs

There are many factors which drive changes in renewable technology costs, some with a degree of controllability (endogenous) and others that cannot be controlled and are often particularly hard to predict (exogenous). Endogenous factors include innovation, economies of scale and supply chain capacity arising from increased deployment of technologies. Exogenous factors include movements in energy prices, commodity prices and exchange rates.

Generally, expanded commercial deployment of new technologies, including renewables, leads to cost reductions as a result of learning-by-doing throughout the supply chain, economies of scale, increased supply chain competition and reduced project risk. Endogenous effects, such as these, are thought to have been a key driver behind the substantial cost reductions seen in onshore wind (around 65 per cent[84]) and solar photovoltaics (around 90 per cent) over the final decades of the twentieth century[85].

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[83] Mott McDonald (2010) UK electricity generation costs update
[84] IEA Wind (2012) The Past and Future Cost of Wind Energy
[85] UKERC (2013) Technology and Policy Assessment, Cost Methodologies Project: PV Case Study -Working Paper. Note: this paper has not been subject to review and approval, and does not have the authority of a full Research Report.

There are two common approaches to predicting how future technology costs are likely to be affected by endogenous factors. One uses bottom-up engineering assessment together with other relevant technical expertise to anticipate how technologies are likely to evolve over time. The other is to extrapolate the future from past experience using known cost trajectories, learning curves and assumed capacity growth. The appropriate methodology will vary according to the maturity of the technology and the availability of data. Care must be taken when using the results from either approach, and it should be remembered that assessments can be prone to 'appraisal optimism'[86]. Furthermore, it is common for early stage technologies to see costs rise, so-called 'first of a kind' premium, as risks arise from new designs, supply chain constraints and the up-scaling of equipment[87]. Despite these complexities and limitations, these experience curves and engineering assessments can provide the most systematic approach to understanding endogenous factors and predicting their impact on technology costs.

Technology costs are also affected by hard-to-predict exogenous factors, such as movements in energy prices, commodity prices and exchange rates. Recent experience across all renewables technologies, but particularly offshore wind, has shown that these factors can be just as significant as endogenous factors. For example, steel and copper costs make up six and five per cent of offshore wind levelised costs respectively (for a six megawatt turbine in 2020). Sensitivity analysis by the Crown Estate[88] shows that a variation in steel prices of plus or minus 50 per cent and copper of plus or minus 65 per cent result in a total levelised cost impact of plus or minus three per cent. As these factors are hard to predict, expressing them as quantified uncertainties is an appropriate way to reflect them in predictions.

The cost of most electricity generation technologies has increased over the last decade. Fossil fuel generation has risen in cost, driven by increases in the price of input fuels, whilst rising commodity prices and currency exchange fluctuations have led to cost increases in wind energy, factors that many past cost estimates failed to anticipate[89]. Offshore wind capital costs have risen most prominently in recent years, nearly doubling between 2003 and 2008[90], and have remained high since. A variety of factors are thought responsible alongside increasing material and currency costs, such as the technical challenges of building projects further offshore and in deeper water[91]. Supply chain bottlenecks are also thought to have contributed to increasing costs, with rapid expansion of the sector making it difficult for suppliers to meet demand and allowing markets to charge a premium[92]. Solar photovoltaic module costs have however seen spectacular prices decreases, falling by over half in the period 2003 to 2012[93].

As a relatively mature technology, there is thought to be modest scope to reduce the costs of onshore wind further. Solar photovoltaic is thought to have significant cost reduction potential, although this will be globally driven and estimates point to uncertainties regarding global demand and the pace of continued technology development. The future cost range for less developed technologies is necessarily wider, with devices such as wave and tidal stream generators at an early demonstration stage. The lack of technology standardisation makes it more difficult to extrapolate potential innovation and learning curves, although the optimistic range of estimates suggests these could become

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86 UKERC (2011) Presenting the Future: An assessment of future costs estimation methodologies in the electricity generation sector
87 Mott Macdonald (2010) UK Electricity Generation Costs Update
88 Crown Estate (2012) Offshore wind cost reduction pathways study
89 UKERC (2012) UKERC Technology and Policy Assessment Cost Methodologies Project: Onshore Wind Case Study
90 UKERC (2010) Great Expectations: The cost of offshore wind in UK waters – understanding the past and projecting the future
91 Ibid.
92 Ibid.
93 Solarbuzz (2012) Solarbuzz module price survey

competitive with other generation by 2030[94]. Development in the UK, which is currently a world leader in these technologies, will be key to continued cost reduction. Offshore wind is thought to have a further cost reduction potential, although this was overestimated in the past. Cost concerns have led Government to link deployment beyond 2020 to an agreed cost reduction target with industry of £100 per megawatt hour. Figure 10 looks in more detail at the short term cost reduction potential for offshore wind, which has been a focus for debate recently.

[94] Mott Macdonald (2011) Costs of low-carbon generation technologies

Figure 10: Short term cost reduction potential for offshore wind

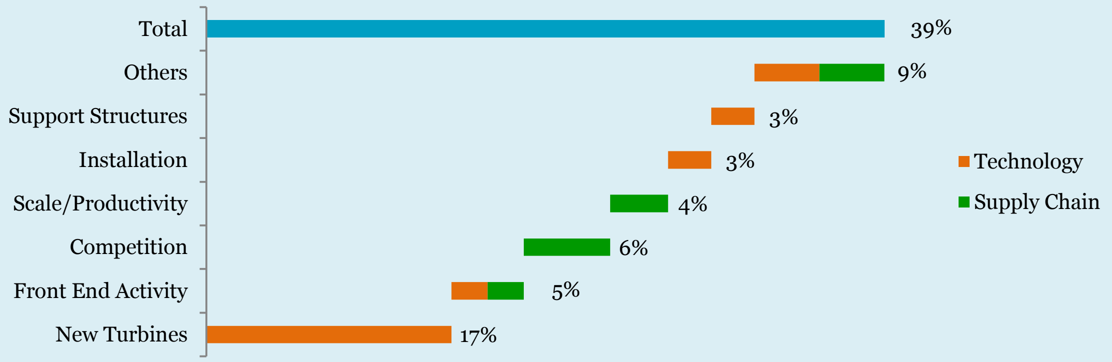
This Figure identifies seven areas in which cost reductions can be realised, and whether they can be made in either the technology or supply chain areas in the relatively short time between 2011 and 2020. The data is based upon a study performed by The Crown Estate in 2011, and replicates the costs of a 500 megawatt wind farm at the final investment decision stage in that year, and the savings which can be achieved compared to a similar sized farm in 2020[95].

The key opportunities for cost reduction are generated by:

- larger turbines with higher reliability and energy capture, and lower operating costs;
- greater competition in key supply markets for turbines, support structures and installation;
- greater optimisation designed in at the start of the project, such as early involvement of suppliers, optimising wind farm layout, front end engineering and design studies and more extensive site surveys;
- economies of scale and productivity improvements such as greater standardisation, learning by doing and better procurement better installation practices and;
- mass produced support structures for use in deeper waters.

As this Figure shows, these opportunities are split between technology improvements and supply chain improvements. The extent to which cost reductions are realised in practice is highly dependent on the evolution of the industry, particularly within the UK, but this Figure demonstrates the potential.

Cost reduction potential in offshore wind to 2020 (2011 baseline)



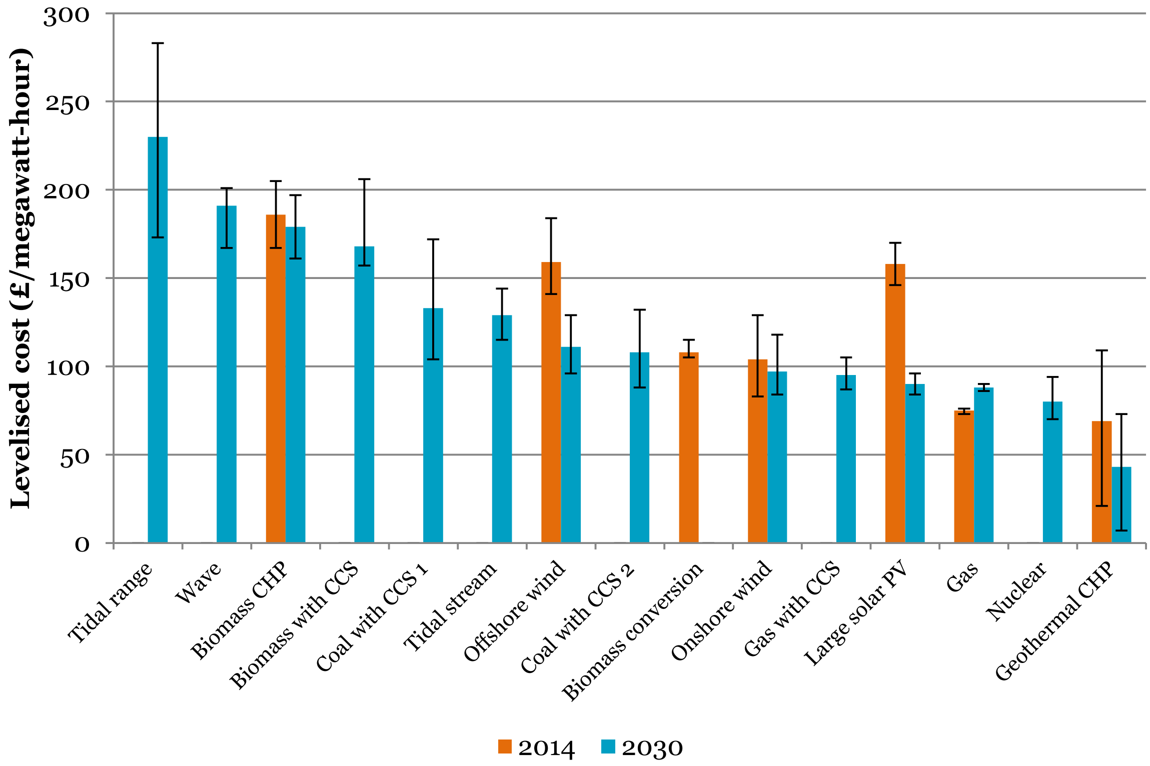
Source: The Crown Estate (2012) Cost reduction pathways study
Notes: 1) Percentage reduction in levelised cost of energy between final investment decisions in 2011 and 2020

The Crown Estate in their 2012 Cost Reduction Pathways Report states that the single most important area to reduce costs in offshore wind is the expansion of the UK supply chain[96]. Currently, the supply chain that is based in the UK only consists of companies who provide services such as foundations and cabling, with no manufacturing of turbines taking place. Currently turbines are manufactured in Germany or Denmark, before being shipped to the UK where they have to be assembled prior to installation[97]. The lack of any original equipment manufacturer means that more time and money is spent on turbine assembly and transport[98].

[95] The Crown Estate (2011) A guide to an offshore wind farm
[96] The Crown Estate (2012) Offshore Wind Cost Reductions Pathway Study
[97] Clean Energy Pipeline (2013) Clean Energy UK Offshore Wind Supply Chain: Why Clusters Matter
[98] Clean Energy Pipeline (2013) Clean Energy UK Offshore Wind Supply Chain: Why Clusters Matter

Figure 11 illustrates levelised cost estimates for projects commissioning in 2014 and 2030, produced by the Government. The ranges in the estimates represent variability across potential sites for renewables, and per project for conventional generation. These estimates are produced using expected carbon and fuel prices, as well as forecast technology reduction curves for newer technologies[99]. Several renewables technologies are expected to see significant cost reductions, such as offshore wind and large scale solar photovoltaic. Others, such as onshore wind, are not expected to mature in cost much.

Figure 11: Levelised cost estimates for projects commissioning in 2014 and 2030



Sourc: DECC (2013) Electricity Generation Costs July 2013

Notes:
1) 2014 and 2030 are project commissioning dates
2) 2012 real prices assuming a 10 per cent discount rate
3) CHP is combined heat and power
4) CCS is carbon capture and storage
5) Coal with CCS 1 is integrated gasification combined cycle and first of a kind
6) Coal with CCS 2 is advanced super-critical with oxyfuel carbon capture and storage and first of a kind
7) Tidal stream is deep
8) Offshore wind is Round 3
9) Gas (including with post combustion carbon capture and storage) is combined cycle gas turbine
10) Nuclear is Nth of a kind
11) Central estimates are shown with upper and lower bounds reflecting high and low capital cost estimates

Finding 16

Offshore wind, wave, tidal and solar photovoltaic renewable technologies are thought to have a large cost reduction potential between now and 2030, however, recent experience and analysis have shown that the impacts of hard-to-predict and uncontrollable factors will always present significant risks to forecasts.

[99] DECC (2013) Electricity Generation Costs 2013

The scope for the UK to drive technology cost reductions varies across technologies, being largely driven by the UK's competitive advantages and the practical deployment potential. Due to these factors, offshore wind, tidal and wave technologies are where the greatest potential for UK-driven cost reduction lies. For marine technologies, the UK is the global leader in research and development and also has substantial practical resource potential. For offshore wind, the UK is leading the world on deployment and has significant further deployment potential. It also has useful skills and expertise that can be transferred from sectors such as the offshore oil and gas sector.

System costs

The costs of building, maintaining and operating the electricity networks are projected to account for 23 per cent of average household electricity bills in 2013[100]. There are two networks: the high voltage transmission network carries electricity from power stations to different regions of the UK, whilst the lower voltage distribution networks distribute electricity from the transmission network to consumers within regions. Ofgem estimates that in 2012, total transmission and distribution network charges accounted for four and sixteen per cent of the average domestic electricity bill, respectively[101].

Connecting generation assets to the electricity network can create the need for network upgrades upstream of the point of connection. These costs will be passed onto all electricity users via transmission and distribution charges. Renewables are likely to increase these costs, as location choices are driven by resource availability (such as wind profile) rather than proximity to centres of demand. This is particularly a problem for small and medium scale renewables that connect at the distribution network level, where information about network capacity in specific localities is limited[102]. The cost of upgrading the transmission networks to meet the 2020 renewable ambition is expected to be £8.8 billion between now and 2020[103]. The connection of smaller generating units to the distribution networks will also create the need for investment. Overall, network costs are expected to increase by around 20 per cent between 2013 and 2020[104], although a large proportion of this requirement is generated by renewables deployment, ageing infrastructure and demographic change are also drivers of investment.

Finding 17

Varying renewables deployment, like other low carbon generation, will create additional network infrastructure costs, which are expected to contribute to some of the expected 20 per cent increase in overall network costs by 2020.

Another set of network costs arise from the actions of the system operator, National Grid, to ensure that electricity supply and demand is continuously balanced. It maintains a pool of reserve to manage anticipated and unexpected shortfalls or excesses in supply during the final hour before electricity is delivered to consumers. These needs are sized according to three factors: the capacity of the largest single generator that could fail, the expected availability of all conventional plant on the system and a given amount of demand prediction errors[105]. It is estimated that these costs account for less than one per cent of

[100] DECC (2013) Estimated impacts of energy and climate change policies on energy prices and bills 2012
[101] OFGEM (2013) Updated household energy bills explained
[102] Carbon Connect (2012) Distributed Generation: From Cinderella to Centre Stage
[103] ESNG (2012) 'Our Electricity Transmission Network: A Vision for 2020'
[104] DECC (2013) Estimated impacts of energy and climate change policies on energy prices and bills 2012
[105] UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network

the unit cost of electricity[106]. Any new generator has the potential to increase or decrease these requirements.

The varying output from some renewables such as wind and solar generation, although predictable to a high degree of accuracy, can still fluctuate over very short periods of time. As the share of varying generation increases, so will the scale of system imbalances they drive. This could lead to additional investment in tools to manage imbalances such as demand side response, storage, flexible power stations and interconnection. The system balancing challenges posed by an increasing penetration of varying renewable generation are therefore not new in nature. The costs of managing the varying output of some renewable technologies are not reflected in levelised cost analysis. Two costs are relevant to affordability considerations: those of managing short term (less than an hour ahead of delivery) fluctuations, and the cost of maintaining system reliability by maintaining a larger overall generating capacity on the network, to manage periods of low output from varying renewables and high demand (outlined in chapter 1).

Services contracted to manage expected wind capacity are estimated to cost £286 million per year by 2020[107]. This compares to an overall budget for actions by the system operator of £603 million in 2012/13[108], which constituted less than one per cent of the unit price of electricity. Research estimates that at a 20 per cent penetration of varying generation, these costs are likely to be between £2 and £3 per megawatt hour[109]. The cost of maintaining additional generation capacity, to ensure peak demands can be met, is estimated to be between £3 and £5 per megawatt hour for penetration of varying wind capacity up to 20 per cent[110]. Combined, the additional system costs of managing varying renewable generation are therefore estimated to add between £5 and £8 per megawatt-hour, or between three and five per cent to the final unit price of electricity.

Beyond 2020, varying renewables, such as wind, are likely to have reached higher than 20 per cent penetration. The additional network costs beyond this point are anticipated to be commensurately higher but are dependent on what technologies are deployed to manage system imbalances, which is currently less certain. The starting point of three to five per cent of the price of electricity is modest however.

Finding 18

Increasing the share of varying renewable generation will add modestly to network balancing costs. The additional cost at 20 per cent penetration of wind is estimated to add between three and five per cent to electricity prices.

Carbon costs

The deployment of low carbon technologies is being supported by requiring emitters to pay for their releases of carbon dioxide. Carbon pricing internalises the costs of carbon emissions, and whilst it increases the costs of the otherwise more cost effective forms of generation today (coal and gas), it is an important part of the UK's management of climate change risks. Carbon pricing will help ensure that the market incentivises electricity supply options that will be lower cost in the carbon constrained future that the UK is committed to.

[106] DECC (2013) Estimated impacts of energy and climate change policies on energy prices and bills 2012
[107] National Grid (2011) Operating the Electricity Transmission Networks in 2020
[108] National Grid (2013) Procurement Guidelines Report
[109] UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network
[110] UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network

As with revenue support policies, the costs of carbon pricing are paid by all electricity users, and will increase the price of electricity – it is estimated that in 2013, this will add two per cent to the average domestic electricity bill[111]. Carbon prices will make all low carbon technologies more competitive with higher carbon technologies, not just renewables. Again, current cost increases should be compared to longer term benefits. The UK's carbon price floor is intended to provide investors with confidence in the short and medium term carbon price, to reduce the risks of investing in high capital cost low-carbon technologies (renewables, nuclear and fossil fuels with carbon capture and storage) as well as shifting investment away from unabated fossil fuels, whose costs will increase as carbon prices rise.

Since 2005, large industrial users have been required to purchase emissions permits though the EU Emissions Trading System. Prices in the UK have been supplemented since April 2013 by the introduction of the Carbon Price Floor, a UK tax which tops up carbon prices paid in the UK under the EU emissions trading system to a minimum level set by Government (£16 per tonne of carbon dioxide emitted, compared to an average EU price of £3.50 in 2013). The policy has been introduced as a result of low and volatile EU prices and to provide clarity over future price minimums. In the near term, carbon pricing will increase wholesale electricity costs by increasing the costs of coal and gas power generation, the dominant form of generation (responsible for 67 per cent of UK electricity supply in 2012[112]). The price floor is scheduled to rise to £30 per tonne of carbon dioxide in 2020 and £70 in 2030. The two policies are expected to add 2.3 per cent to the average electricity retail price paid by households in 2013, rising to 10 per cent by 2020[113]. These costs should be considered alongside evidence that shows that early action on climate change has overall macroeconomic benefits[114].

There have been concerns that the disparity between the very low EU Emissions Trading System price and the UK carbon price floor increases the risk that the latter is politically unsustainable. This underlines the importance of negotiating reforms to the EU Emissions Trading System that will put upward pressure on the carbon price.

Risk

There are two broad risks that supporting and deploying renewables in the short term can help to mitigate. The first is that deploying more renewables increases the predictability of average electricity prices by reducing electricity price exposure to fossil fuels price risk. The second is that investing to support less mature but highly deployable renewable technologies, such as offshore wind, through the cost reduction phase diversifies the UK against the risk that other low carbon technologies remain expensive or are not deployable at scale in the medium and long term.

Predictability of prices is a valued dimension of affordability. The unpredictability of the supply of gas to the UK market combined with limited storage ability has been identified as a relevant factor in driving wholesale prices[115]. Predictability forms part of public perceptions of affordability, because it affects the ability to plan budgets[116]. Fuel costs of power stations are a key driver of wholesale electricity prices and contribute to their long term unpredictability. Because non-thermal renewables do not have fuel costs and instead have higher upfront capital costs, they increase the predictability of average electricity

[111] DECC (2013) Estimated impacts of energy and climate change policies on energy prices and bills 2012
[112] DECC (2013) Digest of United Kingdom Energy Statistics
[113] DECC (2013) Estimated impacts of energy and climate change policies on energy prices and bills 2012 [Impact compared to no policies counterfactual]
[114] Stern (2006) The economics of climate change
[115] House of Commons (2007) Business & Enterprise Committee: Energy prices, fuel poverty and Ofgem
[116] Parkhill, K.A., Demski, C., Butler, C., Spence, A. and Pidgeon, N. (2013) Transforming the UK Energy System: Public Values, Attitudes and Acceptability – Synthesis Report (UKERC: London).

prices. This benefit is not reflected in levelised cost or bill impact analysis. Reducing the use of fossil fuels could also help improve the UK's balance of payments; in 2012, £6.7 billion was spent on imports of gas (net of exports)[117].

Finding 19

Increasing deployment of renewables can reduce the exposure of UK electricity prices to fossil fuel price risk. This improves predictability of average electricity prices which evidence shows is a valued component of affordability.

To meet carbon targets the UK will need to deploy high volumes of low carbon technologies, many of which are currently expensive and at an early stage of cost maturity. The best mix of technologies in future decades is still unclear, primarily because future technology costs are unknown. There is broad support for the Government's approach of supporting a range of low carbon technologies through cost maturity so that the risk of one technology not delivering cost reductions or deployability in future decades is diversified across a portfolio of technology options. The Government is promoting three low carbon options that have particular potential to deliver on a large scale: fossil fuels with carbon capture and storage; nuclear power; and, offshore wind. Part of the value in supporting offshore wind in the short term is therefore that it lowers the risk of high bills in the medium and long term. A similar argument applies to other early-stage renewables, such as marine technologies. This value is not reflected in levelised cost analysis or in analysing the electricity bill impacts of revenue support for low carbon technologies. It is nevertheless an important component of affordability.

This pattern of technology support is not new. Early development of North Sea oil and gas was heavily subsidised by the Government, which allowed the UK to exploit its resources and develop expertise in offshore industries. Similarly, the extraction of fossil fuels is subsidised by Governments the world over. The International Energy Agency estimates that in 2010, nearly $100 billion was spent worldwide subsidising the extraction of natural gas[118].

Finding 20

Part of the value in supporting less mature renewable technologies in the short term is that it lowers the risk of high bills in the medium and long term. This value is not reflected in levelised cost analysis or in analysing the electricity bill impacts of revenue support for low carbon technologies. It is nevertheless an important component of affordability.

Macro-economic impacts

The UK energy sector, of which the power sector is a significant part, was estimated to have a direct contribution to gross domestic product of £20.6 billion (around 1.6 per cent) in 2011[119]. As well as direct impacts, the power sector purchases goods and services from other sectors, for example manufacturing. Given the significant size of the sector economically and the importance of the sectors outputs for economic competitiveness, changes in the power sector can have substantial macro-economic impacts that are material considerations when weighing up decisions against affordability objectives. These include employment, inward investment, export opportunities and competitiveness.

Direct jobs can be created throughout a technology lifecycle, from design, manufacturing and construction through to operation and maintenance. Jobs can also be created

[117] DECC (2013) Digest of United Kingdom Energy Statistics
[118] IEA (2011) IEA analysis of fossil fuel subsidies
[119] Energy UK (2012) Powering the UK

indirectly in supportive industries providing materials and services. It has been estimated that in 2012, there were 100,000 jobs in the immediate renewable energy (power, heat and transport) supply chain[120], with 160,000 indirect jobs related to the sector (2011 estimate)[121].

However, positive and negative impacts on employment should be considered in any assessment, because jobs can be displaced or eliminated as activity is shifted from one economic sector to another. For example, jobs in conventional power generation could decline if investment is shifted away from this sub-sector and into renewables. Assessments of employment impact are therefore particularly sensitive to scope and evaluation of displacement and elimination impacts. In general, the evidence base supporting the job impacts of renewables support is weak.

The economic benefits of exported technologies and services is more clear cut since they can positively affect our balance of trade and are not reliant on domestic subsidies. Recent trade statistics showed for example that the UK has a positive trade balance with China in green goods and services[122].

Finding 21

The development and deployment of renewable technologies can have macroeconomic benefits through employment, inward investment and export opportunities. These benefits are difficult to assess and more evidence is needed to understand them better.

A potential risk of the short term costs to support less mature, more expensive renewable technologies is that the upward pressure on electricity prices damages the UK's competitiveness. However, current electricity prices are broadly competitive with European averages[123], and other European nations are also required to invest in renewables to increase their use of renewable energy by 2020 under the EU Renewable Energy Directive. Additionally, measures are being prepared by Government to exclude energy intensive industries, which are most at risk from rising prices, from revenue support costs in future[124].

Finding 22

The UK's electricity prices are broadly competitive with other countries across Europe and the Government plans to mitigate the risk that forecast price increases, mainly driven by support for low carbon generation, reduce the UK's industrial competitiveness.

Bills

In the eight years to 2011, rising gas prices were the main driver of increased energy bills125. Gas prices can have a significant impact on electricity bills because around 35 to 50 per cent of electricity is generated from gas and around a quarter of an electricity bill derives from fuels used in power stations[126]. Over the next seven years to 2020, the Government predicts average household electricity bills to increase from £563 to £598, a

[120] REA (2012) Renewable Energy: Made in Britain 2012
[121] BIS (2012) Low Carbon And Environmental Goods And Services (Lcegs) 2011/12
[122] http://www.retro-expo.co.uk/media/industry-news/uk-green-economy-celebrates-as-government-figures-show-6bn-boost2/#.Uhy_cGT47nI
[123] DECC (2013) Estimated impacts of energy and climate change policies on energy prices and bills 2012
[124] BIS: Energy-intensive industries: compensation for indirect costs of energy and climate change policies
[125] Ofgem (2011) Factsheet 108: Why are energy prices rising?
[126] Ofgem (2011) Factsheet 108: Why are energy prices rising?

£35 or six per cent increase. Energy and climate change policies are expected to go from saving the average household £18 on electricity in 2013 to £72 in 2020.

Figure 12 shows how factors discussed in this report contribute to the overall expected increase in average household electricity bills between now and 2020. Between 2013 and 2020, the cost of supporting low carbon generation is likely to be the main driver of increases to electricity bills, increasing by around £86. Most of this increase is expected to be attributable to renewables support through Feed-in Tariffs, the Renewables Obligation and the majority of Electricity Market Reform costs over this period. Carbon costs are also expected to increase by £51, primarily driven by the UK's Carbon Price Floor, introduced in April 2013 to supplement the EU Emissions Trading System.

The Government estimates that savings from energy efficiency policies[127] will increase by £149 over the period, more than offsetting increases from carbon costs and supporting low carbon generation. Whilst there is strong consensus that the opportunity exists to realise these savings, some have expressed concern that the evidence base to support the success of Government energy efficiency policies is limited.

Finding 23

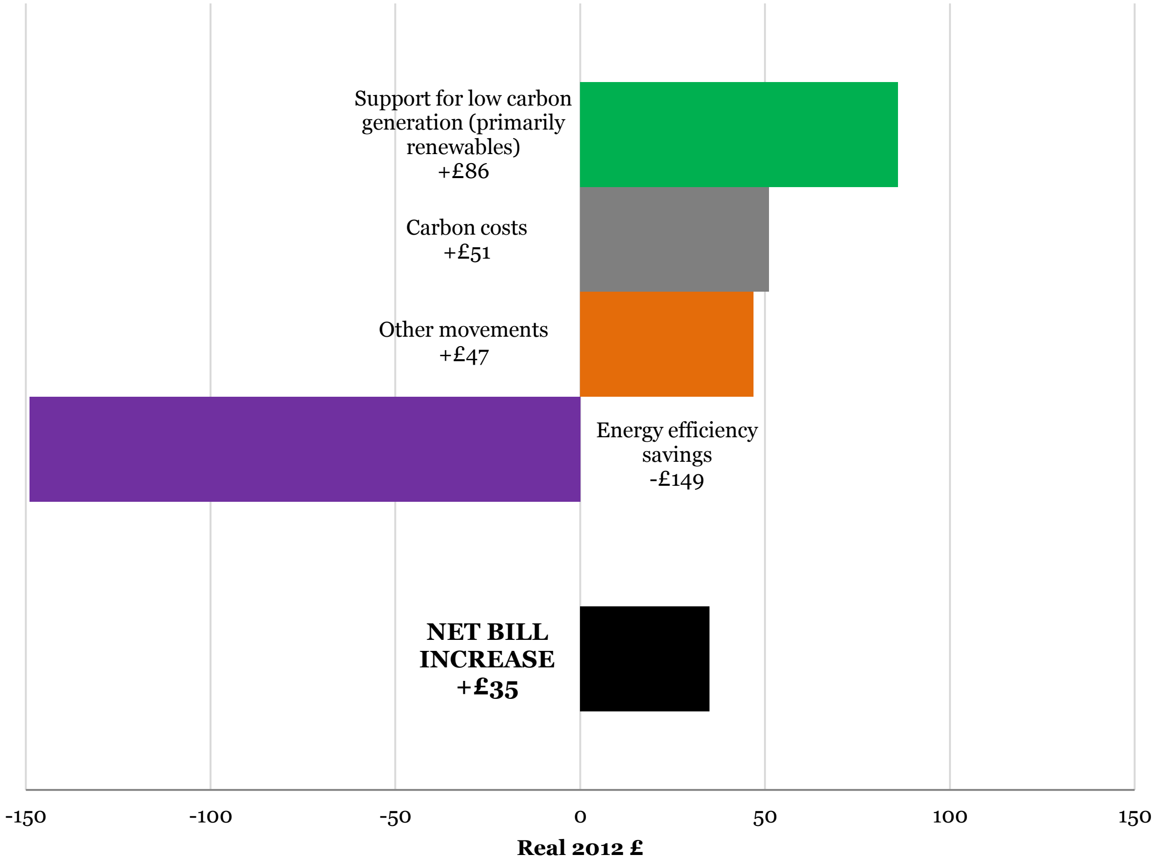
Recent historic energy bill increases were driven by higher gas prices, whereas forecast bill increases are expected to be substantially driven by support for renewables. However, increases to energy efficiency savings could more than offset increases in support for low carbon generation and carbon costs between now and 2020. Evidence to support assumed success of energy efficiency policies is, nevertheless, limited.

Finding 24

Although increasing support for renewables is likely to be a key driver of higher electricity bills to 2020, there are potentially significant benefits not reflected in bill impact analysis including improved bill predictability, future bill savings and macro-economic benefits.

[127] Products policies, EEC, CERT, CESP, ECO and Green Deal

Figure 12: Average household electricity bills, 2013-2020



Source: DECC (2013) Estimated impacts of energy and climate change policies on energy prices and bills

Notes: 1) Support for low carbon generation (primarily renewables) includes Feed-in Tariffs, Renewables Obligation and Electricity Market Reform.
2) Carbon costs include EU Emissions Trading System and UK Carbon Price Floor.
3) Other movements includes price and policy effects.
4) Energy efficiency savings includes EEC 1&2, CERT, CESP, Green Deal, ECO and Products Policy.

As discussed above, affordability is about more than absolute bill impacts. This analysis does not reflect the exposure of consumers to fossil fuel prices. An increased share of renewables is likely to displace some fossil fuel generation, reducing the upside and downside risks from fossil fuel prices and increasing bill predictability. Recent research found that bill predictability is a component of affordability valued by consumers[128]. This is one benefit derived from the current premium paid for renewables that is not reflected in the bills analysis above. Equally, the bills analysis above does not reflect potential macro-economic benefits or future bill savings that support for renewables could lead to.

Electricity prices in the UK have risen considerably over the last decade. Between 2004 and 2010, the average electricity bill for a 'dual fuel' household increased by 60 per cent, compared to general inflation of 17 per cent. This was mainly driven by increases in the price of wholesale gas, with support for low carbon generation and policy to improve energy efficiency in homes accounting for 18 and 12.5 per cent of the increase respectively. Prices continued to rise in 2011[129], with increases in the price of gas primarily driven by rising global demand.

[128] Parkhill, K.A., Demski, C., Butler, C., Spence, A. and Pidgeon, N. (2013) Transforming the UK Energy System: Public Values, Attitudes and Acceptability – Synthesis Report (UKERC: London).
[129] CCC (2012) Energy prices and bills – impacts of meeting carbon budgets

4. DEPLOYMENT

The UK's renewable resource

The UK has some of the world's best renewable energy resources, with excellent wind, wave and tidal potential. It is estimated that the UK's resources have the practical potential to provide up to 769 terawatt hours of electricity per year, more than double current annual supply.

The table below compares different estimates for the practical renewable resource that could be harnessed for power generation in the UK. The practical resource is that which is thought to be viable once technical and physical constraints have been factored in. This is derived by first assessing the total resource available (such as all the energy contained within the wind over the UK). The technical characteristics of technologies, such as their conversion efficiencies, are then used to narrow this estimate down to the technical potential of a resource. External physical constraints, for instance the land and sea that cannot be used to accommodate wind farms, are then factored in to produce the total practical resource estimate that is displayed below.

Figure 13: Practical UK resource estimates for renewables (terawatt hours per annum)

	Offshore Valuation Study	DECC	CCC	Carbon Trust
Onshore wind		83		
Offshore wind	406	430		
Floating wind	1533			
Solar photovoltaic		140		
Hydro		12	8	
Tidal range	36	40		
Tidal stream	114	139	116	21
Wave	40	40		50
Geothermal		35		
Domestic biomass (2050)		200 - 550		
Imported biomass (2050)		100 - 350		

Sources: Offshore valuation group (2010) The offshore valuation: a valuation of the UK's offshore renewable energy resource
DECC (2010) 2050 Pathways Analysis
DECC, DfT, Defra (2012) Bioenergy Strategy – Analytical Annex
Carbon Trust (2011) Accelerating Marine Energy

Uncertainties

The estimates above necessarily rely on a host of assumptions regarding resource availability, technical viability and land and sea use. The uncertainty in these estimates increases for less mature technologies such as marine, as assumptions regarding technical and practical feasibility are inherently uncertain at the early stage of technology or commercial development. Offshore wind technology could be deployed at depths of up to 45 metres using current technology (solid foundations), but the development of floating foundations would potentially allow a far greater resource to be harnessed. This technology is at an early stage of development, although there is relevant expertise in the offshore oil and gas industries[130]. The majority of medium and large hydro sites have already been developed, with the majority of additional potential thought to be at sites of less than five megawatts[131].

The potential contribution from bioelectricity is set by the availability of fuel, which is obtained from solid biomass, and waste streams. Power generation will compete for these feedstocks with uses in transport (conversion to biofuel) and heat. Solid biomass can be produced domestically or imported, whereas waste streams are unlikely to be traded at volume internationally. Current domestic feedstock production is enough to provide up to 75 terawatt hours of energy, the majority of which is from waste. It is estimated that domestic production could provide 100 - 200 terawatt hours by 2050, through increased forest harvesting and energy crop production. Large resources may also be available for import in future. The size of these resources is uncertain, and will be determined by sustainability constraints as well as land, water and resource availability. By 2020, the UK may be able to import 100 – 200 terawatt hours (largely woody biomass), with 100 – 350 terawatt hours thought to be available, within constraints, by 2050[132].

The resources identified above are far larger than current electricity generation, which in 2012 was 354 terawatt hours[133]. These would also be sufficient to meet significantly increased electricity demand in the future. In scenarios that achieve the 2050 carbon target using large scale electrification of heating and transport, total electricity demand could be as high as 610 terawatt hours[134].

Finding 25

Taking account of uncertainties, evidence suggest that the UK has sufficient practical renewable resources to meet at least a substantial proportion of electricity demand volume, now and out to 2050.

How much renewable power could the UK deploy?

The UK has considerable renewable resources, but despite an increase in their use for power generation since 2000, only a small fraction of these are currently harnessed. In 2000, these provided 2.6 per cent of total electricity supply. By 2012, this had increased to 11.3 per cent, or 41.3 terawatt hours[135]. The Government has set a firm strategic direction for the role of renewables to 2020, setting an ambition to source at least 30 per cent of electricity from these sources. By 2030, 70 to 90 per cent of electricity supply will need to be low carbon if Carbon Budgets are to be met[136], and the Committee on Climate Change has set out that renewables could provide between 30 per cent (140 terawatt hours) and 65 per cent (300 terawatt hours) of electricity by 2030. The Committee has also said that if

[130] EWEA (2013) Deep water: The next step for offshore wind energy
[131] ARUP (2011) Review of the generation costs and deployment potential of renewable electricity technologies in the UK
[132] DECC, DfT, DEFRA (2012) Bioenergy Strategy Analytical Annex
[133] DECC (2013) Energy Trends – May 2013
[134] DECC (2011) The Carbon Plan
[135] DECC (2013) Digest of United Kingdom Energy Statistics
[136] CCC (2013) Next Steps for Electricity Market Reform

practical resource potential were the only consideration, renewables could provide the entire volume of electricity expected to be needed in 2050:

> *'The resource potential for renewable electricity sources is commensurate with electricity demand projections that in some scenarios reach over 500 [terawatt-hours] by 2050 (i.e. if resource potential were the only consideration, sector decarbonisation based wholly on renewables would be feasible)'* Committee on Climate Change

An entirely renewable power sector is very unlikely to arise however, due to other constraints that Government must balance.

Key factors

How successful near term targets are met, and the longer term role of renewables in providing low carbon supply will depend on the following factors, rather than on the size of resources:

Affordability

Cost is likely to be the most crucial factor determining the deployment of renewable technologies. The evolution of their generation costs relative to alternate low carbon options, nuclear and fossil fuels with carbon capture and storage, will be vital in determining what role each of these technologies plays in the long term. Onshore wind is already becoming competitive with unabated gas generation, but other technologies are at an earlier stage cost maturity. The Government intends to move to competitive auctions for low carbon supply in the 2020s, where technologies will compete for revenue support through Contracts for Difference. Cost reductions will be contingent on technical and commercial development through research and learning by doing and deployment at scale, themselves dependant on the success of policy support. Other factors, such as the costs of network integration, will also condition the economics of renewables relative to alternative options.

Grid integration

Power stations are connected to consumers by transmission and distribution networks and the owners of the networks play a critical role in integrating power stations into the electricity system and ensuring the safe and reliable operation of the system. The different characteristics of technologies, and where they are located, will impact on system operation and overall network costs. Renewables will often be located in more novel environments requiring extensions to the network to connect new assets, and can trigger the need for reinforcements elsewhere to ensure power can be transferred to where it is needed.

A second cost consideration arises from the different supply characteristics of renewable generation compared to that of traditional thermal generation. As outlined in Chapter 1, managing a network with high levels of renewable power is technically feasible, provided there is sufficient investment in tools to handle varying supply. The overall net costs and benefits are as yet unclear and will form part of longer term consideration of the role of renewables.

As well as being a driver of overall costs, network issues can also slow deployment. Delays to network upgrades will impact on the volume of projects that can be connected in some areas, as has been the case in Scotland in recent years[137]. Expensive or delayed network access can also act to curtail projects, and slow overall deployment.

[137] CCC (2011) Renewable Energy Review

Environmental sustainability

New energy infrastructure will need to be delivered within the environmental constraints outlined in chapter 2. The practical resource estimates outlined above exclude areas of land and sea that are unlikely to be developed due to environmental concerns. However, knowledge of the environmental impacts of newer technologies continues to develop. The ultimate effect on the roll out of specific technologies is unclear, and will tend to be project-specific. For example, a proposed offshore wind farm was rejected by the Government in 2012 over the cumulative effect it would have, along with several other projects, on local bird populations. Environmental constraints are most likely to be a constraining factor for the deployment of solid biomass, which will depend on the development of sustainable imports in the short term, and development of domestic resources in the longer term.

Public acceptability

Local opposition can prevent projects from going ahead, with public understanding and support a key requirement for the successful deployment of all energy infrastructure. It is particularly key for many renewable technologies as these often involve siting infrastructure in more novel locations (compared to the development of the power sector in the second half of the twentieth century). Public attitudes surveys, conducted every quarter since July 2012 on behalf of the Government, show that on average, 80 per cent of the population supports the use of renewable energy. Of those interviewed, 55 per cent said they would be happy to have a large-scale renewable energy development in their area, with 20 per cent saying they would object. These studies also show that solar energy has the most support (82 per cent on average), followed by offshore wind (74 per cent), wave and tidal (73 per cent), onshore wind (66 per cent) and biomass (62 per cent)[138].

Public acceptability has, to date, been lower for onshore technologies. As the most widely deployed renewable technology, this is particularly the case for onshore wind. In recent years, planning application approval rates across the UK have fluctuated between 50 and 80 per cent. However, approval rates in England fell to 35 per cent in 2012/13[139], prompting the Government to make changes to the planning process for onshore wind farms to give greater weight to the concerns of local communities. A five-fold increase to the remuneration offered to local communities has been proposed[140]. Approval of offshore wind projects has historically been 90 per cent[141], although in some instances the visual impact on coastal areas has led to projects being redesigned or reduced in size. Renewable technologies are not alone in risking local opposition, and similar community remuneration schemes have been introduced for new nuclear and shale gas infrastructure. Similarly, community owned energy schemes can help build local engagement and acceptance of new infrastructure[142].

Deliverability

The rate at which technologies can be deployed will condition what role they play over different timescales, and can have important policy implications. Some projects, such as new nuclear or the proposed Severn barrage, could take the best part of a decade to come online once an investment decision is made. Offshore wind lead times can be five to eight years, typically less for onshore wind and in the case of solar PV, can be very rapid. As we show in Chapter 3, supply chain capacity is also important in ensuring costs are kept down. As supply chains and bottlenecks approach their physical limits price increases can

[138] DECC (2013) DECC Public Attitudes Tracking Survey – Wave 1, 2, 3, 4 and 5 Headline Findings
[139] DECC (2013) 'Onshore wind: communities to have a greater say and increased benefits' Press notice 13/057
[140] DECC (2013) Onshore Wind Call for Evidence: Government Response to Parts A and B
[141] RenewableUK (2012) State of the Industry Report
[142] Energy & Climate Change Committee (2013) Local Energy

negatively impact on technology economics. This has been seen recently in the European offshore wind market. Providing stable demand is a key part of bringing newer technologies' costs down, but a balance must be struck between this and the costs of revenue support given to technologies during their early, and more expensive, stage of development.

It is worth bearing in mind the trade-offs between costs and benefits across the portfolio of options. Onshore wind is the cheapest form of renewable generation, and likely to continue being so for some time, although high levels of deployment will create challenges for the planning system. Offshore technologies, whilst more expensive, reduce visual and other impacts onshore. For example, the proposed tidal barrage across the Severn estuary could generate power equivalent to approximately 2600 onshore wind turbines per year if built, although this would come at significant environmental cost[143].

Deployment to 2020

There is a relatively clear pathway of renewables' deployment to the end of this decade, thanks to the EU Renewable Energy Directive target, accompanying technology roadmaps and revenue support through the Renewables Obligation and Contracts for Difference with the Levy Control Framework. In order to meet the EU Renewable Energy Directive, which requires that the UK meet at least 15 per cent of energy demand from renewable sources by 2020, the Government has set an ambition to generate at least 30 per cent of electricity from renewable sources by the end of the decade[144], up from 11.3 per cent in 2012[145]. Based on expected levels of demand, this will require around 120 terawatt hours of electricity from renewables[146] (compared to 41.3 terawatt hours in 2012).

Electricity demand over this period is expected to remain relatively stable, but is particularly sensitive to assumptions on economic growth and the effectiveness of policies to reduce electricity demand[147]. There will be continued power station retirements over this period, with 10.4 gigawatts set to close by 2020[148], and potentially more if some of the remaining 15 gigawatts of coal capacity closes as a result of age, worsening economics and tightening air pollution regulations[149]. Renewables and unabated gas are the two options for providing new capacity this decade. This is because the Government is legislating to prevent the construction of new coal-fired power stations without carbon capture and storage technology, and the lead time for new nuclear plant means that the first reactor in the new build programme, if a Contract for Difference is agreed, will not likely come online until at least 2020. Carbon capture and storage technology for fossil fuel power plants is still in development, and it is likely that only one or two demonstration projects are completed over this time horizon. Therefore only a small volume of new abated fossil fuel capacity is likely at most.

Figure 14 illustrates deployment potential for different renewable technologies to 2020 as set out by the Government in July 2013.

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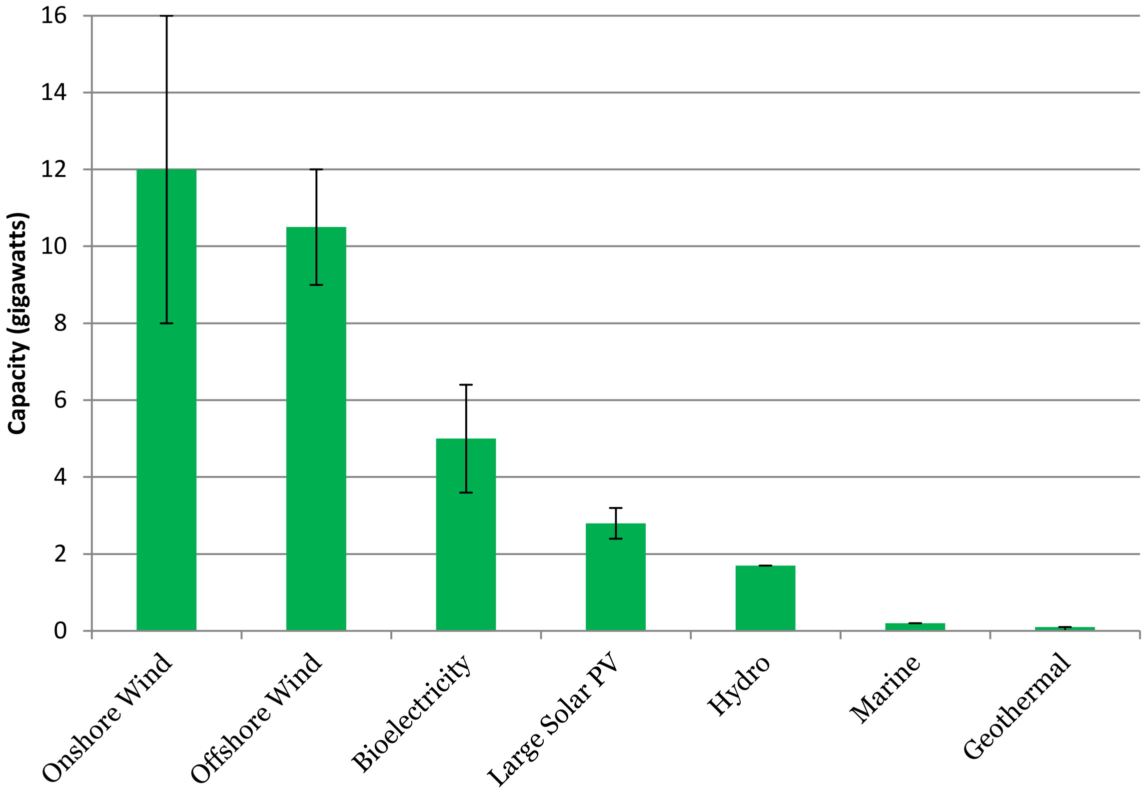
[143] 3 MW turbines; assumed 2056.84 MWh per GW capacity; Total barrage output: 16.5 TWh
[144] DECC (2009) National Renewable Energy Action Plan for the United Kingdom
[145] DECC (2013) Digest of United Kingdom Energy Statistics
[146] DECC (2012) Renewable Roadmap Update & Energy & Emissions Projections (2012)
[147] DECC (2012) Energy & Emissions Projections
[148] CCC (2013) Next Steps for Electricity Market Reform
[149] Carbon Connect (2013) Future Electricity Series Part 1: Power from Fossil Fuels

Figure 14: Potential deployment of renewables technologies by 2020



Source: DECC (2013) Levy Control Framework and Draft CfD Strike Prices

Notes: 1) Dependent on industry cost reductions overtime – figures are not Government forecasts and do not include deployment supported under the small-scale Feed-In Tariff. The upper end of the offshore wind range is reached if costs come down to meet industry aspirations and there is some delay to nuclear and CCS build out.
2) Bioelectricity includes 1.2 – 4.0 gigawatts of biomass conversion, 0.9 gigawattts of landfill gas, 0.5 gigawatts of energy from waste and 0.3 gigawatts of dedicated biomass, plus other sources.

Outlook

The amount of revenue support available to low carbon generators up to 2020 has been agreed by Government under the Levy Control Framework, allowing the combined cost of revenue support to rise to an annual cost of £7.6 billion in 2020 (2012 prices). There is general consensus that this is enough to bring forward capacity to generate around 30 per cent of electricity from renewables by 2020.

Increasing the share of renewables will require changes to the networks, how they run and how system security is maintained. In 2009, the *Electricity Networks Strategy Group*, a forum between industry and Government, identified and agreed key 'low regrets' transmission network upgrades required by 2020, such as reinforcing connections between England and Scotland[150]. Work on these proposals has continued, with key upgrades on track for timely completion[151]. Work is also underway by National Grid and DECC to ensure sufficient generating capacity and grid balancing mechanisms are available to handle higher levels of varying supply[152,153]. The exact mix of renewable technologies in 2020 will be determined by various factors affecting each technology:

[150] ENSG (2009) Our Electricity Transmission Network, A Vision for the Future.
[151] ENSG (2012) Our Electricity Transmission Network, A Vision for the Future: Updated summary report
[152] National Grid (2013) Informal Consultation on Demand Side Balancing Reserve and Supplemental Balancing Reserve
[153] DECC (2012) Capacity Market: Design and Implementation Update

Onshore wind

It is estimated that there is a sufficient quantity of projects in the pipeline[154], given historic planning approval rates, to achieve 15 gigawatts deployment by 2020. To reach this would require the deployment rate to be maintained at recent levels (about 1 gigawatt a year)[155]. Whilst the pipeline appears healthy, the industry has warned that recent increases to community remuneration could make some projects uneconomic[156]. Less onshore wind in the mix is likely to make meeting the 2020 ambition for renewables more expensive.

Offshore wind

Offshore wind is expected to play a large role in meeting the 2020 target, although the exact extent will depend largely on cost reduction. The Government has stated that if costs can be reduced to £100 per megawatt hour by 2020, up to 18 gigawatts of capacity could be brought online[157]. Approximately 12 gigawatts of capacity has, or is waiting to be granted, the necessary consents[158], with a total of 36 gigawatts of projects in development[159]. Meeting the higher end of the range above would require significantly higher build rates than have been achieved historically[160], with construction expected to slow down over the next three to four years due to a reduced number of projects granted consent between 2009 and summer 2012[161]. Deployment at the end of the decade is dependent on cost reductions and successful implementation of the new Contracts for Difference scheme, which is currently creating uncertainty for projects to be delivered after 2017, when the scheme will commence.

Bioenergy

Coal conversions are expected to provide the majority of new biomass capacity this decade, with the conversion of Drax and Ironbridge power stations in 2013 adding one gigawatt of capacity, although this was partly offset by the closure of Tilbury (0.75 gigawatts) in July 2013. Five gigawatts of existing coal capacity is currently considering conversion to biomass. Fuel and environmental concerns will be the key constraint, as domestic sources of woody biomass cannot meet this additional demand, which will instead be met by imports from abroad. These will need to display robust sustainability credentials to ease environmental concerns. Revenue support for new-build dedicated biomass power stations will be limited to 400 megawatts of new capacity. Dedicated plants can accept a wider range of feedstocks, making them more suitable to accept likely UK biomass production in future; however, this level of ambition appears in line with the size of the domestic resource available in the short to medium term.

Solar photovoltaic

The potential contribution of solar photovoltaic is highly uncertain, and will be largely determined by the cost of the technology, which has fallen significantly in recent years. If costs continue to fall, deployment under current revenue support schemes (Feed-in Tariffs and the Renewables Obligation) could range between 5.9 and 24.3 gigawatts by the end of the decade, with greatest deployment potential under the Feed in Tariffs scheme[162]. The Government estimates that 20 gigawatts is the theoretical technical maximum that could

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[154] Those with submitted planning applications through to those awaiting construction
[155] CCC (2013) Meeting Carbon Budgets – 2013 Progress Report to Parliament
[156] RenewableUK; 'Onshore wind industry responds to new Government guidance on local community engagement and benefit funds'; Press notice 06.06.13
[157] DECC (2011) Renewable Energy Roadmap
[158] CCC (2013) Meeting Carbon Budgets – 2013 Progress Report to Parliament
[159] RenewableUK (2013) Offshore Wind Projects; May 2013
[160] National Grid (2013) National Grid EMR Analysis
[161] RenewableUK (2013) Building an Industry: Updated Scenarios for Industrial Development
[162] DECC (2012) Government Response to Consultation on Feed-in Tariffs Comprehensive Review Phase 2A: Solar PV Tariffs and Cost Control & (2013) EMR Spending Review Announcement

be accommodated on the grid by 2020, which would require expansion of current electricity storage and export capacity[163].

The four technologies described above will provide the vast majority of power to meet the 2020 objective. Wave and tidal stream devices are at an early stage of technological development, and are unlikely to be cost effective enough to allow deployment at scale this decade. The industry currently expects that between 120 – 340 megawatts of capacity is achievable[164], short of the ambition announced in the Government's Renewable Energy Roadmap (300 megawatts). Several tidal barrage proposals are in development, although long lead and construction times mean that if pursued they are unlikely to come online until after 2020. A recent feasibility study by the Government into the largest, the Severn Barrage (up to 6.5 gigawatts), ruled out this option in the immediate term[165], although the project continues to be developed.

Finding 26

There is a clear pathway to increase the share of renewable generation this decade, with agreed policy support, renewables targets and work being carried out to ensure the network and framework for its operation are ready.

Finding 27

The UK is currently on track to meet the 2020 targets, but this is most contingent on the following factors: planning consents for onshore wind, the success of biomass conversions for bioelectricity, and technology cost reductions for offshore wind and solar photovoltaic.

Deployment to 2030

The strategic direction for the UK power sector after 2020 is contested. The retirement of old power stations will continue during the decade to 2030, with up to 27 gigawatts of capacity potentially retiring[166], including 4 gigawatts of nuclear by 2023. Electricity demand is expected to grow slowly, especially if ambitious Government efficiency programs are successful. There are important interactions between the different parts of the energy system (power, heat, transport) that must also be considered over this timescale. For example, demand could increase faster towards the end of the 2020s if more heat and transport is electrified.

The Government's strategy is to develop three low carbon options each with the potential to deliver substantial new capacity in the decade to 2030. The three options are fossil fuels with carbon capture and storage, nuclear power and offshore wind. Each faces substantial challenges to being an acceptable option for widespread deployment. Fossil fuels with carbon capture and storage has yet to be demonstrated commercially and at scale. New nuclear is yet to prove it is a commercial possibility at a price acceptable to Government. The costs of offshore wind are currently substantially higher than other options although significant potential for cost reductions have been identified.

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[163] DECC (2012) Renewables Obligation Banding Review for the period 1 April 2013 to 31 March 2017: Government Response to further consultations on solar PV support, biomass affordability and retaining the minimum calorific value requirement in RO
[164] Renewable UK (2013) Wave and Tidal Energy in the UK: Conquering Challenges, Generating Growth
[165] DECC (2010) Severn Tidal Power: Feasibility Study Conclusions and Summary Report
[166] CCC (2011) The Fourth Carbon Budget

Cost

There are two key variables that will decide what supply mix develops during this decade. The first is the cost and deliverability of the three low carbon technology options. The Government intends to move to competitive auctions between technologies during the 2020s,[167] and those providing the lowest cost output will be most successful under conditions of competitive price discovery. This will largely depend on the cost trajectory of renewables compared with nuclear and fossil fuels with carbon capture and storage. Recent modelling suggests that developing a balanced mix will ensure long term cost effectiveness, as a portfolio of options will mitigate against the risks that one or several technologies cannot be delivered as required beyond 2030[168]. Such risks include the failure or delay in demonstrating and commercialising carbon capture and storage technology for fossil fuel power stations, or that new build nuclear or offshore wind costs do not fall as expected. In these instances, the technology mix can be adapted.

Carbon abatement

The extent to which power sector carbon emissions are reduced through this decade will also be a key factor in determining the share of low carbon, and renewable, generation. To be on track to meet the 2050 carbon reduction target, the Committee on Climate Change recommends that the carbon intensity of supply be reduced to around 50 gCO2/kWh by 2030. If the Government's ambition for renewable power is achieved, the carbon intensity of supply will be around 200 gCO2/kWh by 2020.

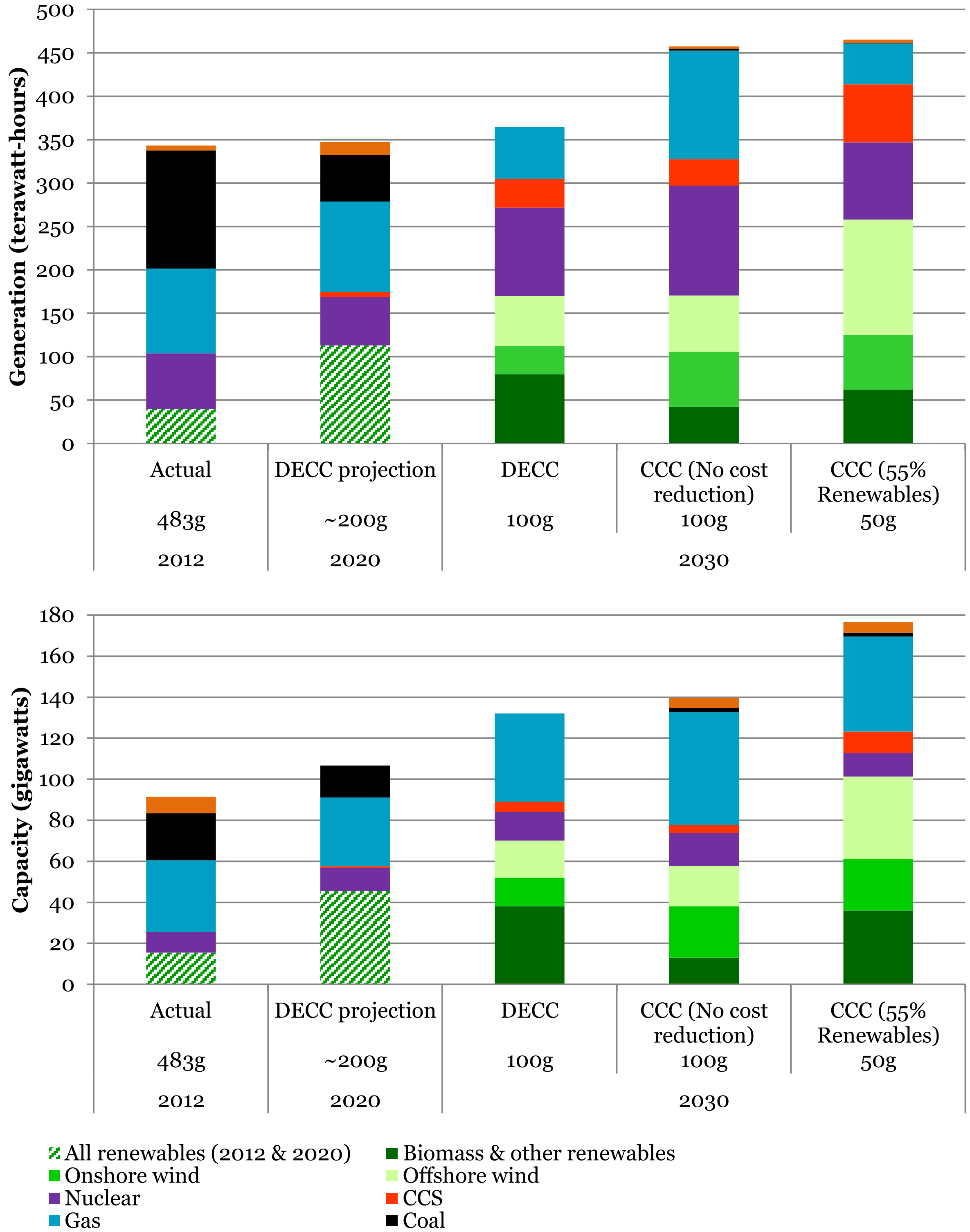
The Government has yet to provide clarity on what ambition will be set for 2030. It has set economy wide carbon budgets up to 2027 and has indicated the existing and planned policies are likely to result in an emissions intensity for the power sector of around 100 gCO2/kWh, although it has model scenarios between 50 and 200 gCO2/kWh in 2030[169]. Tighter emissions targets will require that more power comes from low carbon sources, requiring a share of between 72 and 90 per cent (328 to 411 terawatt hours[170]) under a 50 and 100g scenario[171]. A lower abatement ambition implies that more power comes from unabated gas, and remaining coal generation, with only 43 per cent of supply coming from low carbon sources in the 200g scenario modelled by Government[172].

Although it does not recommend this trajectory, the Committee on Climate Change believes that carbon budgets could be met under certain 100g scenarios, provided steeper savings are made in other sectors. The Committee has warned, however, that a 200g scenario would be incompatible with meeting the 2050 target[173].

Figure 15 below illustrates different scenarios, based around different technology deliverability scenarios and carbon abatement ambition.

[167] DECC (2013) Consultation on the Draft EMR Delivery Plan
[168] UKERC (2013) The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios
[169] DECC (2013) Consultation on the draft Electricity Market Reform Delivery Plan
[170] CCC (2013) Next steps on EMR reform: securing the benefits of low-carbon investment; nb. total supply assumed increased to between 460 and 458 TWh
[171] CCC (2013) Next steps on EMR reform: securing the benefits of low-carbon investment
172 DECC (2013) CFD Impact Assessment, January 2013
[173] CCC (2013) Next steps on EMR reform: securing the benefits of low-carbon investment

Figure 15: Comparing modelled generation and capacity mixes (2012-2030)



Sources: DECC (2013) Energy Trends
DECC (2013) Energy and emissions projections
DECC (2013) Electricity Market Reform Delivery Plan
CCC (2013) Electricity Market Reform: The Next Steps

Notes: 1) Capacity are not de-rated

Figure 15 illustrates the role of renewables under different carbon abatement and future technology cost scenarios in 2030, modelled by the Government and the Committee on Climate Change. The Government's scenario in 2030 achieves the upper bound of the recommended carbon intensity (50 – 100g), and suggests a renewables share of 45 per cent, alongside a large increase in nuclear power. The first scenarios by the Committee on Climate Change illustrates a 100g carbon intensity that could occur if technology costs do not reduce as expected; this is broadly in line with the equivalent Government scenario. The second scenario achieves the recommended 50g carbon intensity, and assumes that developing technology costs reduce, with the result that renewable generation increases to a 55 per cent share. The majority of this increase is due to extended offshore wind deployment, which highlights the potentially large role for this technology, given the size of the available resource.

It should be noted that the Committee on Climate Change scenarios forecast supply to rise by around a quarter, reflecting increased demand for electrification of other sectors (heat and some transport) whereas Government assumes power sector demand remains stable. These scenarios are drawn from a range modelled by both organisations, and are presented here to illustrate two variables (carbon abatement and costs). Others, such as deliverability of nuclear and commercialisation of carbon capture and storage for fossil fuel power stations could be equally important in future. Nuclear power plays a significant role in the scenarios described above, and failure to deliver new capacity would require an increase in the deployment of renewables and fossil fuel power stations with carbon capture and storage to achieve the carbon abatement ambition. There are also further factors and constraints specific to each technology that will condition deployment over this time horizon:

Onshore wind

There may be limited scope to increase onshore wind generation without greater public support, with deployment in 2020 reaching around half of the available practical resource (15 out of 28 gigawatts[174]). Analysis suggests that an additional five gigawatts of capacity could be added this decade[175]. There will also be scope to repower old sites with new, more powerful turbines.

Offshore wind

The practical potential of offshore wind is very large, and the extent to which it forms a part of the mix will this decade will rely on cost reduction. This is itself dependent on providing sufficient confidence to industry to invest in supply chains for deployment to 2020 and beyond (see chapter 3). A failure to do so will reduce the likelihood that this technology is available for deployment at scale and at the right cost in the 2020s. This is particularly critical as offshore wind is likely to be the only renewable technology that can be deployed at sufficient scale should other low carbon technologies cannot be delivered as currently expected. This is because of the size of the resource and relatively few other constraints. This is reflected in the range of current deployment estimates. Government estimates that capacity by 2030 could be between 9 and 39 gigawatts, providing 26 to 119 terawatt hours per year[176]. Given expected deployment to the end of this decade, the lower figure would assume that no new capacity is added in 2020s.

Bioelectricity

Expansion of bioelectricity is likely to come from additional energy from waste facilities, and dedicated biomass plant producing combined heat and power (CHP). Support for coal conversions will be withdrawn by 2027, with new dedicated biomass plants (without heat

[174] DECC (2010) 2050 Pathways; [83 terawatt hours converted to 28 gigawatts capacity]
[175] CCC (2011) Renewable Energy Review
[176] DECC (2013) EMR Delivery Plan Consultation

capture) excluded from revenue support after 2017. Deployment of biomass CHP will also be contingent on the development of district heat networks, to provide a demand for the heat produced in these power stations.

Solar photovoltaic

Cost reduction will again be vital, which will be driven globally. Although public acceptance of ground based solar farms may become a limiting factor, the potential on buildings remains very large at around 140 terawatt hours per year[177]. Deployment beyond 20 gigawatts however would require significant investment in management of both the transmission and distribution networks, as well as greater interconnection, storage and demand side response.

Marine

These technologies could provide a means to substantially increase renewable power, particularly if other renewable technologies encounter deployment constraints (onshore wind) or fail to reduce in cost (offshore wind). Marine technologies are likely to face lower public opposition, being located offshore, but their costs will remain highly uncertain whilst in the process of commercialisation. It is thought that wave and tidal stream devices could be delivering between 2 and 8 terawatt hours per year by 2030[178]. Several tidal range schemes could also be delivered in this time period, unlocking the estimated 40 terawatt hours available per year from this resource. Government has committed to enter direct negotiations with these projects over the level of revenue support they may receive under Contracts for Difference[179].

Geothermal

Deep geothermal power generation is not currently deployed in the UK. Although revenue and research and development support has been provided by Government, projects have struggled to advance and industry has called on Government to provide greater support if projects in development are to move forward[180].

All technologies could be deployed to some extent in this timeframe. Deployment of more mature technologies, such as onshore wind, may encounter increasing practical constraints as deployment nears anticipated practical limits. This decade will be crucial to those technologies that are less developed, with stable policy support required if these are to be successfully commercialised. A 50 per cent share for renewables would require a substantial increase in the use of offshore wind, and may be appropriate if nuclear investment is not increased beyond currently approved sites. Estimates of maximum feasible renewable deployment vary between 65[181] and 87 per cent[182], which would require deployment of wind, solar and biomass at the upper end of feasible estimates, as well as additional supply from tidal and wave technologies. A significant increase in supply chain capacity would also be required to deliver these ranges by 2030.

Higher levels of renewable penetration would also require investment in and modification of electricity networks to manage increased variation in supply (outlined in chapter 1) which would otherwise impact both on system security, and the operation of power markets (periods of high renewable output and low demand could lead to very low prices, dampening incentives to build further generation capacity). The high deployment

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[177] CCC (2011) Renewable Energy Review
[178] DECC (2010) 2050 Pathways
[179] DECC (2013) Electricity Market Reform: Delivering UK Investment
[180] Renewable Energy Association; ‘Response to the Government’s conclusions on RO banding levels’; 25.07.2012
[181] CCC (2011) Renewable Energy Review
[182] Garrad Hassan (2011) UK Generation and Demand Scenarios for 2030

scenarios imply significant expansion of interconnection, storage and demand side response to manage varying supply from some renewables.

Finding 28

The Government expects that nuclear power is likely to provide the majority of additional low carbon electricity between 2020 and 2030. However, should costs or deliverability prevent this from happening, more low carbon electricity from renewables or fossil fuels with carbon capture and storage will be needed to meet carbon objectives.

Finding 29

Should other low carbon technologies (nuclear, fossil fuels with carbon capture and storage) fail to be delivered as currently expected, renewables could provide between 45 and 55 per cent of total generation by 2030.

Strategic direction in the 2020s

There are numerous uncertainties facing the electricity supply mix beyond 2020, including technology costs, fossil fuel prices and carbon prices. Whilst the 2020 renewable energy target and policies to support its achievement have given strategic direction in the decade to 2020, beyond 2020 there is little to indicate the direction of travel. Carbon budgets are the only near-term indicator, but as they cover the whole economy, they leave open a wide range of possibilities for the power sector and for individual technologies within it. Consequently, debate about technology deployment in the decade to 2030 has been extremely wide in its scope.

Deciding when and to what extent to set strategic direction is a balancing act and dependent upon Government's risk appetite. Committing to a strategic direction early risks skewing deployment towards technologies that end up being more costly or setting an unhelpful precedent if commitments are not honoured. Committing to a strategic direction late, however, risks delaying commercialisation and deployment of less mature technologies which runs counter to climate science emphasising the need for early action due to the cumulative nature of greenhouse gas emissions. It also risks forgoing the wider economic benefits of attracting supply chains to the UK, including jobs, inward investment, increased international competitiveness and export opportunities. Furthermore, finance costs for all technologies are likely to be higher because of higher policy and political risk. Quantifying the potential impact and likelihood of these risks materialising is not easy because of inherent uncertainties that are impossible to avoid.

'Low regrets' actions

We found there to be good consensus that, taking these risks into account, Government could be doing more to provide clarity of strategic direction for the power sector beyond 2020. In particular, Government could do more to narrow the scope of debate about technology mix by working with industry and academia, first to establish 'low regrets' levels of technology deployment, and second to ensure that policies are in place to incentivise investments needed to deliver these low regrets actions.

This approach is likely to result in earlier and lower cost supply chain investments which secure additional economic benefits and open up additional economic opportunities. The downside risk is limited by only committing to low regrets deployment, until better technology information is available.

There are examples of similar approaches being adopted in related areas. For example, Technology Innovation Needs Assessments (TINAs) aim to fulfil a similar role for public sector investments. The methodology involves analysing the potential role of each technology, estimating the value from cutting technology costs and creating green growth opportunities from exports. This analysis is used to identify innovation priorities of greatest benefit to the UK and assess the case for UK public sector intervention.

A similar approach was also used by the Electricity Networks Strategy Group, a forum of industry and Government, which identified and advised on low regrets network reinforcements required to enable the 2020 renewable power ambition to be met, such as the reinforcement of connections between Scotland and England.

Identifying low regrets levels

Government should work together with industry and academia to establish levels of deployment for specific technologies that are 'low regrets'. These are minimum levels of deployment common to a high proportion of likely future scenarios. To give a simplified example, taking modelling used by the Committee on Climate Change in its 'Next steps on Electricity Market Reform' report, under a range of deployment scenarios offshore wind deployment rises from 12 gigawatts in 2020[183] to at least 20 gigawatts by 2030. This implies 'low regrets' additional deployment for offshore wind beyond 2020 of eight gigawatts. As in the case of Technology Innovation Needs Assessments, this number could be stretched higher to reflect expectations about macro-economic benefits from supply chain investments. The example given is a crude simplification of the process and testing advisable, but the principle is similar. Conducting the process transparently and being explicit about the results would help make sure that policy is based on the best possible evidence, aid consensus building and narrow the scope of debate.

Offshore wind example

Without sufficient long term clarity over demand for offshore wind in the UK, it is unlikely that the UK will develop a strong domestic supply chain[184]. Competitive supply chains are needed to reduce costs through competition and innovation, with supply chain bottlenecks contributing to the higher costs of wind power in recent years. A UK supply chain could also significantly support cost reduction by reducing transport costs and by ensuring equipment is adapted to UK conditions[185]. The long payback period of supply chain investments (factories, ports) require long term confidence in a sufficient rate of deployment during the 2020s, which is not provided by the current framework. A failure to attract supply chains to the UK could also result in the loss of potential industrial benefits through employment, investment and export potential, and see the UK fail to capitalise on its current global lead in development and deployment of the technology.

A 'low regrets' approach would help provide the longer term clarity to the offshore wind industry that is required to secure supply chain investments. Although offshore wind is not currently thought to be the lead contender for providing the bulk of low carbon supply required by 2030, such a policy would increase the likelihood that necessary cost reductions are achieved, and mitigate against the higher costs that would result in the failure to deliver nuclear and carbon capture and storage as currently projected. Industry analysis suggests that a higher level of deployment (45 gigawatts) by 2030 would be the optimal scenario for inward investment, although some inward investment benefits could still be captured at lower levels[186].

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[183] Also the upper end of the potential deployment outlined by the Department of Energy and Climate Change on publication of draft strike prices, as displayed in Figure 14.
[184] RenewableUK (2013) Building an Industry: Updated Scenarios for Industrial Development
[185] Crown Estate (2013) Offshore Wind Cost Reduction Pathways Study
[186] RenewableUK (2013) Building an Industry: Updated Scenarios for Industrial Development

Finding 30

Government could do more to narrow the scope of debate about technology mix beyond 2020 by working with industry and academia, first to establish 'low regrets' levels of technology deployment, and second to ensure that policies are in place to incentivise investments needed to deliver these low regrets actions.

Deployment to 2050

The electricity supply mix out to 2050 is necessarily less certain, but is likely to be guided by two principle factors. Firstly, power sector emissions will need to be reduced further as carbon budgets tighten, and secondly, demand for electricity is likely to increase. These considerations are also relevant when considering the medium term trajectory that leads to this period. By 2050, total UK greenhouse gas emissions will need to have been reduced by 80 per cent on 1990 levels. As a result, power sector emissions will need to have reduced by up to 96 per cent relative to 2012[187], alongside deep cuts to emissions across the rest of the energy system.

Electricity demand will also need to increase, potentially significantly, during this period. Whilst the effects of economic growth on electricity demand are likely to be restrained if energy efficiency policies are successful, energy system modelling consistently shows that some electrification of the heat and transport sectors is likely to be required to achieve the 2050 target[188,189,190]. Individual gas boilers and internal combustion engines will need to be replaced, and there are a number of electric (electric vehicles, heat pumps) and non-electric (biofuels, hydrogen fuel cells) options that could be substituted for them. If electrification is preferred, this would lead to a substantial increase in demand for power, of between 30 to 60 per cent by 2050 (on 2007 levels)[191].

The technologies needed to meet the range of possible future challenges exist, but it is not yet clear what mix of them will best meet the objectives of energy policy, particularly affordability. Research by the UK Energy Research Centre suggests that the Government's broad tactic of supporting deployment of all options until an optimal mix of technologies becomes more apparent is sensible.

Finding 31

The best technology mix and size of the power sector beyond 2030 are highly uncertain, mainly due to unknown future technology costs and unknown future electricity demand, itself dependent on the extent to which heat and transport sectors are electrified.

Deployment scenarios

New generating capacity will be required to replace retiring plant, including wind capacity added in the 2010s and 2020s. Given tightening carbon budgets during this period, new generation will need to come from low carbon sources, with little scope to add unabated gas if it is to be used for baseload power. Renewables are likely to continue to play a significant part, and could become the dominant form of generation, depending on achieved cost reductions and the availability of alternatives. Updates to the model used to inform the Government's Carbon Plan in 2011 and the Fourth Carbon Budget, suggests

[187] Derived from CCC (2012) The 2050 Target; and DECC (2012) DUKES (carbon emissions)
[188] UKERC (2013) The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios
[189] ETI (2011) Modelling the UK energy system: practical insights for technology development and policy making
[190] AEA (2011) Pathways to 2050 – Key Results
[191] DECC (2011) The Carbon Plan

that renewables could contribute significantly across many future scenarios, although it may be difficult to achieve full decarbonisation if neither carbon capture and storage nor nuclear is available.

Scenarios where renewables are the dominant form of generation see the deployment of significant amounts of offshore wind, wave and tidal stream technology, as well as bioenergy if carbon capture and storage technology is available[192]. Commercialisation of less developed technologies would need to take place in the preceding decades to ensure their cost effective delivery at scale, as would further investment in measures to manage supply from varying renewables.

Finding 32

If a high proportion of renewables transpires to be favourable beyond 2030, offshore wind, marine, solar and possibly bioelectricity are likely to be the technologies offering highest deployment potential.

Bioenergy with carbon capture and storage

There could be a substantial role for bioenergy in this timeframe should carbon capture and storage technology be successfully commercialised. If it is available, evidence suggests that its use in conjunction with bioenergy, to produce negative emissions, will likely be the most cost effective way to achieve the overall carbon target. This is because, if bioenergy feedstocks can be sustainably sourced, capturing their emissions on combustion will lead to a net removal of carbon dioxide from the atmosphere. Modelling carried out by the Energy Technologies Institute suggests that a low carbon energy system that achieves the 2050 carbon reduction target would cost on average £44 billlion more per year without bioenergy, using it to provide heat and power directly within industrial processes such as refining, and using gasification to produce hydrogen, synthetic natural gas and some power generation[193]. It is important to note, however, that these models assume bioenergy is zero carbon, which as discussed in chapter 2 is unlikely to be the case.

Finding 33

Bioenergy across the energy sector could reduce the cost of meeting the 2050 carbon target by £44 billion per year by 2050 if a) carbon capture and storage technology is commercialised, giving the possibility of negative emissions, and b) adequate feedstocks can be sustainably sourced.

[192] UKERC (2013) The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios
[193] Energy Technologies Institute (2011) Modelling the UK energy system: practical insights for technology development and policy making

ABOUT CARBON CONNECT

Carbon Connect is the independent forum that facilitates discussion and debate between business, government and parliament to bring about a low carbon transformation underpinned by sustainable energy.

For our members we provide an events and research programme that is progressive, independent and affordable. As well as benefitting from our own independent analysis, members engage in a lively dialogue with government, parliament and other leading businesses. Together, we discuss and debate the opportunities and challenges presented by a low carbon transformation underpinned by sustainable energy.

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