centre for sustainable energy

Common concerns about wind power (2nd edn)

Chapter 5
Intermittency of wind turbines

This is one of a series of chapters of evidence-based analysis drawing on peer-reviewed academic research and publicly funded studies.

For other chapters, see
www.cse.org.uk/concerns-wind-power-2017

Centre for Sustainable Energy, June 2017

centre for sustainable energy

OFFICE 3 St Peter's Court
Bedminster Parade
Bristol BS3 4AQ

PHONE 0117 934 1400

EMAIL info@cse.org.uk
WEB cse.org.uk
TWITTER cse_bristol

CHARITY 298740
COMPANY 2219673
FOUNDED 1979

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Chapter 5
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The first edition of Common Concerns about Wind Power was published in 2011 to provide factual information about wind energy, in part to counter the many myths and misconceptions surrounding this technology.

Since 2011, much has changed in the legal and economic sphere, and a second edition became necessary. Research has been carried out for this edition since 2014. Therefore, this edition is formatted as a series of individual chapters available for download at www.cse.org.uk/concerns-wind-power-2017

All chapters written and researched by Iain Cox.

Centre for Sustainable Energy, June 2017
Written and researched: 2014

The Centre for Sustainable Energy is a national charity committed to ending the misery of cold homes and fighting climate change.

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We are based in Bristol although most of our work has relevance and impact across the UK. Our clients and funders include national, regional and local government agencies, energy companies and charitable sources.

Chapter 5
Intermittency of wind turbines

Summary

Weather patterns can be forecast with some degree of accuracy, which is crucial to balancing supply and demand in a power system that incorporates wind as a generator. Within a regional or national grid the electricity supply must be equal to the electricity demand at all times, something that becomes particularly challenging when relying on increasing levels of variable wind power output. This notwithstanding, the problem of dispatch, whereby electricity supply is constantly tailored to meet demand, is not new to the industry. Large and, at times, unpredictable swings in the grid system are already balanced on a daily basis. Whilst the short-term (hours to days) intermittency of traditional thermal generators is much lower than for wind farms, they are still prone to sudden unplanned outages. Given the large-scale, unitary nature of traditional thermal generators, the potential loss of power from such a plant exerts a continual risk on the grid that has to be supported by a network of balance response units, the cost of which can be significant. Smoothing out variable output from geographically dispersed wind farms across a grid presents novel statistical challenges for the transmission service operator, but they are challenges that are being met, and can be met in the future. Forecasts for wind speeds and wind power output already achieve a high level of accuracy, and these are steadily improving as more data is obtained and prediction methods are refined. More powerful forecasting tools will further reduce operating costs and improve security of transmission for the system operator, and will allow more competitive market trading for generators.

The projected share of wind in the generating sector will necessitate some financial costs to improve interconnectivity and to operate reserve capacity. However, many of the costs towards upgrading grid infrastructure are necessary in any case to replace ageing components and improve the UK's interconnectedness within the European electricity market, and many small renewable generators have been forced to pay the shared costs arising from the risks imposed by larger conventional generators on security of supply for some time. Contrary to popular belief, wind power does not need 'one-for-one' backup to allow for its intermittency – indeed, the fraction of reserve capacity needed is under one third of the installed wind capacity. A considerable capacity reserve already exists in the UK's national energy infrastructure to provide the security of supply as mandated by the transmission service operator, and the further expansion of a distributed network of wind farms will bring further benefits in terms of low-carbon, low-marginal cost electricity across the grid.

What is this based on?

One major disadvantage often stated for wind power is that it is not available as a smooth, uninterrupted supply, because wind itself is intermittent. For the transmission service operator (TSO) of a national power system, this is usually described in terms of traditional 'dispatchable' generators and the alternative 'non-dispatchable' generators that rely on intermittent natural flows. Although it is quite possibly the most important energy carrier in modern society, electricity cannot be efficiently or cheaply stored (unlike, say, fuel stocks or heat). Hence, electricity supply must be balanced with demand at all times; if it is not, then the power system may suffer excessive fluctuations in operating parameters, such as voltage and frequency, which can cause loss of load (i.e. electricity supply falls short of demand) and possibly damage expensive equipment or infrastructure. The key role of the TSO is to ensure the system can withstand any sudden events that may cause such disturbances, thus guaranteeing the system's reliability.

In the face of constantly changing customer demand, the TSO seeks to balance forecast demand with the projected generation offered in advance by the generators. The TSO relies on the ability of conventional thermal plant run by traditional generators to provide voltage regulation and frequency response services that help maintain stable transmission and distribution. When there is a mismatch between supply and demand, generators of conventional plant can act to 'ramp' up or down their supply of electricity. This is typically achieved by fossil fuel-fired plants, which will differ in efficiency, flexibility and cost depending on the exact type of plant. In some cases the TSO can also use parts of the grid infrastructure, such as interconnectors, to provide a degree of stability, but this capacity is limited.

Historically, peak electricity demand in the UK – and therefore peak supply – has been less than 80% of total national capacity. Maximum demand in 2012 fell on 12 December, and was just 70% of the UK's total capacity.[1] This is a good illustration of the spare capacity built into power systems. If the generating facilities and infrastructure were to run constantly at full load, i.e. where all available capacity was barely sufficient to meet demand, the system would not have the flexibility to cope with changes in customer usage (up or down) at the same time as providing for unforseen events that involve component failure or connection losses on the grid. Since the power system is designed to operate within its maximum total capacity, this helps ensure the system's adequacy, such that it is able guarantee sufficient electricity output to meet the aggregate demand of its customers at any given time, taking into account scheduled or unscheduled outages that may occur on parts of the system.

In a perfect world, the TSO would have access to wind forecasts that were 100% accurate, allowing it to schedule its dispatchable generating assets accordingly. But even if this were the case, it would not change the fact that the wind would still be variable – it is the variability that the TSO ultimately cannot control. Whilst short-term variability of conventional plant is much lower than that of wind farms, the TSO must allow for the fact that unforseen events resulting in loss of supply do occur and cannot be controlled. In many respects, variations in wind forecasts that look more than several hours ahead have a bearing on the grid's adequacy, because the power system is operating with spare capacity and potential mismatches can be hedged via spot-market trading and TSO scheduling.[2] The power system must, however, operate sufficient dispatchable reserve capacity at a given level of wind generation to allow for sudden changes in the short-term or very short-term (anything from minutes to a few hours) that may harm the system's reliability. The national grid already bears a significant risk from large conventional generators, which, should they suffer an unscheduled outage, can place considerable strain on the power system.[3] Thus, the variability of wind is a significant challenge, but it is not entirely unprecedented that the national grid must cope with large and instantaneous fluctuations on a regular basis.

The need to maintain and upgrade the UK's power infrastructure, which is an existing and ongoing challenge, must be combined with the need to transition to a low-carbon grid. Modern society cannot function without electricity, but neither can it afford to persist with its current inordinate reliance on fossil fuels. Thus, these challenges represent a 'social resource cost', where the move to a new type of flexible grid that can accommodate intermittent energy sources like wind is one cost that should be weighed against the cost of continuing along society's current trajectory of unsustainable energy consumption. It should also be remembered that wind is not the only renewable source of energy, and can work effectively alongside technologies that are not intermittent, such as biomass, tidal or geothermal.

What is the evidence?

Wind power on the national grid

The output of electrical power across the grid must exactly balance the demand, as the expense and inefficiency of current storage technology means there are only limited means to store excess electricity.[2] Before 2013, onshore wind had been the leading source of renewable electricity in the UK, increasing steadily year-on-year,[4] only pushed into second place briefly by the conversion of several large coal-fired units to biomass over 2012/13. This meant that biomass-fired electricity generation made up 34% of total renewable electricity, compared with 32% for onshore wind.

However, the continuing deployment of both onshore and offshore wind means that combined wind power generated more than half of all renewable electricity in the UK in 2013, amounting to 28,433 gigawatt-hours* (GWh), which was 8% of the total electricity supplied to the grid that year.[5,6] These figures represent a generation increase on the previous year of 40% for onshore and 52% for offshore wind. Over the same period this is an increase in installed capacity of 27% and 23% for onshore and offshore wind, respectively, bringing total capacity to 12.2 GW. This illustrates the continued strong growth of the wind power sector.

The National Grid estimates that the UK will have anywhere from 13 to 20 gigawatts (GW) of installed wind capacity by 2020, which would be a 16%–78% increase in installed capacity on 2013 levels.[7] The upper limit may be even higher if onshore or offshore developments are particularly favoured, and the figure does not include a potentially small but significant contribution from embedded wind turbines. These embedded 'private wire' turbines that are directly connected to properties do not typically supply electricity to the national transmission grid, but they do serve to reduce total load by meeting local distribution demand.

With these projections, it appears likely that wind power will be more than 20% of the UK's total installed capacity by 2020, and there may be times when wind generation will supply one-third to one-half of total demand.† Looking ahead even further to 2035, where installed wind capacity may be 51 GW or more, it is possible that there will be periods where electricity generation from wind will exceed the minimum demand on the grid.

* One gigawatt-hour (GWh) is 1 × 109 watt-hours. The more familiar kilowatt-hour (kWh) is 1 x 103 watt-hours; hence, 1 GWh = 1,000,000 kWh.

† In fact this is already happening. Wind power in the UK set a new record in December 2014 by meeting 43% of domestic electricity demand (see J. Kollewe, 'British windfarms set new power production record', Guardian, 9 December, 2014, www.theguardian.com/business/2014/dec/09/british-wind-farms-set-new-record).

No power plant supplies all of its theoretical maximum output as based on its rated capacity. The fraction of this maximum output that is actually generated over a given period is the capacity factor of the plant (see chapter 4). Taking present-day figures for the UK wind sector, this capacity factor will be around 29% overall, although the expected improvements in offshore wind performance means this present value is almost certainly going to rise above 30%. This means that by 2020 onshore and offshore wind could supply around 50,800 GWh per annum, cutting carbon emissions across the entire UK electricity sector by 15%.[8,9]

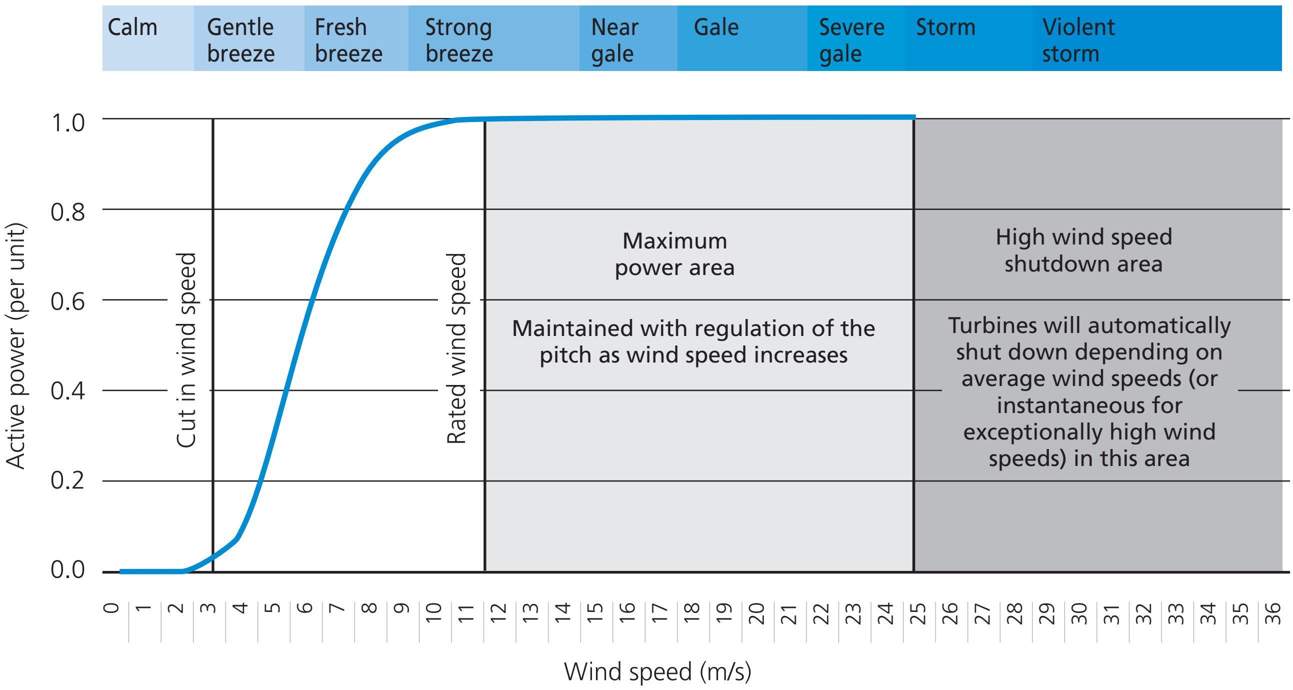
Predicting variability

However, there is no denying that wind is a variable power source. The output of a wind turbine ramps up or down depending on the speed of the wind (measured in metres per second, or m/s) and can be seen to follow a power curve, as illustrated in Figure 5.1. This typical power curve can be split into three regions. In the first region wind speeds are too low at less than 3 m/s (6.7 mph) and no power is generated. The second region begins at the cut-in speed, usually 3–4 m/s, at which point the turbine can extract useful energy from the wind. In this region, wind speed and power output are related through a cubic relationship, which means a small change in wind speed can result in a large change in power output – note how a change in wind speed from 4 m/s to 12 m/s (26.8 mph) causes the turbine to go from 5% of its rated output to 100%. The third region is the maximum power area, where the turbine maintains its rated output in the face of increasing wind speeds through various methods involving pitching the blades or stall control. All generation stops at speeds above 25 m/s (56 mph), known as the cut-out speed, to protect the turbine rotor and structural components.[10]

On average, over the course of a year, individual turbines do not generate any electricity for roughly 20% of the time, almost always due to lack of wind rather than excessive wind speeds.[11] For an individual turbine or wind farm, a weather pattern moving across the area can often result in wind output ranging from zero to maximum output on any given day. When geographically dispersed across the British Isles as a whole wind farms can act more like an aggregated power system, so the issue of variability of any one turbine becomes less of an issue because the reliability of the resource as a whole follows a probabilistic distribution.[2,12] The accuracy of forecasts for wind speed and power output is obviously important in this situation, but the TSO must also be able to assess the likelihood that it will need to call upon dispatchable capacity at times of insufficient wind generation and require curtailing of wind power output at times of excess generation. Thus, the TSO must know the degree of uncertainty (or forecast error) and be able to apply it meaningfully to daily operations so as to maintain an appropriate level of backup plant.

There are many different models used to forecast wind speeds and wind power outputs – it is important to note these are two related, but different, parameters that are being forecast.[13] These models are usually grouped into either statistical methods that rely on large amounts of historical data, physical models that forecast the wind speed at a given time from meteorological data and

Figure 5.1 Indicative power curve of a typical modern wind turbine



known atmospheric dynamics, or hybrid methods that combine various aspects of these.[14] These models are typically 'benchmarked' to assess their performance against a known reference model. Most of these benchmark models involve the 'persistence model', which, at heart, is based on the simple premise that the future wind speed will be the same as the current wind speed.[13] Although this sounds obvious, the persistence model and its derivations perform well for wind speed forecasts over very short-term forecast horizons (the next few minutes) and short-term forecast horizons (up to two hours). However, accuracy very quickly drops off past this horizon, and more advanced alternatives employing statistical and physical approaches can be seen to perform better. This is important to the grid TSO, who must run normal operation reserve, commit units to day-ahead generation schedules, and coordinate when units can be taken offline for planned maintenance.[14]

The normal operation reserve is of particular importance, because this is where the TSO must consider the trade-off between the cost of maintaining the reserve and the risk of there being insufficient reserve to cover loss of load.[15] To run a power system with an acceptable risk threshold that satisfies cost constraints with reliability concerns is why the TSO must understand the degree of uncertainty. Normal operation reserve covers both instantaneous regulating reserve and secondary operating reserve.[16] The former is concerned with sudden disturbances that require instant response (within thirty seconds) to correct system frequency and excessive load fluctuations. Operating reserve is used to make up shortfall due to unforseen load (i.e. higher than forecast demand) or a mismatch between forecast wind power and actual output. Given that the response of regulating reserve is instantaneous, operating reserve is generally required to activate over a period of ten minutes and gradually replace the regulating reserve. Some units within the operating reserve are 'spinning', meaning they are connected to the transmission grid already and can ramp up immediately; other units are 'non-spinning' and require several minutes to warm up before connecting.

The forecast error is defined as the difference between the forecast value and actual measured value, and many different standard statistical evaluations can be applied to the forecast error to assess the quality of a model's predictions.[14] In this way, forecast error can be treated as a probabilistic problem that can be made to fit a normal distribution, which is extremely useful for random naturally occurring variables.[15] For example, it can be calculated that a grid with 10 GW of installed wind capacity must be able to cope with a potential mismatch of 1.103 GW in every half-hour period (see Box 5.1).[17] It is important to note that without the wind capacity, the same grid would face a potential mismatch of 1.02 GW in every half-hour period, so the presence of 10 GW of wind has necessitated an 8% increase in existing reserve capacity. As the time horizon moves past the very short-term to the short-term (from minutes to several hours) there is a drop in forecast accuracy.[14] In the above example, the SD for the wind power forecast for a 4-hour window is 0.93 GW.[17] This means a potential mismatch of 2.97 GW in any 4-hour window. Since operating reserve can cover both immediate response (via spinning reserve) and replace regulatory reserve over the short-term horizon (non-spinning reserve) the half hour and 4-hour time windows are generally considered appropriate when accounting for uncertainty in operating reserve requirements.

Box 5.1
As an illustration, one study looked at the effect of 10 GW installed wind capacity on the UK grid by calculating the load uncertainty and wind power output uncertainty as two random variables that both follow a normal distribution.[17] With existing conventional plant it is accepted that load forecast over a half-hour (0.5 h) window will be subject to a 0.34 GW standard deviation (SD), but with 10 GW installed wind capacity there is also a 0.14 GW SD over the same half-hour period. Adding these independent forecast errors together gives a combined SD of 0.368 GW (to add these SD values take the square root of $[0.34^2 + 0.14^2]$, i.e. $\sqrt{.1352} = 0.368$). Because we are following a random variable that follows normal distribution, if the operating reserve is equal to three standard deviations of the overall forecast error that will cover 99.74% of possible mismatches: for the system containing 10 GW of wind capacity that is 3 × 0.368 = 1.103 GW.

Forecasting is a continuous, reiterative process, so TSOs can update their data at multiple times. In addition to addressing immediate operational needs through forecast techniques, various statistical models can be combined to improve forecasts for day-ahead and longer advance periods.[13,14] Whilst reiterative short-term forecasting can cope with smoothing out immediate mismatches in power output and demand, forecasts that look further ahead enable the TSO to strategically plan long-term reserves for periods that cover days instead of hours.[18] Long-term reserve allows the system to gradually replace regulatory reserve if additional power is still required for more than four or five hours, such as times when a weather front may result in an absence of wind for an extended period covering days. It is important to remember that reserve capacity is an existing need, even with conventional power generation.[19] Much of the long-term reserve needed to accommodate wind power availibility can be provided by existing plant, so no new capacity is required.

The above example illustrates two important principles related to wind power. They can both be summed up with the phrase 'megawatt for megawatt'. The first is that, contrary to popular belief, the variable output of wind power does not entail installing backup generators to run on a 'megawatt for megawatt' basis. As we saw above, 10 GW of installed wind capacity requires roughly 3 GW (2.97 GW) of operating reserve to manage potential mismatches in demand and output. However, the inherent uncertainty of wind means that when it achieves around 10% penetration on the grid‡ its capacity credit peaks. At this point, the ability of wind power to replace conventional generating capacity peaks at near wind's average energy output. Output depends on the capacity factor of wind farms,§ which is around 30%.[2] This means the capacity credit for wind peaks at roughly 0.3, and this reduces as installed capacity exceeds 10% of the total grid's capacity.[17] So, by the same token, installed wind capacity cannot substitute conventional plant capacity on a 'megawatt for megawatt' basis. For example, a simplistic way to understand capacity credit is to assume 10 GW is 10% of the total installed capacity of a power system: the capacity credit of 0.3 for 10 GW of installed wind means only 3 GW of conventional fossil fuel capacity is permanently withdrawn. But, remember this is installed capacity, not what is being generated at any one time. By displacing conventional power output (i.e., the actual electricity generated, not the installed capacity) wind can make significant savings in carbon emissions, since fossil fuels are only consumed in those periods when wind is not available.

Operating with increased wind capacity

The explosive growth of utility-scale wind power is a relatively recent phenomenon that has taken place mostly in the 21st century, whilst many features of the existing grid and power management systems are designed to follow the demands of conventional thermal generation that have remained, in principle, much the same for over 70 years.[14] As the existing grid systems are updated over time, conventional generation will be able to operate with more flexibility and can be integrated with 'smart' load management, i.e., power demand and output can be more effectively controlled to match wind power availbility.[18]

The relatively low capacity credit of wind in comparison with conventional thermal stations has generated some controversy in the past. Conventional plant must be kept to allow for periods when there is insufficient wind power output, and the variability of wind also means that regulating and operating reserve must also be on hand to smooth out any effects. When it was still nationalised, the UK grid maintained a 24% 'margin' where the operator worked on the principle that 100% of demand could be met with 76% of generating capacity.[17] There are significant implications for the way in which reserve capacity is maintained with wind in comparison to traditional generating systems. If conventional thermal plants operate more frequently as spinning reserve then they will only run part-loaded for much of the time, making them less efficient and liable to generate more CO_2 emissions per unit electricity generated (although total emissions are likely to be lower overall). Furthermore, conventional plant, such as coal-fired steam and combined cycle gas turbine (CCGT), is designed to run most of the time and are not suited to adjusting their output ('load-cycling') to the degree that may be needed to cope with variable wind output.[20] The physical stress placed on these conventional plant components operating this way will mean they become less reliable and cost more to maintain.[20,21]

The increasing geographical dispersion of wind farms as it becomes more prevalent counteracts some of the variability, because the 'balancing region' is less vulnerable to changes in any one wind farm location and local demand/supply mismatches can be smoothed out.[11] It is also well known that forecast error drops significantly over a wider area, enabling the TSO to accurately commit units for its operating reserve, minimising cost and needless stress on conventional plant.[14,18,22] It is telling that regions with a relatively high penetration of wind coupled with a good wind resource across a nation's territory show a significantly reduced need for additional reserve capacity over what is normally needed.[18] For example, during one year with poor winds in the Republic of Ireland, which shares with the UK the distinction of having one of the best wind resources in Europe, the wind power available on the grid was still more cost-effective than thermal plant.[2] This could hardly be the case if every megawatt of installed capacity had required a megawatt of conventional capacity to cover it. A large part of wind's effectiveness in Ireland was due to geographical smoothing across the balancing area (i.e. Ireland), coupled with the fact that peaks in wind power availability follow peaks in demand. The coincidence of availability and demand is noteworthy, since the UK wind resource also exhibits this property, whereby seasonal and daily demand cycles occur mostly at times of higher winds.[2,11]

The impact on reliability is also not as great as it may appear, since a distributed network of wind farms will not go offline without warning. The need for regulatory

‡ Note that at the close of 2013, the UK had 7.5 GW onshore and 3.7 GW offshore of installed capacity for wind power (ref.5). This is between 12 and 13 per cent grid penetration.

§ Because wind does not blow constantly at the same speed, wind turbines do not operate at their full rated capacity all of the time. The capacity factor is the amount of electricity generated in a year as a percentage of the total energy that could be generated if the turbine operated at 100% for the entire year. Note that no power plant operates at 100% of its rated capacity across a year (see Chapter 4 for a more detailed discussion).

reserve under normal operating conditions means that additional reserve does not have to be matched 'megawatt for megawatt' – national power systems can maintain reliability in the face of significant in-feed loss, and thus can cope with fast fluctuations.[23] Large conventional plant places a burden of risk on the grid, because any voltage mismatch that can cause a conventional power station to disconnect from the grid creates an instantaneous 'hole' of considerable size that must be balanced immediately.[19] By constrast, with wind the predictability of an entire wind farm going offline is such that the change in wind power output can be forecast within the TSO's operating window.[3,14] For instance, because of the modular nature of a wind farm made up of multiple turbines, even the presence of extreme variations, as might be found in an advancing weather front, will only cause a stepwise change in output as the front moves across a wind farm, not the sudden drop experienced by conventional plant going offline; hence, the down-ramping of wind is 'softer' than with conventional plant.[23,24] The design of modern wind turbines also means they have 'fault ride-through' capability, meaning they do not trip if the grid voltage suddenly dips. Since most modern turbines are also asynchronous generators connected via converters, it is possible that turbines can be used in a similar fashion to high voltage transmission interconnectors to rapidly recover frequency dips on the grid,[7] thus relieving some of the need for synchronous conventional plant to perform this role.**

Rates of national energy consumption, electricity included, are known to be subject to seasonal variations in weather, as well as differences in weather from year to year.[25] Seasonal variations can affect forecast accuracy, notably unstable weather conditions under low pressure. It has been noted that on rare occasions the UK and surrounding areas of the European mainland can experience days of low pressure and low winds in the winter.[17,26] Most months are likely to have a period where low winds are prevalent over the UK for one or two days, although periods longer than this are extremely rare. Nonetheless, this can pose a problem when there is low wind but high electricity demand.[27] The risk of such rare events is largely why wind's ability to substitute for dispatchable power (i.e. wind's low capacity credit).[17,26] However, in the winter months wind speeds typically coincide with periods of high demand, and forecast accuracy is also greater under high pressure fronts and high wind conditions, which is when wind power output is higher and thus likely to cause more disturbance to the grid if out were to be lost in a short space of time.[11,13] As discussed in the introductory section above, it is the controllability rather than the variability that creates a problem for the TSO, which increased forecast accuracy can mitigate.[2] Projected wind capacity for 2020 will be manageable, even during extended lulls when wind is low and demand is high, but by 2030 it is expected that power demand will have increased significantly as fossil fuels for heating and transport are steadily replaced by cleaner electricity.[27] It is vital that strategic planning decisions made today ensure a flexible system is available in the future. The decades-old tradition of monolithic, centralised suppliers of inflexible baseload power will need to be superceded by a diverse, intelligently managed and coordinated power system.

** Traditional thermal plant relies on a rotating turbine shaft directly connected to a generator. Sudden changes to grid frequency caused by fluctuations in load or generation can be counteracted by the inertia of the rotating shaft itself, and such generators are said to be synchronous. Wind turbines are designed to operate at variable speeds and work through an AC/DC converter, so they are asynchronous. High voltage DC lines are also asynchronous, which is why they are used to connect two differently synchronised networks across long distances.

Cost of backup generation

The need to maintain operating reserve specifically to cover variability in wind power output creates an additional cost to the power system. The TSO works to arrive at the best trade-off between risk of loss of load and cost of maintaining a reserve, exactly as was the case before modern wind power became integrated into power systems.[2,15] One should bear in mind that some of these additional costs are simply the result of a shift from one form of power system to another, and that preserving existing infrastructure centred on what is best for conventional generators will save balancing costs, but will continue to incur other external costs in terms of unsustainability and greenhouse gas emissions, not to mention steadily rising fossil fuel prices and price volatility. In addition, the national grid has always required reserve capacity – even though wind may not replace an equivalent capacity of conventional plant, the existence of this plant plus the reserve capacity already in place means that very little new capacity has to be built 'just for wind'.[19] Impending coal-fired plant closures (due to age and more stringent air quality standards), the need to upgrade ageing infrastructure, rising consumer demand, and future plans to improve connectivity with the European electricity market, have all been identified as necessary investments, and a large part of this is independent of any investment that might be required as a result of increasing wind power capacity.[7,28]

The need to capitalise on the benefits of a diversified energy network that incorporates geographically dispersed wind farms will place additional burdens on the UK's transmission network.[3] Paying generators to operate conventional thermal plant under suboptimal regimes will also mean additional costs in constraints payments on the part of the TSO, and operators having to pay more to maintain their plant.[20] It is crucial that conventional operators are not dissuaded from operating in markets with high wind penetration due to increased operating costs. These increased costs for existing generating plant are unavoidable, since the national grid will need to transition from the existing model of centralised energy dominated by inflexible baseload power to one where despatchable generation will need to be far more responsive. It should not be forgotten that wind is not meant to be the sole provider of renewable energy – the UK government has repeatedly stated its aim is to pursue a diverse mix of energy sources.[29] Increasing investment in biomass, marine and tidal energy will create further renewable energy resources that have much less volatilty and can substitute for fossil fuel reserve when needed. However, under the present day model of privatised energy markets, the value of low-margin electricity produced by wind should also be acknowledged and conventional generators must to some extent adapt in the face of a changing market that reflects this new form of electricity.[2]

When the requirements for operating reserve capacity for wind power are separated out from the existing reserve requirements, the added cost to the price of electricity can be estimated. Remember that the additional costs are not for installing a new megawatt of reserve capacity for every megawatt of wind, for the reasons discussed earlier. A comprehensive look at the impact of wind penetration based on 25 GW of installed capacity (this would equate to approximately 25% penetration following 2020 projections) resulted in a combined cost for balancing and reinforcing the transmission network of 0.15 p/kWh.[17] That study was published in 2007, at which time the prevailing domestic cost of electricity was around 5–6 p/kWh. These costs therefore represented roughly 3% added to the average domestic electricity bill at that time.

More recently, the National Grid carried out a very detailed analysis of the cost of supporting more than 26 GW of installed wind capacity in the UK by 2021, which gave a more conservative estimate of the likely increase in household bills.[3] Based on 2011 real prices (the year the updated report was published) the estimated cost of operating response necessary for wind would add 0.2 p/kWh to the cost of electricity, going from 2011 costs of 0.21 to 0.41 p/kWh in real terms. This represents an increase of slightly more than 1% of the average domestic electricity bill. One needs to consider this rise in the context of the existing energy system – consider that between 2007 and 2012 household electricity bills rose by 20% (in real terms), and the largest single driver of this increase was the wholesale price of gas.[30]

Conclusion

The projected level of installed capacity of wind power (both onshore and offshore) across the UK will pose a considerable technical challenge. As penetration of wind surpasses 10% of total installed capacity (by 2013 it was roughly 12%) the variable output of wind power means that the transmission system operator (TSO) will be required to compensate for fluctuations on the grid to balance electrical supply with demand and maintain reliability of the power system. However, whilst availability of wind is to some extent uncertain for any one turbine or wind farm, coping with large swings in supply and demand is a problem transmission operators have been familiar with for some time. Operators run reserve capacity as a matter of course to ensure reliability and adequacy of supply. Variability is an inescapable fact of natural wind flows, but variability in itself is not the cause of concern; it is the predictability and controllability that is important to the TSO. With increasingly accurate and sophisticated wind speed and power output forecasts, system operators can effectively cope with regulation responses, changes in system load, and commit units for day-ahead operation and scheduled maintenance. This enables better dispatch of non-wind resources and allows traders to operate more efficiently on the electricity market.

The reduced capacity credit of wind power as its prevalence increases does entail some additional conventional plant to be held in reserve, but at a fraction of the ‘megawatt for megawatt’ reserve that many of wind power’s detractors often claim. This effectively means that wind cannot substitute more than a small proportion of conventional fossil-fuelled plant directly, but neither does it necessitate building new fossil fuel capacity for new wind. Crucially, significant carbon emissions can be avoided by displacing fossil fuel generation, even if the conventional generating units are not replaced altogether. The increased operating reserve that will be required to support increased levels of wind power in the future will exert a burden on the existing conventional plant that is not set up to operate in a reserve capacity. Although there are fuel savings to be made when wind power displaces fossil fuel, the extra physical demands on load-cycling conventional units will lead to extra costs, and it is incumbent on national energy planners to ensure that plant operators are not dissuaded from maintaining capacity for power systems of the future where it is needed. By the same token, investment in other sources of renewable energy that offer predictable and dispatchable generation, such as biomass, tidal or geothermal, would create less volatile capacity that can be used as additional reserve.

Due to their modular nature, wind farms can offer a certain degree of flexibility on a properly integrated power system. Geographic dispersal can mitigate the effects of variability between sites, although it cannot remove it altogether due to the rare occasions where large weather patterns cover the whole of the British Isles. Generally, however, wind patterns across the UK follow seasonal peaks in demand, meaning that periods of average high wind speeds coincide with higher than average demand, mainly in the winter. Even at times when wind power output is high, and therefore loss of generation would create a significant disturbance on the grid, output across each wind farm drops in a stepwise manner, unlike the instantaneous loss of large amounts of output when a large conventional plant fails.

Whilst coping with wind variability does add to the cost of generating electricity, the final effect on domestic bills is relatively minor (a few per cent), especially when considered in the light of large drivers of costs in the last decade attributable to rising prices of natural gas. In a location like the UK, which is endowed with one of Europe's best wind resources, the value of wind is comparable to that of conventional thermal generation. The 'social resource cost' for accommodating the variability of wind power is arguably a measure of the willingness of society to pay for a sustainable and clean source of electricity that will remain the most commercially viable renewable energy application for some time to come.

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