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Will British weather provide reliable electricity?

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ABSTRACT

There has been much academic debate on the ability of wind to provide a reliable electricity supply. The model presented here calculates the hourly power delivery of 25 GW of wind turbines distributed across Britain's grid, and assesses power delivery volatility and the implications for individual generators on the system. Met Office hourly wind speed data are used to determine power output and are calibrated using Ofgem's published wind output records. There are two main results. First, the model suggests that power swings of 70% within 12 h are to be expected in winter, and will require individual generators to go on or off line frequently, thereby reducing the utilisation and reliability of large centralised plants. These reductions will lead to increases in the cost of electricity and reductions in potential carbon savings. Secondly, it is shown that electricity demand in Britain can reach its annual peak with a simultaneous demise of wind power in Britain and neighbouring countries to very low levels. This significantly undermines the case for connecting the UK transmission grid to neighbouring grids. Recommendations are made for improving 'cost of wind' calculations. The authors are grateful for the sponsorship provided by The Renewable Energy Foundation.

1. Introduction

The government of the United Kingdom aims to achieve high levels of grid connected renewable electricity. This is a policy driven by the twin goals of climate change mitigation and lower dependence on imported fuels. Through the mechanism of the Renewables Obligation, the UK aims to achieve 10% of its supplied electrical energy from renewable resources by 2010, and 15% by 2015, with the further aspiration to generate 20% by 2020. The present administration expects most of this, some 70–80% up to 2010, to come from wind power (BERR, 2007) and much incremental growth in renewable electrical energy after 2010 is foreseen as coming from this technology (NDS, 2007).

A target of "20% renewable electricity" does not mean that 20% of generators could be replaced by renewable plants, with other generators carrying on as before. That would be the case if power were to be delivered consistently from such generators. However, wind in Northern Europe is highly variable, producing volatile power delivery, as reported in Germany (E.ON Netz, 2005) and Denmark (Sharman, 2005). This paper sets out to assess how consistent wind power is likely to be in the UK, and the consequences of any volatility on the control and utilisation of individual generation plant on the grid. It calculates that the likely degree of fluctuation in UK wind power is high. The implications of volatile wind delivery are significant, since such volatility would require other generators, which typically use fossil fuel, to ramp up and down as wind comes and goes, and this would restrict continuous base load operation for these plants.

In discussion, the then DTI stated that they had considered funding a model of the nature presented here but had not yet done so (Armstrong, 2007). National Grid plc is aware of the volatility of wind power delivery, as they monitor live transmission system connected wind farm data at their control centre. They use these data to manage the difference between forecast wind and actual output, as illustrated in Fig. 1 (Ahmed, 2007a). However, much of this transmission system connected wind is concentrated in a relatively small geographical area, and National Grid's concern is the balancing of the grid over the last half hour of generation, not the effect wind volatility might have on other generating plants.

As a contribution towards improving understanding, the present paper sets out to model the dynamic behaviour of 25 GW of wind on the UK grid system, assess the volatility of wind, and considers the implications for individual generating plant. This large capacity would deliver 16% of the UK's electrical energy demand at a wind load factor (LF) of 30% or 18.8% at a LF of 35% (UK total demand in 2005 was 407 TWh). The present analysis has been limited to the month of peak demand, January, for the last 12 years, since this is also the month of highest wind output, and may therefore be the period in which problems, if any, are likely to manifest themselves. An exploratory analysis of wind and demand in July has also been carried out, and confirmed the view that summer months are less likely to produce challenging conditions.

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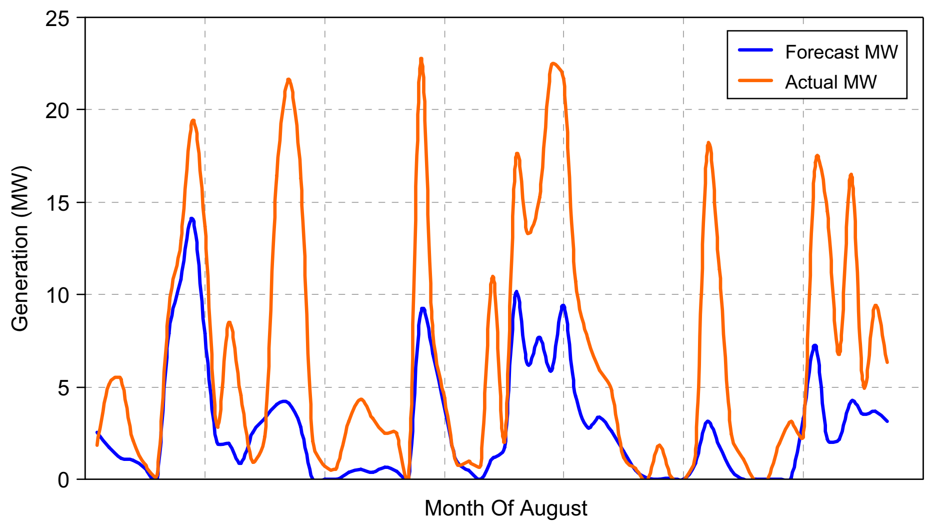

Fig. 1. Forecast and actual wind power generation for a single wind farm.

While this work is in some respects a pilot study the simulations conducted so far allow three main conclusions:

1. Although the aggregate output of a distributed wind carpet in the United Kingdom is smoother than the output of individual wind farms and regions, the power delivered by such an aggregate wind fleet is highly volatile. For example, had 25 GW of wind been installed, with full access to the grid, in January 2005, the residual demand on the supporting plant would have varied over the month between 5.5 and 56 GW.
2. The volatile power swings will require the fossil fuel plant to undergo more frequent loading cycles, thus reducing their reliability and utilisation.
   - Reduced reliability will require more thermal plant to be installed so as to achieve the same level of system reliability. Cost of wind calculations would be more accurate if they included this factor.
   - Reduced utilisation will encourage generators to install lower-cost and lower-efficiency plant rather than high-efficiency base load plant. These have higher CO_2 emissions than high-efficiency plants. Carbon saving calculations would be more accurate if they included this factor.
3. Wind output in Britain can be very low at the moment of maximum annual UK demand (e.g. 2 February 2006); these are times of cold weather and little wind. Simultaneously, the wind output in neighbouring countries can also be very low and this suggests that intercontinental transmission grids to neighbouring countries will be difficult to justify.

2. Previous studies and understanding

There is considerable research literature, and much meteorological science, contributing to the understanding of wind power and its likely variability. The United Kingdom Energy Research Centre (Gross et al., 2006) has collated and summarised the findings of many studies and worked to standardise methods and language and thus facilitate a common understanding of the issues. The present paper sets out to provide complementary findings using data and examples.

Gross et al. (2006) in particular set out an excellent summary of the work to date, and review 200 international studies with the aim of understanding and quantifying the impacts of intermittent generation on the British electricity network, and the assignment of costs. The analyses reviewed are predominantly statistical in nature, and explain the costs arising from increasing levels of intermittency as costs over and above 'those imposed by conventional generation making an equivalent contribution to energy and reliability'. The study separates these costs into two categories: costs arising from (1) '*additional system balancing actions*' and (2) '*the need to install or maintain capacity to ensure reliability of supplies*'. This is a useful framework, and the work presented here is intended to contribute to furthering that understanding. However, where much of the work reviewed by Gross et al. (2006) is statistical in its foundations, the work here relies on the examination of case studies, on a power flow model derived from empirical UK wind speed measurements, and on examples of wind power time series data in Britain and other European countries. This approach provides real and modelled examples of the nature of power changes on the grid and the resulting impact on individual generators. This perspective is adopted since an individual plant does not see the statistical delivery of power but, rather, a specific requirement for power. The examples given lead to suggestions as to how the cost calculations reviewed by UKERC can be improved. The examples studied will also be useful to operators and designers of the generating plant, and to policymakers attempting to understand the practicalities of controlling individual generators once large quantities of wind are embedded in the electricity system. The work supports many of the findings of Gross et al. (2006) and recommends further analysis and adjustments to their analysis so as to take account of costs in the category they define as '*the need to install or maintain capacity to ensure reliability of supplies*'. It provides no particular evidence or relevance to costs described by Gross et al. (2006) under the heading '*additional system balancing actions*'.

This study begins by assessing the volatility of wind using a power flow model derived from Met Office wind speed data and makes comparisons with empirical data for the UK (Ahmed, 2007a, b), Ireland (EirGrid, 2001, 2006), and Germany (E.ON Netz, 2005, 2006). A comparison to Spanish wind data is also made. These comparisons offer validation of the model developed and also provide some indicative information with regard to simultaneous wind output variations across Western Europe. These findings are discussed through comparisons with meteorological expectations and meteorological charts, and then employed in consideration of the impact on other generation plants, which is required to support wind's volatile power delivery.

3. Meteorological understanding

Barry and Richards (2003) provide valuable insight into global wind and weather, with British weather receiving a particular mention as it is situated in a location with interesting variations between low- and high-pressure systems. Specifically, the country sits in the path of low-pressure systems, which are formed on the western side of the Atlantic and then travel east and then north, generally passing on the western side of Britain. The country is also subjected to high-pressure systems, which are larger than low-pressure systems, and often move in from the east bringing clear skies, little wind and sometimes low temperatures.

Barry and Richards (2003) explain the formation of low-pressure systems on the eastern side of the North Atlantic. They are formed when warm air from the tropics moves north across the Atlantic until it meets cold air moving south and east off the Canadian land mass. These air masses are very large (many times larger than a European country, for example) and they meet at approximately 40° north of the equator and collide. The different air temperatures and densities prevent them from easily mixing and instead they form a 'front'. Periodically, the initially straight front breaks and the two air masses start to form a spinning cyclone. This spinning leads to a reduction in pressure at the centre, which is readily measured by a barometer, hence the name 'low-pressure system'. From this point the system generally moves east and typically passes between Scotland and Iceland, but enveloping both. In the summer the planet axis tilts and the cold and warm air meets further north, and consequently the low-pressure systems form and travel further north, to some extent missing Britain. This largely explains why wind speeds in Northern Europe are lower in summer than in winter. After about 8 days a typical depression will dissipate, only to be replaced by a new one coming in from the west. This periodic forming, moving, and dissipating nature of depressions leads to the expectation that there is a corresponding natural periodicity to wind speeds. This has already been observed and reported by van der Hoven in Brookhaven, New York, in 1957 and referenced in Burton et al. (2001). This showed there are distinct natural periodicities to wind and the passing of weather systems mentioned above is termed a "synoptic" effect by Burton. The modelling methods used in the study here should capture such macro effects reasonably accurately. However, there are other, localised ways, for winds to form, such as sea breezes, and since our analysis uses eight widely separated locations for Met Office data, it is unlikely that these local affects are captured. Since our concern is with the large-scale effects of wind power fluctuations, and the results correlate reasonably with empirical data for both neighbouring countries and the UK (from National Grid plc), as is shown later, we conclude that micro inaccuracies are not disabling to the analysis.

In distinction to previous studies, this paper does not employ a statistical approach and does not aim to calculate the probability of loss of load, or the capacity credit factor, or the difference between wind forecast and actual wind, or the challenge of balancing the grid, or system margin, or the importance of gate closure in system balancing. Instead the intent is to examine case study examples of wind power volatility, and then consider how individual generators would have to respond, and how operator businesses would respond to these new operational requirements. This is essentially a question of control and utilisation of individual generation plant installations; it is not a probabilistic assessment of the characteristics of the whole system.

A good way to assess control is to consider the extreme conditions under which these other generators must cope in order to satisfy demand. This includes consideration of rates of change of power, number of stops and starts, and the number of generators which will have to stop and start in response. This leads to considerations beyond the issue of control, and in particular the reliability and utilisation of plant and what choices investors will make in building and investing in these installations. For example, an operator building a combined cycle gas turbine (CCGT) plant normally expects to operate at high utilisation across the year, with few stops and starts, and may not expect this to change in the event of high levels of wind penetration.

Clearly any national power system has to manage under the worst case conditions likely to occur, and to this end the present study focuses on such conditions. These are not extreme cases, whose frequency is so low as to render the events negligible. Rather, these are representative power fluctuations, which may present difficulties to the design of a reliable power system. With this aim a number of example cases have been examined, starting with the study of wind output in 12 Januaries.

4. Method

The power output of wind turbines distributed across the UK has been modelled by calculating output for each hourly interval in each January of the last 12 years. Hourly wind speed records from the Met Office (BADC, 2006) were used to determine this hourly power for the eight locations shown in Fig. 2. These locations were chosen with two main criteria in mind. Firstly, all are in regions where wind farms are currently already clustered, suggesting a significant wind resource and therefore potential for further wind farm development. Secondly, the locations are geographically distant from one another, which was assumed to offer smoothing of the results. Thirdly, Ofgem (2006) provides empirical records of monthly energy output, thus enabling the scaling of modelled wind speeds to improve accuracy.

Eight modelling points may, from some perspectives, appear too few to represent the complex nature of wind, and, indeed, one of the best known statistical analyses employed far more locations (Sinden, 2007). However, Coelingh (1999) used only five in his study of Ireland, and as already noted the emphasis here was to provide a reasonable representation of the worst case conditions, and these were judged to be indicated by the maximum and minimum wind power outputs. However, the calculated results from the eight region model were compared to those from a more widely distributed 16 region model, showing there to be little difference between the two. It was therefore concluded that the eight region model provides acceptable accuracy, whilst giving the benefit of reduced data handling.

As will be apparent from Fig. 2, there are no locations in South-Eastern England, or in Northern Ireland. At the time of the analysis, there was insufficient long-term wind farm data for these areas, and so no scaling factors were available for these regions. However, South-Eastern England is an area of low wind resource and is not expected to make a large contribution to wind power in the future.

The positioning of the eight wind farms shows seven to be largely in line and one to the east of this line. This is partly as a result of the fact that Britain is quite simply a long thin island. However, it may make the model vulnerable to errors arising from a weather system approaching perpendicular to this line. Conversely, the results may exaggerate the smoothing of rates of power changes arising from a low-pressure system approaching from the north (one such case is examined in detail (Appendix A)).

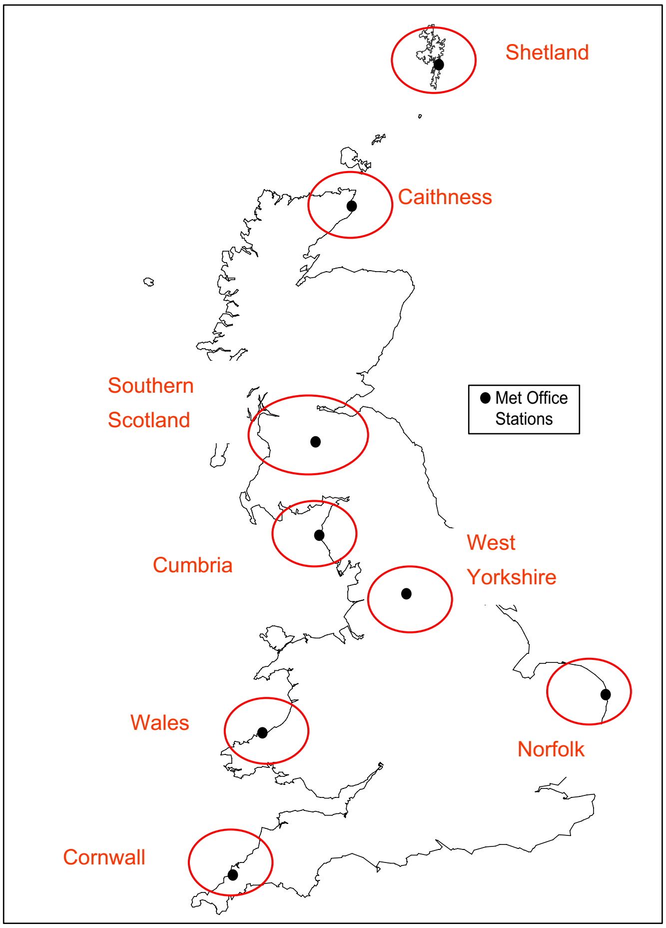

Fig. 2. Locations of the eight regions and eight Met Office stations selected for the 25 GW model.

However, as will be shown, since the model output correlates well with empirical wind output data for Ireland, the United Kingdom, and Germany, the results are considered to achieve the necessary accuracy.

4.1. Wind turbine characteristics

Understanding the performance characteristic of a wind turbine is useful in understanding the sensitivity of turbine output to wind speed and hence the sensitivity of any errors in wind speed in determining power. Fig. 3 shows a typical turbine power characteristic (solid line) alongside the available power in the wind (dotted line). Firstly, it is worth noting that the wind turbine has four distinct regions of operation and each of these has different sensitivities to wind speed.

1. Below approximately 4 m/s there is insufficient wind and output is zero.
2. Between 4 and 12 m/s the output rapidly climbs to the maximum rating. It is worth noting that a doubling of wind speed from 5 to 10 m/s leads to a 12-fold increase in power.
3. Between 12 and 25 m/s the output remains constant at the maximum rating.
4. Above 25 m/s the turbine is shut down, and a brake applied to prevent mechanical damage.

Each of these regions of operation has different levels of sensitivity to error in wind speed. At low speeds (region 1) an error in wind speed makes little difference to the power calculated because the answer will be zero or close to zero. In region 2 the accuracy of the calculation is sensitive to variation in wind speed and therefore sensitive to error in wind speed data. In region 3 the calculated wind output is again insensitive to wind speed error as the answer will be 100% unless the wind speed is close to the shutdown speed of 25 m/s. At about 25 m/s the result is again sensitive as the wind turbine can be tripped into the shutdown mode. The work here focuses on assessing the operation of the wind turbine fleet at low wind speeds (region 1) and high wind speeds (region 3), which are the two regions of least sensitivity to error in wind speed.

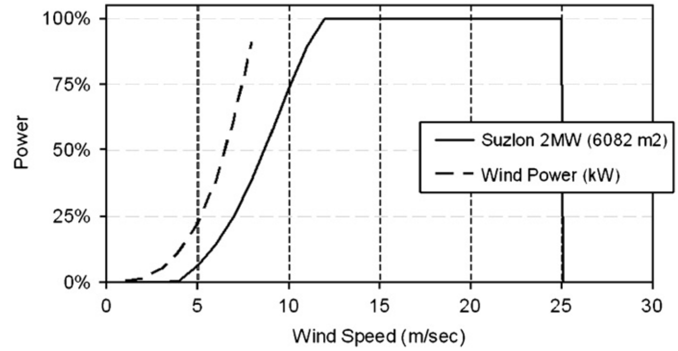

Fig. 3. Wind turbine power curve.

Trial models were also constructed using the characteristics of Enercon turbines, which are capable of commencing generation at very low wind speeds (2 m/s), but no significant difference was found in the results.

4.2. Calibration and scaling

The wind speed was scaled to account for wind turbine hub height being higher above the ground than the height of Met Office data measurements, and was also scaled to align with actual wind farm performance as recorded in Ofgem's Renewable Obligation Certificate (ROC) register (Oswald Consultancy, 2006a). The scale factor for hub height is the most significant and was calculated as follows:

$$\text{Scale Factor, Wind Shear} = \frac{\ln(\text{Hub height}/\text{Grass height})}{\ln(\text{Anemometer height}/\text{Grass height})}$$

With regard to the second point, the modelling was intended to be generous so as to represent a best case scenario, and to this end the output for each region has been scaled so as to correspond with the monthly output of one of the best performing wind farms in the selected region, as explained below. Consequently, the modelled LF is high.

Fig. 4 shows the actual LFs achieved in 2005 for wind farms grouped in the region 'South of Scotland' as shown in Fig. 2 (Oswald Consultancy, 2006b).

The best performing wind farm was Hare Hill, which was used as the basis for the representation of the 'Southern Scotland' region, and a scale factor of 1.2 was applied to the hourly wind speed data taken from the nearest Met Office station. This provided good alignment between modelled and actual wind turbine output as recorded in Ofgem's ROC register for 2005 as shown in Fig. 5.

Scale factors for other regions were as follows: Cornwall (1.03), Mid Wales (0.93), Norfolk (1.15), Yorkshire (1.3), Cumbria (0.91), South Scotland (1.2), Caithness (0.95), and Shetland (1.2).

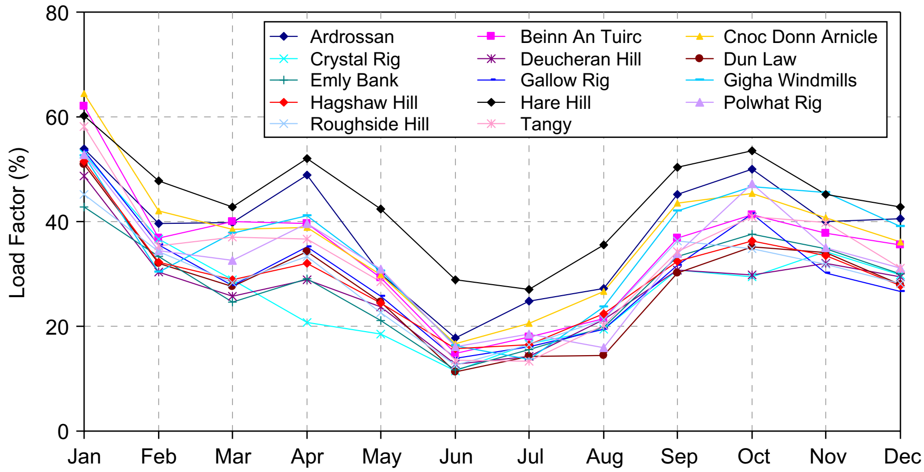

Fig. 4. 2005 monthly load factors for 14 wind farms (231 MW) in Southern Scotland.

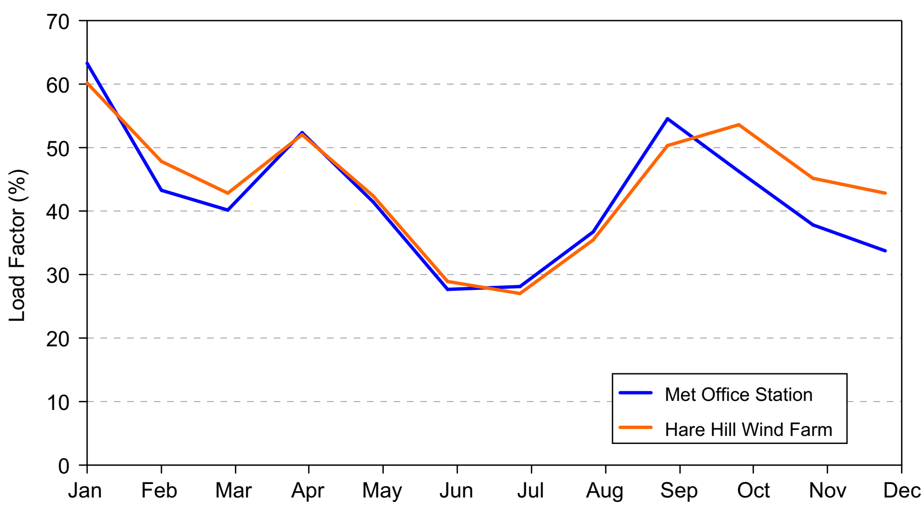

Fig. 5. Calibrated theoretical power and actual output for the Hare Hill Wind Farm in Cumbria. Scale factor used = 1.2.

When the regional LFs thus modelled are aggregated we obtain a national LF of 57.9% for January, which is 1.26 times greater than that actually achieved in 2005 (LF = 45.6%, (Oswald Consultancy, 2006b). At an annual level the model thus represents a 2005 LF of 35.5%, rather than the actually achieved 28.2% (Oswald Consultancy, 2006b). This is at the higher end of expectations even when offshore wind is included, but serves the aim of providing a best case scenario.

5. Results

5.1. Aggregation smoothes power flow

In aggregating output for the eight regions, examples of which are shown individually in Fig. 6, a perfect transmission grid, free of constraints, has been assumed, whereas in practice bottlenecks in the transmission network will limit the flow of power across the country (Gross et al., 2006). The assumption is, therefore, generous, and will lead to some overestimation of the level of smoothing, but is consistent with the aim of representing a best case scenario.

Output in the regions is clearly volatile. It is also apparent that the output varies between regions, which leads to the reasonable expectation that when combined there will be smoothing. Note, for example, the low output in Caithness between hours 600 and 700, as compared to high output in Norfolk during this period, and the corresponding smoothing when the regional models are summed, as is shown in Fig. 7.

Nevertheless, it is immediately evident that there is no consistent delivery of power, but that it is characterised by volatility. For example, in the severe trough between hours 310 and 340 the aggregate output falls by 70% in 12 h and then rises back up again in the next 12-h period.

Analysis of the Januaries from 1996 to 2005 shows similar results: large, rapid, and frequent changes of power output being common occurrences. Table 1 summarises the ranges of output found. The implication for the power industry of large-scale power swings of this magnitude is significant, but before discussing such events it is prudent to test the accuracy of the results by comparing the model results to empirical data for Scottish, Irish, and German wind farms.

5.2. Comparison—Scottish wind farms

National Grid plc monitor the output of wind farms connected directly to the transmission grid and generously provided 33 days

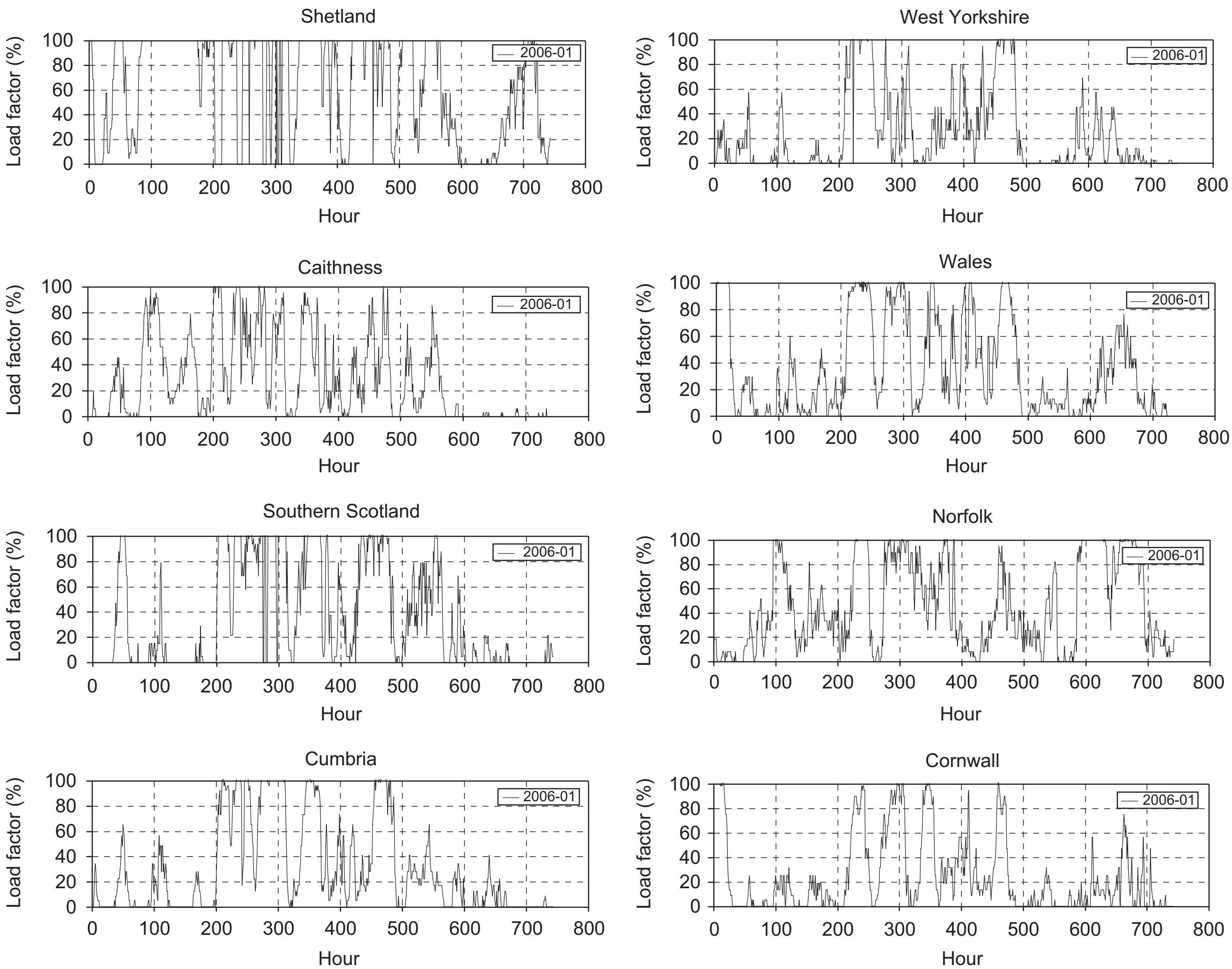

Fig. 6. Local power flows from each of the regions, (from top left working down): Shetland, Caithness, Southern Scotland, and from top right: Cumbria, West Yorkshire, Wales, Norfolk, and Cornwall, for the 744 h of January 2006.

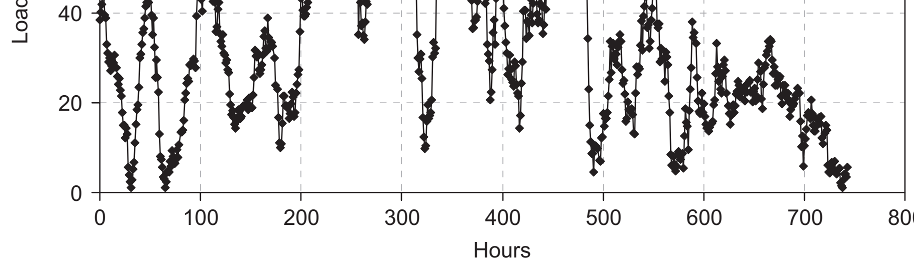

Fig. 7. Modelled aggregate power for 25 GW of wind, January 2006.

of output data for two Scottish wind farms starting on 26 January 2006 (Ahmed, 2007b). One of these wind farms has a low LF and the other a high LF. To maintain commercial confidentiality the identity of the wind farms and their locations on the mainland was not provided. As the model represents a high LF scenario, the empirical data for the single high LF Scottish wind farm was compared to the aggregate of the two modelled mainland Scottish regions (i.e. South Scotland and Caithness, as shown in Fig. 8).

In terms of peaks and troughs and rates of change of power, the results show good agreement; there is a long period of little wind for the first 220 h followed by about three periods of high output with corresponding troughs in power. It is concluded that the mainland Scottish regions give a good representation of major wind power swings in Scotland.

5.3. Comparison—Irish wind farms

As discussed earlier, meteorologists would argue that major high or low wind events are strongly driven by the presence of low- and high-pressure systems over the country. This leads to the concept that comparison with Ireland's wind farm output might show similar wind power fluctuations to the calculated result for Britain. Data for EirGrid's wind farms are readily available from their web site (EirGrid, 2001) and are shown compared to the 8 region model in Fig. 9 for January 2001. Again, major power swings show good agreement with the model; there are five or six major troughs with periods of high output in between. The maxima and minima coincide at a similar time, and the magnitudes are very similar. A rapid fall in wind power can be seen at hour 500 (90% in Ireland and 40% in Britain), and it is interesting to note that this collapse in wind power occurs in Ireland a few hours before it occurs in Britain. This supports the argument that major power swings in Britain are typically caused by low-pressure systems moving east. It will also be quickly appreciated that if the grids of Ireland and Britain were connected during this period and if they had comparable levels of installed capacity that brief power swings lasting a few hours could be smoothed. In practice, it is likely that the British wind farm fleet will be much larger than Ireland's and therefore Ireland will provide little smoothing to Britain, but, on the other hand, Britain may provide smoothing to Ireland. It also suggests that a model using more wind farms in an east/west direction would provide smoother output for changes over a few hours but would provide no smoothing for longer lasting power changes. This will be discussed further below.

Table 1
Ranges of UK modelled wind output summarised for Januaries from 1996 to 2005

Date	Max power range (%)	Minimum power (%)
January 2006	97	1
January 2005	93	7
January 2004	93	3.2
January 2003	96	3.9
January 2002	92	8.7
January 2001	92	0.8
January 2000	98	1.7
January 1999	99	0.6
January 1998	99	1.1
January 1997	80	2.8
January 1996	89	10.2
January 1995	96	3.7
Average	94	3.7

5.4. Comparison with Germany

The comparison with Ireland showed such good agreement that it suggests that countries on the far side of the North Sea may also be synchronised with Britain's wind farm output. This was investigated by comparing the model results with empirical wind data for the E.ON Netz wind grid, which is readily available on the internet (E.ON Netz, 2005). This is shown for a single week over Christmas 2004 in Fig. 10. As can be seen, this is a single large power swing over several days, which starts with a trough, peaks after a few days and then concludes with a trough. Again, there is good agreement between the model and the German empirical data, which further supports the argument that wind output is controlled by the arrival and dispersal of large low-pressure systems moving over the coasts of Western Europe. Appendix A provides more detail on this week's events.

5.5. Relationship between low winds and demand

The relationship between wind speed and electrical demand is interesting and worth considering in the light of the model

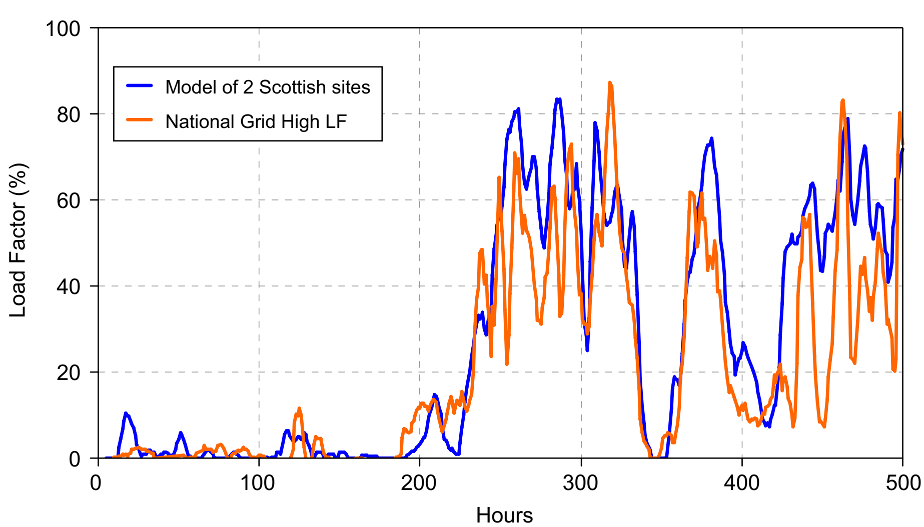

Fig. 8. Load factors for modelled mainland Scotland and single high LF wind farm.

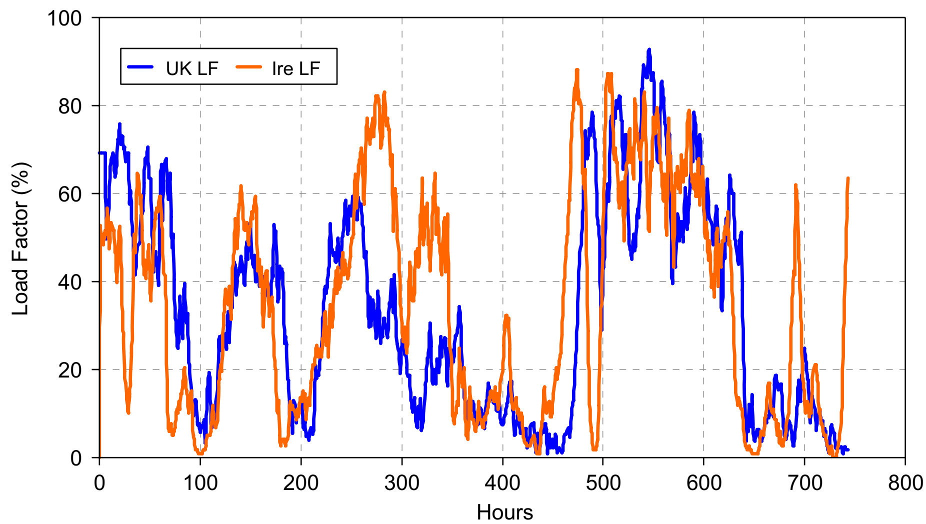

Fig. 9. Comparison of Irish empirical and UK modelled hourly load factors for January 2001.

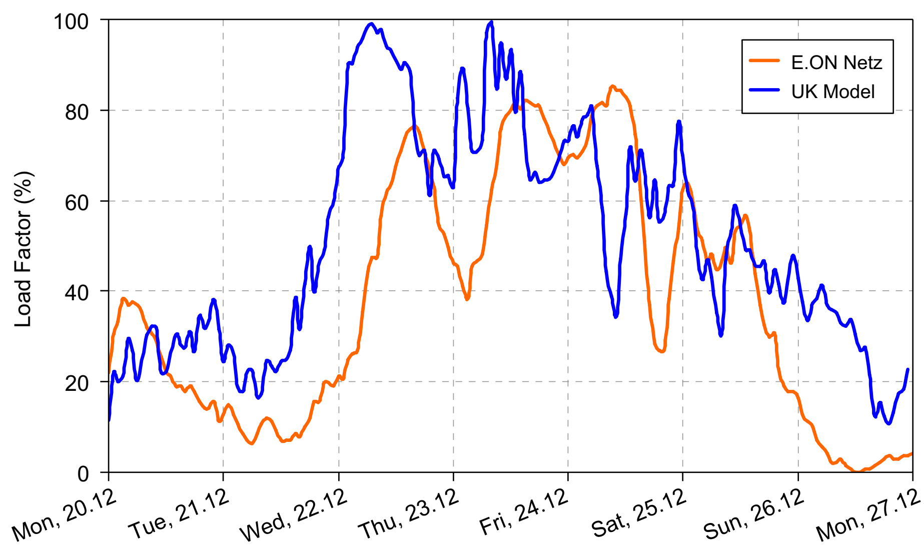

Fig. 10. Actual wind load factors in the E.ON Netz control area, and UK wind power model, 20–26 December 2004.

results. Milborrow (2003) for example has argued that peak national electricity demand occurs when the ambient temperatures are low and the winds are high. This is supported with an example of data below.

The relationship between wind power and demand was analysed by considering the moments of peak electrical demand in each of the last 6 years (Haffner, 2006) and using the model to evaluate the wind output for these moments, as shown in Fig. 11. The points indicated are the half hours of highest demand across the whole year; each of them occur on a winter's day between 5 pm and 6 pm, as this is the time when commercial and domestic demand combines into the day's peak. As can be seen the two end points (16 January 2001 and 2 February 2006) were times of very little wind output (4.3% and 0%). The half hour ending at 6 pm on 2 February 2006 is particularly interesting as the model calculates zero wind output across the whole country, which was the only time point in all the data when this occurred. This particular moment is considered in more detail later.

The two end points represent cases of low wind and high demand and would likely fall into the category described by UKERC (Gross et al., 2006) as 'low wind cold snap'. This suggests that a line between these two points approximates to peak national demand for 'low wind cold snap' conditions, and this is shown with a broken line drawn between the two points. It is immediately interesting to note that all the other years show higher demand than this but also show higher wind output. This simple example supports the argument that wind supports the grid at times of the very worst maximum demand and therefore has capacity credit. The UKERC authors would actually argue that even if this were not the case then wind would still have capacity credit as there remain other times when the wind will assist the grid in achieving an overall probability level of meeting demand. This example simply reinforces the findings of above-mentioned authors with an illustration.

5.6. *Weather systems and fuel flow*

As previously argued, wind turbines are largely driven and fuelled by the prevailing weather system, and in particular the pressure gradients existing across the relevant geographical

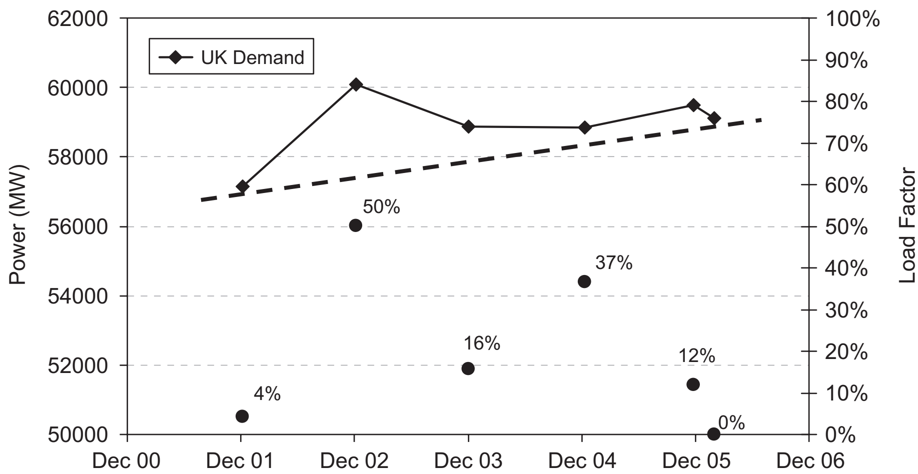

Fig. 11. Wind load factor at the half hour of maximum annual electricity demand 2001–2006.

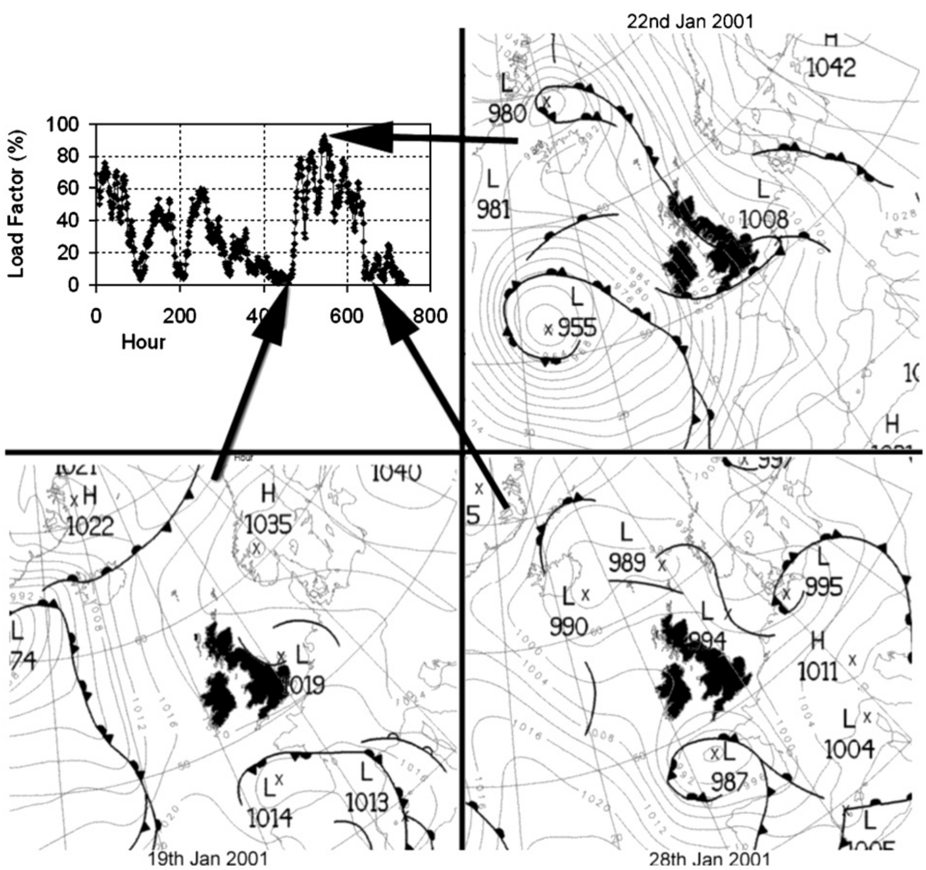

Fig. 12. Wind power and pressure charts January 2001.

area, with steeper pressure gradients generating higher wind speeds. Meteorologists represent these gradients pictorially as pressure charts, and these can in fact be seen as diagrams of fuel flow for wind plant. This point can be illustrated by considering the modelled power output for January 2001, shown in Fig. 12, in juxtaposition with Met Office pressure charts.

The model shows periods of low wind power at hours 450 and 650, but a peak at hour 550. The pressure charts at these times are shown in Fig. 12. At hour 450 (19 January 2001) the isobars are far apart and there is therefore very little pressure gradient across the country. Consequently the wind, and national wind power output, can be expected to be low. At hour 550 (22 January 2001), the low-pressure system that was previously to the west of Iceland has moved closer to Britain and intensified. The isobars are now much closer together, the winds higher, and the modelled national wind power output close to maximum. By hour 650 (28 January 2001) the low-pressure system has moved to the south and dissipated, and wind outputs are once again very low over the whole of the UK.

Weather systems can move large distances or significantly change intensity within 12 h. Thus, the volatility of output is unsurprising since we know from the performance characteristics of wind turbines that a doubling of wind speed can result in a 12-fold increase in power. The weather charts also help to explain why Irish wind farm output aligns well with British wind farm output: the two islands are generally enveloped by the same weather systems. A further example, comparing Germany and Britain, also supports this but in this case the depression moves in from the north (Appendix A).

5.7. 18:00 h 2 February 2006

As mentioned above, at 18:00 h on 2 February 2006 the electricity demand in Britain reached its peak for 2006. The wind power model suggests that the output for the wind farms of Britain at that time would have been zero. To investigate this further the empirical wind farm output for neighbouring countries has been determined for the same moment in time and is shown in Table 2. This data show the measured output from Britain (National Grid), North West Germany, Ireland, and Spain as low, whilst Britain's electricity demand reached a peak for the year (as a result of the cold weather brought by a high-pressure system, as will be explained). The 16 wind farms monitored by National Grid represents 760 MW of installed wind farms and is shown as negative as the consumption of electricity used by these wind farms (to drive auxiliary loads) exceeded the total output.

Table 2
Empirical wind farm output for the UK and neighbouring countries at 18:00 on 2 February 2006

Location/source	Load factor % 2006-02-02 18:00
Britain (National Grid data, 16 wind farms)[a]	−0.1
Ireland[b]	10.6
Germany[c]	4.3
Spain[d]	2.2
UK model	0

[a] Ahmed (2008).
[b] EirGrid (2006).
[c] RED Electrica (2006).
[d] E.ON Netz (2006).

Fig. 13 shows the measured wind power output from Germany and Ireland along with the modelled UK wind output and the corresponding pressure chart for this period of time. It shows a high-pressure system sitting squarely over the island of Britain (6 h after the time of peak demand), making it unsurprising that wind output was low and demand was high. An event like this, in say 2020, with 25 GW of wind installed in Britain with large wind installations in neighbouring countries would lead to a simultaneous and large increase in demand on other plants. Energy storage might be suggested as a way of alleviating the shortfall, but unfortunately the lack of wind is seen to last for approximately 150 h prior to finally rising to a more typical January level. This would mean any storage solution proposed would need to store days' worth of energy requirements (as opposed to the current practice of storing hours' worth of energy, for example in either pumped storage or as heat in electric storage heaters). Another potential solution to smoothing wind's volatile output is a trans-European transmission system, as that envisaged by Airtricity (2006) known as The Supergrid, but that does not seem justified as neighbouring countries are seen to experience a simultaneous shortfall in wind power. It seems more likely and more cost effective to build other plants to support the grid in these times of little wind. Once these plants are built, intercontinental transmission grids would be limited to providing some smoothing to power changes lasting a few hours (Fig. 9).

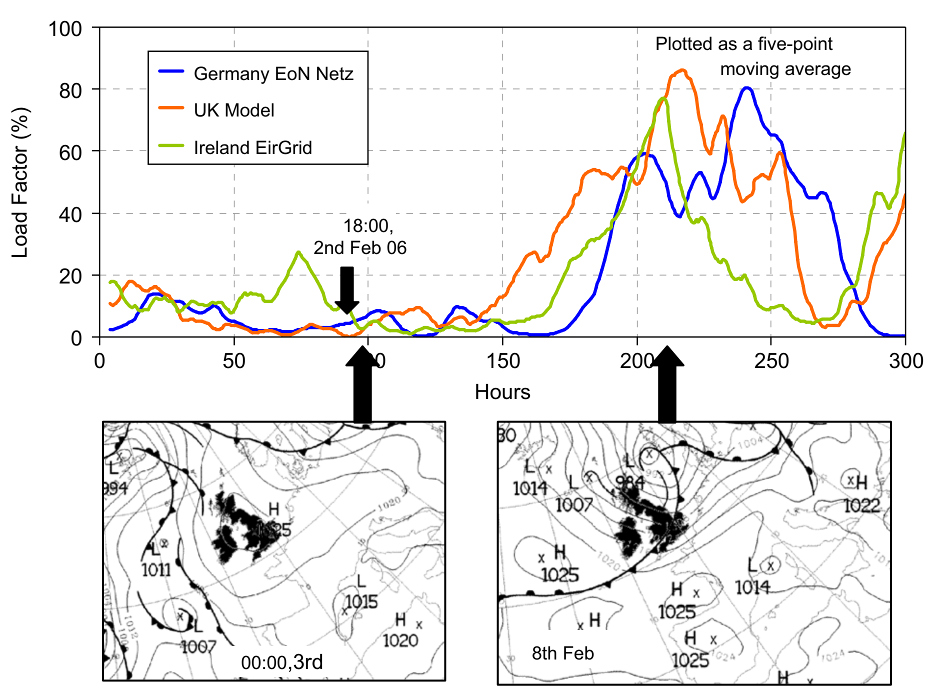

Fig. 13. North European hourly wind load factors, from 30 January to 11 February 2006.

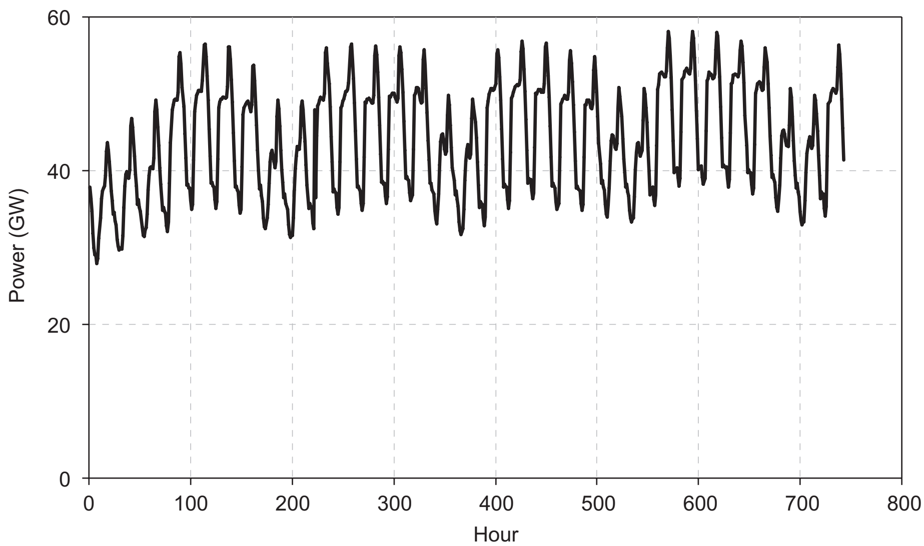

Fig. 14. UK electricity demand in January 2005.

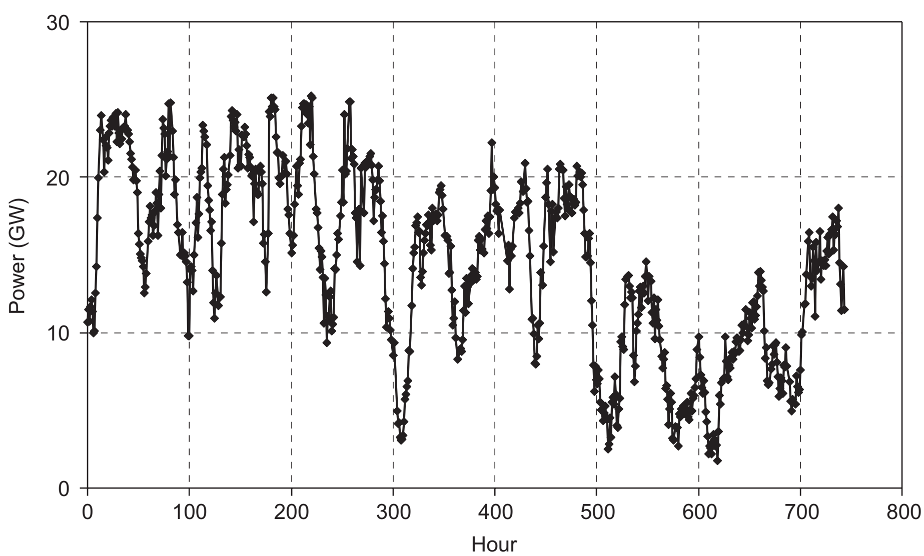

Fig. 15. Modelled UK wind output January 2005.

6. Implications for the UK electricity system

The purpose of this paper is to consider the impact of wind's volatility on the individual generating installations which provide the supporting role to 25 GW of wind. The assumption is made that the stock of the generating plant in 2020 will still be predominantly large and centralised. This could be disputed as unimaginative, but previous researchers (such as Dale et al., 2004) have, reasonably, assumed large centralised plants in their cost modelling, and it is unlikely that there is sufficient time to both develop and install significant generation capacity from new low carbon technologies including tidal, wave, or solar. However, it does remain possible that significant quantities of combined heat and power plant (CHP) could be installed by 2020, but it is not known how well this could support prolonged periods of little wind as shown in Fig. 13. If CHP were to be used in this role then it is likely that the heat captured by the CHP plant would not be used effectively. Whether this happens or not it seems likely that large centralised plants will have a dominant role to play in 2020; furthermore, it seems likely that a substantial proportion of this central generation will be powered by natural gas. If this transpires then the power swings from wind will need to be compensated for by power swings from gas-powered plants, which in turn will induce comparable power swings on the gas network as plant ramp up and down. This will have a cost implication for the gas network, an implication that does not seem to have been included in cost of wind calculations as summarised by UKERC (Gross et al., 2006).

The effect on the individual plant is now assessed by considering demand and supply during a typical January. Fig. 14 shows the electricity demand for Great Britain for the 744 h of January 2005. This chart exhibits a variable but regular and therefore a predictable demand curve (weekends are clearly visible, as is the end of the Christmas holiday). Fig. 15 shows the

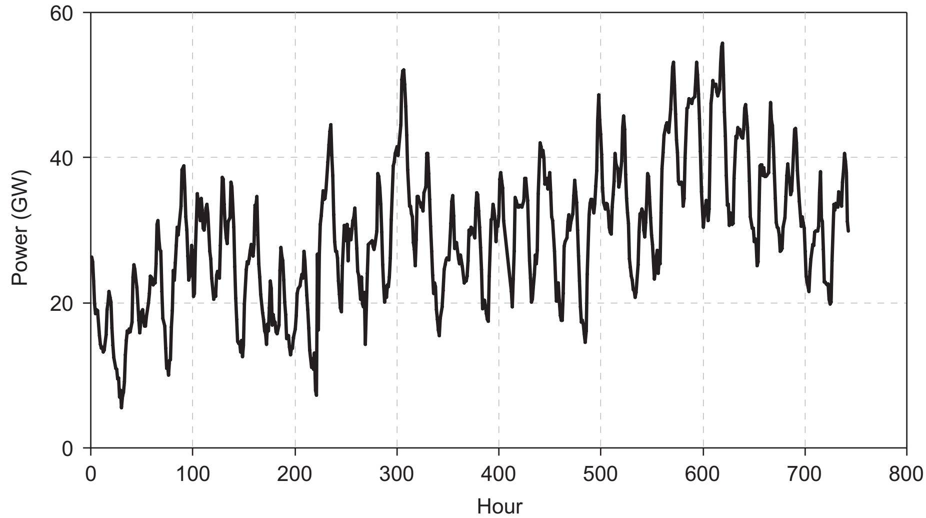

Fig. 16. Modelled residual demand on conventional plant for January 2005.

modelled power output of the 25 GW wind fleet for the same time period:

If we assume that wind output gains priority access to the grid (because of the preference to use carbon free energy) we can subtract the wind output from the demand curve to leave the residual demand which must be served by other generation plant, as shown in Fig. 16. In practice, it may be best to curtail wind power under certain circumstance, and this would certainly provide some power smoothing. However, the level of curtailment is not finalised (Gross et al., 2006 report it at between 0% and 7%) and for simplicity it is ignored in the following.

The residual demand curve (Fig. 16) derived from the model contrasts with the 'normal' demand curve; it varies between 5.5 and 56 GW over the month, and there are many power cycles of a larger magnitude than currently sustained by the generation portfolio. For example, around the 300th hour an 18 GW fall in 22 h is closely followed by a 14 GW rise in 16 h. To achieve this fluctuation, a large proportion of the nation's generating capacity would need to ramp down, disconnect from the grid and then within 38 h be ramped back up and reconnected. This is seen as having two negative effects: namely, it would reduce the reliability and the utilisation of the thermal plant.

High-efficiency base load plant is not designed or developed for load cycling. For example the CCGT plant achieves its high efficiency through the use of heat recovery steam generators (HRSG) situated in the gas turbine exhaust to produce steam, which is passed to the steam turbine for additional power recovery, and therefore higher efficiency. Load cycling CCGT plant will induce thermal stress cracking in hot components such as HRSGs (Starr, 2003) and combustors and therefore cause a reduction in plant reliability and therefore availability. Any reduction in plant availability as a result of wind should be included in the cost of wind calculations, but does not appear to be so at present (for example in Gross et al., 2006).

The other impact on the individual plant is a reduction in the plant's utilisation (or LF). This has an economic consequence, which will encourage operators of generation plants to buy cheaper, lower-efficiency and therefore higher carbon emission plants.

Consider a 1000 MW combined cycle plant delivering the 30th GW of power into the grid (i.e. from 29 to 30 GW). Under today's scenario (Fig. 14) this is seen to run in a largely uninterrupted fashion. However, under the future scenario of Fig. 16 it will have to come on and off line a total of 23 times and deliver power for a fraction of the 744 h in the month. Clearly its utilisation is greatly reduced. From one perspective, one might argue that this is the exact purpose of renewable plants, namely to reduce fossil fuel burning. However, it does this not by obviating the need for that plant, but instead by reducing the utilisation of power plants which continue to be indispensable.

Electricity operators will respond to the reduced utilisation by installing lower-cost plant (£/kW) as high capital plant is not justified under low utilisation regimes. Ofgem (2007) put the price of CCGTs at £440/MW and open cycle gas turbines at 350/MW and their respective efficiencies of 54% and 37%. Under high utilisations the CCGT plant will pay for itself with fuel savings, but under low utilisation businesses will find this less persuasive. Calculating the carbon saving of wind goes beyond the scope of this paper, but it is critically important that the carbon saving achieved by the whole system is known, understood, and achieved in practice. The effect of this higher carbon calculation does not appear to be mentioned in UKERC (Gross et al., 2006) and warrants further assessment.

7. Conclusions

A model of a large and distributed installation of wind generators has been produced for the UK and used to analyse the power output characteristics for each January in the last 12 years. It suggests that

- Although the aggregate output of a distributed wind carpet in the United Kingdom is smoother than the output of individual wind farms and regions, the power delivered by such an aggregate wind fleet is highly volatile. For example, if 25 GW of wind turbines had been installed, with full access to the grid, in January 2005 the residual demand on the supporting plant would have varied over the month between 5.5 and 56 GW.
- Wind output in Britain can be very low at the moment of maximum annual UK demand (e.g. 2 February 2006); these

are times of cold weather and little wind. Simultaneously, the wind output in neighbouring countries can also be very low and this suggests that intercontinental transmission grids to neighbouring countries will be difficult to justify.

- The volatile power swings will require fossil fuel plants to undergo more frequent loading cycles, thus reducing their reliability and utilisation.
- Reduced reliability will require more thermal capacity to be built to compensate, whilst achieving the same level of system reliability. Cost of wind calculations would be more accurate if they included this factor.
- Reduced utilisation will encourage generators to install lower cost and lower-efficiency plants rather than high-efficiency base load plants. These have higher CO_2 emissions than high-efficiency plants. Carbon saving calculations would be more accurate if they included this factor.
- Power swings from wind will need to be compensated for by power swings from gas-powered plants which in turn will induce comparable power swings on the gas network as plant ramps up and down. This will have a cost implication for the gas network. Calculations of cost of wind would be more accurate if they included this factor.

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Appendix A. German comparison

The example used previously for Germany (Fig. 10) was particularly interesting to Eon Netz as it was a week in which the forecast was particularly different from what actually happened (as reported in *Wind Report 2005*, E.ON Netz, 2005). By reviewing the pressure charts for that period we can see what occurred. Fig. A1 shows the power output and selected pressure charts for the period 21–27 December 2004.

On the 21st of December the UK and North West Germany (where the relevant wind farms are located) were exposed to two high-pressure systems in the east and the west, and there was little pressure gradient across the region. Consequently, the model predicts little wind power, a point also witnessed by the empirical records of E.ON Netz. On the following day a low-pressure system moved in from the north and lingered until the 25th. The pressure gradient for this depression was steep, and high winds and high power output should be expected, and were indeed measured by E.ON and also calculated by the model. By the 27th the low-pressure system had been replaced by high-pressure regions to the west and north, and again there was little gradient across the region suggesting low winds and little power output, exactly as recorded empirically by E.ON Netz and shown theoretically in the UK model. E.ON Netz (2005) commented that they failed to forecast the high winds and it is worth considering that the low-pressure system formed not on the east of the Atlantic, as is usual, but immediately north of Britain and this perhaps explains why meteorologists had little warning of its arrival. No doubt weather forecasting will get better, but even if it were perfect, it seems the British electricity system will be subjected to large power swings should a large capacity of wind be connected to the system.

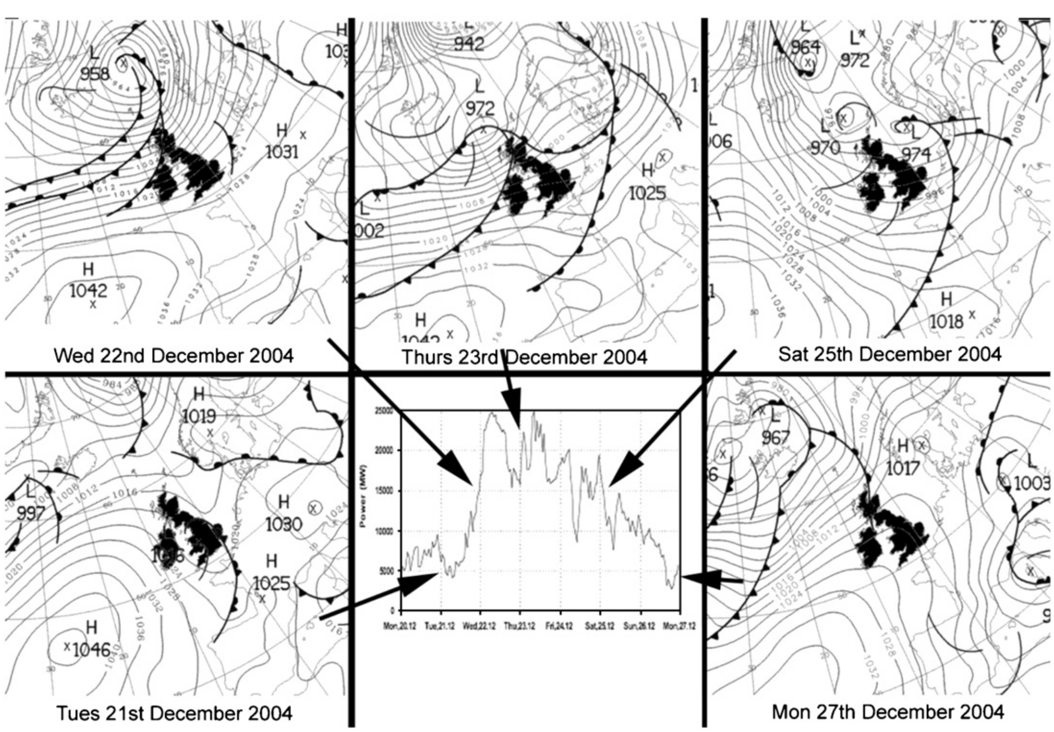

Fig. A1. . UK load factor and associated Northern Europe pressure charts for the week of Christmas 2004.

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