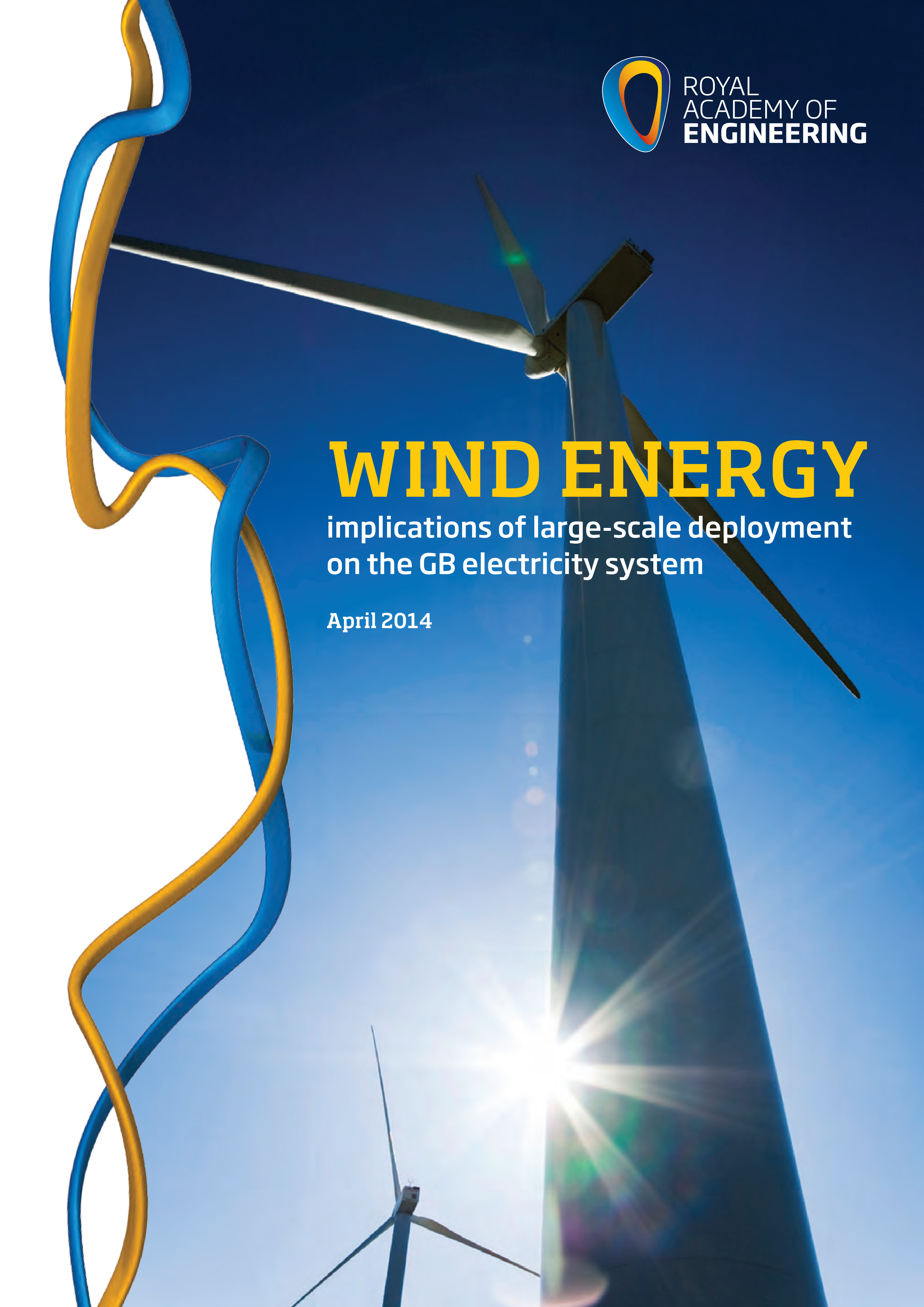

ROYAL ACADEMY OF ENGINEERING

WIND ENERGY

implications of large-scale deployment on the GB electricity system

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Foreword

The Royal Academy of Engineering has undertaken a considerable body of policy work on aspects of the UK energy system because it is critical to the UK economy and to society as a whole.

Wind energy has emerged as the first variable renewable generating technology to be deployed at scale on the system. In its deliberations on whether to undertake this study, the Academy's Engineering Policy Committee was aware that the debate around wind energy has become polarised and, in some respects, heated. The committee therefore felt that the Academy could make a useful contribution by setting out the engineering characteristics of the technology and exploring the implications of increasing the amount of wind energy on the electricity system.

The study did not seek to form a position on whether wind power should play an increased role in the energy system but rather to identify the engineering issues that need to be addressed with this form of generation. The study took as its starting point the need, enshrined in law, to reduce greenhouse gas emissions by 80% from 1990 levels by 2050 and the requirement by the EU for 15% of total energy to be generated from renewable sources by 2020.

To avoid any perception that the study was inclined towards or against wind energy, it was agreed that it should be chaired by an Academy Fellow with no connection to the energy industry. In that role, I have been ably supported by a small expert working group and an Academy staff secretariat.

In preparation for our report, we undertook a search of the literature, invited written evidence and held sessions in which we took evidence from people with a range of expertise, experience and views. The report has been reviewed both by expert Academy Fellows and other experts outside the Academy.

As I have learned in the course of this study, the issues raised by wind energy are many, novel and complex. The deployment of deep offshore wind energy especially brings with it many challenges in terms of operation and maintenance and connection to the grid. However, the challenge of the wider transformation of the grid that is needed by 2030 is far greater; a higher level of penetration of wind will be only one of the pressures on the grid system of the future.

These matters deserve debate. I hope that readers will find that this report on wind energy provides a helpful and balanced assessment of the challenges that engineers are tackling and will need to tackle as the UK seeks to create an energy system that is fit for the future.

Rear Admiral John Trewby CB FREng
Chair of the working group

Executive summary

GOVERNMENT POLICIES ARE COMMITTED TO PROVIDING 15% OF ENERGY FROM RENEWABLES BY 2020 AND TO CUTTING 80% OF GREENHOUSE GAS EMISSIONS BY 2050

Introduction

Wind power is set to play an increasingly significant part in the future energy system of Great Britain. Government policies are committed to providing 15% of energy from renewables by 2020 and to cutting 80% of greenhouse gas emissions by 2050.

The Academy has, in previous reports, assessed the impact of these policies on the country's overall energy system and, separately, on the transport and heat sectors. This report considers wind energy, the first variable renewable technology to reach significant levels of deployment on the GB electrical system and one that is expected to increase penetration levels in the future.

The purpose of this report is to identify the engineering challenges that are associated with the deployment of wind energy and the implications of its deployment at greater scale from the perspective of the energy 'trilemma' – security, cost and decarbonisation.

Wind capacity

The UK has some of the best wind resource in Europe. Wind generation in the UK has increased significantly since the 1990s, and the latest provisional figures indicate that it now accounts for around 7.7% of major sources of electricity generation. This remains, however, less than 2% of total energy demand, with heat and transport continuing to rely predominantly on gas and oil. The level of penetration of wind energy is some way behind other countries such as Germany, Denmark, Spain and Ireland, whose experience can be drawn on to inform the UK programme.

Estimates for the amount of wind capacity expected in the future vary but, by 2020, it is possible that the installed capacity of wind could more than double to around 26GW and provide around 20% of electrical energy consumed. Estimates for 2030 are more uncertain, but should deployment rates continue at the upper end of industry forecasts, the level of capacity could more than double again and reach levels that are currently unknown on any large-scale grid system. Before this increased proportion of wind energy can be accommodated, there are many engineering challenges to be overcome and an acceptable risk profile achieved.

AS MOVES ARE MADE INTO DEEPER WATER AND HARSHER CONDITIONS, NEWER, OFFSHORE-SPECIFIC DESIGNS ARE BEING DEVELOPED THAT ARE EASIER TO INSTALL, OPERATE AND MAINTAIN

The technology

Onshore wind turbines are a mature technology. Improvements in power output, reliability and connection to distribution networks are still being made but there are over four decades of operational experience to draw on. Offshore wind is less mature with early, shallow water turbines being mainly onshore turbines adapted for the marine environment. As moves are made into deeper water and harsher conditions, newer, offshore-specific designs are being developed that are easier to install, operate and maintain. However, the marine environment will always be demanding and, as a result, offshore wind energy is likely to remain more challenging and expensive than onshore. Moreover, there remain a number of important issues affecting offshore transmission connections that need to be resolved.

The payoff with offshore wind is a better wind resource and higher load factors with greater space to exploit and less impact on local communities. However, it is important to note that the seas around the UK are extremely busy and any offshore wind developments must be integrated carefully with close cooperation and sensitivity to existing industry and ecosystems.

Integrating wind into the national grid system

Traditionally, the electrical system has consisted mainly of thermal generation plant that could be dispatched – or called on – as and when demand required. The primary energy for this has predominantly come from fossil fuels (gas, coal and oil), with nuclear power and now a small but increasing proportion of renewables. Each of these different types of generation has its own characteristics: from the constant base load of nuclear to fast response open cycle gas turbines. The market determines the basic overall mix of plant and within that the system operator, National Grid, must ensure the secure operation of the system.

Wind energy has its own particular characteristics, some of which present novel challenges for the system operator. The most obvious difference with wind energy is that its output is determined by local weather conditions. Whether or not this presents a problem, however, depends on a number of factors, not least the level of demand. Low wind at times of low demand and high wind at times of peak demand are not a problem for the system to manage. But low wind at times of peak demand could potentially put the system into difficulties. Equally, high wind at a time of low demand presents a different set of issues.

Managing these events is fundamental to the operation of the system and, to date, the balancing mechanisms already in place have been sufficient to cope with the amount of wind energy on the system. Only recently has wind output needed to be considered as a specific uncertainty to be addressed by means of additional balancing mechanisms. Issues will arise but evidence suggests that, at penetration levels for wind energy of up to around 20% of electricity demand, the established grid system mechanisms should be able to cope. This level of penetration is expected sometime around 2020 or soon thereafter.

In order to run the grid securely, the system operator needs to know what demand and generation conditions are coming over various timescales – annually, daily and hourly. Forecasts of wind output already provide accurate predictions up to a day in advance. Research continues to improve these forecasts but the chaotic nature of the wind will always result in uncertainties the system will need to cope with.

The longer-term analysis of wind output over many years should give system operators the information they need to plan the type and scale of back-up services required to operate the grid securely. The shorter-term forecasting of wind conditions, looking just a few hours into the future, enables system operators to manage the mix of generation more efficiently and securely. Further research in these areas will be critical to keeping system costs down.

In calculating the system capacity margin, the total capacity of the wind fleet is not counted, as the wind cannot be guaranteed to blow when demand is at its highest. A measure known as 'equivalent firm capacity' determines what proportion of wind capacity can be counted towards the overall margin. In its latest assessment of the capacity margin, Ofgem, the gas and electricity market regulator, determined that 17 to 24% of wind capacity could be counted towards the overall margin. This does not mean that wind is expected to produce at least 17% or more of its total installed capacity all the time; this measure is part of a more general probabilistic calculation on the overall risk that supply might fall below demand. However, there is debate regarding the figure used by Ofgem and work continues to refine the assessment of capacity margins.

EVIDENCE INDICATES THAT WIND ENERGY WILL REDUCE THE AMOUNT OF FUEL BURNT TO GENERATE ELECTRICITY WHERE IT DISPLACES FOSSIL FUEL PLANT

Carbon emissions

Evidence indicates that wind energy will reduce the amount of fuel burnt to generate electricity where it displaces fossil fuel plant, as is the case on the current GB system. The scale of the reduction in carbon emissions depends on a complex range of factors including the type of generation that is replaced by the wind energy, the structure of the market and reserve requirements. Some inefficiency from part-loaded plant and additional operating reserves will further attenuate the carbon emissions reduction, but on a well-engineered system this ought to be negligible.

For the GB grid, the marginal avoided emissions for wind energy are roughly equivalent to the average emissions of coal and gas plant but slightly less than the amount of emissions that would be avoided by reducing demand by the same amount.

Economics

It is tempting to look for one figure to give the definitive cost of energy from wind but any potential metric, such as the levelised cost of energy, will always have limitations and uncertainties. Despite this, most cost estimates suggest that onshore wind is one of the cheapest forms of low carbon electricity and that offshore wind is currently more expensive. This is borne out by the recent announcements on 'strike prices' for the new Contracts for Difference feed-in tariff subsidy mechanism. These are the prices that each low carbon generating technology will be guaranteed for each unit of electricity produced. Over the next five years, onshore wind will receive £95 – £90/MWh and offshore wind will receive £155 – £140/MWh on contracts that will last 15 years.

In terms of the system and the cost to the customer, different generating technologies have different economic characteristics. Gas or coal plant (without carbon capture and storage) are cheaper but do not meet carbon reduction criteria. They have low capital costs per MW but are subject to higher and more volatile running costs. Adding carbon capture

GOVERNMENT POLICY IS DRIVING TOWARDS A FUTURE WHERE WIND ENERGY PLAYS A MUCH GREATER ROLE IN THE ENERGY SYSTEM

and storage would make them better in terms of carbon emissions but would increase both the size and uncertainty of the capital costs. Nuclear energy has higher capital costs but lower and more certain running costs. Wind energy also has high capital costs and low running costs. The future energy system is likely to be a mix of all these technologies and will need to balance the required level of capital investment with the expected price of energy to the consumer.

Increasing the level of UK manufactured content in the wind industry would also help the overall economic impact. Even though the UK leads the world in installing offshore wind, only around 25% of the capital is spent in the UK. None of the major wind turbine manufacturers currently have a factory in the UK, although, at the time of writing, plans were being announced. There is a variety of reasons for the lack of a UK supply chain; political uncertainty concerning the electricity market in the UK has almost certainly been a major factor. The implementation of the government's Electricity Market Reform should help remove some of this uncertainty, but the industry needs confidence that the offshore wind industry has a secure future in order to invest in infrastructure (particularly ports), the supply chain and the skilled jobs that this would create.

Wind and the future energy system

Government policy is driving towards a future where wind energy plays a much greater role in the energy system. This will by no means be the only pressure on the future energy system. In order to meet the targets set out in the Climate Change Act, the grid will need to be largely decarbonised by around 2030. To achieve that, it is likely that much of the energy requirement for domestic heating and transport would need to be electrified in the form of heat pumps and electric vehicles. This would significantly increase overall electricity demand as well as affecting the fluctuations in demand, both daily and seasonally.

Such a future system would require a number of new tools alongside low carbon generation so that it could be operated securely and cost-effectively. Foremost among these are demand side management, flexible generation, energy storage and interconnection.

This combination of the engineering challenges of deploying renewable energy at a much greater scale alongside a very different load profile would represent a paradigm shift in the country's energy system. A programme of change and investment in infrastructure of this scope and scale is unprecedented in peacetime Britain. The engineering challenges involved would be huge and complex but, with sufficient, sustained political will, strategic planning and innovative engineering, such a system could be built. However, such a future system would also require a fundamental shift in society's attitude to and use of energy. This would require an honest conversation with the public on the spectrum of issues. But without a clear, consistent strategy agreed by all stakeholders, it is highly likely that the future energy system would be less robust or much more expensive than it needed to be.

Conclusions

- Wind energy can make a significant contribution to electricity supply in the UK. Onshore wind is already a mature generation technology. Offshore wind brings more and complex engineering challenges, but engineers are providing innovative solutions.
- For levels of penetration of wind energy up to around 20% of electricity consumption on current demand profiles, as expected early in the 2020s, the system will remain secure using the balancing mechanisms already in place. Technical issues will arise, such as those relating to system inertia and frequency control, but these will be manageable if given sufficient consideration.
- Wind energy has a small carbon footprint and does reduce the carbon intensity of the grid system, although calculating the actual savings is complex and varies according to the location of the turbine and the generation mix of the system.
- At current fuel and carbon prices, onshore wind energy is more expensive than gas or coal plant but is one of the cheapest low carbon sources of electricity. Offshore wind is more expensive, as reflected in the strike prices offered for the new Contracts for Difference feed-in tariffs, but shows potential for cost reduction. The ultimate effect of wind energy on the price of energy to consumers is difficult to evaluate precisely because of inherent limitations and uncertainties in calculating current and future energy costs.
- Energy systems and technologies are global in nature and several countries are ahead of the UK in aspects of developing wind energy. Lessons should be learned where possible.
- Industry needs clarity and confidence in the regulatory regime and support mechanisms. The completion of legislation to enact Electricity Market Reform is encouraging but it needs to be implemented without delay and the trajectory to decarbonise the grid made clear as part of the next Carbon Budget. Long-term, cross-party consensus on future energy policy will be vital to ensuring sufficient investment and establishing a UK supply chain.
- By 2030, a wholesale transformation of the UK energy system will be required if government targets on carbon emissions are to be met. Integrating higher levels of wind energy will be one challenge among many. As well as low carbon generation such as wind energy, the future system would need to deploy such tools as demand reduction and management, flexible generation, interconnection, and storage. Significant changes in heating and transport are also expected.
- These challenges require a fundamental shift in society's attitude to and use of energy and will only be met with the support of both domestic and business customers. High levels of wind energy will result in large numbers of very large turbines. Whether these are onshore or at sea, they will inevitably have an impact on local communities and stakeholders. Government and industry must both play their respective parts in engaging honestly with these stakeholders, setting out clearly both the impacts and the benefits.
- The government must take the strategic lead in preparing for the transformation of the UK energy system, in partnership with industry and other stakeholders. The future energy system needs to be mapped out, at least in general terms, with solid engineering evidence backed up by economic and social considerations. Wind energy can play a significant role along with other forms of low carbon generation as well as demand reduction and management, interconnection and storage. However, without careful strategic planning incorporating all these elements as a system, the challenges will not be met.

1. The technology

1.1. Basic physics behind wind power

A wind turbine, like all forms of power-generating technologies, is a device that converts one type of energy into electrical energy: in this case, the kinetic energy of the wind. The turbine does this by slowing down the stream of air flowing past it and the resulting change in momentum is converted to electrical output via a generator.

In order for the turbine to be 100% efficient, all the kinetic energy would need to be removed from the air stream. But this would mean that the air behind the turbine blades would be stationary and no air could flow. In the early part of the 20th century, Frederick Lanchester, Albert Betz and Nikolay Zhukovsky independently determined that the theoretical maximum efficiency of any turbine, irrespective of design, is 59.3%.

This is similar to the theoretical efficiency of heat engines that are limited by Carnot's theorem and, as is the case in heat engines, in the real world, this theoretical maximum is never reached. Additional losses occur as the result of a variety of factors such as wake rotation, tip-loss and turbulence[1]. In practice, the highest attainable power coefficient is around 0.47 or about 80% of the theoretical limit.

It is often said that wind power is 'inefficient', but 'efficiency' can be confused with 'load factor', the measure of how much electricity is actually generated relative to its theoretical potential (See Section 4.3.1). Taking efficiency to mean how much of the available energy contained in the primary fuel (in this case wind) is converted into electrical energy, the reality is that wind energy efficiency compares favourably with other technologies. Turbines achieve overall efficiencies of almost 50% compared to approaching 60% for a modern combined cycle gas turbine or a maximum of around 30% for an internal combustion engine.

In practice, a wind turbine will produce its maximum power output over a range of wind speeds and will be designed in such a way as to maximise the energy output for the wind speed distribution at the location where it is to be installed. In general, a turbine will not produce any output for wind speeds below around 3m/s (7mph); it will attain maximum output at around 12m/s (27mph) and will cut out at about 25m/s (56mph). Cut-out at high wind speed can create problems for the grid system as it occurs more abruptly than cutting in from low wind speeds but current turbines are being designed to cut out in a more gradual and controlled fashion.

In terms of energy conversion, wind turbines are relatively efficient machines, comparing favourably with other types of generating technologies.

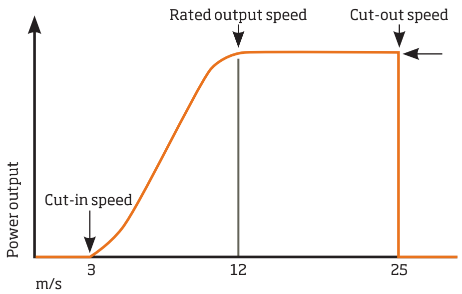


Figure 1.1 Typical wind turbine power output with steady windspeed

THE LARGEST MACHINE IS CURRENTLY AN 8MW TURBINE WITH A ROTOR DIAMETER OF 164M – FOR COMPARISON, THE WINGSPAN OF AN AIRBUS A380 IS 80M OR THE DIAMETER OF THE LONDON EYE IS 120M

1.2. Size of turbines and arrays

The basic physics of a turbine tells us that its power output increases with swept area (or the square of the diameter of the blade). So, for example, a turbine with a blade diameter of 40m gives a maximum power output of 0.5MW compared to a similar design of turbine with double the blade diameter of 80m that gives a maximum output of four times that amount of 2.0MW[2]. The increased power output is at least partly offset by increased costs resulting from bigger and more expensive rotors. And given that the rotor mass increases with the cube of the rotor diameter, there is an argument that larger turbines should be less cost-effective, although to date, innovations in turbine design have countered this trend.

In practice, the optimum size of the turbine can be calculated by a cost optimisation model that takes into account the marginal change in costs that result from a change in one of the design parameters.

In general, turbines have increased in size from relatively small, 50kW machines with a rotor diameter of around 15m in the early 1980s, to 2MW machines with a rotor diameter of 80m in 2000. Today, the largest machine is an 8MW turbine with a rotor diameter of 164m – for comparison, the wingspan of an Airbus A380 is 80m or the diameter of the London Eye is 120m. Larger, 10MW machines are being developed, but it is likely that the continued increase in size will level out to some degree.

Bigger turbines do produce more power but, when placed together in arrays, they need to be further apart, thus limiting the possible overall energy density of the wind farm. Compared to other types of electricity generation, wind energy is relatively low density. The actual energy density will depend on the specific location and MacKay[3] gives figures ranging from 6MW/km^2 or more for sites with high load factors or less than 1MW/km^2 for less productive sites. In comparison, nuclear power has energy densities in the order of 500MW/km^2. Fossil fuel powered thermal plant also have higher energy densities but they are high carbon and non-renewable. Other forms of renewable power tend to have energy densities of a similar order of magnitude to wind.

The reason why energy density is important is the amount of land area required to supply meaningful amounts of electricity. Wind energy needs a lot of space, which is limited in the British Isles, especially when restricted to non-built-up regions with a suitable wind resource. However, it should be noted that wind farms do not necessarily consume all the land that they occupy. Only a fraction (1–3%) of the land is taken up by the turbines and farming can still take place around them; Whitelee wind farm near Glasgow even has a thriving visitor centre and parklands. However, land will always be limited and planning permission on the best sites is increasingly difficult to obtain, which is one of the compelling reasons for developing offshore wind where there is less of a premium on space.

Wind energy is relatively low density and requires a significant land or sea area. Although the land can still be used for other purposes, the level of generation needed to meet the UK's targets is likely to require a greater area than can be readily be accommodated on land, hence the move to offshore.

1.3. Design of a turbine

The use of wind turbines to generate electricity dates back to the late 19th century but the development of large-scale grid systems meant there was little interest in wind turbines until the later part of the 20th century. At this point, two drivers emerged that encouraged both industry and governments to push the development and deployment of wind turbines. The first was the oil crisis of 1973 and the second was the need to decarbonise the energy system.

As with most technologies in the early stage of development, it took some time for an optimum design to become established. The 1980s saw the three-bladed, horizontal axis design gain prominence, although this is by no means the only design, and even within this design there are a number of variations and new developments, particularly for offshore turbines. The following subsections assess some of the basic engineering considerations in wind turbine design and likely future developments.

1.3.1. Rotor and blades

The rotor converts the movement of the wind into rotational shaft energy in the hub. In blade design, there are two major considerations: the number of blades and the material.

The number of blades is determined by a variety of factors including cost versus performance, noise and visual appearance. Most modern horizontal axis turbines have two or three blades. The optimum design is determined by a complex calculation that will take into account the expected operational parameters of the turbine such as the power rating, tip speed and loadings on the hub. Noise constraints will generally favour slower moving blades and there is a general consensus that three-bladed turbines are visually more acceptable. Combining these factors has led to three-bladed designs being favoured.

Materials are chosen for a combination of strength-to-weight ratio, cost, stiffness and fatigue life. The most popular materials are glass/polyester ply or laminate, glass/epoxy ply, and wood/epoxy laminate.

1.3.2. Drive train

The drive train, which consists mainly of the gearbox and generator in most cases, takes the rotating shaft energy and converts it to electricity. The aim is to produce the most efficient power output from the turbine while balancing torsion and load requirements on the machinery and electrical output characteristics for the grid connections.

Early turbines operated at fixed speed and fixed pitch but that mode of operation has essentially disappeared as the technology has developed. Modern turbine designs operate at variable speed. At low wind speeds, the rotational speed of the turbine is low; as the wind speed increases, so does the rotational speed, keeping the tip speed ratio (ratio of the tip speed of the blade to the oncoming wind speed) at the optimum level just like cruise conditions on an aeroplane. When the turbine reaches its maximum (rated) power, the blade pitch and electrical torque are adjusted to keep constant power and constant rotational speed.

Closely linked to the type of drive is the type of generator. The majority of large, thermal generators on the grid system use synchronous generators that synchronise to the national grid system at the same frequency. However, for a variety of technical reasons, mainly torsional and damping, this was not possible on early turbine designs. This meant that induction generators had to be used which led to higher energy losses in the rotor than synchronous machines and problems with integrating the turbine into the grid system.

As turbines have increased in size, drive systems have evolved. Fixed-speed induction generators were the drive system of choice on early turbines and worked effectively on turbines up to 1.5MW. Doubly-fed induction generators became common around 2000, offering the benefits of variable speed operation. At a similar time, full power conversion designs were developed that use both gearbox and direct drive set-ups with either wound rotor or permanent magnets.

FOUNDATION DESIGN FOR ONSHORE INSTALLATIONS IS WELL UNDERSTOOD, IN THE CASE OF OFFSHORE WIND TURBINES, IT IS AN AREA OF INTENSE RESEARCH

Developments continue with no clear consensus on the best drive train system for the future, but very large turbines with variable speed systems are now the norm.

The high cost of maintaining offshore turbines has focused developments on drive train reliability. Low ratio gear boxes and direct drive permanent magnet generators are being proposed for offshore turbines, where higher upfront capital costs are rewarded by lower operation and maintenance costs.

1.3.3. Tower and foundations

Towers are made mostly from steel and designed to support the nacelle and rotor safely under both extreme and fatigue loading. Computational dynamic models are now routinely applied to undertake comprehensive calculations of the aeroelastic response of the turbines. The dynamics are a vital part of the design. Modern steel rolling techniques allow a smooth taper from base to nacelle. The diameter at the base can be restricted by the size of loads allowed on the roads during transport to final site. Transport requirements can therefore be one of the main size restrictions on the maximum turbine capacity.

The foundation will be designed to cope with the maximum overturning moment of the turbine under extreme wind conditions. A variety of slab, multi-pile and monopile designs have been used depending on the local ground conditions.

Although foundation design for onshore installations is well understood, in the case of offshore wind turbines, it is an area of intense research. Not only does the design for offshore support structure have to take into account the load from the nacelle and rotor, but it also has to account for wave loading. Monopiles (cylindrical steel tubes driven into the seabed) have been the most common subsea support structure to date. These have experienced issues on a large number of offshore turbines, particularly with the transition piece that connects the tower to the foundation. This has resulted in expensive remedial work, but solutions to the problem are being developed. As water depth increases and wave forces become more significant, the weight of the monopile becomes excessive. Steel jacket structures, gravity bases and piling have also been used, and as offshore wind farms move further offshore and into deeper water, the option of floating turbines is also being investigated.

1.3.4. Control and monitoring system

Control systems are incorporated into all turbines to allow them to operate unattended and implement continuous optimisation of both the power performance and load alleviation.

As turbines get more sophisticated, the control system has become central to the performance of the turbine. Indeed, data gathering and modelling techniques are being used at all stages of turbine and wind farm design to improve performance. This is especially important for offshore wind turbines where better monitoring can limit the amount of repairs and maintenance

THE UK IS UNUSUAL IN THAT AROUND 35% OF ITS WIND FLEET IS OFFSHORE; GLOBALLY ONLY AROUND 2% OF WIND CAPACITY IS OFFSHORE

required to keep the turbines available to generate electricity for longer periods (see Section 1.4).

1.3.5. Offshore turbines

Although there are clearly many similarities between the designs of onshore and offshore wind turbines, there are differences that result from the particular operating environment. The marine environment offers both advantages and disadvantages. Installation in water is obviously more difficult than on land and becomes increasingly harder with deeper water (Section 1.3.3 has already dealt with foundation issues). Salt water is also highly corrosive. These negative factors are offset by stronger and less turbulent winds and fewer restrictions on the area available. Given their distance from domestic residences, there are also fewer constraints on noise, allowing faster blade tip speeds.

Originally, offshore installations took advantage of the most appropriate sites, close to land in shallow water, and utilised onshore turbine designs. Even early large-scale offshore farms such as Horns Rev 1 used turbines that had originally been designed for onshore installations.

However, the further exploitation of offshore wind energy will require sites much further from shore and in much deeper water. Experience of offshore operations has already refined the turbine design, but major developments are underway including more radical designs. The Energy Technologies Institute, for example, has investigated a number of new possibilities including tension leg floating platforms, vertical axis turbines, large blades and optimised deep-water horizontal axis designs[4]. The main aim of these projects, as with most offshore wind research, is to improve reliability and reduce costs.

The UK is unusual in that around 35% of its wind fleet is offshore; globally only around 2% of wind capacity is offshore (see Section 2). This reflects the leading position of the UK in the installation of offshore wind but also the fact that offshore wind is at a much earlier stage of development than onshore wind in terms of operational experience, despite over 20 years of large-scale offshore wind farms. This is developing rapidly, but the potential technical issues and uncertainties relating to the large-scale deployment of deep water offshore wind farms far from the shore should not be underestimated.

Safety at sea is also of vital importance. The waters around the UK are extremely busy and offshore wind farms are covering increasingly large areas that interact with shipping lanes. The design of offshore wind arrays that seeks to optimise output can conflict with the requirements for marine safety, particularly relating to the boundary of the array and navigation of ships. Close cooperation between wind developers and organisations such as Trinity House is important in order to resolve potential issues.

The design of turbines continues to progress, particularly in the drive train and control systems. More radical design innovations are being considered for offshore wind as it moves into deeper waters further from land.

1.4. Maintenance

The longevity of mechanical plant is always a concern to owners and developers and wind turbines are no exception. The owners of wind farms will have committed a large amount of capital to the construction and installation of the turbines on which they will only obtain a return if the turbine is available to generate electricity. Keeping the turbine operational in increasingly hostile locations is therefore critical to the profitability of the development. This is particularly true for offshore developments where access is limited by weather conditions. Turbines are typically designed for 20 years' life and now many early turbines have completed such lifespans. Typically, modern onshore turbines are available to generate electricity 97–98% of the time. Availability of offshore wind is lower but improving, particularly as access for maintenance has increased from around 30% of the time five years ago to around 70% today.

TURBINES ARE TYPICALLY DESIGNED FOR 20 YEARS' LIFE AND NOW MANY EARLY TURBINES HAVE COMPLETED SUCH LIFESPANS

As the installed capacity of the wind fleet has grown, so has the level and sophistication of operations and maintenance (O&M). In the first few years, the O&M is usually undertaken by the original equipment manufacturer. Later on, large owners may have their own O&M division, but there are also other specialist companies that fulfil this role. The wind energy business is coming of age in the context of O&M; however, it is not yet up to quite the same level as conventional plant since, for example, condition monitoring is still at a fairly early stage. Offshore, the task is, of course, much more demanding but vital. In the early days of offshore operations, access was a major problem but now access arrangements have been developed and availability is steadily rising. Increasing the level of early-stage engineering and testing of components prior to installation will also improve the performance of the turbines and the industry is steadily improving in this regard. Research has indicated that, as they age, the load factors of UK onshore wind farms have decreased at an average rate of around 0.4 percentage points a year, which is a similar rate to the performance degradation observed in other kinds of power stations. There are signs, however, that newer farms are losing output at a slower rate than this.[5]

Comprehensive Supervisory Control and Data Acquisition (SCADA) systems are employed in all commercial wind farms. They collect data from individual turbines and from substations. Often there are meteorological masts that are also used to gather wind data for the site. In the last 10 years or so, a great deal of effort has been expended on the development of analysis systems to investigate the behaviour of the operational farms and a high level of understanding has developed, allowing optimisation of both wind farm design and operation. This task is more complicated for wind farms than for large conventional plant since there are many external influences that play an important part, including topography, local flow conditions, forests, wakes from the turbine blades and ice. There are sophisticated tools for examining both the behaviour of operational farms and also the estimation of the performance of the farms pre-construction. The latter has benefited greatly from recent developments in meteorology – remote sensing, satellite data and computational tools – as well as the application of computational fluid dynamics to promote understanding of the local flow over the site. This subject does however remain an essential field for research and development and the science is moving fast.

Early stage engineering, monitoring and maintenance are vital to keep turbines available to generate energy and improve performance.

FOR WIND FARMS THAT ARE FAR FROM LAND, IT MAKES SENSE FOR THERE TO BE A COMMON CONNECTION FOR SEVERAL WIND FARMS

1.5. Connection

1.5.1. Electricity transmission connections to the GB system

Wind turbines can be connected either to the high-voltage transmission network or to a distribution network. Most individual wind turbines, erected for businesses or local communities, are connected to the latter, while large wind farms are connected to the former.

To obtain an electrical connection and capacity on the GB transmission network, an application for connection must be made to National Grid which has the role of the National Electricity Transmission System Operator (NETSO).

As a result of this application, analysis will be undertaken to assess the impacts on the GB transmission network and identify what reinforcements are required and when they are likely to be completed. A connection date is then agreed with the new generation project and contracts are signed that place obligations on the developer of the project, the NETSO and the transmission operator to which the project is connecting.

During the lifecycle of the project, up to final connection, the developer of the project is required to underwrite and provide security against the liability inherent in the investment required by the transmission operator. Once connected, the developer pays an annual locational charge for use of the transmission network.

The technical requirements for a connection to the GB transmission network are detailed in the Grid Code and the rules that determine the reinforcements required are contained within the Security and Quality of Supply Standards.

1.5.2. Offshore transmission electricity connections to the GB system

The process for connection of offshore generation is more complicated. When offshore wind was first planned, it was assumed that operators would also manage the connection to shore, which is sensible for wind farms close to land.

For wind farms that are far from land, it makes sense for there to be a common connection for several wind farms. In 2010, Ofgem introduced regulations establishing the concept of an offshore transmission owner (OFTO). The regulations prohibit the OFTO being the same entity as the wind farm owner and also prohibit National Grid from acting as an OFTO. Although introduced to increase competition and bring new participants and capital funding into the industry, this arrangement suffers from a serious 'chicken and egg' problem: potential wind farm operators are reluctant to commit capital to building a wind farm with no guarantee of a grid connection when they need it and potential OFTOs are reluctant to invest in a new connection without guarantees that there will be customers for the capacity they are installing.

One option that is available to developers is to build the offshore transmission connection themselves and then to transfer it to an OFTO when the wind farm is commissioned, in return for a payment based on the asset value and set by Ofgem.

The current arrangements for connecting offshore wind farms to the grid are complicated and may be a deterrent to investment; continued efforts are needed involving all stakeholders if this matter is to be addressed.

2. Capacity of wind in the UK

2.1. Current levels in the UK

As of the third quarter 2013, the UK had 10.8GW of wind installed (approximately 7.1GW onshore and 3.7GW offshore)[6]. Of this, around 8GW is connected to the transmission system, meaning that almost 3GW of onshore wind is embedded in the distribution system and not visible to the transmission system operator.

Figure 2.1 shows how this has progressed from virtually nothing 20 years ago to more rapid deployment over the last 10 years. The figure shows that, after four years of around 1GW installed per year, with an increasing proportion from offshore wind, 2012 saw a jump to 2GW of new capacity split roughly equally between on and offshore. 2013 has seen this trend continue.

This level of capacity relates to a total electrical system that averages around 43GW of total supply, ranging from about 20GW overnight in summer to about 55GW at peak times in winter (see Figure 3.1).

While there are few parts of the UK that are without wind turbines, Figure 2.2 overleaf shows that they are not distributed evenly[7]. The highest density is in the central belt of Scotland as well as the northern Highlands and Grampians. Wales and the West Country also have significant numbers of wind turbines, as does Northern Ireland, while the West Midlands and southern England have the fewest. This reflects the desire by wind developers to locate turbines in the windiest and least populated locations but also results in the turbines generally being built a long way from the centres of demand, thus requiring extensions and upgrades of transmission lines.

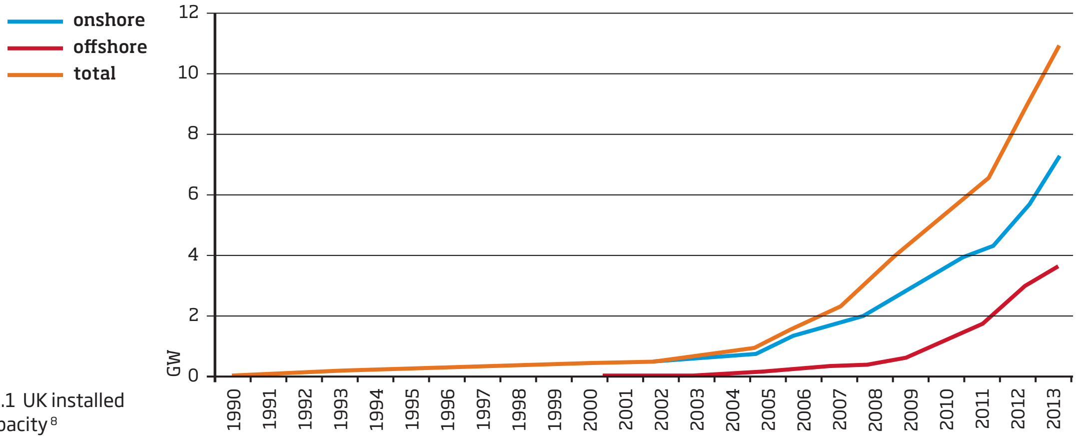


Figure 2.1 UK installed wind capacity[8]

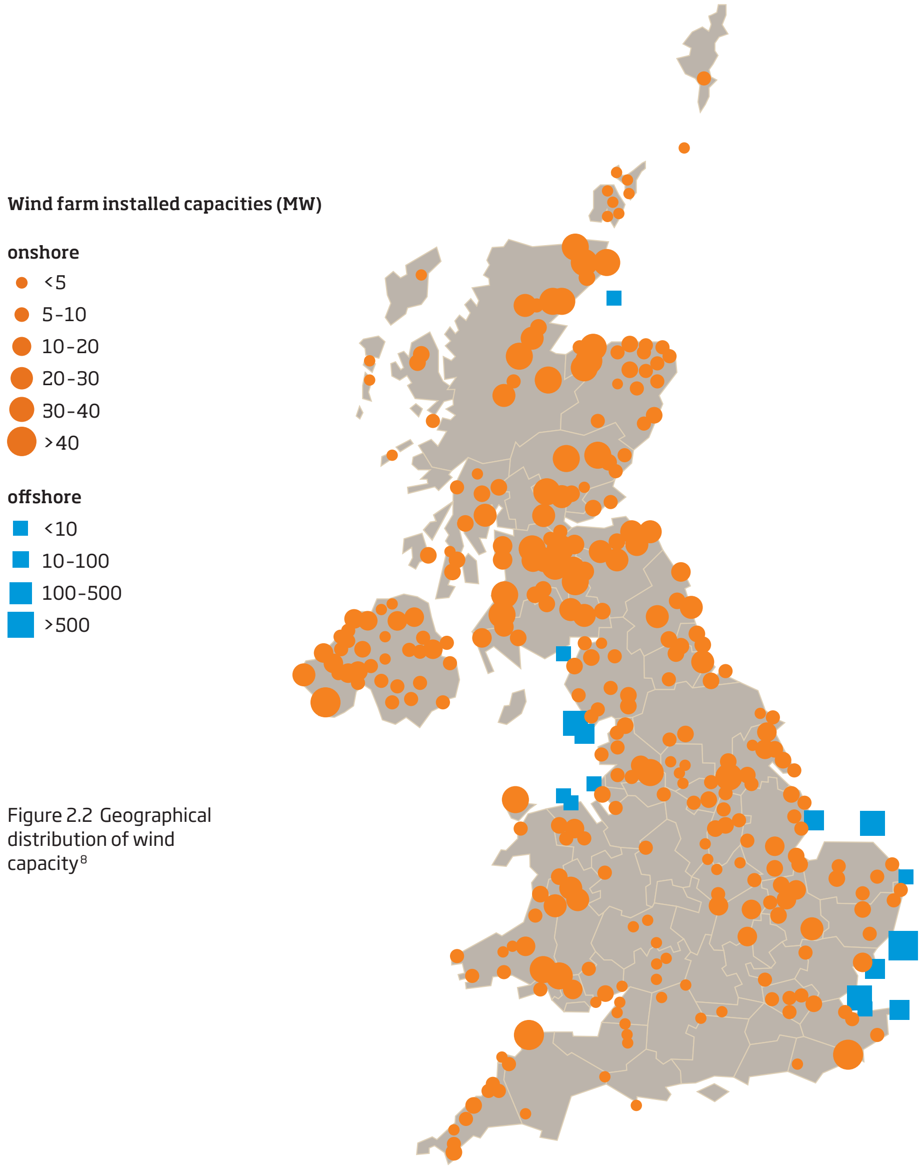


Figure 2.2 Geographical distribution of wind capacity[8]

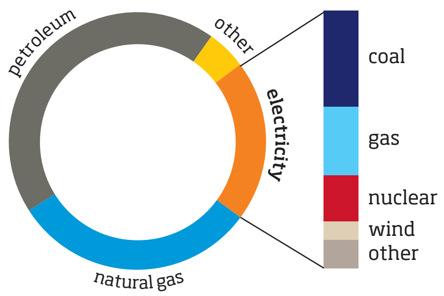


Figure 2.3 Primary fuel mix for total UK energy demand in 2013[8]

2.2. Contribution to energy supply

In terms of total energy, electricity makes up around 20% of total final energy consumption, with heating and transport still relying almost exclusively on gas and oil. The latest provisional figures from government[9] estimate that wind energy accounts for 7.7% of electricity but less than 2% of UK total energy. This highlights the fact that wind energy still contributes relatively little to the UK's total energy demand, although these figures are increasing as more capacity is added to the system.

The UK has over 10GW of wind capacity, making up almost 8% of electrical demand and just around 2% of total energy demand.

2.3. Drivers for increasing wind capacity in the UK

The proportion of renewable energy, including wind, is set to change over the course of this decade as we move towards the first of government's primary energy targets – the European 2009 Renewable Energy Directive that requires the UK to obtain 15% of its total energy consumption from renewable sources by 2020. Latest figures show that in 2012, 4.1% of energy consumption came from renewable sources.

To meet the 2020 renewable energy target, the government expects wind to play a major role. Its *Delivery Roadmap*[10], which assessed potential deployment rates in terms of costs, build rates and policy framework, took the view that wind could contribute between 57TWh and 90TWh of electricity by 2020 which would be between 3.7% and 5.8%

THE UK HAS THE THIRD HIGHEST AMOUNT OF INSTALLED WIND CAPACITY IN THE EU, SIMILAR IN SCALE TO FRANCE AND ITALY BUT SIGNIFICANTLY BEHIND GERMANY AND SPAIN

of the estimated total energy demand in 2020, or between 18% and 28% of electrical demand. If current build rates are maintained, these targets are attainable, but they are challenging.

The other policy driver for wind energy is the 2008 Climate Change Act that requires the UK to reduce its total emissions of greenhouse gases by 80% by 2050 relative to 1990 levels. Intermediate, five-year carbon budgets are recommended by the Committee on Climate Change (CCC), four of which have been adopted by government, covering the period up to 2027. These require a 50% reduction in greenhouse gas emissions by 2025 relative to 1990 levels. The CCC have reported that the first carbon budget has been met and the UK is on track to meet the second budget but is not currently on track to meet the third or fourth[11].

The CCC has also recommended that the electricity system be largely decarbonised by 2030 (50gCO_2e/kWh from its current level of above 500gCO_2e/kWh)[12]. An amendment was put forward to the recent Energy Bill for a decarbonisation target for the electricity sector, but this was defeated[13] and any 2030 target will now have to wait until the fifth carbon budget is set in 2016.

Increasing wind capacity is being driven by both domestic and European legislation to reduce greenhouse gas emissions and increase renewable energy.

2.4. Comparison with other countries

The UK has the third highest amount of installed wind capacity in the EU, similar in scale to France and Italy but significantly less than Germany and Spain, which have three to four times more installed capacity. In 2013, wind produced 21.1% of Spain's electricity – more than any other form of generation[14]. Denmark, while lower in terms of installed capacity, has the highest levels of wind penetration at over 25% (see Figure 2.4 for further comparisons).

Globally, as of 2013, there were 318GW of wind capacity. China and the US together made up almost half of that total with the UK accounting for just over 3%[15]. Where the UK does lead is in offshore wind, with over half of the global capacity at the end of 2012. However, this still only accounts for about 2% of global installed wind capacity, indicating that offshore wind is at a very early stage of deployment compared to onshore wind.

There are alternative ways of measuring the amount of wind energy, including installed capacity per person or per unit of GDP. Relative to the number of people in the country, the UK is just outside the top 10 and, in terms of GDP, the UK is about 20th in the world[16]. In both cases, countries such as Denmark, Portugal, Germany and Ireland are significantly ahead of the UK in terms of installed wind capacity.

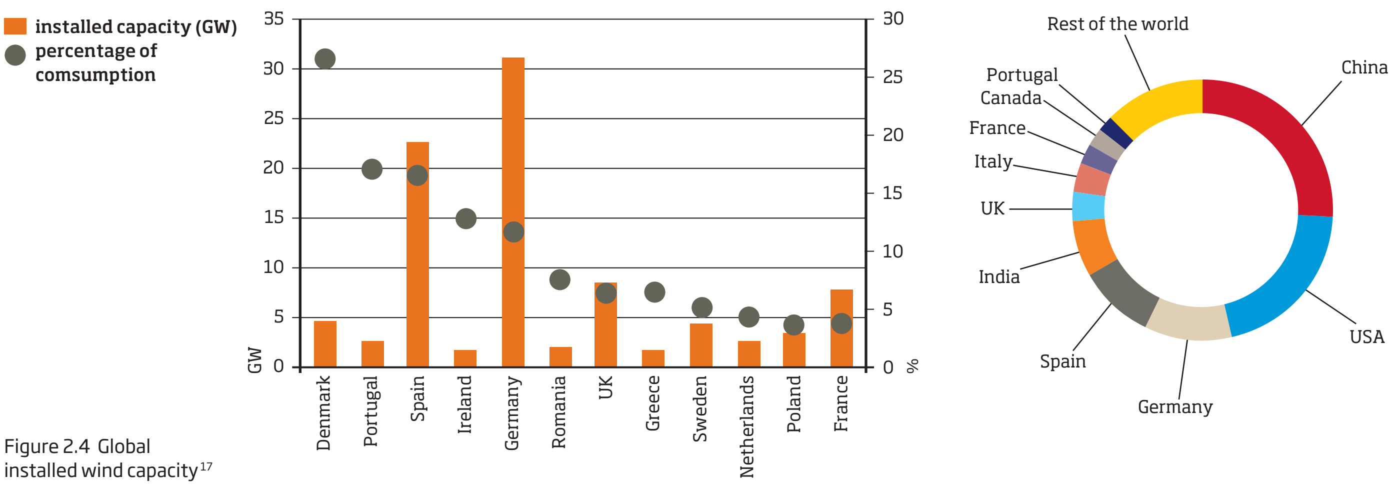


Figure 2.4 Global installed wind capacity[17]

Table 2.1 UKWED state of UK wind capacity in February 2014[18]

GW (no. of turbines)	Operational	Under construction	Consented	Total
Onshore	6.76 (4,169)	1.51 (644)	4.45 (1,881)	12.72 (6,694)
Offshore	3.65 (1,075)	1.18 (304)	3.13 (738)	7.96 (2,117)
Total	10.41 (5,244)	2.69 (948)	7.58 (2,619)	20.68 (8,811)

Overall, this indicates that, while the UK has seen significant development of wind energy, it is by no means exceptional in global terms. Certain renewable forms of generation can be more suited to certain regions; there are aspects of the UK that are favourable for wind and others that are not.

The UK is the windiest region in Europe[19], and being an island provides the opportunity for offshore wind. But it is also a densely populated country with fewer wide open spaces for large wind farms compared to, for example, Spain or the US.

The fact that some countries are some way ahead of the UK in deploying wind energy means that many of the technical issues that arise from integrating wind energy into the system will already have been encountered. Each system is unique and the GB grid has particular characteristics as an island system; even so, there will still be an opportunity to learn lessons from those countries that have more experience of deploying wind than the UK. Spain is perhaps one of the most useful comparators, given that it has a grid system of a similar size and level of interconnection to the GB grid system but it also has a very different mix of generation that must be taken into account.

The UK has, by most measures, an above average amount of installed wind capacity – more than most but still some way behind such countries as Denmark, Germany, Spain and Ireland. The UK has the largest amount of installed offshore wind capacity in the world.

2.5. How much will there be?

The Renewables UK wind energy database (UKWED) gives a breakdown of wind developments that are operational, under construction and consented. Projects listed as consented are not guaranteed to be built, as economic circumstances can change and there are other projects that may be under consideration but not yet consented; however, this database gives the best current picture of plans for wind developments in the immediate future. The table above is a summary of the situation in February 2014.

Several organisations have made estimates of how much wind capacity might be installed in the UK. The methods used vary from indicative scenarios in the case of National Grid to assessments based on costs and policy constraints by Arup. Below is a table that shows a variety of estimates of the capacity of wind on the GB system in 2020 and 2030.

Although there is a wide range covered in the above scenarios, both in the totals and the split between onshore and offshore, the central estimates show a reasonable level of agreement. For the purposes of this report, assumptions have been made on how much wind capacity can be expected in 2020 and 2030 as well as the proportion of electrical demand that will be met by wind energy. These will only be indicative figures but will be used as representative figures to assess the impact on the system at those two points in time.

Table 2.2 Estimates of future installed wind capacity in GW

		2020			2030		
		onshore	offshore	total	onshore	offshore	total
National Grid[20]	Slow progression	7.5	10.1	17.6	20.8	13.6	34.4
	Gone green	12.1	14.2	**26.3**	36.0	21.0	**57.0**
Government[21]	Low	10	10	20			
	Central	13	18	**31**			
	High	19	16	35			
Arup[22]	Low	9.8	14.1	23.9	14.6	35.3	49.9
	Central	10.9	17.6	**28.5**	17.3	41.3	**58.6**
	High	14.1	22.3	36.4	23.6	51.7	75.3
RAEng GtF[23]		13.5	9	**22.5**	18.5	19	**37.5**
Poyry[24]	High	15	13	**28**	21	38	**57**

BY THE EARLY PART OF THE 2020s, THE UK IS LIKELY TO HAVE BOTH LEVELS OF CAPACITY AND CONTRIBUTION TO ELECTRICAL DEMAND OF UP TO THREE TIMES HIGHER THAN PRESENT

2.5.1. Expected capacity in 2020

Considering first the outlook for 2020, the various estimates range between 17GW and 36GW, averaging at around 26GW. This would require an additional 16GW of capacity to be added in around seven years. If split roughly equally between on- and offshore wind, this would equate to something in the order of an extra 1GW of both being installed each year – similar to what was installed in 2012. This is still somewhat higher than the 20GW given in the UKWED for current, under construction and consented wind capacity. Completion times for the consented projects are difficult to determine precisely, especially for the larger offshore developments, but it could be expected that if consented projects go ahead, they should be completed by 2020. It is also possible that additional projects not currently listed on the UKWED are completed by 2020. The Academy's own 2010 report[25] gave an estimate of 22.5GW, but installation rates since then have already been shown to be higher than expected, so it is possible that this figure was a little low. So, overall, the estimate of 26GW of installed wind capacity, split equally between onshore and offshore would appear to be a reasonable, if optimistic, estimate for 2020.

When considering the technical issues of integrating certain levels of wind into the GB system, this figure has been used to give some indication of when certain milestones can be expected to be reached and to stress test the system. The various estimates noted above show that there is a high degree of uncertainty concerning exact deployment rates and 26GW is simply an average to be used for illustrative purposes. It is possible that this level will not be reached in 2020 but it is likely that it will be reached sometime close to that date and that the technical issues relating to it will be similar.

In terms of levels of penetration, the National Grid *Gone Green* scenario, estimates electrical demand in 2020 to be broadly the same as now at around 320TWh. This estimate is subject to a number of uncertainties, particularly economic growth forecasts and changes in the heat and transport sectors. For example, if the uptake of electric vehicles (EVs) increases significantly, this would have a considerable effect on electrical demand as every million new EVs would add around 70TWh per year to demand. However, this is likely to be much more of a factor in 2030 than in 2020. Assuming, therefore, that demand stays broadly the same up to 2020, 26GW of wind capacity would account for approximately 20% of electricity. (Assuming load factors of 27% for onshore wind and 35% for offshore wind, amount of embedded wind capacity broadly unchanged at 3GW and system losses of 8%.)

Much obviously depends on levels of investment, which are linked closely to government support mechanisms and the development of manufacturing and supply chain capabilities. It is highly possible that wind capacity is built more quickly or slowly than we assume but the above figures suggest that, by the early part of the 2020s, the UK is likely to have both levels of capacity and contribution to electrical demand of up to three times higher than present. This would be similar to levels currently seen in countries such as Denmark, Spain and Ireland.

For the purposes of this report, by 2020, the UK is expected to have 26GW of wind capacity meeting 20% of electrical demand.

2.5.2. Expected capacity in 2030

Looking further out to 2030, the estimates become much less certain but, again for the purposes of this report, it is helpful to have a representative estimate for the level of deployment that might be expected by that date. Considering the estimates given in Table 2.2 and current deployment rates, it is possible that there could be around 50GW or more of wind capacity, albeit with a wide margin of error. The percentage of electrical demand that 50GW of wind capacity would represent is much more difficult to estimate in any meaningful way. The demand profile of the system could have changed dramatically by then, with the deployment of EVs and electrified heat. This could significantly change both the average and peak demands of the system. The generation mix of the system is also likely to be much changed which will impact on the technical issues that will need to be managed by the system.

Despite the uncertainties, the figure of 50GW by 2030 has been used in this report for illustrative purposes. This would represent levels unprecedented in any current system and raise serious issues for managing the system that are considered in Section 7. However, these figures need to be treated with caution. As the estimates in Table 2.2 show, for 2030 there is a wide range of possible future scenarios that will depend on a range of political, economic and social factors. Reality could turn out to be rather different, but the figures given for 2020 and 2030 give some indication as to what stage along the deployment pathway the GB grid might be expected to have to manage at these two milestones.

For the purposes of this report, by 2030, the UK is expected to have 50GW of wind capacity. It is difficult to estimate what percentage of supply this would represent given potential changes in demand and the overall generation mix.

3. The wind resource

OVER THE PAST TWO DECADES, SIGNIFICANT ADVANCES HAVE BEEN MADE IN THE APPLICATION OF METEOROLOGICAL SCIENCE TO WIND ENERGY

Wind turbines rely on the kinetic energy in the wind as their energy source. A good understanding of the nature of the wind resource is therefore essential in order to assess the effectiveness of wind energy. Over the past two decades, significant advances have been made in the application of meteorological science to wind energy. The following section analyses data from the UK and other EU countries to investigate some of the main characteristics of wind and how this relates to the utilisation of wind energy by the GB electrical system.

The analysis can focus either on average conditions for the entire wind fleet over extended periods (months or years) or on more specific periods of high or low wind output or high or low demand. Both are important; average conditions relate mainly to the long-term contribution of wind energy to electricity demand and the economics of the technology while the specific short-term characteristics relate to how wind energy impacts on the day-to-day operation and security of the grid, although this will also have an impact on the economics of wind energy. Both economics and grid operations are considered in more detail in later sections of the report.

3.1. Long-term characteristics of wind output

Figure 3.1 overleaf shows the two basic relevant variables for the GB system over the course of a year – demand in red and transmission-connected wind output in blue. Practically all onshore wind farms in England and Wales and some in Scotland are connected to the distribution system and do not report their half-hourly output to National Grid. Instead, as with the output from other small-scale generators, it is netted off from customers' demands so that National Grid's data for demand give only the amount of power that is supplied through the transmission system. This embedded wind output is currently about 40% of the transmission-connected output shown in the figures; the share is falling slowly over time as more offshore wind farms are connected to the transmission system. Figure 3.2 overleaf replaces wind output with the percentage of demand met by wind.

Both figures clearly show both weekly and seasonal fluctuations in demand (as well as the Christmas dip in the middle of winter when industry is shut down). Average demand is 36GW, ranging between 18GW and 57GW. Figure 3.1 indicates that actual wind output is relatively small in comparison with total demand. Figure 3.2 shows more clearly that the wind appears to be a random variable. While the average wind percentage for the period is 4.7% (1,635MW), this

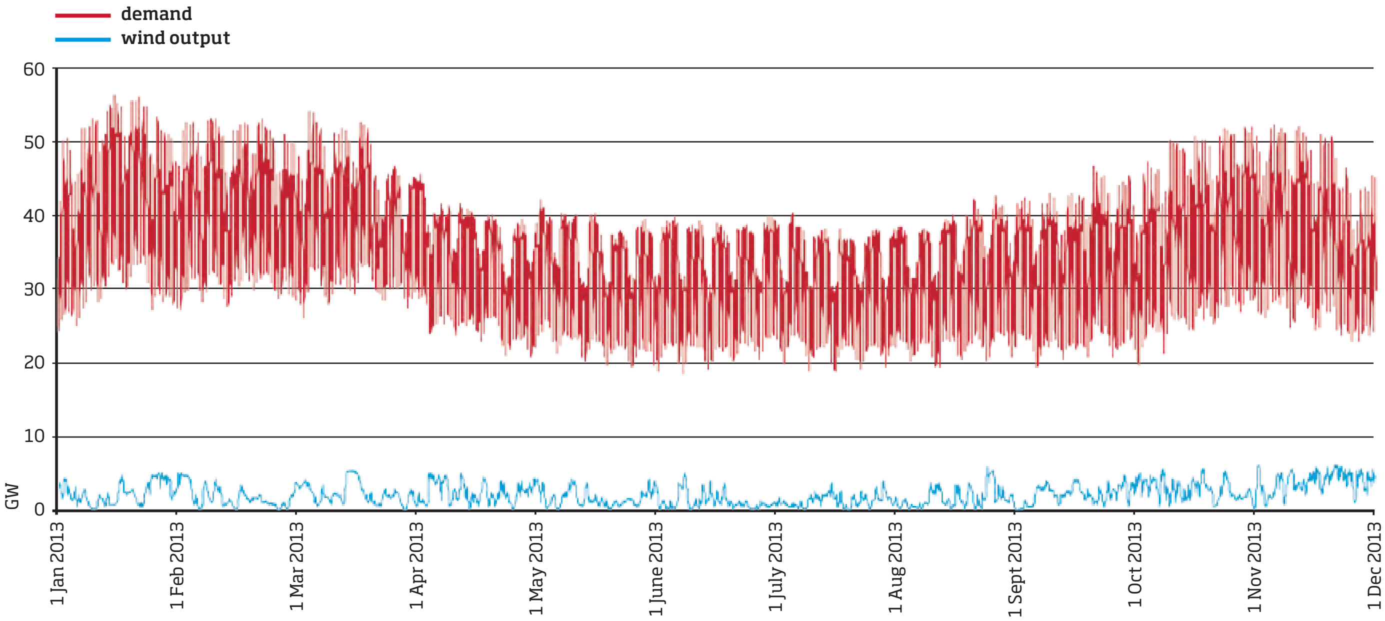


Figure 3.1 GB demand and wind output (2013)[26]

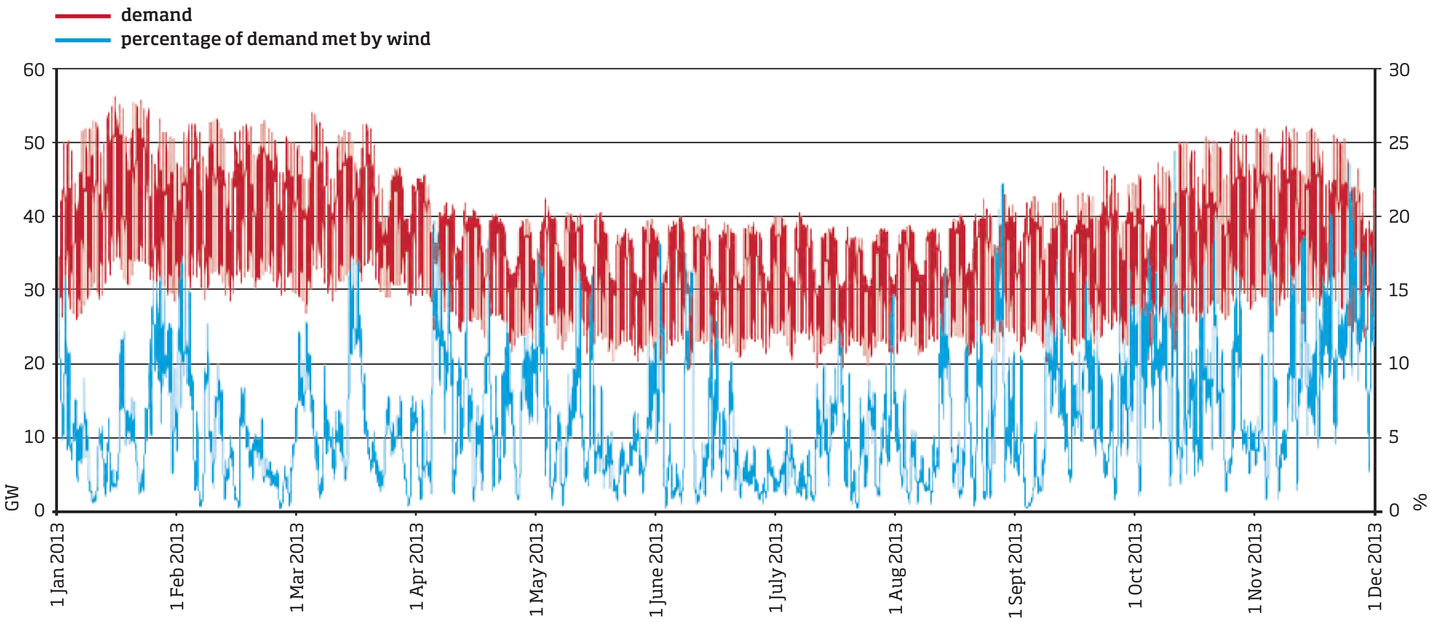


Figure 3.2 GB wind percentage and demand[26]

oscillates between zero and just short of 20%. Instances of demand above 15% are more prevalent towards the right hand side of the graph as installed capacity has increased over the time period. Including the output from distribution-connected wind farms would increase the percentages slightly.

This general profile of wind output and demand is similar to that seen in other EU countries, although there are regional variations. For example, the German wind output and demand for 2012, shown in Figure 3.3, opposite, shows that the weekly changes in demand can readily be identified but the seasonal variation is much less pronounced. Wind output, while generally higher because of the greater installed capacity, is once again variable in nature. While specific wind conditions are unpredictable more than a few days to a week in advance, modern forecasting techniques are able to predict this variation accurately up to around 24 hours ahead. This is a very active area of research and progress continues to be made making the short-term forecasts more reliable and hence making wind energy more valuable (see Section 4.3.3).

The output from wind energy is randomly variable in nature.

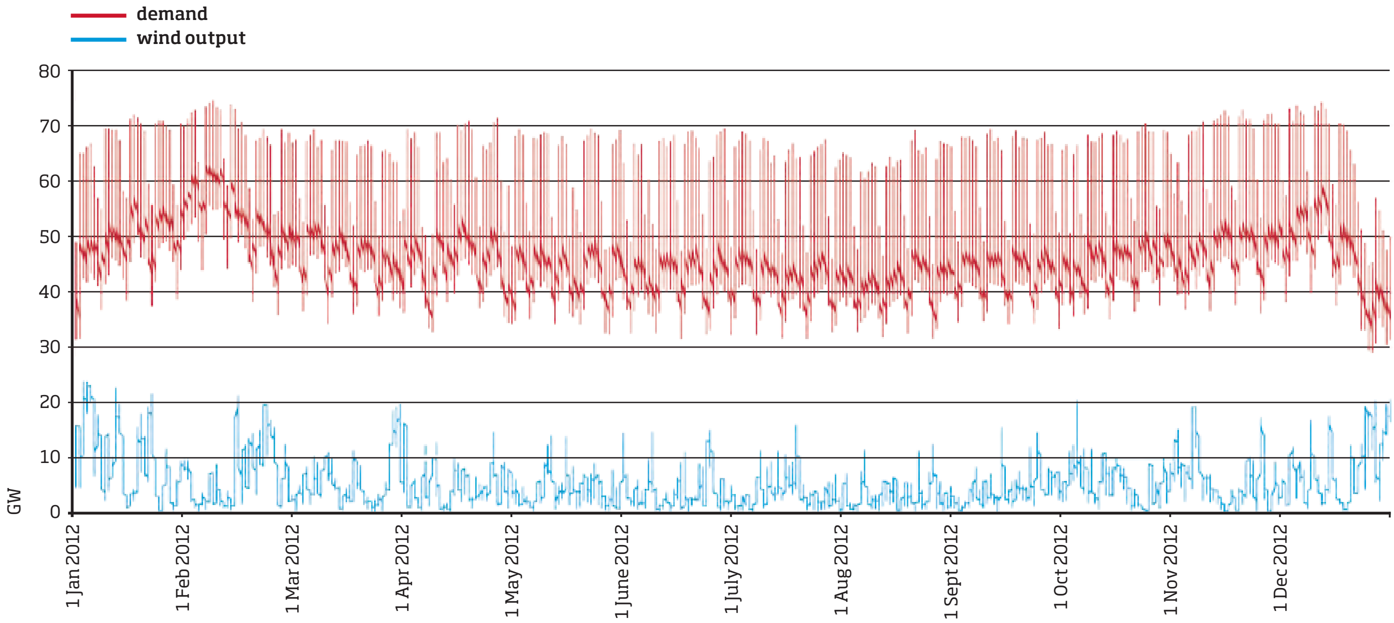


Figure 3.3 German demand and wind output (2012)[27]

3.2. Comparison to other European countries

The wind resource will vary from place to place, but it is generally recognised that the UK is well placed within Europe in terms of the potential resource to exploit. Figure 3.4 shows average wind speeds over a five-year period (after correction for topography and local roughness), indicating that the highest wind speeds are found in northwest Europe and the UK.

Looking at the spread of wind energy over the course of a year for a number of different countries, Figure 3.5 overleaf shows the cumulative distribution of wind energy as a percentage of demand throughout 2012 for Germany, Great Britain and Ireland.

For the time period, the total contribution of transmission-connected wind energy to the demand was: 4.1% for Great Britain, 10.2% for Germany and 16.3% for Ireland.

The cumulative contribution from wind for the three countries, shown in Figure 3.5, is illustrative of the general performance of wind energy on a system. On the GB system, the contribution from transmission-connected wind is below 7% for 80% of the time and never gets above 20%. With the German and Irish systems we can see how the contribution from wind is likely to increase with more capacity. It should be noted that the German system has instances of higher maximum hourly percentage from wind compared to the Irish system as the Irish system curtails its wind energy when it reaches 50%. This is because the Irish system is smaller and more isolated and less able to cope with high levels of wind energy compared to the German system which is integrated into the much larger European grid.

Experience from other countries gives a good indication of how wind will contribute to the electrical system as capacity increases.

What Figures 3.1 to 3.5 show is that, regardless of the size or location of the wind fleet, there will always be periods when output from wind drops to very low levels. Figure 3.5 indicates that, as the size of the fleet increases, the frequency of periods of output that fall below a certain percentage of demand will get progressively less frequent but they will, nonetheless, continue to occur. How the power system can be managed to deal with such instances will be considered in Section 4.

Periods of high or low wind will occur and the power system must be designed and operated to cope with these eventualities.

Average wind velocity at hub height 2000–2005 (m/s)

- 0–4
- 4–5
- 5–6
- 6–7
- 7–8
- > 8
- countries outside subject area

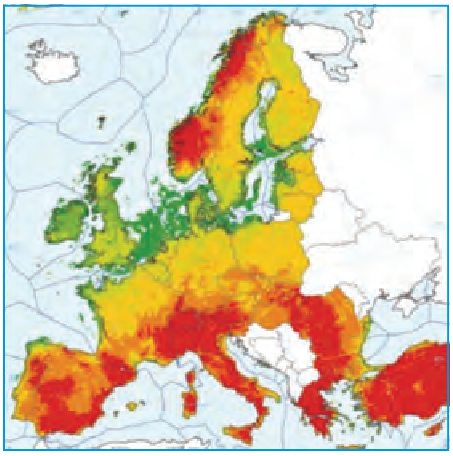


Figure 3.4 Average wind speeds over Europe[28]

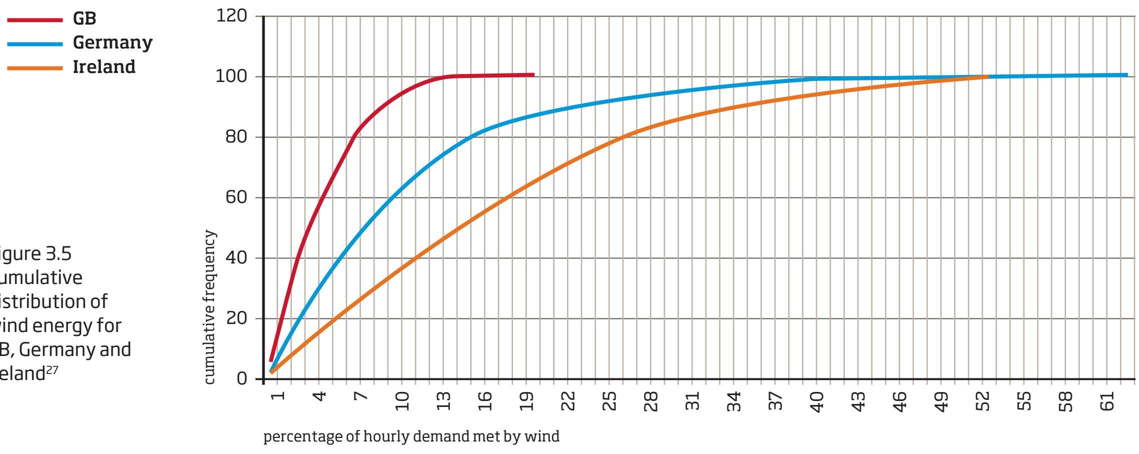


Figure 3.5 Cumulative distribution of wind energy for GB, Germany and Ireland[27]

WIND SPEEDS TENDED TO BE HIGHER IN WINTER MONTHS AND WIND SPEEDS AROUND THE UK ARE HIGHER THAN FOR THE REST OF EUROPE

3.3. Further analysis of the wind resource

A number of papers have analysed the wind resource and power output from wind fleets in more detail. Various approaches are used in order to generate the data using either direct empirical data, synthetic modelling or a mixture of both. Empirical data has the obvious advantage of being realistic but there are also certain limitations. The amount of data is restricted to the time period over which the data have been collected and the regions where measurements were taken; omissions and errors are not uncommon with historic data. Also, relying purely on empirical data does not necessarily give precise information about the level of output that can be expected from a higher level of capacity.

Combining historic data with modelling can help to create estimates of how much wind output would be expected if the level of capacity in the UK increases or if the location of the wind farms expands, as would be the case with offshore wind.

For example, Sinden[29] (2007) used Met Office wind speed data from sites across the UK to model wind output over more than 20 years. This showed a number of relationships and general trends such as higher output over winter months compared to summer months and higher output during the day compared to overnight – both of which are an advantage as they correlate with electricity demand.

Other papers have looked at much longer timescales. For example, Stephens[30] (2000) considered more than a century of Met Office data to recreate offshore wind speeds. This also found that wind speeds tended to be higher in winter months and that the wind speeds around the UK are higher than for the rest of Europe. Its headline result, however, showed that significant interdecadal variations exist that could affect the economic performance of wind farms. This highlights the importance of considering long-term data when analysing wind energy as certain trends may not otherwise be apparent. It is also important to consider possible future changes to wind patterns that could arise as a result of long-term climate trends, although this is not considered in this report.

Purely synthetic models are more flexible and are able to categorise the wind output for any region in terms of a common set of parameters such as turbine density, terrain and wind conditions. For example, Sturt and Strbac[31] (2011) show that the output from large-scale wind fleets can be accurately modelled, although there are some limitations with regard to cut-out at high wind speed, interdependence with temperature and interconnection with other systems.

Modelling techniques provide an effective means of extending forecasts where historic data is unavailable, such as for new regions and levels of wind capacity.

3.4 Summary

Empirical data for wind energy are readily available for many European countries. This shows that the general characteristics of the wind are broadly similar but that the UK is well-placed in terms of the potential energy resource.

The strength of the wind is randomly variable and the precise output at any particular time from the wind fleet can only be predicted with accuracy around a day ahead. There are, however, certain trends over timescales of days, years and decades that can be distinguished. Looking further ahead, the impact of longer-term changes in climate could be significant and is the subject of ongoing research.

Empirical data can only provide limited information in terms of timescales and geographical areas. Modelling techniques are available that either augment the empirical data or are purely synthetic which can extend the analysis.

The conclusions in this chapter deal with the overall nature of the wind resource. Operational issues arise as a result of a coincidence of certain wind events with certain system events, such as for example, low wind at times of peak demand. These are considered in the next section.

THE UK IS WELL-PLACED IN TERMS OF THE POTENTIAL ENERGY RESOURCE

4. Integrating wind into the grid system

THE OPERATIONAL MANAGEMENT OF THE GRID IS LED BY DEMAND, MEANING THAT AT ANY ONE MOMENT, THE DEMAND FROM CUSTOMERS MUST BE MET BY A SUFFICIENT AMOUNT OF GENERATION

The GB electricity grid is a large, interconnected, synchronous system that serves England, Scotland and Wales, with a total generating capacity of 80GW and a peak load of around 55GW. Peak demand has been as high as 60GW in 2005/06 but has decreased in recent years, mainly through a combination of increased efficiency and the economic downturn. It is significant in size but is by no means the largest grid (the European Continental Grid has a capacity of 670GW). It has a relatively low level of interconnection with links to France, the Netherlands, Isle of Man, Northern Ireland and the Republic of Ireland equivalent to around 5% of capacity. It operates with an alternating current at 50Hz.

The operational management of the grid is led by demand, meaning that at any one moment, the demand from customers must be met by a sufficient amount of generation. The GB grid has been built up over the course of many decades and the collective experience of generators, the transmission and distribution system operators and retailers means that the level of demand can be forecast to a high degree of accuracy and generators have a good idea of when their electricity will be needed. However, uncertainties do exist and the system must be designed and managed so as to be robust against a range of unexpected eventualities.

The level of output from wind is one of the uncertainties that the grid must cope with but by no means the only one. Fluctuations in demand, unexpected plant outages and transmission failures are just some of the uncertainties that the grid system has always had to deal with. This section aims to summarise how the GB grid is run and how wind is currently integrated into the system.

4.1. The GB electricity market

The electricity industry has traditionally been centrally dispatched, with one team of system controllers giving instructions to every power station on when to start up or shut down and what level of output to produce. For three decades until 1990, the controllers for England and Wales belonged to the Central Electricity Generating Board (CEGB), which owned all the major power stations and the transmission system, selling power to 12 Area Electricity Boards which distributed it to consumers. In Northern Ireland and in Scotland, three other public corporations (the Northern Ireland Electricity Service, North of Scotland Hydro-Electric Board and South of Scotland Electricity Board) were vertically integrated, covering all stages of the supply chain. The CEGB used a computer programme that calculated the least-cost way of meeting the expected demand, based on cost information and data on technical constraints from every power station.

When the electricity industry in Great Britain was restructured for privatisation in 1990, the National Grid Company ran the transmission system and employed the system controllers, while a new centralised wholesale market, The Electricity Pool of England and Wales, was created for generators to sell power to electricity

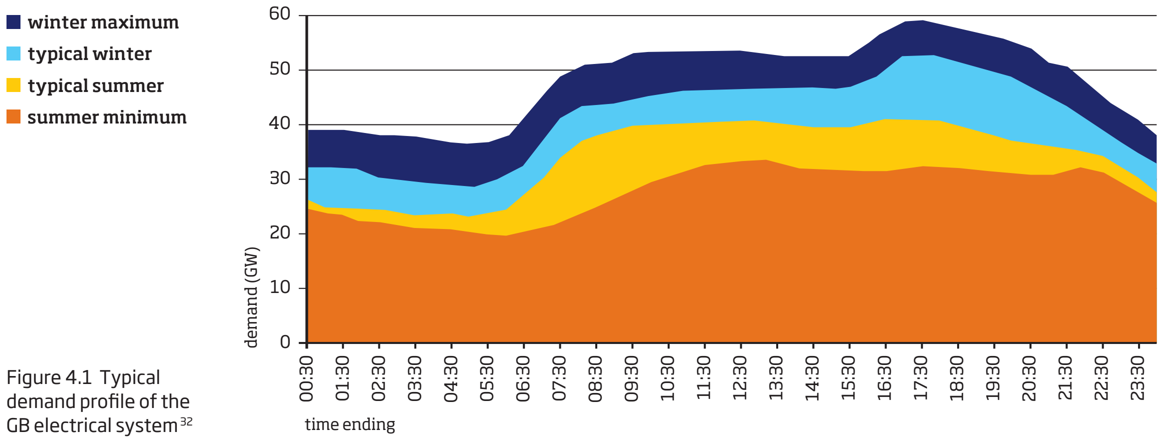


Figure 4.1 Typical demand profile of the GB electrical system[32]

suppliers (retailers). The Pool was still based on central dispatch, with the same computer programme used to schedule power stations, but generators now submitted price offers instead of costs. The Pool calculated the price of electricity in every half hour, but these prices were sometimes counterintuitive and the Pool was accused of being too vulnerable to market power. In 2001, the Pool was replaced with the New Electricity Trading Arrangements (NETA), expanded in 2005 to the British Electricity Trading and Transmission Arrangements (BETTA) to cover the whole of the GB grid system.

BETTA operates as a wholesale commodity market that allows a wide range of bilateral trades between generators and retailers, from simple over-the-counter trades to long-term future contracts. Generators now self-dispatch in order to produce the power that they have sold, but it is still the case that the Transmission System Operator, National Grid, must be able to balance the system in real time. To ensure the secure operation of the system, an operating margin is maintained and a balancing mechanism exists that allows National Grid to vary supply or demand in response to imbalances in the system.

Electricity has a unique characteristic as a commodity in that it cannot be easily stored. Timing is therefore crucial; BETTA functions on a rolling half-hourly basis. Trading is carried out up to 'gate closure' one hour before each of the half-hour periods in the day with generators having to declare their contracted position at that point. During the half-hour delivery period, reality may not match the contractual position and generators may find themselves in a position of imbalance and incurring costs that are reconciled in the settlement period following delivery.

Currently, there is considerable political and public interest in energy prices and the electricity market is being scrutinised for its effectiveness to deliver cost effectiveness and transparency. The recent Electricity Market Reform, brought into effect with the 2013 Energy Act, has already reformed some aspects of the market and there is uncertainty over whether further reforms of the electricity market will be forthcoming in the near future. Such uncertainty is already affecting investment decisions across the whole power sector including wind energy.

The current electricity market operates as a wholesale commodity market with generators self-dispatching and the system operator maintaining system security. Reforms of the market are ongoing, resulting in uncertainties that are affecting investment decisions for new generating plant including wind energy.

4.2. Demand

While BETTA defines the operation of the market, the system operator, National Grid along with the distribution network operators (DNOs), must continually balance actual supply and demand on the grid.

Demand varies through the day with a trough throughout the night, rising in the morning, holding steady through the day and reaching a peak in the evening. This is the standard load profile of the current GB system. It varies seasonally, with winter peaks being generally higher and more pronounced at around 55GW, compared to the summer with flatter peaks of around 40GW. There is also a general lowering of demand over weekends and holidays[33] (see Figure 4.1 above).

This profile is not expected to change much over the next decade[34], but, as noted in Section 2.5, if there is large scale adoption of electric vehicles and heat pumps, the size and shape of the demand profile is likely to change dramatically towards the end of the next decade and beyond.

Electricity demand is unlikely to impact on the development of wind energy until there is large-scale electrification of transport and heat.

4.3. Supply

Demand is met by various different forms of generation. Each type of generation utilises different primary fuels and technical processes to produce electricity, each with their own performance characteristics. The following sections describe the main characteristics of concern for grid operations.

4.3.1. Load factor

The load factor (or capacity factor) for any power plant is the ratio between average load and rated load for a given period of time. For wind turbines (either individually or as a fleet), this is generally calculated over a year and expressed as a percentage, giving a measure of how much electricity is generated relative to its theoretical potential. Load factors are of concern to the owner of the generating plant as they determine the cost of the electricity it produces and therefore the profitability of the plant. No generating technology achieves a load factor of 100% and there are four main reasons why:

- **Lack of availability through mechanical failure or planned maintenance**

  This is applicable to all types of generation and will depend on the particular technology and factors such as the age of the plant.

- **Not required by the system to meet demand**

  There always needs to be more generating capacity available than demand so, at any one time, some plant will not be required. Plant with low running costs will generally be used ahead of plant with higher running costs.

- **Inability to generate due to grid constraints**

  This can apply to any generating plant and is caused by current or voltage limitations or grid stability concerns. In this case, the generator will likely be compensated financially for their inability to trade in the market (constraint payments).

- **Inability to generate due to environmental conditions**

  This is specific to certain types of renewable energy that use natural sources of energy to generate electricity such as wind, wave, tidal or solar.

A combination of these factors will determine the load factor for each type of generation. Load factors can be calculated for just about any mechanical device and a low load factor is not necessarily a bad thing. For example, domestic central heating boilers in a well-insulated home would have a very low load factor. Despite not being used at all for six months of the year and, even in winter, still only being used for a fraction of the day, they are still considered valuable equipment. For the electrical grid system, some plant may still serve a valuable function despite very low load factors such as very fast response plant that is used to meet spikes in demand or unexpected generation shortfalls.

Table 4.1 below shows the load factors of the three main types of plant – nuclear, coal and combined cycle gas turbines (CCGT) – over the five years to 2012. The general rise in the load factor for nuclear is a result of increased availability of some reactors following recent performance issues. More significantly, the drop in the load factor for CCGT is symptomatic of various factors that have reduced the time CCGT has been required by the system. Relatively cheap coal from the

Table 4.1 System load factors for main generating technologies[8]

Plant load factor	2008	2009	2010	2011	2012
CCGT	71.0	64.2	61.6	47.8	30.4
Coal	45.0	38.5	40.2	40.8	57.1
Nuclear	49.4	65.6	59.3	66.4	70.8

WIND ENERGY HAS ALSO IMPACTED ON THE LOAD FACTOR OF CCGT PLANT AS THESE WILL RUN LESS AS THE PROPORTION OF WIND ENERGY INCREASES

US alongside a flat or rising cost of gas is the predominant reason and is reflected by a corresponding rise in the load factor for coal. Wind energy has also impacted on the load factor of CCGT plant as these will run less as the proportion of wind energy increases. This has made CCGT plant less profitable and hampered investment, highlighting the fact that as the system evolves, for whatever reason, the performance of all elements of the system will be affected.

As with other generating technologies, wind will be unavailable at times because of mechanical issues. The low unit cost means that any electricity generated by wind turbines will, if possible, be utilised by the grid. The output of a wind farm is dependent on the wind and therefore, unlike conventional plant for which mechanical availability and system constraints are the two main causes of reduced operating time, the variable nature of the wind significantly affects the load factor.

Figure 4.2 below shows the load factors for both on and offshore wind since 1990. As the amount of capacity has increased and the technology has matured, the load factors have tended to increase and stabilise. Offshore wind, with higher and more consistent wind speeds, is expected to have a higher load factor than onshore wind. This has been borne out in the statistics shown in Figure 4.2[35].

Load factors for onshore wind have stabilised at around 26%, and for offshore wind they are increasing to around 35%. Increasing levels of wind energy will reduce the load factor of other plant on the system.

4.3.2. Dispatchability/flexibility

'Dispatchable' means, to quote an old British Gas advertisement, 'easily turn off-and-onable'. This covers most types of thermal generation and means that the system operator can call on that generation when demand requires it and the plant is available. This includes fossil fuel generation, nuclear power and renewable generation from biomass or waste. The degree to which they can easily be turned off or on, and the rate at which they can reach full output will vary considerably; a small open cycle gas plant can be switched on or off in a matter of minutes, whereas turning on a nuclear reactor is a complex procedure that can take weeks. Other types of generation may be dispatchable in very short timescales but may not be able to generate for extended periods of time, as is the case with pumped storage. It is important for the system operator to have a range of such technologies that afford the level of flexibility required to manage the grid.

Wind generation is not dispatchable and it is this difference that sets wind apart from what the GB grid operator has traditionally

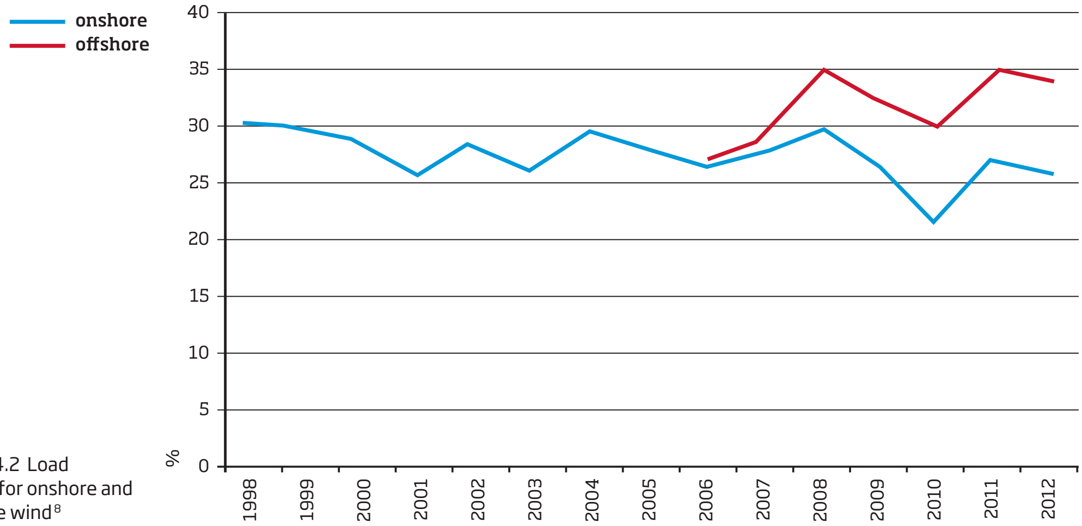


Figure 4.2 Load factors for onshore and offshore wind[8]

had to manage. Other variable renewables such as wave and solar energy also fall into the category of non-dispatchable.

It is, however, possible that wind could provide a useful degree of flexibility to the system. It is clear that if the wind is not blowing there cannot be any output from a wind turbine. Conversely, if the wind is blowing, a wind turbine can be very easily controlled to provide less than maximum output. Currently, this is not the case as its low running costs mean that economically it makes more sense to utilise all available output. As the capacity of wind energy increases, it may become practical to exploit the fact that wind could be run at perhaps 80% of possible output, leaving 20% available for fast balancing services. While technically feasible, this would require changes in the way wind is paid for in the market. This application of wind farms is already used in prototype form in Denmark.

Wind energy is non-dispatchable but, under different market structures, could provide a useful degree of flexibility to the system.

4.3.3. Predictability

Prediction is a vital factor in operating the grid. In terms of demand, historic operational data, temperature forecasts and even television schedules allow highly accurate demand predictions to be made, allowing generators to schedule the appropriate amount of supply. Forecasts are made every six hours. Details of these forecasts can be viewed on bmreports[36], with the latest forecast being updated every time the forecast is re-run. Two examples are shown below in Figure 4.3.

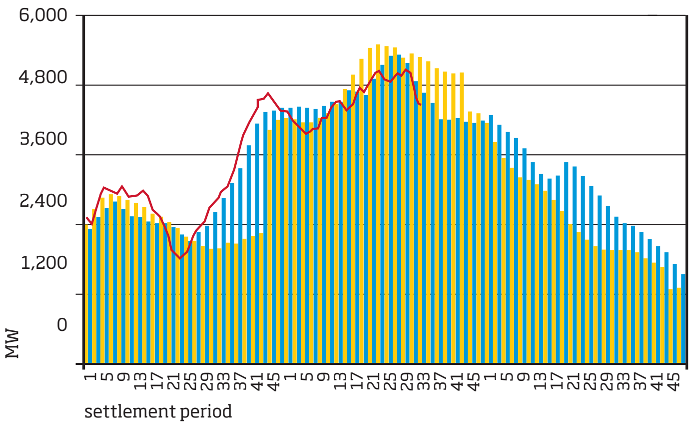
On the left, we see an example where the initial forecast and latest forecasts differ relatively little and show a high degree of correlation with the final outturn. However, on the right we have an example where the final outturn is higher than the latest forecast.

At current levels of wind penetration, this level of forecast error remains within the parameters that the system is designed to cope with. However, as levels of penetration rise, the situation could change. At present, the forecasting system employed by National Grid has an error of approximately 5%, measured as mean absolute forecast error against capacity. Efforts continue to improve performance but errors will always occur and the system operator will need to have enough back-up services in place to cope with the worst case scenario, even though these will occur only rarely. With the 26GW capacity of wind fleet this report assumes by 2020, there may be a need for additional reserve requirements, particularly on days forecast to have high levels of wind output when errors will correspond to larger amounts of generation. Beyond that, with

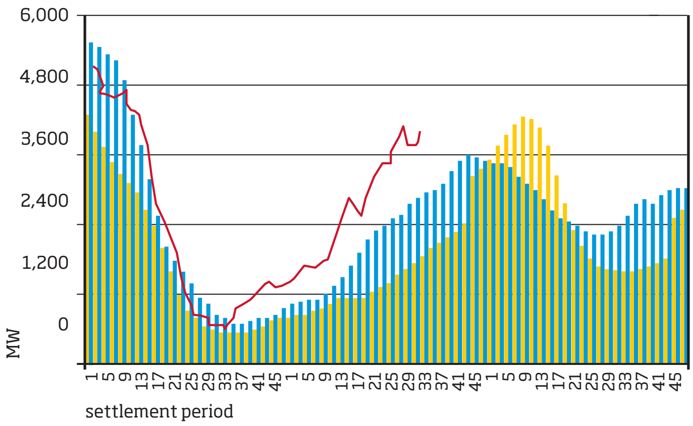
Figure 4.3 Examples of wind forecasts, reproduced courtesy of bmreports

initial forecast value
latest forecast value
out-turn forecast value

Data referring to dates: 2013-11-19, 2013-11-20, 2013-11-21



Data referring to dates: 2013-12-01, 2013-12-02, 2013-12-03



AT PRESENT, THE FORECASTING SYSTEM EMPLOYED BY NATIONAL GRID HAS AN ERROR OF APPROXIMATELY 5%, MEASURED AS MEAN ABSOLUTE FORECAST ERROR AGAINST CAPACITY

the 50GW expected by 2030, even a 5% error on maximum output could mean a 2.5GW discrepancy between predicted generation and actual generation.

Although wind energy cannot be dispatched by the system operator, its level of output can be predicted to a high degree of accuracy. In the short term, forecast errors can be accommodated by existing balancing services, but as capacity increases, additional generation back-up may be required, potentially through additional measures such as demand management, interconnection and storage.

4.3.4. System inertia and grid frequency

The rotating mass of the synchronous turbines within the electrical system provides a considerable amount of system inertia that helps to regulate the frequency of the system to about 50Hz. Where wind generation is connected by power electronics, it does not, at present, contribute to system inertia and makes the system, in a sense, lighter and more difficult to manage. Increasing amounts of wind capacity have therefore meant that, at times of high wind output, the system inertia has dropped and the system frequency can fluctuate faster than normal. This can create problems for the system operator and has led some systems such as Ireland to limit the proportion of electricity that wind is permitted to contribute to its system.

Different types of wind generator have different effects on frequency stability. Some designs of small wind turbines use induction generators with fixed-ratio gearing in which the inertia of the mechanical system is directly coupled to the electrical system. Larger turbines traditionally use doubly-fed induction generators in which the rotational speed of the generator can be decoupled from the frequency of the grid so that the mechanical inertia does not influence the frequency response of the grid. Recent designs of large turbines using permanent magnet synchronous generators are coupled to the grid via back-to-back insulated-gate bipolar transistor (IGBT) power electronic inverters that completely isolate the rotational speed of the turbine from the grid frequency.

How doubly-fed and converter-fed generators affect the overall electromechanical time constant of the grid is no longer a function of the characteristics of the machinery but is determined by the control algorithms built into the converter control circuits. With such equipment, it should be possible to simulate much greater system inertia by 'gearing up' short term variations in grid frequency to correspond to larger variations in turbine speed – this approach is already being demonstrated.

A move from fossil fuel generation to wind turbines is not the only influence on grid frequency stability. Traditionally, most mechanical loads were supplied by induction motors running just below synchronous speed. If the frequency drops, the inertia of the load reduces power demand during the change in frequency, thus contributing to system stability. For many loads, such as fans

A MOVE FROM FOSSIL FUEL GENERATION TO WIND TURBINES **IS NOT THE ONLY INFLUENCE ON GRID FREQUENCY STABILITY**

or pumps, a reduction in supply frequency results in reduced power demand which, in turn, improves grid stability. Modern drive systems frequently use power electronic inverters to allow a partially-loaded motor to run more slowly, and thus use less energy. However, such electronic control systems decouple the load taken by the motor from the frequency or voltage of the supply. This creates an adverse change of characteristics: if the frequency changes, the load stays the same, and if the voltage drops, the current increases.

Apart from wind turbines, renewable generation includes increasing amounts of widely-distributed solar PV. These panels produce DC power that is fed into the distribution network by a power electronic inverter. Grid standard G83/2 allows the inverter to feed into the grid as long as the grid frequency is between 47 Hz and 52 Hz. If the grid frequency remains within these limits, feed-in power is constant and thus solar PV contributes nothing to system inertia. Whether or not the reduction in system inertia caused by wind turbines, solar PV and inverter-controlled motors is sufficient to cause grid stability problems depends, *inter alia*, on the proportion of these new sources of power and loads compared to the more traditional equipment. Changing the characteristics of the electronic control systems to contribute to grid stability should not be difficult and, if requested prior to manufacture, is expected to cost very little. While this is not a problem at current levels of wind generation, it needs to be kept under review.

Another problem that could be created by large amounts of wind and solar PV generation fed in to the distribution network is fault protection. At present, short circuit and earth fault protection on the low voltage and much of the medium voltage distribution networks relies on overcurrent protection. Typically, the source impedance of the network is 5–10%, so a short circuit results in a current 10 to 20 times higher than normal, which trips circuit breakers and/or blows fuses. Well-established protection discrimination design rules are in place to ensure that the minimum number of protection devices operate as a result of a single incident.

Inverters interfacing between a wind turbine or solar panel and the grid generally have control systems to limit the current in the event of a fault on the network. If the numbers are sufficiently high, this introduces a risk of the inverters feeding a short circuit at a current that is not sufficiently high to trip the local circuit breaker but is high enough potentially to start a fire at the point of fault. This is a problem similar to one that has been seen on some overseas railway networks where locomotives regenerating braking energy back into the supply have resulted in a situation where the overcurrent protection has been unable to detect a short circuit, leading to an equipment fire. There are several established solutions to such problems, including under-voltage protection or various forms of remote sensing. The important point is that, like frequency stability, this type of problem has to be recognised well in advance of the numbers of turbines and other inverter-connected generation reaching a critical level.

Wind energy can introduce a number of technical issues relating to system inertia, grid frequency and fault detection. Engineering solutions are available in principle but must be considered early in terms of both turbine and system design, and proven operationally.

4.4. The generation mix

Generating plant, with a spread of the characteristics considered above, combine to meet the required power demand. When balancing the grid in real time, the system operator is not concerned about which type of generation *per se* is providing the electricity, only that the demand is being met securely and at minimum cost for the wholesale electricity.

The choice of generation is in effect made by the wholesale market, which can be expected to reflect the cost of each type of generation, with the cheapest sources being used first and the most expensive last. This is effectively a 'merit order' based on offer price.

Nuclear generation has limited flexibility so is operated most of the time it is available as base load, and wind energy is used whenever the wind is blowing, provided there are no network constraints. Plant with very high running costs, such as open cycle gas turbines or oil, tend only to be used by the market during peaks of demand. Coal and combined cycle gas turbine (CCGT) lie in the middle of the cost range, determined by the relative costs of the fuel and the efficiency of the plant. At any one point in time, certain plant will fall on the cusp of being called to meet demand and is known as the 'marginal plant'. Currently, predominantly as a result of cheap coal on the global market, coal generation has become cheaper than CCGT leaving CCGT as the marginal plant. This does not mean that all coal plant is cheaper than CCGT as some modern CCGT operating at high levels of efficiency may be more cost effective than older, less efficient coal plant. But, in the current system, more often than not, CCGT is the marginal plant.

To illustrate the typical mix of generation, the output from the three main thermal sources of generation – gas (CCGT), coal and nuclear – is shown in Figure 4.4 overleaf the course of two days along with output from wind, the French interconnector and other types of generation combined.

As is shown, the overall demand follows the typical load profile. In terms of the generation mix, the relative costs of the different generating plant are seen to have an impact. Output from nuclear plant remains almost constant at about 6GW, as does the input from the French interconnector at 2GW. Above that, coal, CCGT and wind make up the required demand. Wind output varies from a high of just over 5,000MW at the start of the period to a low of around 800MW on the evening of the second day. Coal remains relatively constant at around 13GW most of the time, dropping to about 9GW overnight on the first day. The majority of the changes in demand are absorbed by CCGT which varies between a peak of about 17GW on the evening of the second day and just 4GW overnight on the first day. The variation in wind output affects mainly the CCGT, seen most clearly when comparing the two peaks of demand. Some coal is displaced by wind during the trough of demand on the first night.

This represents a fairly typical couple of days in the operation of the current grid system during which normal fluctuations in demand are managed alongside quite large swings in wind output. All of this must be accommodated by the system operator, National Grid, which responds to the market

Beyond merit order

The current dispatching approach is not an accurate representation of the costs of generation as seen from the network operator's perspective. Remote sites incur greater transmission losses and can cause network voltage and power capacity problems whereas generation closer to major loads can be integrated more easily. 'Use of system' and 'Connection' charges are a poor reflection of those additional costs but techniques for representing those extra costs have been available for a long time and are used in all the main electricity markets in the US. Network transmission constraints are also not currently integrated into the dispatching of generation but are handled in an iterative 'check and re-dispatch' approach that cannot guarantee the optimum dispatch. In short, the UK is well behind current best practice in generation dispatching and power trading.

The implementation of the final dispatched generation, however that has been arrived at, is currently effectively an offline approach with no centralised automatic control of generator governor set points. Elsewhere automatic generator control (AGC) has been in use for decades bringing together online real time control of the generator output with control of the system frequency. The larger system frequency variations already being encountered as the proportion of variable renewables has increased indicates that the UK should consider implementing AGC.

If those challenges were not enough, the UK also lacks a comprehensive system model that would facilitate the study of the much needed new control schemes, not just at transmission level but one that could model the effects of embedded generation and major new loads in the distribution system. There is a growing recognition of the need for such a model and how it could aid the development of a so-called 'smart grid'.

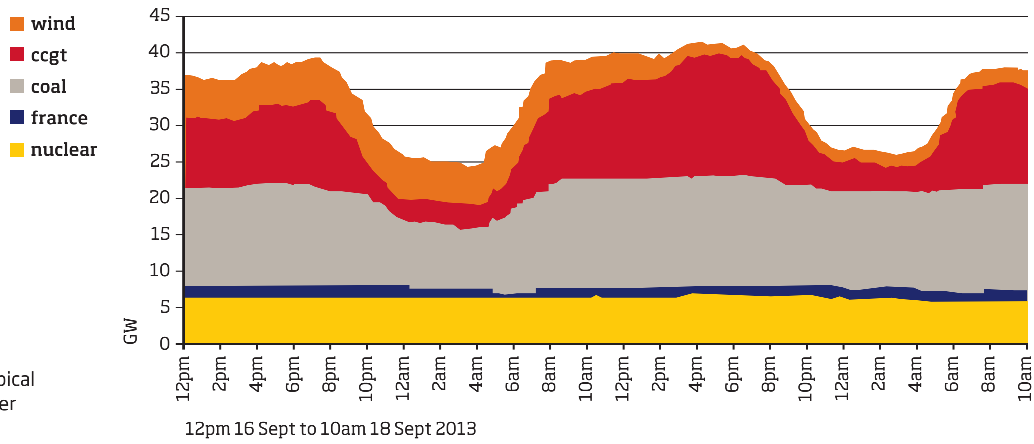


Figure 4.4 Typical generation over two days[26]

actions of generators to ensure secure overall operation of the system; this includes remaining within the capacity available in the transmission and distribution networks, allowing power to flow to final end users.

Wind energy, with very low running costs, is generally used whenever it is available. Further developments offer opportunities to improve the cost-effective use of generation across the system.

4.5. System security

To ensure the secure operation of the grid, two main conditions need to be met. First, over the long term, there needs to be sufficient generating capacity to cover the maximum peak demand, normally referred to as capacity margin. Secondly, on any particular day, there needs to be spare capacity that the system operator can call on to manage unexpected events, normally referred to as the operating margin.

4.5.1. Capacity margin

It is standard practice on any complex system to have some headroom to ensure that demand can be met. The grid system is no different, and secure operation will always require that more generating capacity is available than that simply needed to match the maximum peak demand which normally occurs on cold, weekday evenings in winter.

Traditionally, this margin has been calculated in a relatively straightforward manner using the rated capacity of all the generating plant. The capacity margin is then expressed as a percentage of spare capacity above the peak demand (referred to as the gross capacity margin). However, the increase in wind energy has affected this measure. The low load factors and variable nature of wind energy have meant that using the rated capacity of the wind fleet would give an artificially high gross capacity margin. Mainly for this reason, a 'de-rated' capacity margin is now used. This applies a de-rating factor to each generating technology depending on its expected mean availability. De-rating factors for traditional plant fall between around 80% and 90% (reflecting plant reliability) but for wind this is much lower (to reflect wind characteristics) with a range of 17% to 24% used by Ofgem[37]. This is based on an 'equivalent firm capacity' (EFC) measure which is the quantity of firm (always available) capacity that can be replaced by a certain volume of wind generation to give the same level of security of supply. This relates directly to the amount of thermal capacity on the system that could be replaced by wind capacity.

The exact de-rating value that should be applied to wind capacity is a subject of much debate, with some arguing that the Ofgem figure is too high. The debate is understandable given that this is a new method of calculating capacity margins and the figure depends on numerous factors including, *inter alia*, the size of the wind fleet, its geographical spread and the measure of security of supply that is to be met by the system operator. Further research and operational experience should help to resolve the issue.

The capacity margin addresses the issue of whether there will be sufficient generating capacity available to the system to meet demand. Analysis shows that, for a variety of reasons, the capacity margin will tighten over the short term but the switch to the de-rated method of calculating capacity margins should account for the variable nature of wind energy and show how much generation capacity should be installed to maintain a consistent level of system security. As it is calculated, the capacity margin assesses system security in terms of

THE REAL BUSINESS OF MEETING ACTUAL DEMAND WITH EXISTING PLANT BEGINS A DAY AHEAD OF REAL TIME AND IS DIVIDED INTO TWO MAIN CATEGORIES: CONTINGENCY RESERVE AND OPERATING RESERVE

probabilistic loss of load. In practice, there may be specific occasions when system security is threatened. This has always been the case and there are multiple reasons the system could be put under stress – most likely it will be a combination of events. How wind energy will impact on this as levels of penetration increase is considered in Section 4.6.1.

4.5.2. Operating margin

In addition to the capacity margin, the system operator must also maintain a sufficient operating margin for real-time security. This means keeping the necessary headroom on the system to ensure a 1-in-365 (99.7%) criterion of meeting demand in full against uncertainties such as plant loss, plant shortfall or forecasting errors[38].

Planning for managing the grid actually begins a long time in advance and becomes progressively more detailed the nearer it is to real time. The longer forecasts are more concerned with long-term trends in demand and potential plant capacity that will be available to meet that demand.

The real business of meeting actual demand with existing plant begins a day ahead of real time and is divided into two main categories:

- **Contingency reserve** – this is plant held to cover the probability of plant breakdowns in the lead up to real time. It decays gradually from a day ahead up to the final planning stage four hours ahead of real time.
- **Operating reserve** – this is the reserve held in readiness to cope with unexpected events. It is further divided into the following subcategories:
  - Reserve for frequency response – this reserve provides the space for frequency response providers to react to changes in frequency, caused by demand and generation changes, to maintain the frequency in the operating range of 49.8Hz – 50.2Hz. Frequency response provision also covers the single biggest credible generation loss on the system which is currently 1,320MW, ensuring that the frequency is restored to acceptable limits should this loss occur. From 1 April 2014, the single biggest loss criterion has increased up to a maximum of 1,800MW which will allow the connection of larger generation units in the future.
  - Regulating reserve – this is reserve on synchronised generators that can be dispatched within two minutes. It is used to balance the system should there be sudden, and sometimes unpredictable, changes in generation or demand.
  - Short term operating reserve (STOR) – power held in reserve in the form of either generation or demand reduction to be able to deal with actual demand being greater than forecast demand and/or plant unavailability. Generally, this can be dispatched to be fully effective within 20 minutes and sustained for at least two hours.
  - Reserve for wind – reserve held in case wind output turns out to be different in real time from forecast levels of output.

Each of these types of reserve has specific criteria they must fulfil in order to qualify. The system operator is not concerned with where the services are sourced, only that participants provide the necessary reserve that meet the criteria. In practice, the balancing services are provided by a wide range of technologies:

- **Spinning reserve** – part-loaded thermal plant that can be throttled up or down to vary its output.
- **Hot standby/warming service** – thermal plant in state of readiness to provide electricity at short notice.
- **Fast response standing reserve** – mainly diesel generators, CHP or open cycle gas turbines plant.
- **Demand side response** – large blocks of demand that can be taken off the system when required for a short period.
- **Pumped storage** – hydro power stations that pump water into an upper lake overnight when national demand is low and then during the day can use that store of water to generate electricity.

THERE WILL BE PERIODS OF EXTREME WIND CONDITIONS BUT WHAT IS OF PRIMARY CONCERN TO SYSTEM OPERATORS ARE THOSE PERIODS WHEN WIND AND DEMAND DO NOT CORRELATE – LOW WIND AT TIMES OF HIGH DEMAND AND HIGH WIND AT TIMES OF LOW DEMAND

- **Interconnectors** – high-voltage direct current, point-to-point links with France, the Netherlands, Northern Ireland and the Republic of Ireland.

Any generating plant may be used wholly or partly to provide balancing services and details can be found on National Grid's website[39].

To be secure, the grid system must maintain a general capacity margin and sufficient operating reserve. Wind variability is just one of the sources of uncertainty that system operators must plan for.

4.6. How wind is dealt with on the system

The previous sections have described the key features of operating the grid securely and made some particular observations on how wind energy impacts on the system. The following sections focus in more detail on the main issues relating to wind energy integrating into the electrical system.

Two types of events must be managed – expected events and unexpected events. The main unexpected event for wind will be forecast errors when wind provides significantly more or less energy than predicted. Section 4.3.3 concluded that, at present levels, forecasts are sufficiently accurate for existing back-up services to accommodate, but that as capacity increases, either forecast accuracy will need to improve or additional back-up will be required, either from generation, interconnectors, or by demand management.

There are three main events that, while not predictable in terms of when they occur, can be expected to happen at some point. These are low wind events, high wind events and rapid fluctuations in wind. These are considered below.

4.6.1. Too much wind or not enough

Section 3 considered the general nature of the wind resource, concluding that the output from wind is randomly variable in nature and the system must be designed to cope with all eventualities. It is clear that there will be periods of extreme wind conditions but what is of primary concern to system operators are those periods when wind and demand do not correlate – low wind at times of high demand and high wind at times of low demand.

Figures 4.5 and 4.6 look in more detail at the output from transmission-connected wind energy during periods when demand is high and low. Figure 4.5 shows the output of wind energy for all half-hour periods when demand was greater than 50GW over the course of 2013 – roughly 250 hours accounting for about 3% of the total time period. Figure 4.6 shows the equivalent graph for periods when demand was less than 22.5GW (also about 3% of the time period). Both graphs show basically the same variable output from wind. The output from distribution-connected stations will have little impact on the overall patterns.

Figure 4.5 shows that, during periods of high demand, wind still often produces very low levels of output. When considered in terms of the capacity margin (see Section 4.5.1), this suggests that there are periods when demand is high but the wind fleet is not contributing to security of supply.

At low levels of penetration, this should not be a major issue and, indeed, up to now security has not been compromised despite periods of virtually no output from wind and maximum demands. However, as levels of penetration increase, the situation can be expected to change adversely. With a wind fleet of 26GW (as expected in 2020 or soon thereafter) and using a de-rating factor of 0.17, the equivalent firm capacity would be 4.4GW. On occasions of negligible output from wind, this would mean a potential shortfall of 4.4GW which should still be manageable assuming a healthy overall capacity margin. Additional unexpected events such as a generating plant outage

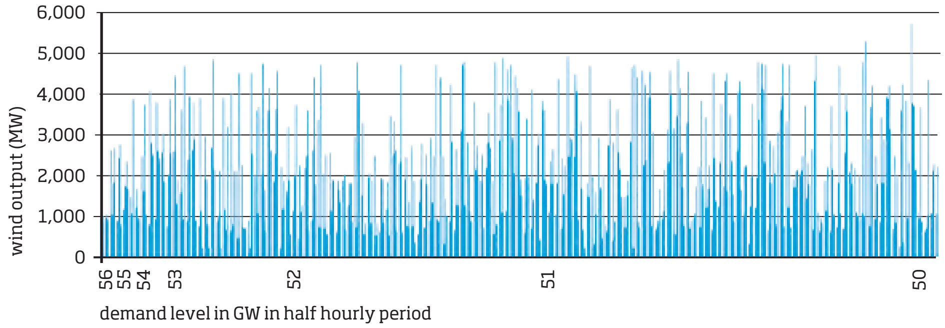


Figure 4.5 Wind output for demand above 50GW (top 3%) (ordered by demand high to low, x-axis in hours)[26]

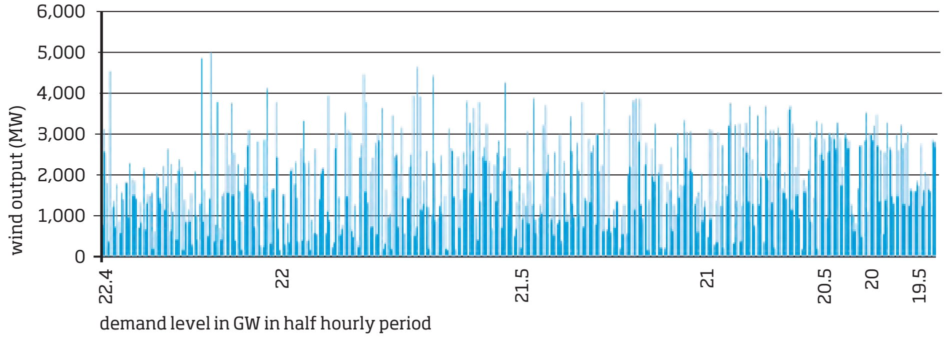


Figure 4.6 Wind output for demand below ~23GW (bottom 3%) (ordered by demand high to low)[26]

could compound the situation but the probability of this happening would be low enough to constitute an acceptable level of risk. The de-rating factor is likely to fall as wind capacity rises, since a de-rating factor of 0.17 and a wind fleet of 50GW, as suggested for 2030, would produce a potential shortfall of 8.5GW which would present problems for security of supply on its own. However, as noted in Section 4.5.1, the issue of the de-rating factor for wind is an ongoing area of research that should be refined over time.

Figure 4.6 shows that, in the reverse situation, wind output can still be high when demand is at its lowest. In this situation, there is no security of supply issue in terms of capacity, but other issues do arise such as the proportion of controllable plant that is available. Local network capacity issues can occur, leading to constraint payments to the generator. This is a reasonable approach at low levels of penetration but inefficient and costly as penetration levels rise. Serious problems start to arise when the wind capacity is around the level of minimum demand and displaces base load electricity from the system, as is beginning to occur in Germany.

Considering 2020 and a wind fleet of 26GW, if minimum demand is still around 20GW it is unlikely, but possible on rare occasions, that wind could be producing almost as much electricity as the system requires. This might therefore be a level of penetration of wind energy when issues could start to occur that could have knock-on effects for other types of generation and overall system security.

By 2030 and with a wind fleet of 50GW, the situation would be much more extreme. Output from wind could easily exceed demand and the system would need to find ways to manage the situation. The easiest is simply to 'spill' the excess wind, although this raises the cost per unit actually sold, and the generator may require compensation for the lost production and so would not be desirable. Additional sources of load, particularly electric vehicles, could alleviate the situation by providing additional demand during off-peak times. Energy storage would help alleviate the issues.

The electrical system must be able to cope with periods of low wind but high demand, and periods of high wind but low demand. Up to 2020, the level of wind penetration should not present serious difficulties but by 2030 it will be a very different world where, at times, the system will have to accommodate a generation mix almost totally of nuclear and renewables.

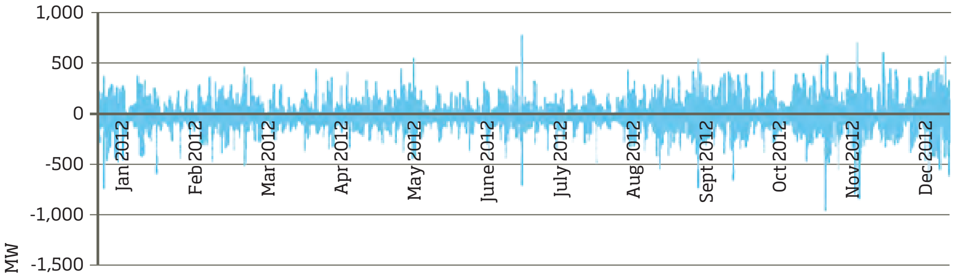


Figure 4.7 GB ramp rates (2012)[26]

RAPID FLUCTUATIONS IN WIND ENERGY OUTPUT ARE CURRENTLY NOT A MAJOR ISSUE, BUT WILL REQUIRE CAREFUL CONSIDERATION AS LEVELS INCREASE BEYOND 2020

4.6.2. Rapid changes in wind output

Rapidly changing wind conditions can be as challenging as high or low wind events. Figure 4.7 above shows the difference in transmission-connected wind output from hour to hour over the course of 2012. This shows fairly random fluctuations mostly within the range of +/-200MW but with occasional instances of up to 700MW (actual fluctuations could be larger as these figures only include transmission-connected wind capacity). Again, fluctuations show a steady increase throughout the year as capacity increases. This is still some way off the requirements for fast response balancing services that must have a delivery rate of at least 25MW/min (1,500MW/hr) but a doubling of capacity may see rare instances of wind fluctuations greater than the minimum standard for fast response (although modern gas turbines can achieve ramp rates of up to 50MW/min).

Rapid fluctuations in wind energy output are currently not a major issue but, as with other issues, will require careful consideration as levels increase beyond 2020.

4.7. Summary

The GB grid system is a complex system matching demand for electricity with supply from a variety of generators, each with their own particular characteristics. Wind must be integrated into this system in such a way as to maintain secure operation. The system has always been run with certain safeguards including a general surplus of generating capacity and back-up services to cope with unexpected events and forecasting errors. Wind energy has characteristics that set it apart from other types of generation: most notably, it cannot necessarily be dispatched when required, relying as it does on the current weather conditions. This is offset by forecasts that can predict the level of wind output to a high degree of accuracy from a day ahead. Specific issues also arise relating to system inertia and frequency control.

In general, there are three types of event relating to wind that the system must be designed to cope with – low wind at times of peak demand, high wind at times of low demand and rapid fluctuations in wind output. To date, the safeguards already in place have been sufficient to cope with all these events and, assuming sufficient innovation and forethought, the current system should be able to manage up to levels of wind penetration expected in 2020. Beyond this, however, the situation will begin to change dramatically as both the generation mix and demand profile evolve in line with government policy. In this case, wind will be just one of the tools incorporated into a much more radical system design that will require careful and timely planning. This is considered in more detail in Section 7.

5. Carbon emissions

One of the primary reasons for adopting wind energy has been to reduce carbon emissions from the electricity supply. The average emissions from power generation are approximately 500gCO_2e/kWh and lowering the carbon intensity of the grid is, therefore, vital if the emissions reduction targets set out in the 2008 Climate Change Act are to be realised. The Committee on Climate Change recommends a target of 50gCO_2e/kWh for the grid system in 2030[40]. Attaining this level is a considerable challenge, especially if electrical demand increases with the adoption of electric vehicles and heat pumps for domestic heating.

There are two main areas where wind energy impacts on greenhouse gas emissions: the emissions embodied within the wind turbine and associated infrastructure, and the overall reduction in system emissions.

5.1. Embodied carbon

The embodied carbon – or more commonly 'carbon footprint' – describes the greenhouse gas emissions that arise from manufacturing, constructing, operating and decommissioning wind farms. This is normally assessed within a Life Cycle Assessment (LCA), which systematically assesses the resource inputs and emissions across the whole wind farm lifecycle. 'Embodied carbon' almost exclusively refers to the lifecycle impacts of the wind farm itself and not its consequential impact on the wider system. Although the embodied carbon can be expressed in tonnes of CO_2 equivalent (CO_2e), where the impacts of all greenhouse gases are factored according to their potency relative to CO_2, the most common metric in use is the ratio of total lifecycle embodied carbon to life time production, given in grams of CO_2 equivalent per kilowatt-hour (gCO_2e/kWh). Another measure commonly used is 'carbon payback', which describes how long it takes for the emissions embodied in the wind farm to be recovered by avoiding emissions: that is, reducing emissions elsewhere in the power system. This is a more contentious measure as the value depends on what type of generation wind energy is replacing. This issue is tackled in the next section.

The lifecycle of a wind farm can typically be said to consist of:

- Extraction of raw materials (such as iron ore) and conversion into primary materials (such as steel)
- Manufacturing of turbines and other equipment: components, assembly of equipment
- Installation of turbines
- Operation and maintenance: inspections, maintenance, replacement of parts
- Decommissioning: removal of components, recycling and/or disposal of materials.

Transportation of materials and people also feature in such stages as the shipping of ore, the installation of turbine blades and the activities of maintenance crews. At each stage, energy and other resources will be the input and products, by-products and waste products will be the output.

Table 5.1 Contribution of materials to mass and greenhouse gas emissions of an 11-turbine wind farm[41]

Material type	Materials balance (%) Mass	CO_2 emissions
Ferrous metals	2.3	55.7
Composites	0.1	11.0
Other metals	<0.1	8.7
Plastics	0.1	7.1
Aggregates and concrete	97.4	15.9
Other	<0.1	1.6

WIND FARMS ARE ALSO BEING INCREASINGLY CONSTRUCTED WITHIN OR AROUND FORESTED AREAS, TYPICALLY FORESTRY COMMISSION PLANTATIONS

The precise balance of these lifecycle stages will vary between wind farm projects depending on whether they are on- or offshore, their scale and location, as well as specific design and installation features. The wide range of studies of wind farm lifecycle emissions are unanimous in demonstrating that the emissions arising from the extraction and use of raw materials in the turbine and associated infrastructure dominates the lifecycle – typically being responsible for around 90% of emissions. The contribution from operation, maintenance and decommissioning is more modest.

As an example, one of the more complete and accessible studies of an 11-turbine onshore wind farm in Italy offers a detailed breakdown of the turbine materials and those of the civil and electrical infrastructure. Table 5.1 shows the percentage contribution of different materials and their associated carbon emissions. The differences between the material mass balance and the emissions associated with these materials arise from substantial differences between the embodied carbon of the materials. Steel and other metals have relatively higher emissions per unit mass than concrete and aggregates, while plastics (specifically the composites used in turbine blades) are more carbon-intensive still.

For offshore wind farms, differences in the balance of materials used, alongside greater use of shipping for access during installation, maintenance and decommissioning, will raise the level and alter the balance of lifecycle emissions. Despite this, LCA studies tend to suggest that overall carbon footprint is broadly the same as that for onshore wind, owing to higher production levels[42].

Variations in reported carbon footprints arise from underlying assumptions about resource levels and energy production, specific materials and operational details, as well as important methodological choices – such as the inclusion or otherwise of specific processes or lifecycle stages and the treatment of recycling. A specific area where differences occur is between studies conducted using either 'process-based' or 'input-output' methods. The former takes a much more engineering-focused approach, breaking the system down into components and systematically tracing inputs and emissions, while input-output uses typical sector-wide 'relationships' between costs and resource consumption and carbon emissions. There are advantages and disadvantages to each approach, but process-based assessments dominate.

Variations introduced by the other underlying assumptions are not particularly large, and harmonisation studies have been undertaken to further minimise some of these impacts. One of the most recent and comprehensive exercises, carried out by the National Renewable Energy Laboratory (NREL) in the USA, suggests that wind energy has a median carbon footprint of 11 gCO_2e/kWh within a typical range of +/- 5. Typical carbon paybacks are estimated to be around six months.

In the UK, an area of contention has arisen relating to land use change, specifically the interaction of wind farms with natural stores of carbon, such as peat and trees. The concern around peat centres on the release of stored methane (a very potent greenhouse gas) as peat dries out; the construction of foundations and roads can both displace peat and affect the drainage of any that is left otherwise undisturbed[43]. The Scottish Government introduced mandatory assessments of at-risk sites, and design and construction must follow good practice guidelines that minimise interference with hydrology through, for example, raft road construction. Even with best practice, however, construction on peatlands will result in some reduction of any carbon benefits.

Wind farms are also being increasingly constructed within or around forested areas, typically Forestry Commission plantations. The felling of trees, either wholesale 'clearfelling' or a more selective 'keyholing' strategy, reduces the carbon taken up by the forest as a whole. This can be handled by replanting at the site. An analysis by Mitchell et al. (2010)[44] found that very large areas of

THE CARBON FOOTPRINTS OF MOST OTHER RENEWABLE TECHNOLOGIES ARE DOMINATED BY THE EMISSIONS ASSOCIATED WITH CONSTRUCTION OF THE GENERATORS AND INFRASTRUCTURE

clearfelling were necessary to significantly reduce carbon benefits. When considering the carbon footprints of onshore wind farms, however, it is important to bear in mind that the carbon impacts of land use change remain quite uncertain.

Carbon footprints can be calculated for any generating technology (Figure 5.1). As with wind, the carbon footprints of most other renewable technologies, as well as nuclear power, are dominated by the emissions associated with construction of the generators and infrastructure; however, the carbon footprint of fossil-fuelled generation is dominated by the emissions arising from combustion. These values implicitly make assumptions about the capacity factor of the technology – with nuclear and fossil plant operating at very high levels and renewables at lower values – which, of course, depend very much on the operation of the plant. Should there be reductions in the production due to market conditions or increasing generation from wind, then the carbon footprint will increase.

Individually, each different generating technology is responsible for different quantities of greenhouse gas emissions. Typical carbon footprints for each of the main types on the GB grid system, normalised per unit of output energy, are given in Figure 5.1 (the second and third quartile ranges are given along with estimates for CCS).

The carbon footprint of wind energy is very low with typical carbon payback periods of six months, although the carbon impact from land use is more uncertain.

5.2. System-avoided carbon emissions

While it is clear that wind power will reduce overall carbon emissions by replacing the output from coal and gas power stations, there is debate as to the extent to which the variability of wind affects these reductions. Fluctuations in wind energy output will require other types of generator to be called on to balance demand: some by running at only part load, which will result in lower efficiencies and higher greenhouse gas emissions per unit output, and others by operating as very fast-response peaking plant, with inherently high emissions. It has been conventional wisdom that the carbon emissions avoided by wind energy would be determined by the carbon emissions of the marginal plant (that which is regarded as reducing its output as a result of the additional unit of production from wind); however, there has been substantial debate over many years as to whether this plant would be a coal- or gas-fired generator. The main issue is that the displaced emissions

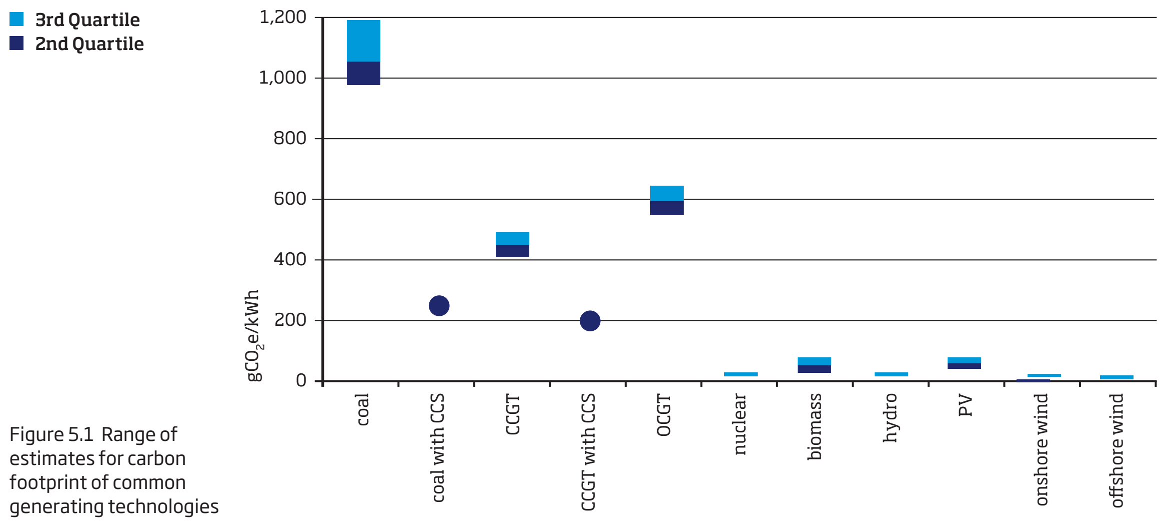


Figure 5.1 Range of estimates for carbon footprint of common generating technologies

would then differ substantially: high levels of avoided greenhouse gas emissions if coal is displaced, with lower, but not insignificant, levels if gas is displaced. Defra and DECC recommend that the average grid carbon intensity is used for avoided emissions[45], but this value does not represent the marginal plant. Some commentators have also suggested that the 'efficiency penalties' associated with part-loading generators would completely negate any carbon reduction benefits of wind or perhaps even increase net greenhouse gas emissions[46],[47].

There is a conceptual problem with the marginal plant approach in that it assumes that there is a single identifiable plant which supplies the 'last MWh' required. With simple economic dispatch models it is possible to do this, but in a real market such as BETTA, this simplified view fails to adequately describe reality: firstly, by assuming that the merit order depends solely on the relative prices of coal and gas; and secondly, that there is a single marginal plant that provides the marginal generation. In reality, any increase in wind production alongside simultaneous changes in demand levels will be met by raising or lowering the output from a series of conventional generators providing reserve, largely through part-loading. The true carbon avoided will, therefore, depend upon a number of factors: decisions made within the electricity trading markets, the efficiency penalties of operating power stations at lower output, and the additional emissions of any associated reserve capacity.

A number of international studies have been carried out to examine the true marginal emissions displacement of wind power on other networks[48]. These analyses have confirmed that wind power displaces a combination of gas- and coal-fired generation, and that the impact of part-loading efficiency penalties is not insignificant; however, the precise estimates of avoided emissions depend on the specific network being studied, so their findings cannot be directly applied to the UK. Work that has been published for the UK concentrates only on the marginal impact of demand-side changes on carbon emissions[49], also confirming that the marginal plant is a combination of coal- and gas-fired generation, but not providing specific estimates for the avoided emissions of wind power. DECC has been examining the UK system but has not, as yet, published its results.

Independently, Thomson[50] (2014), at the University of Edinburgh, recently analysed almost five years of detailed power station production records for the GB system to identify the historical carbon displacement of wind power. This work accounted for operation of wind farms within the balancing mechanism, as well as the impacts of any part-load inefficiencies. The marginal changes in CO_2 emissions between each half hour market period were reconstructed using representative carbon intensities and part-load efficiency curves for coal and CCGT (a lack of public data on UK power station heat rates precluded the application of real performance data). The analysis found that the average marginal emissions of the system as a whole were 604gCO_2e/kWh: this is essentially the emissions that would be avoided if demand was reduced by 1kWh. The marginal avoided emissions for fluctuating wind power output were 562gCO_2e/kWh, some 7% lower. This demonstrates that reductions in demand will have a slightly greater impact on carbon emissions than increase in wind power generation; however, it is important to note that these avoided emissions from wind are some 22% higher than the recommended 'official' value. While this work did confirm that the impact of the efficiency penalties of part-loading coal and CCGT generators on the avoided carbon emissions of wind power was significant, the avoided emissions are still higher than the average emissions of the network. This work also confirms that variations in wind and demand are met by a portfolio of different types of generation.

Wind energy reduces the carbon intensity of the grid system with marginal avoided emissions of around 550gCO_2e/kWh, this is roughly equivalent to the average of emissions from coal and gas plant and slightly lower than avoided emissions from demand reduction.

6. Economics

PROVIDING AFFORDABLE POWER FOR BOTH DOMESTIC AND BUSINESS CONSUMERS HAS ALWAYS BEEN A KEY OBJECTIVE BUT HAS BECOME EVEN MORE IMPORTANT SINCE THE GLOBAL FINANCIAL CRISIS OF 2008

The cost of wind energy is critical to its viability to deliver overall energy policy objectives. Providing affordable power for both domestic and business consumers has always been a key objective but has become even more important since the global financial crisis of 2008. The price of electricity has an impact on business and industry and, therefore an impact on economic growth. Rising fuel bills set against a general increase in the cost of living have forced energy prices to the top of the political agenda, and this looks set to be one of the major issues in the 2015 general election.

The cost or price of any particular generation technology can be considered from a number of different perspectives. Conclusions might be different depending on whether you are a developer taking an investment decision, the government deciding on the market structure and regulatory regime, or a final consumer of energy.

There are, inevitably, trade-offs between price to the consumer, effect on the national economy, carbon footprint and security of supply. While renewables represented a small fraction of the total electricity consumption, not all of these issues mattered, but as the proportion of wind energy increases, they all become significant.

6.1. Levelised costs

Discussion on the comparative economics of different types of generating technologies typically begins with levelised costs of electricity (LCOE). This approach attempts to compare the costs of each different technology in as uniform a way as possible. The results give a cost (or a range of costs) per unit of electricity for each technology and are a way of comparing one generating technology against another.

It is tempting to seek to carry out such an analysis; to produce a single number that says how expensive the electricity produced by a particular technology will be and then choose the cheapest. However, the situation is rarely that simple and the characteristics of each technology mean that direct comparisons can be difficult. Despite this, levelised costs remain a useful metric as long as their limitations are recognised.

Levelised costs generally take into account three main components:

- **Cost of capital** – fixed cost of building the asset including: the engineering, procurement and construction price, development costs and financial costs
- **Fixed operational and maintenance costs** – ongoing fixed cost of keeping the plant running including labour, maintenance, property rates, insurance and network charges
- **Variable operational and maintenance costs** – including fuel, carbon costs and others.

Table 6.1 Levelised costs for a range of generating technologies[51]

Generation technology	Range of cost estimates (£/MWh)
Gas (CCGT)	60 - 100
Onshore wind	70 - 125
Offshore wind	100 - 200
nuclear	70 - 105
CCS (gas post-combustion)	105 - 115
CCS (coal)	105 - 140

THE COSTS OF ELECTRICITY TO THE CONSUMER WOULD BE LARGELY DETERMINED BY THE AMOUNT OF GENERATING CAPACITY NECESSITATED BY THE PEAK DEMAND

Decommissioning is considered but generally a fixed charge per MWh is assumed for nuclear plant and, for all other technologies, the decommissioning cost is assumed to equal the scrap value of the asset.

When comparing technologies where other factors (such as carbon impact, effect on balance of payments, security of supply, societal impact) are roughly equal, a calculation of LCOE is straightforward. Where these other factors are unequal (such as state underwriting of nuclear insurance or decommissioning liabilities) and where the financial value put on them (such as the cost of carbon or the landscape value of national parks) is non-comparable or ill-defined, a comparison of LCOE is unlikely to be definitive.

There are other problems with the use of LCOE. The first is its use for generation technologies where a large component of the cost is the fuel. It is difficult to be sure of the cost of fuels such as gas beyond the short term (forward contracts can last a year or more but beyond that it is uncertain). This means the LCOE for plant with high running costs have a high degree of sensitivity to global fuel prices and therefore, over the timescales considered in the report, the costs are uncertain.

All types of generation will incur their own particular system costs and system costs are also difficult to integrate fully into LCOE. Transmission costs are generally excluded from the calculation and will apply unevenly to different types of generation. Even wind capacity will have very different transmission costs depending such factors as whether it is an onshore wind farm in the north of Scotland or an offshore wind farm in the Thames estuary. Costs of balancing services required owing to intermittency are included but will vary considerably depending on the particular generation mix. There have been several studies investigating the additional system costs of low carbon technology which come to very different conclusions, depending on the assumptions made. This report has not attempted to put a figure on the system costs of wind energy under different conditions; it is a complicated area that is heavily dependent on many other factors.

A further issue is that this type of analysis breaks down when dealing with a largely decarbonised system – as envisaged by the Committee on Climate Change from about 2030. This kind of system is likely to be dominated by nuclear power and intermittent renewables, with high capital costs and low running costs. The costs of electricity to the consumer would be largely determined by the amount of generating capacity necessitated by the peak demand. In effect, the country's total annual costs would be related to power (GW), not energy (GWh). In this situation, levelised costs in £/GWh would become irrelevant.

A final additional uncertainty relates to the way in which the technology interacts with the varying and geographically located demand for electricity. If all sources of generation had a small footprint, could be located close to the consumer and were able to ramp output up and down at any rate and with no detriment to efficiency, calculation of LCOE would be straightforward. However, that is not the case – some technologies, such as offshore wind, are available only at locations remote from centres of population; others, such as solar energy, only during particular periods of the day; others, such as CCS coal, cannot readily be located near residential areas; and others, such as nuclear, have limits on the rate at which output can be ramped up or down.

Despite these 'health warnings', levelised costs remain a useful metric as long as their limitations are recognised.

Results vary but Table 6.1 gives UKERC's range of estimates based on work by Arup, Parsons Brinckerhoff, Mott McDonald and DECC[50].

Offshore wind has the biggest range of costs, the highest of which is considerably higher than the other technologies. The lower end of the estimate, however, puts offshore wind at a competitive level with onshore wind. Much work has been done to reduce the costs of offshore wind. The Offshore Wind Cost Reduction Task Force, a group made up of government, industry and the Crown Estate, estimates that "the offshore wind levelised cost of energy can be reduced to £100/MWh by 2020 if there is sufficient

WHEN IT COMES TO THE PRICE OF WIND ENERGY FOR THE CONSUMER, THE MOST PERTINENT MEASURE IS THE SUBSIDY LEVEL PAID THROUGH EITHER TAXATION OR UTILITY BILLS

project momentum, supply chain competition and stronger intra-industry and stakeholder cooperation"[52]. The Energy Technologies Institute (ETI) supports this view with the potential for further reductions to around £85/MWh for optimum sites built in 2030.

A number of other methods besides levelised costs can be used to assess the economics of either individual generating technologies or the electrical system as a whole. Industry will use a variety of approaches to assess the economic viability of potential projects such as net present value. Another approach is to determine the cost of decarbonisation for each type of generating technology by assigning a price per tonne of greenhouse gas abated. This approach can be seen in, for example, marginal abatement curves (MAC) such as those produced by McKinsey[53].

Economic cost optimisation models are also used, such as MARKAL models or the Energy Technologies Institute's Energy Systems Modelling Environment (ESME) to assess potential options for the future UK energy system that include heat and transport as well as electricity generation.

Each of these approaches has its merits but all are prone to the similar limitations and uncertainties of LCOE.

In terms of the cost of building generating capacity, onshore wind is one of the cheapest forms of large-scale, low carbon technologies. Offshore wind is more expensive but could show cost reductions as the technology matures.

There are a number of limitations and uncertainties with levelised costs. These are becoming better understood and levelised costs remain a useful tool for policymakers as long as the limitations are taken into account.

A number of alternative methods exist for calculating the cost of wind energy alongside other generating technologies. Each has uncertainties and limitations but each can be used effectively by either developers or policymakers. For most, onshore wind is seen as being competitive while offshore wind as being more expensive.

6.2. Financial support mechanisms

The sections above describe methods used to estimate the cost of different types of electricity generation including wind energy. However, when it comes to the price of wind energy for the consumer, the most pertinent measure is the subsidy level paid through either taxation or utility bills.

Almost all forms of electricity generation have received, or continue to receive, subsidies of one kind or another. The question of what constitutes a subsidy is a contentious issue but, in the case of renewables such as wind, a number of governments have offered various types of support mechanisms to encourage its development. This began in the 1970s as a result of the oil crisis and was extended in the 1990s to encourage reductions in carbon emissions.

Subsidies exist for two primary reasons in the case of electricity generation. The first is to support the development of technologies that are considered desirable but are not sufficiently mature to compete with more established technologies. Taking a technology from an early research stage to full commercialisation is an expensive and risky process. Financial support through the product development process can mean the difference between success and failure.

Secondly, even for mature technologies, subsidies may still be required to account for externalities not subsumed in the basic market structure. Carbon is one such externality in the energy market if low carbon forms of generation get no premium when sold in the market. In order to encourage lower carbon generation, either penalties can be imposed on high carbon forms of generation (such as a carbon tax or emissions trading scheme) or low carbon generators can be paid a premium for their product. Other externalities that could be internalised by taxation or subsidy relate to security of supply or the balance of payments. A number of mechanisms have existed and continue to exist in the UK to fulfil both these purposes.

Table 6.2 CfD strike prices for wind energy[54]

	Strike prices £/MWh (2012 prices) 2014/15	2015/16	2016/17	2017/18	2018/19
Onshore wind	95	95	95	90	90
Offshore wind	155	155	150	140	140

6.2.1. Government support mechanisms

Government support for renewables began in 1990 with the Non-Fossil Fuel Obligation (NFFO). This ran until 2002, when it was replaced by the Renewables Obligation (RO). This was an obligation on electricity suppliers to obtain a certain amount of their electricity from renewable sources. The level has risen year on year from 9.3TWh in 2002/03 (approximately 2.5% of demand) to 34.7TWh in 2010/11 (approximately 9.5% of demand). It was originally technology-neutral in that it did not matter which particular renewable technology was used. As a result, industry naturally focused on the cheapest, most mature renewable technologies which, in the early stages, were mainly landfill gas, hydro and onshore wind. Since April 2009, the number of ROCs issued per MWh of renewable power generated has varied, with more expensive technologies such as offshore wind receiving more ROCs than cheaper ones such as landfill gas.

The Renewables Obligation will cease for new generators in March 2017 when provisions in the Electricity Market Reform legislation will fundamentally change the support mechanism for low carbon generation. It will be replaced with a Contract for Difference (CfD) feed-in tariff that will provide a guaranteed income for all forms of low carbon generation. Generators of low carbon electricity will receive a fixed amount for each unit of electricity they produce – the 'strike price'. This will be made up of the wholesale price of the electricity on the market, topped up to the strike price through customers' utility bills, should the wholesale price be lower than the strike price, or the difference paid back by the supplier, should the wholesale price be higher than the strike price.

The level of income will differ for each of a range of low-carbon technologies, depending on the strike price. Table 6.2 above gives the strike prices up to 2018/19 for on- and offshore wind[55] on contracts that will last 15 years.

It is important to compare like with like when considering if strike prices offer value for money. Many of the base load coal stations used during the winter of 2013–14 were constructed more than 40 years ago and the capital costs have been fully depreciated. Some are scheduled for closure under the European emissions directives so maintenance can be on a 'run it into the ground' basis and there are no plans to build new coal-fired power stations.

It is therefore inappropriate to compare the strike price of wind with the current wholesale price of electricity; rather it should be compared with the entry cost of fossil fuel generation, compliant with current legislation and thus eligible to be constructed and operated into the 2030s. It is shown in Table 6.1 above that a new CCGT, which would have a limited life if regulations remain the same, would generate electricity at around £60–100/MWh; emissions-compliant CCS is unlikely to be cheaper.

An additional consideration is that the CfDs will in themselves interact with the wholesale price. Currently, the impact of additional plant funded by the RO is to depress wholesale prices. So society pays a subsidy against which is set the potential for wholesale prices in the wider market to go down until excess capacity is removed. In the short term, the subsidy/wholesale price differential exaggerates the relative cost effectiveness of wind versus other forms of generation.

The new CfDs give the clearest indication of the price of wind energy for the consumer in the short to medium term and how it compares to other types of generation. It is clear that, in order to drive decarbonisation, a premium must be paid to encourage low carbon generation and onshore wind is more mature than offshore wind which explains offshore wind receiving a higher strike price.

The overall payment level for the Renewables Obligation, CfDs and small-scale FiTs is capped by the Levy Control Framework at £2bn in 2011/12, rising to £7.6bn in 2020/21 (2011/12 prices). What is less clear is the impact that this will have on consumers' bills in the long term, depending as this does on future fossil fuel and carbon prices which are uncertain.

ALTHOUGH THE UK LEADS THE WORLD IN OFFSHORE INSTALLATIONS, THERE ARE CURRENTLY NO WIND TURBINE MANUFACTURING FACILITIES IN THE UK

There is also value in investing in assets in the UK that do not depend on imported fuel. While they may have a higher cost, they have the added benefits of operating and price security.

The new Contract for Difference support mechanism gives the clearest indication of the price of wind energy. With initial strike prices of £95 for onshore wind and £155 for offshore wind on contracts lasting 15 years, the price of wind energy to consumers is set for at least the medium term.

6.3. UK content of wind industry

There are wider economic considerations for the UK beyond the price of energy, not all of which are within the scope of this report. A secure and affordable energy system is vital for any developed, industrialised nation. Rising energy prices could have the effect of hindering business investment in the UK or even driving it elsewhere if the price of energy is relatively cheaper in competing countries. This is especially true for energy-intensive industries, although the government has introduced measures to address this. Security of supply is even more critical. The electrical system in the UK has operated with few interruptions, other than due to industrial action, since the 1940s, and both individuals and businesses have developed a reliance on this security. The adaptation costs to a system that did not offer this degree of security would be significant, and the carbon impact (such as the use of inefficient standby generators) would adversely affect decarbonisation targets.

Balancing affordability and security concerns together with the need to decarbonise is hugely challenging. Integrating wind energy into the future energy system will be part of the challenge. The economic effects of the large-scale deployment of wind energy include a number of related but separate issues.

The UK content of the wind industry is currently low, particularly in terms of capital expenditure. If large-scale deployment of wind is to continue, it can be argued that it would be economically beneficial to increase the UK's manufacturing and supply chain capabilities. However, although the UK leads the world in offshore installations there are currently no wind turbine manufacturing facilities in the UK.

In Europe, the market is dominated by Vestas (Denmark), Enercon (Germany) and Gamesa (Spain) which between them account for around 70% of installed capacity. Globally, Chinese companies such as Sinovel and Goldwind as well as the Indian company Suzlon are becoming major players along with more established companies such as GE Wind and Siemens.

It is no coincidence that the countries that have pushed most aggressively on the installation of wind energy also have thriving wind industries, with Denmark, Germany and Spain all boasting some of the biggest manufacturers of wind turbines in Europe. This not only provides employment but also avoids a negative balance of trade created by having to import the machines. Any export business is equally advantageous for the balance of trade.

A previous publication by the Academy[56] highlighted the importance of attracting Tier 1 manufacturers to the UK. It is estimated that for every Tier 1 job created, another eight will be created in the wider supply chain. However, major manufacturing plant have been difficult to secure with Vestas and Gamesa pulling out of possible deals in Kent and Dundee and other major port developments still to be realised with Scottish and Southern Energy (SSE) and Siemens. At present, only Vestas has any UK plant with a blade test and research facility on the Isle of Wight.

The situation is ever-changing and, as this report goes to press, there has been an announcement by Siemens that production and installation facilities are to be built in Hull and Paull, East Yorkshire.

A secure pipeline of projects is important for establishing a UK wind energy industry.

IF LARGE-SCALE DEPLOYMENT OF WIND IS TO CONTINUE, IT WOULD BE ECONOMICALLY BENEFICIAL TO INCREASE THE UK'S MANUFACTURING AND SUPPLY CHAIN CAPABILITIES

Stable demand for a product is vital in any business, particularly in an industry with assets that have an operational lifespan of 20 or 25 years. It is unreasonable to expect all political uncertainty to be removed from the UK's energy system, but, without a high degree of confidence in the direction of travel expected, it is unlikely that the UK content of wind capacity installed will increase significantly. This would require continued government support and a consistent, long-term energy strategy.

The UK manufacturing content of wind developments is currently low, particularly for capital expenditure. If large-scale deployment of wind is to continue, it would be economically beneficial to increase the UK's manufacturing and supply chain capabilities. This would require continued government support and consistent, long-term energy strategy.

6.4. Summary

The economics of wind energy are complex. Costs can be assessed from a variety of perspectives including those of developers, government or consumers. Considerations over different timescales can also deliver different results. There are a number of approaches used, all of which have inherent uncertainties and limitations and it is dangerous to look for one simple figure for how much wind energy will cost.

Ignoring carbon externalities and assuming fossil fuel costs stay within predicted bounds, most measures suggest that onshore wind is more expensive than traditional forms of unabated fossil fuel generation but is one of the cheaper forms of low carbon electricity. Offshore wind is currently more expensive, but cost reductions could be realised as the technology matures. This may, however, be partially negated as offshore wind moves into increasingly harsh environments.

Wind energy has been, and will continue to be, reliant on financial transfers to internalise the external costs of different generation technologies. These serve the dual function of helping the technology mature and incentivising low carbon forms of generation. The recently announced strike prices for the new Contract for Difference (CfD) feed-in tariffs reflect both these functions and the relative costs of wind energy. Initial strike prices are £95 for onshore wind and £155 for offshore wind on 15-year contracts, with gradual reductions over time.

Different types of generation have different economic characteristics. Renewable generation tends to have high capital costs but the CfDs give a high degree of certainty for their operating costs. Thermal plant such as CCGT have lower capital costs but uncertain operating costs as a result of volatile fuel costs, and their continued extensive use would mean that the UK would not meet carbon reduction targets. Any future electricity system will need to balance these different elements to deliver a system that can find sufficient capital investment while still delivering secure and affordable energy.

All generation incurs the additional costs of electricity transmission, the infrastructure to transport fuel, back-up capacity and spinning reserve to cope with sudden outages and demand forecast errors. We have not been able to put a definitive figure on these other system costs for wind energy, as the cost varies, depending on the overall mix of generation and the assumptions made about demand response and accuracy of forecasting.

The UK content of wind energy is currently low, particularly in terms of capital expenditure. It is clear that, if wind capacity continues to grow to the levels expected, any increase in the UK content would be of economic benefit. This would require manufacturing plant to be built in the UK which would, in turn, expand the associated supply chain. So far, efforts to attract such facilities have faltered. Government has a major role to play, particularly in setting consistent, long-term energy policy.

7. Operating the grid in 2030

BY 2030, IT IS EXPECTED THAT THE GRID WILL BE LARGELY DECARBONISED AND INCREASING PROPORTIONS OF HEAT AND TRANSPORT DEMAND WILL BE PLACED ON THE ELECTRICITY SYSTEM

Section 4 dealt with the major issues relating to wind energy that the electricity system must be able to manage. It was concluded that, in general, at levels of penetration that can be expected for the GB system up to 2020, issues should be manageable. Technical issues will arise and lessons must be learned from neighbouring systems that are already dealing with higher levels of penetration but, overall, the system will be similar to the current one.

As we move towards 2030, however, the situation will change radically. By 2030, it is expected that the grid will be largely decarbonised and increasing proportions of heat and transport demand will be placed on the electricity system through heat pumps and electric vehicles. Unabated fossil fuel plant will be severely reduced, and given that they currently make up over 70% of supply, this fact alone will mean a radically different system.

In terms of generation, as set out in Section 2.5.2, there could be 50GW or more of wind energy on the system, although as pointed out, this is subject to significant uncertainties relating to market conditions and regulations. Wind energy will be just one of a range of possible low carbon technologies that are expected to supply electricity. All will have advantages and disadvantages and the relative mix will depend on a variety of factors. The main options other than wind are:

- **Nuclear** – known technology that can supply large-scale, secure, base load electricity. Initial capital costs are high and although plant can be designed to vary output, the degree of flexibility is limited
- **CCS** – potentially large-scale supply but, while the component parts of the technology have been shown to work, a full-scale, full-chain demonstrator is still to be built. Until then, the true costs and performance will be uncertain
- **Other variable renewables (wave, tidal and solar photovoltaic)** – high capital costs and non-dispatchable like wind power. In most cases, they are less mature than wind
- **Bioenergy** – dispatchable, large-scale generation but the long-term sustainability for the feedstock requires significant development.

The future system will be a combination of the above technologies but it will not be demand-led, as is the assumption with the current system. Much higher levels of control will be needed as well as a range of additional tools.

It is beyond the scope of this study to consider the full implications of the future energy system but, in the following section, we consider some of the issues that are of particular concern for wind energy.

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SMART METERS ARE CURRENTLY IN THE PROCESS OF BEING ROLLED OUT AND THE GOVERNMENT AIMS TO HAVE ALL HOMES AND BUSINESSES FITTED WITH SMART METERS BY 2020

7.1. Demand side management

Demand, both average and peak, is expected to increase significantly on the electrical system with the addition of electric vehicles and heat pumps. Controlling demand is likely to be one of the major developments on the future grid. The ways in which demand can be managed include:

- **Load shedding** – this reduces the demand on the system by shutting off large industrial loads when required. Such services already exist but it is expected that further opportunities could arise through the aggregation of smaller loads. The ability temporarily to reduce the demand would provide the system operator with an additional tool to balance the system in the event of possible shortages in supply or shocks to the system
- **Load shifting** – this would control the level of demand by shifting loads away from periods of peak demand to periods of lower demand or periods when there is a surplus of supply. It would require appliances that are capable of two-way communication with system operators. It would be particularly important to control the demand from additional loads such as electric vehicles.

Smart meters are currently in the process of being rolled out and the government aims to have all homes and businesses fitted with smart meters by 2020. This in itself is a major undertaking but is only the first stage in the implementation of a 'smart grid'. A smart grid will require appliances that communicate with system operators and react to price signals in real time, constituting a degree of dynamic control previously unseen in grid systems. The benefits of being able to control both supply and demand are clear. Ideally, it would be possible to shift large amounts of demand either to times of traditionally low demand overnight or to times when supply is high from variable sources like wind. But, as yet, it is not clear how effective this will be or what degree of engagement will be required from consumers.

The ability to manage demand to reflect the output from wind will be vital to the successful integration of larger amounts of wind capacity. However, despite increasing efforts to research demand management, particularly through trials, there is still much uncertainty on how effective it will be and at what cost.

It should also be noted that, in terms of demand, the one approach that will always be of benefit is demand reduction through energy efficiency – whatever happens with the future system, it will be made easier if less energy is needed.

Demand management through a 'smart grid' will be vital for the future energy system but its full potential and effectiveness are yet to be proven at scale.

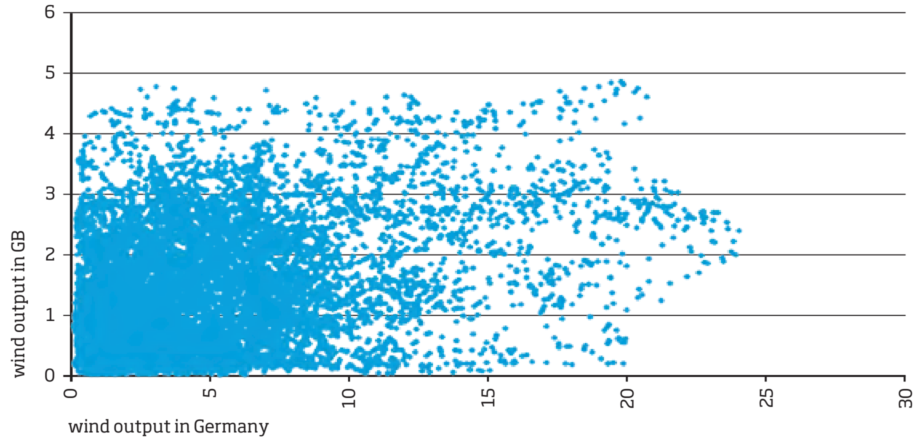


Figure 7.1 Correlations between Germany and UK wind output[27]

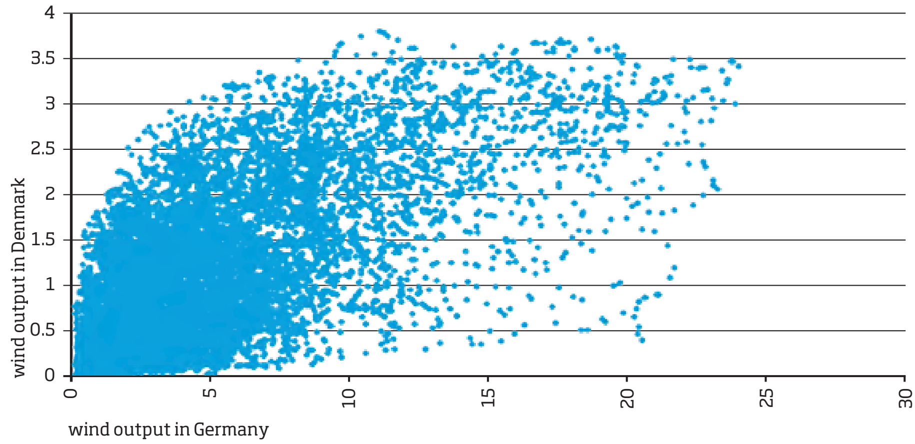


Figure 7.2 Correlations between Germany and Denmark wind output[27]

7.2. Interconnection

Given the likelihood of periods of low wind when demand is high, it has been suggested that greater levels of interconnection to the continent may be a solution as the wind is always blowing somewhere. To investigate this claim, the above two figures look at the relationship between wind output in Germany and either the UK or Denmark. For the same period of 2012 and half of 2013, each hour is plotted as a point with the output from German wind farms on the x-axis and the output from UK on the y-axis (Figure 7.1) or from Denmark (Figure 7.2). Germany has been chosen for the comparison as a country in Europe with a large amount of wind capacity.

Germany and the UK (Figure 7.1) show relatively little correlation with the scatter plot showing a fairly random distribution. However, the concentration of points in the lower left-hand corner suggests that, when wind output is low in the UK, there is a good chance that wind output will also be low in Germany.

For comparison, looking at Germany and Denmark, there is some degree of correlation and the scatter plot has a more linear appearance. This is to be expected given their geographical proximity. Overall, this suggests that, as geographical separation increases, correlation of wind output breaks down. But, this does not seem to indicate that any inverse correlation begins to establish itself so low wind output in one region is unlikely to ever guarantee high wind output in another.

Higher levels of interconnection with other systems and the full range of generation that they offer will afford greater levels of flexibility. However, Figures 7.1 and 7.2 indicate that the UK system must still be designed to cope with periods of low contribution from wind energy, regardless of where it is from. In the future, assuming higher degrees of interconnection, it will be important to consider the UK grid as part of the larger EU grid with a detailed analysis of various mixes of generation required on a European basis.

Increased interconnection with the continent will provide greater system flexibility but wind output can still be low across large regions.

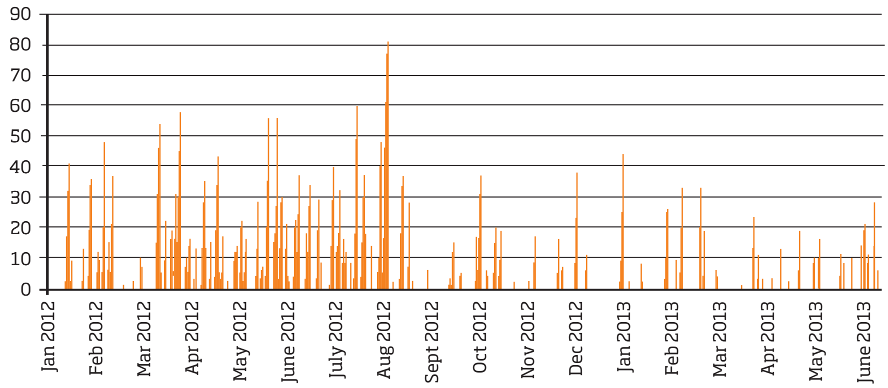


Figure 7.3 Extended periods of low wind (height of spikes equates to number of hours of wind below 500MW)[26]

7.3. Storage

Another characteristic of wind that could be a problem for the system is extended periods of low output from wind. While low wind is mainly only an issue during periods of peak demand, it could in the future become more problematic if we are relying on wind to provide energy for heating and transport.

Figure 7.3 above shows spikes during which wind output drops below 500MW over the course of 2012 and the first half of 2013, the height of the spike indicating how many hours output remained below that level. The number and height of the spikes clearly reduces in the second half of the graph as capacity increases with no periods of low wind lasting more than 48 hours occurring then. But there are still regular periods of low output lasting 12 hours or more and in the first half of the graph, there are periods of up to 80 hours with low output from wind.

IT IS IMPORTANT TO UNDERSTAND HOW REGULARLY PERIODS OF LOW WIND OCCUR AND, PERHAPS MORE CRUCIALLY, HOW LONG THEY LAST. THIS RELATES DIRECTLY TO METHODS OF STORAGE THAT ARE BEING DEVELOPED

It is important to understand how regularly periods of low wind occur and, perhaps more crucially, how long they last. This relates directly to methods of storage that are being developed. For example, taking the case of electric vehicles (EVs), it may be possible for a large proportion of EVs to go without charging for two or three days should such a period of low wind be forecast. However, were the low wind conditions to persist for longer, this might present a much more serious problem. Increased demand from electric heat pumps might be more difficult to shift, but developments are being investigated that use large-scale water repositories as a store for the heat. Although it only considers one system over a relatively short time period, Figure 7.3 suggests that periods of very low output from wind occur infrequently. Examples do exist, such as in December 2010[57] when the UK experienced a blocking high pressure that gave very cold but still conditions for around a week. Such eventualities need to be accommodated by the system, but in general, the majority of calm periods will not last more than a few days. Even in a long period of calm weather, the daily troughs in demand should provide an opportunity to recharge storage systems that can help to meet the following day's peak, unless the available capacity of other kinds of generation falls to very low levels.

Periods of calm will occur but, except on rare occasions, will not persist for more than a few days. Storage options will need to be developed that help to cope with such events.

7.4. Summary

The electrical system of 2030 will be dramatically different from today's system. Demand will rise with the expected electrification of heat and transport and the mix of generating technologies will change considerably to achieve decarbonisation. The issues that arise as a result of integrating wind energy into the system will be exacerbated by the fact that wind generation capacity will be much greater than today and will result in levels of penetration significantly beyond those seen on any power system currently operating.

A number of technological innovations are being developed that could alleviate the problems such as demand management, interconnection and storage. However, most of these have still to be tested at large scale and how they will operate as part of a system is yet to be determined. It is probable that combinations of technologies will be required to deliver a secure and functioning grid. For example, increased wind capacity in conjunction with electric vehicles and a smart grid to manage the demand could provide at least part of a system that could cope with large amounts of variable wind energy and help to decarbonise the transport sector. When integrated together carefully using a systems engineering approach, such technologies could be complementary, working together in a secure and cost-effective manner. But, if no consideration is given to the design of the system, it is possible that technologies could act in a counterproductive way.

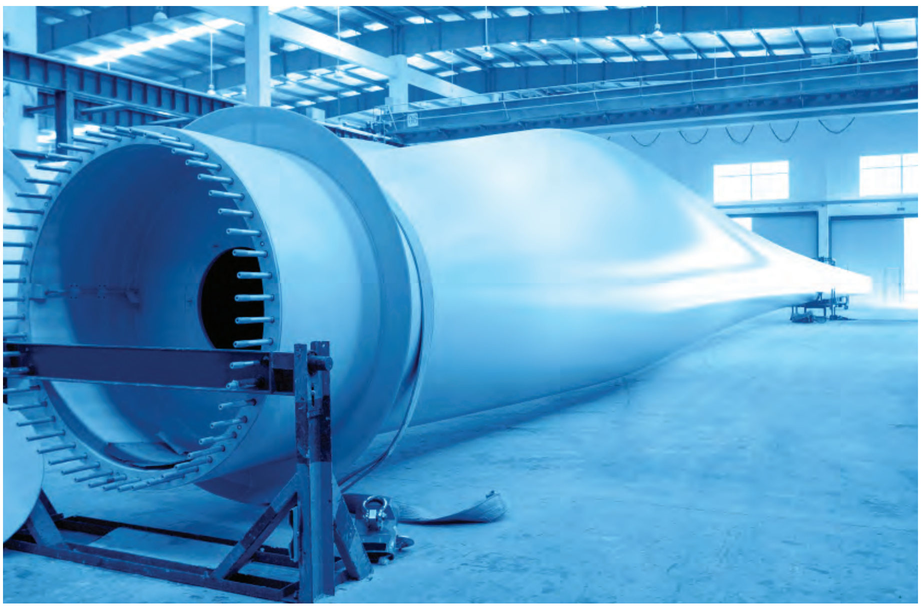
Equally important will be the development of market mechanisms that will need to reward these different technologies and deliver a cost-optimised system; this is likely to be every bit as challenging as the technical issues.

The future system must be designed carefully and well in advance. Wind energy will only be one of the pieces but it can play a crucial role in delivering the required system. This will only happen if a single body is given responsibility to map out the future energy system, at least in general terms, with solid engineering evidence backed up by economic and social considerations. This report has postulated 50GW of wind or more could be on the system by 2030. This is certainly possible, but evidence is needed to demonstrate how this level of wind capacity would function and how the rest of the system would look.

In a recent report[58], the IET called on DECC and industry to work together to establish a 'systems architect' to achieve a whole systems approach for the future electricity system. This is a vital task and one which the Academy fully supports. There is even an argument that the role should go beyond electricity and consider the integration of the whole energy system, including an assessment of all possible primary fuel and generation mixes.

An equally challenging problem is providing affordable energy for consumers while investing heavily to upgrade and decarbonise the system – managing this within repetitive political cycles of five years in an industry with assets that last many decades will not be simple. The Academy is fully committed to helping realise the necessary transformation of the energy system.

THE ACADEMY IS FULLY COMMITTED TO HELPING REALISE THE NECESSARY TRANSFORMATION OF THE ENERGY SYSTEM



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Acronyms

Acronyms

AGC	Automatic Generator Control
BETTA	British Electricity Trading and Transmission Arrangements
CCC	Climate Change Committee
CCGT	Combined cycle gas turbine
CCS	carbon capture and storage
CEGB	Central Electricity Generating Board
CfD	Contract for Difference
CHP	combined heat and power
DC power	Direct current power
DECC	Department of Energy and Climate Change
DNOs	Distribution network operators
EFC	Equivalent Firm Capacity
EMR	Electricity Market Reform
ESME	ETI's energy system modelling environment
ETI	Energy Technology Institute
EV	Electric vehicle
FiTs	Feed-in-Tariffs
GB	Great Britain
gCO_2e/kWh	grams of carbon dioxide equivalent per kilowatt hour
GDP	Gross Domestic Product
GW	Gigawatt
Hz	Hertz
IGBT	insulated-gate bipolar transistor
kW	Kilowatt
LCA	Life cycle assessment
LCOE	levelised cost of electricity
MAC	marginal abatement curves
MW	Megawatt
MWh	Megawatt-hour
NETA	New Electricity Trading Arrangements
NETSO	National Electricity Transmission System Operator
NFFO	Non-Fossil Fuel Obligation
NG	National Grid
NPV	net present value
NREL	National Renewable Energy Laboratory (USA)
OFTO	Offshore transmission owner
PV	Photovoltaic
RO	Renewables Obligation
ROCs	Renewable Obligation Certificates
SSE	Scottish and Southern Energy
STOR	Short Term Operating Reserve
TSO	Transmission System Operator
TWh	Terawatt-hour
UKERC	UK Energy Research Centre
UKWED	UK wind energy database. Held by Renewables UK
MW/km^2	Megawatts per square kilometre

Appendix 1

Working group

Rear Admiral John Trewby CB FREng – Chair

Professor Roger Kemp FREng

Professor Sir Michael Sterling FREng

Professor Richard Green Imperial college London

Professor Gareth Harrison University of Edinburgh

Dr Rob Gross Imperial College London

Richard Smith National Grid

Professor Steve Williamson FREng (part-time)

Reviewers

Professor Nick Jenkins FREng

David Eyton FREng

Andrew Haslett FREng

John Scott Chiltern Power Ltd

Dr Andrew Garrad FREng

Also, thanks to those members of the Academy's Energy and Environment Community of Practice who also provided comments on the report, particularly Professor David Fisk CB FREng, Dr Peter Chester FREng and Dr Malcolm Kennedy CBE FREng FRSE. Also, thanks to Dr Camilla Thomson for her contribution to Section 5 of this report.

Secretariat support – **Dr Alan Walker**

Appendix 2

Terms of reference

Wind power is set to play an increasingly significant part in the future energy system of the UK. Government policy is committed to providing 15% of energy from renewables by 2020. This, they say, would require a total of 15GW of onshore turbines and 13GW of offshore turbines amounting to thousands of turbines in total. However, wind power has attracted increased levels of opposition from a variety of sources in recent years and the debate has become ever more polarised and heated.

In this charged atmosphere it is vital that policy makers make decisions based on sound evidence rather than rhetoric. This report will seek to establish the evidence behind the question – what are the implications of large-scale deployment of wind on the future UK energy system? It will not answer the question of whether wind power should play a role, simply whether it is able to in terms of cost, grid operations and reduction in carbon emissions and at what level of penetration. It will also assess the effect wind power may have on other industries and society.

Procedure

1. A small working group (WG) will be formed (no more than seven members) that will include an independent Chair with no links to the power industry and members with expertise in the UK energy system, grid operations, economics and sustainability.
2. The WG will have full-time secretariat support from the Academy.
3. The study will focus on wind power because of its position as the first large-scale variable source of electricity. It will, however, do so within the context of other generating technologies and electricity demand.
4. The study will seek to answer questions relating to cost, grid operations and carbon footprint (see below for details) but also consider additional issues relating to the large-scale deployment of wind power. It will focus on a medium time horizon of 2030.
5. The study will be carried out mainly by the following methods:
    - a comprehensive literature search,
    - a call for evidence,
    - interviews with relevant experts identified by the working group,
    - a critical assessment of the evidence gathered by the above three methods.
6. The evidence will be written up in a report and a first draft will be presented to the March 2014 meeting of the Academy's Engineering Policy Committee.
7. The report will be reviewed by a panel of independent experts prior to publication.
8. The report will be disseminated widely amongst relevant stakeholders.

Questions to be addressed by study

Grid A summary of some basic concepts including intermittency or variability, dispatchable generation, load factor, efficiency, back-up, synchronisation, short term operating reserve and grid balancing.

The effect of wind on grid balancing and the operating reserve. This will include experiences of the UK system and other countries such as Denmark, Spain, Germany, Spain and Ireland.

How predictable is wind power over various time scales and how does this affect the operation of the grid?

How might innovations in the electrical system, such as storage and smart grids, affect the performance of wind power?

Cost What are the levelised costs of wind power, how do they compare with other generating technologies and how might they vary in the future?

What other methods exist to estimate the cost of generating technologies?

Carbon What are the carbon emissions of wind power during manufacture and installations?

What effect does wind power have on the carbon emissions of the grid in operation?

Other What evidence is there on the long-term performance of wind turbines in terms of installation, operation and maintenance, and decommissioning? How do onshore and offshore wind compare in this regard?

What are the main local environmental and social issues associated with the large-scale deployment of wind power?

What impact will large-scale deployment of wind power have on other industries, particularly in the case of offshore wind?

What future research developments are you aware of that could significantly affect wind power in the future?

Appendix 3

Call for evidence submissions

1. **Chris Anastasi** GDF SUEZ Energy UK-Europe
2. **Dr John Beynon FREng**
3. **Derek Birkett**, former grid control engineer
4. **Professor Feargal Brennan** Cranfield University
5. **Dr Peter Chester FREng**
6. **S. Davies**
7. **Energy Technologies Institute**
8. **Brendan Fox** Queen's University Belfast
9. **GL Garrad Hassan**
10. **Dr Martin Grant FREng**
11. **Victor Harnett**
12. **IESIS**
13. **Professor David Infield** Strathclyde University
14. **Professor Michael Kelly FREng FRS**
15. **Jason Kennedy** System Operator for Northern Ireland (SONI)
16. **Dr Malcolm Kennedy CBE FREng FRSE**
17. **Professor Michael Laughton FREng**
18. **Mainstream Renewable Power**
19. **Sir Donald Miller FREng FRSE**
20. **Dr Leslie Mitchell FREng**
21. **Richard Perkins** Institute of Acoustics
22. **Professor Jack Ponton FREng**
23. **RenewableUK**
24. **Siemens**
25. **Ramboll Energy**
26. **Professor Peter Tavner** Durham University
27. **Mark Whitby FREng**

Appendix 4

Oral evidence sessions

Grid integration – 30 April 2013

Attendees

Julian Leslie Transmission Network Services, National Grid

Mervyn Sara Business Transformation Manager, Siemens Power Transmission Division

Paul Gardner Senior Principal Consultant, GL Garrad Hassan

Professor Brendan Fox Queen's University Belfast

Paul Fidler Director of Operations, Energy Networks Association

Paul-Frederik Bach Consultant (formerly Planning Director at Eltra)

Professor Goran Strbac Imperial College London

Offshore wind – 7 May 2013

Attendees

Kate Payne Technical Specialist - Renewable Energy, DECC

Julian Leslie Transmission Network Services, National Grid

Ray Thompson Business Development Manager, Siemens Wind Power

Colin Morgan Head of Offshore Wind, GL Garrad Hassan

Richard Howard Chief Economist, Crown Estate

Adrian Fox Programme Manager Supply Chain and Technology, Crown Estate

Hugh Yendole Programme Manager, Director, DONG Energy

Dr David Clarke FREng Chief Exective, Energy Technologies Institute

Economics – 28 May 2013

Attendees

Alice Barrs Senior Analyst, Committee on Climate Change

Dr John Constable Director, Renewable Energy Foundation

Dr Peter Chester FREng

William Heller Managing Director, Falck Renewables

Lindsay McQuade Head of Policy, Scottish Power Renewables

Mike Blanch Associate Director, BVG Associates

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