Is wind power reliable?

The UK has committed itself to a very ambitious target to increase its wind powered generation capacity by 2020. The EC's 15% renewable energy target implies that renewable electricity, much of its wind power, will have to provide between 35-40% of electricity supplies. This has caused concerns in some quarters that the UK 's security of supply will be placed in jeopardy. However, others say this concern is overplayed. In the following article, David Milborrow* debunks myths surrounding wind power's reliability.

The cold snap at the beginning of January encouraged several letters to the press making much of the fact that there had not been much wind during this time. "How foolish of the government to rely on it", is the usual conclusion.

The letter writers seemed unconcerned (or unaware) that there was also a shortage of nuclear output during the cold snap. In early January, only about 50% of nuclear capacity was online. 5000 MW was “missing” – but the electricity system continued to do its job.

The reasons it continues to deliver are twofold: electricity systems do not rely exclusively on any one technology or fuel and, secondly, there is always a significant "plant margin" - currently about 30% in Great Britain - so that is why we can cope with low wind and a significant shortage of nuclear.

The "plant margin" is the difference between the total plant capacity and the expected peak demand. In round numbers, the peak demand this winter is expected to be around 60,000 MW and there is 75,000 MW of plant. The margin is therefore around 25%, which is slightly higher than the theoretically desirable figure.

Can wind energy contribute to peak demands?

For some reason, there is a disproportionate amount of interest in the ability of wind energy to contribute to peak electricity demands. Setting aside the fact that there is a lot of extremely competent analysis that points to the fact that, statistically, wind can make a contribution, that is not the major role of wind energy. It does save fuel, however, and that contribution is more valuable.

The key issue here is "statistically". The management of electricity systems is all about managing risk – and that is a statistical concept. So the fact that wind (or nuclear) output may be "below par" during one particular cold snap, or one particular season, does not necessarily invalidate assumptions that are based on long-term observations. In the case of nuclear, that leads to an assumption of an 80% availability during the winter peaks and in the case of wind, it leads to an assumption that the "winter quarter" capacity factor is appropriate – around 35%. Both these figures are quoted in National Grid's "Winter Outlook Report 2008/9".

"Capacity credit" is a statistical concept, as noted above. The ratio between the "firm capacity" and the rated capacity is sometimes termed the "capacity credit", but a more common definition, in the context of wind, is :-

“The reduction, due to the introduction of wind energy conversion systems, in the capacity of conventional plant needed to provide reliable supplies of electricity.” (1)

Table 1 Capacity credits - England and Wales

Description (ref)	Years data	Sites	Capacity factors		Capacity credit (CC)	CC/CF
			Annual (CF)	Winter		
Grubb (peak loads)[1]	8	16	32	37	41	1.26
Paulutikof[2]	8	4	16-34	20-44	7-45	0.41-1.41
CEGB for EC[3]	10	12	25	34	31	1.3
National Wind Power[4]	3	5	34-38	n.a.	38-58	1.42-1.5

Source : David Milborrow

1 Grubb, M J, 1988. On capacity credits and wind-load correlations in Britain. Proc tenth BWEA Wind Energy Conf., London. MEP Ltd, London

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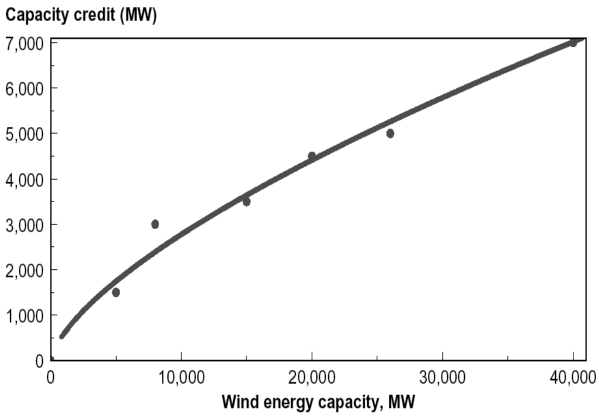
3 Holt, J S, Milborrow, D J and Thorpe, A, 1990. Assessment of the impact of wind energy on the CEGB system. Report for the EC

4 Warren, J G, Hannah, P, Hoskin, R E, Lindley, D and Musgrove, P J, 1995. Performance of wind farms in complex terrain. Proc 17th BWEA Wind Energy Conf., Warwick, MEP Ltd, London

Fig 1 : UK Capacity credits



Source : David Milborrow
The relationship between capacity credit and wind energy capacity, derived from various references already cited, together with Shakoor and Strbac[9]

Capacity credits at higher penetration levels

Capacity credits - as percentage of the rated output of the wind plant - fall with increasing levels of wind energy penetration. This is because of the skewed nature of wind speed probability distributions. However, there is, again, a good consensus of results from the various studies that have been cited and the results are shown in figure 1. This shows how the incremental capacity credit falls off with increased wind penetration and there is probably a "saturation" level around 7500 MW - possibly higher.

It needs several years worth of data, or more, to establish reliable estimates, and there will always be fluctuations about the mean value – for wind, nuclear, or anything else. Although a recent House of Lords Select Committee received evidence of low output from wind plant last winter (2007-08), analysis of a five-year time series of wind speeds by National Grid did not "provide any statistical evidence for wind variations at peak being substantially different to those at other demand levels for similar times of the year." (2)

The evidence

There have been a number of other studies of capacity credit for England and Wales and these are compared in Table 1.

The table includes estimates of winter quarter capacity factors (if known) and of the ratio (capacity credit/annual capacity factor) to aid comparisons between the data sets. Capacity factors and credits are expressed as percentages of rated power.

This comparison suggests that capacity credits depend on capacity factor (ie wind speed) and, for the UK, lie between 1.26 and 1.53 times annual capacity factors.

The study by Palutikof et al (4) provided detailed information on the effects of diversity. Although only four meteorological stations were used for the simulations, the authors showed that there was always some wind available during eight peak demand periods between 1972 and 1978. Only one of these peak demand periods would have registered a wind plant capacity factor significantly lower than the annual average value. The authors discuss the meteorological factors that influence the results and concluded "it was found that peak demand tends to be associated with cold, windy conditions rather than cold, calm conditions." As this study used data from only four sites, this may account for the wide range of capacity credits.

The study by National Wind Power yielded very similar results. This examined the outputs from two wind farms at the time of the "Triad Periods". Although the number of datasets was limited, below-average outputs from wind farms were only recorded during one of the six Triad periods examined.

The analysis by Grubb focused on the likely wind outputs at or near times of peak demand and was based on simulations, using 16 sites spread over England and Wales. The treatment included comments on the uncertainties associated with the thermal sources of generation noting, for example, that the standard deviation of the available capacity at times of peak demand is around 2000 MW. It also notes "the overall probability of obtaining zero wind output is small, with typically six hours per month bereft of any wind in winter, and about twice this in summer."

Grubb discussed the statistical concepts behind estimation of capacity credit in some detail and also drew attention to the difficulty of quantifying estimates with total precision, particularly inter-annual variations in system demands and wind availability and the fact that "[power systems] face periods of overshoot and undershoot in relation to planned capacity margins, and this tends to mask the practical importance of inter-annual variations in peak demands." Grubb concluded "the capacity credit of wind energy in Britain can be assessed assuming that wind and demand vary independently in winter." In a later paper, he suggested (7) that the capacity credit of 10,000 MW of dispersed wind would be about 3,000 MW and of 26,000 MW of wind and about 5,000 MW. This ties in almost exactly with recent estimates by National Grid.

Table 2 Wind outputs at times of system peaks*

Time of peak	Wind output (MW)	%metered
3 December 17.00	228	0.18
15 December 17.00	690	0.54
6 January 17.00	231	0.18
Average	**383**	**0.30**

*Winter 2009/9
Information derived from “bmreports” website, as of 8 January. The final Triad peaks for the winter may be different.

Source : David Milborrow

All the studies noted that dispersed siting is very important, as there are large variations between individual sites. Without dispersed siting, capacity credits are lower. One recent study (8) that provided a complete matrix of (modelled) wind outputs for a range of system demands, based on a simulation over 10 years, suggested that there will be 23 one-hour periods in a year when the output from wind turbines is less than 10% of rated power and demand is between 90% and 100% of peak demand. However, the modelling included no sites south of the Thames, in Wales or the West Country and so it is possible that it underestimated the effects of geographical diversity.

To return to the present, if we look at the output of the wind plant that is metered by National Grid at each of the “Triad” peak demand periods, we find that the average is about 30% of the rated power – pretty much in line with the more sophisticated studies (*see table 2*).

Backup for windless days

When a new thermal power station is built there is no discussion as to how the electricity system will manage when it is out of action for maintenance, or when it suddenly trips out due to an operational fault. The "plant margin" and the operational reserve deal, respectively, with each of these events. A new nuclear power station, say, with an output of 1000 MW, will provide about 850 MW "firm capacity", that is capacity that can, statistically, be relied on to contribute to system security.

When wind is added to an electricity network, the situation is not fundamentally different. If the new wind plant has some capacity credit then it will be possible to retire some of the older plant, without compromising system security. If the new plant has zero capacity credit, then no plant can be retired, but, importantly, no new plant needs to be built for "backup" – it already exists.
This point can become obscured and there are discussions of the need to provide "backup for windless days". However, whether or not wind is assigned a capacity credit, there is no need to build extra thermal plant when wind is installed, except, perhaps, for very modest amounts to fulfil the need for additional operational reserve.

Extra balancing needs and costs

Electricity networks with wind energy need extra reserves to deal with the extra uncertainty associated with the presence of wind on the network. It is important to emphasise that this extra uncertainty is not equal to the uncertainty of the wind generation, but to the combined uncertainty of wind, demand and thermal generation. This combined uncertainty is determined from a “sum of squares” calculation: -

ß^2 (total) = ß^2 (demand) + ß^2 (wind)

In the UK, for example, the standard deviation of the error in the demand forecast, four hours ahead, is about 1%.

The requirement for operating reserve in Great Britain is around 3850 MW at the winter peak, based on uncertainties in demand and generation up to four hours ahead . The standard deviation in the uncertainty of wind generation (10), four hours ahead, is around 6% and so, when Britain has 5000 MW of wind generation (11), the standard error in the wind output, four hours ahead, will be around 300 MW. It follows that the additional standard error at the peak (60,000 MW) – using the sum of squares calculation – will be around 70 MW. If the “worst case” error is taken as three standard deviations then 210 MW of extra reserve may be required on a four-hour horizon.

Calculations of this type can be made for a range of system loads and on various timescales to determine the total needs for extra reserve. 1 hour ahead the uncertainties are less, and so the extra reserve needs are less – but shorter-term reserve costs more.

The characteristics of most electricity systems are similar, so estimates of the extra reserve needed to cope with wind energy are also similar. With wind supplying 10% of the electricity, estimates of the additional reserve capacity are in the range 3 to 6% of the rated capacity of wind plant. With 20% wind, the range is 4 to 8%, approximately.

National Grid has recently quoted estimates of the

Fig 2 : Estimates of additional GB balancing costs

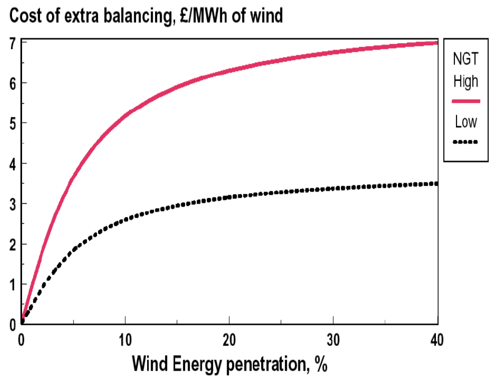
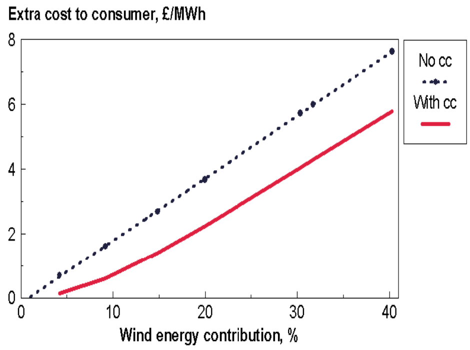


Fig 3 : Extra costs of variability



Source : David Milborrow

extra balancing costs for wind in the UK for 40% wind. These would increase balancing costs in 2020 by £500-1000 million per annum (£3.5-7/MWh of wind) (12). The uncertainty arises because the future trajectory of balancing services costs is uncertain, as they are dependent on fuel prices. The increased use of the demand-side management could also reduce the costs (the way in which balancing costs are likely to increase with wind penetration level is illustrated in figure 2).

This makes use of the National Grid data as "anchor points" and uses information on demand and wind uncertainty to synthesise the rest of the curve. So 10% wind energy is likely to occur extra costs in the range £2.5-5/MWh and 20% wind energy in the range £3-6/MWh, approximately.

Extra costs incurred by thermal plant

Wind energy is different from nuclear or thermal plant at levels above about 5% penetration. Above this level, the capacity credit of wind is less than its capacity factor. This means that 26,000 MW of wind, say, (roughly 20% energy penetration) delivers electricity that corresponds to around 9000 MW of thermal plant (assuming a wind capacity factor of 30% and a thermal plant load factor of 85%) but only displaces around 5000 MW of thermal plant.

This has the effect of reducing the load factor on the remaining thermal plant, which pushes up their generation costs. This provides a basis for estimating the "additional costs of backup", using the methodology used by Dale et al. This paper examined the additional costs (13) associated with 20% wind energy on the UK system, making comparisons with an all-gas system. As the construction of significant amounts of wind energy is likely to inhibit the construction of gas plant, this is considered to be a realistic approach and other estimates of the extra cost of renewables in the UK have also used gas plant as a reference.

Using an up to date price for combined cycle gas turbine plant of £700/kW, (rather than the value in the original paper) the total costs of variability – defined as additional balancing costs, plus backup costs as discussed in the preceding paragraph - can be derived. A mid-range estimate of additional balancing costs has been used for this analysis and the results are shown in figure 3. In view of the controversy that exists over the question of capacity credits, two sets of data are shown, one with capacity credits derived from figure 2, and the other assuming a zero capacity credit. However, it must be emphasised that the evidence for UK wind having a capacity credit is very strong and there do not appear to be any robust analyses that demonstrate it is as low as zero.

It must be emphasised that the estimates in figure 3, which range up to £7.6/MWh, with 40% wind and no capacity credit, or £5.8/MWh with capacity credit are not "total system costs". The total additional costs of 40% wind may be higher or lower than these figures depending on the relative generation costs between wind and gas. A recent analysis from the Carbon Trust has looked at all the additional costs, including transmission (14).

Beware of foreign data

The characteristics of wind tend to be similar the world over and the same applies to electricity networks – but there are some differences. Although the extra costs of reserve for wind in

Britain and a number of American electricity jurisdictions are similar, significantly higher figures are quoted for Germany. This is due partly to the way that the electricity network is operated, partly to the lower wind speeds that prevail there. The average capacity factor of German wind is about 15%, which compares with 25% in Denmark and 30% in Britain. This means that the wind plant capacity needed to generate a given amount of energy in Germany is roughly twice the capacity needed in Britain. The magnitude of the power swings from the plant in Germany will therefore be higher than those in Britain, and the additional uncertainty means that the system operator needs to schedule more reserve.

Lower capacity factors also mean lower capacity credits – as the two are linked. So the fact that lower capacity credits are quoted for Germany does not necessarily imply any significant inconsistency with the conclusions that have been drawn for the UK.

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Liberalisation at 20 : is deregulation dead or alive?

There is a increasingly popular school of thought that argues that competition and market forces are fine when there are ample supplies of primary fuels, plenty of spare generation and transmission capacity and limited externalities (such as environmental constraints) but that it cannot work when some or all of these conditions no longer hold. The conclusion is that some or all of the functions now “left to the market” will need to be determined centrally in the future. In the following article, Tim Russell* argues that many of the perceived inadequacies are not due to any failure in the way markets work but rather in some aspects of the framework in which they operate and the fudging of issues and blurring of the lines of responsibility between parties.

Power stations (of all types) are still the most expensive parts of the system to build and operate although the balance between capital and operational costs varies considerably between different types of generation as do their effects on the environment. But to what extent can the market decide what volume of total capacity to build and how to split this between different types of generation?

For the first ten year’s of liberalisation in England and Wales the position was clear. It was decided centrally by the government that the value of not being supplied with electricity when one wanted it was £2/kWh. The market rules, known as the Pooling and Settlement Agreement, were set up so that the price (at this point there was one very clear price at which anybody could buy and sell electricity) would reach this level but no higher when there was inadequate capacity. When generation was adequate the price moved towards what should have been, under conditions of perfect competition, the marginal cost of production on the system.

This system should have given generators incentives not only to build the right amount of generation in total (with the definition of “right” being set firmly by government in the form of the value of lost load of £2/kWh) but also to build the