MANAGING VARIABILITY

Wind Farm at Deli Farm, Delabole, Cornwall. Photo: Report author

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24 June 2009

A report to WWF-UK, RSPB, Greenpeace UK and Friends of the Earth EWNI

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SUMMARY

In order to comply with legislation from the European Union, the UK's renewable energy target (to produce 15% of final energy consumption from renewable sources by 2020) may require between 35 and 40% of our electricity to come from renewable energy sources by 2020. After 2020, a higher proportion may be needed. A significant amount of this renewable electricity is likely to come from wind, and the variability of this power needs to be managed. Although aspects of the management of wind variability can be controversial, utilities the world over generally agree that there is no fundamental technical reason why high proportions of wind energy cannot be assimilated into the system. There is a large body of literature on the topic and the steady growth of wind power, worldwide, indicates that it is seen as a robust choice for reducing greenhouse gas emissions.

An understanding of the impacts of the variable sources of renewable energy must take into account the wider issues associated with managing electricity systems. Modern integrated networks are designed to cope with 'shocks' such as the sudden loss of large thermal power stations and with uncertainties in consumer demand. As the tools to deal with these are already available the key question is the extent to which the introduction of large amounts of wind energy will increase the overall uncertainty in matching supply and demand.

This extra uncertainty means that additional short-term reserves are needed to guarantee the security of the system. The extra cost of these reserves -- with wind providing 20% of electricity consumption – is unlikely to be more than £1.20/MWh on electricity bills (a little over 1% on domestic bills). With 40% of electricity provided by wind, the corresponding figure would be £2.8/MWh.

The costs of additional reserves are one component of 'the costs of wind variability'. A second is the backup cost and the third is 'constraint costs'. No special backup provisions need to be made for wind energy. All generating plants make use of a common pool of backup plant that is typically around 20% of the peak demand on the electricity network. When wind is introduced, system operators do not rely on the rated power of all the installed wind farms being available at the times of peak demand, but a lower amount - roughly 30% of the rated capacity at low penetration levels, falling to about 15% at high penetration levels. This lower 'capacity credit' gives rise to a modest 'backup cost'. 'Constraint costs' arise when the output from the wind turbines exceeds the demand on the electricity network. They are unlikely to arise until wind energy is contributing around 25% of electricity requirements.

Overall, it is concluded that the additional costs associated with variability – with wind power providing up to about 40% of all electricity, are quite small. If wind provides 22% of electricity by 2020 (as modelling for Government suggests), variability costs would increase the domestic electricity price by about 2%. Further increases in the level of wind penetration beyond that point are feasible and do not rely on the introduction of new technology.

There are numerous technical innovations at various stages of development that can mitigate the costs associated with variability. Improved methods of wind prediction are under development worldwide and could potentially reduce the costs of additional reserve by around 30%. Most other mitigation measures reduce the costs of managing the electricity network as a whole. 'Smart grids', for example, cover a range of technologies that may reduce the costs of short-term reserves; additional interconnections with continental Europe, including 'Supergrids' also deliver system-wide benefits and aid the assimilation of variable renewables. Electric cars hold out the prospect of reduced emissions for the transport network as a whole and could act as a form of storage for the electricity network -- for which the electricity generator would not have to pay.

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1. INTRODUCTION

Meeting the European Union's Directive that 15% of UK final energy consumption should come from renewable sources by 2020 demands a significant increase in the proportion of electricity that comes from renewable sources. Modelling for the Government suggests that this level may be about to 32%[1] and suggests that wind energy will contribute a major share -- about 22%[i] of electricity production in the UK by 2020.

Numerous misconceptions surround the issues associated with the integration of the variable sources of renewable energy into electricity networks. "What happens when the wind stops blowing", is a common question -- the implication being that the lights may go out. "Every megawatt of wind energy needs a megawatt of backup plant", is a slightly more sophisticated -- but still incorrect -- assertion.

So where does the truth lie? In a nutshell: nothing will happen when the wind stops blowing, simply because it never stops blowing, suddenly, over the whole of the British Isles. The variations from distributed wind are generally less than the demand fluctuations regularly encountered on electricity networks. To cope with these, every network has reserves scheduled at all times and what matters is the additional reserve needed to cope with the variability of wind. That is only a few percent of the rated power of wind plant -- not 100%.

There are also concerns that a system with a high proportion of variable renewables would risk power cuts at times of peak demand. The ability of wind energy to contribute to these peak demands needs to be examined. This introduces the concept of ‘capacity credit’ -- how much thermal plant can be retired with the introduction of wind energy?

National Grid, in common with other electricity utilities, is on record affirming that any limits to the penetration of wind energy are likely to be economic rather than technical. As the proportion of wind energy rises above about 20-25%, it may be necessary to constrain wind output at times. The aim of this paper is to clarify the issues in more detail, drawing upon the analysis that has been carried out during the past 30 years (one recent review identified over 150 references[2]) and also to review ways in which the impacts of variability may be mitigated.

This report is structured as follows: -

- A brief description of electricity network issues comes first as this is essential background to discussions of issues surrounding the integration of variable renewable energy sources.
- Next comes an examination of exactly what is meant by ‘wind variability’. (‘Variable’ is a better description of the power fluctuations from wind, wave, etc than ‘intermittent’).
- The next section deals with the integration of the variable sources into power systems, the costs and other issues.
- The final section deals with ways in which the additional costs might be mitigated and covers concepts that are available now through to some of the more conceptual possibilities that are currently under discussion.

Most of the literature relating to variability issues is linked to the performance of wind energy, so this is reflected in the paper. The issues associated with the other variable sources are similar in many respects, although there are important differences.

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[i] Unless otherwise stated, wind energy penetration levels in this report are the proportion of GB electricity supply (on an annual basis) that comes from wind energy. Not all the references that are cited distinguish between "production" and "consumption", but this is unlikely to make material differences.

2. ELECTRICITY NETWORKS

It is impossible to analyse the impacts of variable renewable energy sources on an electricity network without reference to the characteristics of the network itself. All electricity networks need to manage unpredictable fluctuations in consumer demand and plant breakdowns. They do this by looking at the performance of the system as a whole, rather than by focusing on any one type of plant. 'Short-term operational reserve' ensures that plant is available to cope with unexpected power fluctuations in the short term and the 'plant margin', or 'backup' -- the excess of installed capacity over and above the expected peak demand -- ensures that there is always adequate power available to meet consumer demands. Aggregating both demand and supply realises significant savings and ensures that the operational reserve and the plant margin are no larger than necessary. Thermal plant outputs, such as nuclear, coal and gas-fired power plant are truly 'intermittent', inasmuch as they can disappear without warning when components fail, posing a greater threat to the stability of electricity networks than the relatively benign fluctuations of power output from wind installations.

2.1 Economies of scale

'Economies of scale' have a dramatic effect on the performance of electricity networks. The bigger the network, the lower, potentially, is the cost of electricity to consumers. Savings accrue partly from the use of large, highly efficient generating units, but also from the plant savings that result from the aggregation of demand and generation. The greater the aggregation, the smaller (in proportion) are the variations in demand and the easier it is to predict them. At one end of the spectrum, the minimum demand from a domestic dwelling in the UK is a few watts, the average is about 0.5 kW and the maximum is 5 to 10 kW (10 to 20 times the average). If each household met its own maximum demand - 5 kW, say, then 100 GW of generating plant would be needed for the domestic sector, alone. In practice, only about 75 GW of plant is needed for all consumers - domestic, commercial and industrial. Aggregation smooths variations in demand from all sectors and so, nationally, the maximum demand in Great Britain is 60 GW, about 1.5 times the average demand. Smaller electricity systems need, in proportion, more plant. To illustrate the point, the ratio between the installed capacity in Great Britain (78.7 GW) and the average demand in 2006 was almost exactly 2. In Bermuda (175 MW of plant) that ratio was 2.47 and in the Faroe Islands (86 MW) it was 2.77[3].

Although large integrated electricity systems are efficient they still require 'operational reserve' to deal with short-term mismatches in supply and demand and a 'plant margin' (additional plant, over and above that required to meet the maximum demand) to deal with plant breakdowns and other outages. The effect of wind energy on the short-term reserves and margin needs is the subject of much discussion and in this report each issue is discussed in the context of electricity networks.

2.2 Demand fluctuations

Although aggregation smooths variations in consumer demand, there are still substantial fluctuations when numbers of consumers together increase power needs – at the morning and evening rush hours, for example. Figure 1 (left) illustrates the demand variations on 9 January 2009. From a night-time minimum of just over 40,000 MW at 0500 hrs, demand rose rapidly to just under 54,000 MW at 1000 hrs. It then fell off slightly until there was another surge in demand at the evening peak of just under 60,000 MW, reached at 1730. Demand then fell off steadily. The intra-half hourly changes in demand are shown in the right-hand figure. During the morning peak the maximum change between two successive half hours was 2300 MW and during the evening peak was 3100 MW. Negative changes in demand were recorded from 1800 hrs onwards, reaching a maximum of 2600 MW at 2230.

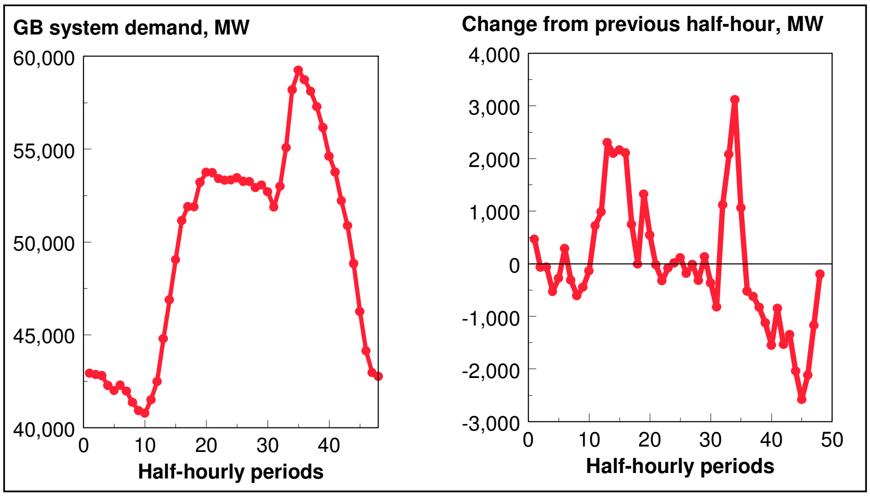

Figure 1. Demand fluctuations in Great Britain on 9 January 2009.

2.2.1 Operational reserve

All power systems, with or without wind energy, need short-term operational reserve, often called 'spinning reserve'. The terms cover various types of plant with different characteristics, outlined briefly below. Nomenclature varies between utilities, but the exact details are not central to this discussion.

Most of the demand changes shown in Figure 1 are reasonably predictable but absolute precision is unrealistic. The weather is a key driver of electricity demand, although other factors come into play. Apart from demand uncertainty, there is also the possibility of plant breakdowns. The standard error in the supply/demand balance is around 2%, 24 hours ahead, falling to about 1.3% four hours ahead. To deal with these uncertainties, various types of plant – the 'short-term operational reserve' - are used to ensure that supply and demand are matched and that system frequency is kept as close as possible to 50 Hz. The principal types of plant are: --

- Frequency response: such plant automatically adjusts its output, increasing it when system frequency is low and vice versa.
- Fast reserve: this plant is able to increase or decrease its output, under instruction from National Grid on a short timescale (typically half an hour)
- Standing reserve: similar to fast reserve, but on a longer timescale (typically 1-4h).

In the UK, the operational reserves are mostly part-loaded thermal units. They operate at below maximum capacity, so that the output can be increased or decreased to cater for mismatches between generation and demand. Pumped storage plant is also used, as it can respond very rapidly to a need for more generation.

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[4]. The level of uncertainty at any given time dictates the level of reserves, although other factors come into the equation. When the demand on the network in England and Wales is 40,000 MW (around the average level) then around 2200 MW of frequency response plant is required if a sudden loss of a 1200 MW power station is a 'worst case' scenario[5].

It is important to note that the levels of reserve scheduled at any particular time ensure that the electricity network operates in a stable manner, with a defined level of risk. 100% risk-free operation is unrealistic. No power stations are 100% reliable and to suggest that "Nuclear is not intermittent; neither is fossil fuel generation…[6]" is misleading, as thermal plant can, and do, 'trip' without warning. This can lead to the instantaneous loss of several hundred megawatts of generation, such as the incident, which occurred in May 2008[7].

2.2.2 Costs of reserve

The costs of the reserve reflect the fact that they need to operate at part-load (and lower efficiency). Annual costs of frequency response plant are around £145 million and each of the other types was expected to cost around £60 million in 2008/09[8].

The costs of reserve depend on the precise type and price structure. Average UK levels are broadly in line with international values, and are in the range £4-8/MW-h [ii], although some fast response plant, such as pumped storage, secures higher values. These costs compensate the plant owners for the lower efficiency of plant whose output is below its maximum, extra wear and tear, and possibly extra controls; they are additional to payments for the energy actually generated.

2.3 Plant margin, or 'backup'

Reserves ensure minute-by-minute system security but longer-term security is managed by making sure that there is always enough plant available to meet the highest demands on the electricity network. The 'Plant margin' is a measure of the difference between the total capacity of the plant on the network and the expected maximum demand. The desirable plant margin (plant capacity minus maximum demand) for a large system such as that of Great Britain is modest – around 24%[9]. Maximum demand in Great Britain last winter (2008/9) was around 60 GW and so there needs to be at least 73.2 GW of plant – which there is. This does not guarantee that the lights will never go out but ensures this will happen very rarely. The high level of security and low plant margin stems from the fact that a large system has a number of generating units each with a quantifiable probability of failure, but the combined probability of, say, three units failing at the same time, is much less. It may be noted that the plant margin in the UK has been higher than the theoretical figure for many years. It is very difficult to design a market that delivers the theoretically desirable optimum, simply because power plant equipment takes a long time to build, and plant closures are not always easy to predict in advance.

3. CHARACTERISTICS OF WIND ENERGY

Contrary to popular perception, wind energy is not totally random and unpredictable. It is variable, rather than intermittent as wind outputs, aggregated over the whole country, fluctuate in a way that can be quantified. A reasonably consistent picture comes from analyses of power fluctuations (real and simulated) in Denmark, Germany and the UK. With 3000 MW of wind in Britain, generating, say, 1000 MW at noon, the output at 1300 hrs will most probably lie between 910 and 1090 MW. The probability of it lying outside this range can be quantified, so providing a basis for combining 'demand uncertainty' with 'wind uncertainty'.

The need to schedule reserves to cover for possible trips of conventional thermal plant emphasises the point that no generation is 100% reliable. The loss of 1000 MW of thermal plant is a real risk, but it is extremely unlikely that 1000 MW of dispersed wind will disappear instantaneously. As wind capacity increases, the increased geographical spread reduces the fluctuations, and so sudden changes of wind output across the whole country do not occur. The smoothing effects of geographical dispersion are quite dramatic. Using one statistical measure, the fluctuations across western Denmark

[ii] These prices derive from a holding charge and a usage charge. The prices of frequency response plant moved upwards from October 2005, following changes to the administrative arrangements.

are about one quarter of those measured on a typical wind farm and figure 2 illustrates this point graphically.

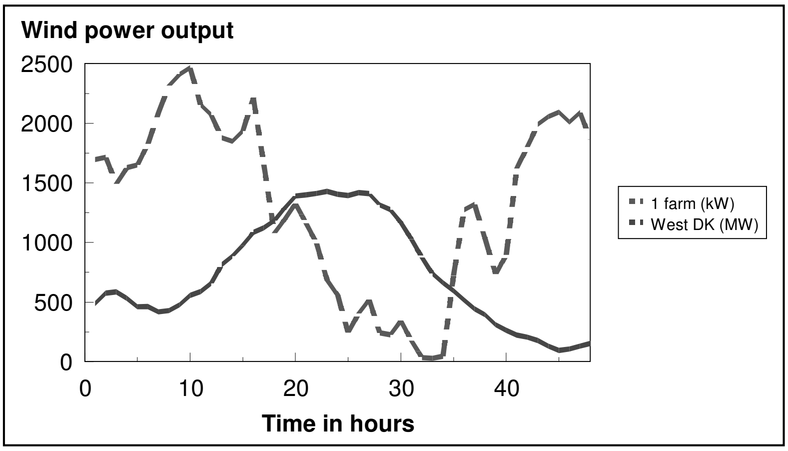

Figure 2. A comparison of the fluctuations from a single wind farm (dashed line, output in kW) with the fluctuations in the whole of western Denmark (solid line, output in MW).

An analysis of the wind power fluctuations in Western Denmark in 2007 suggests that for 42% of the year (3700 hours) the intra-hourly fluctuations were within the range plus or minus 25 MW (1% of the wind capacity). Extending the range to plus or minus 50 MW captures another 1800 hrs of fluctuations. At the extremes, fluctuations in excess of plus or minus 375 MW (16% of capacity) only occurred 10 times in the year. The complete histogram of power swings is shown in Figure 3.The standard deviation of the fluctuations is around 3%. Comparisons with an analysis carried out by National Grid for Great Britain have yielded very similar results. They are summarised in Table 1 and compared with other data[10]. This table also includes data that shows how aggregation of wind power fluctuations reduces, in proportion, the magnitude of the standard deviation and of the maximum excursions. Information of the type shown in table 1 and figure 3 provides a basis for estimating the effects of integrating wind energy into an electricity network.

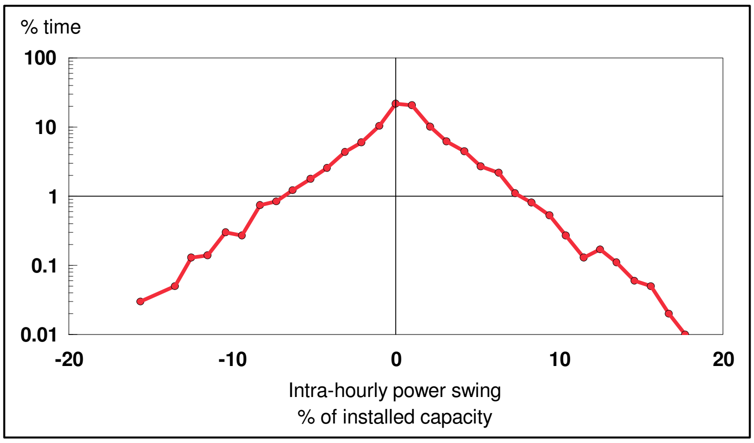

Figure 3. Intra-hourly power swings observed in Western Denmark in the year 2007. Note that these never exceeded around 18% (up or down) and the standard deviation was about 3%.

	Standard deviation		Maximum swing	
Lead time, hr	1	4	1	4
Nation-wide				
NGC[11] and Ilex[12]	3.1	9	-14, +18	-21, +29
Danish (W) data (2007)	3	10	-16, +18	-49, +56
Single wind farm	11.8	20.8	-90, +60	-100, +100

Table 1. Summary of data on power swings for Great Britain and Western Denmark and a comparison with single wind farm data. Some data from western Denmark have been updated from the original source.

4. INTEGRATING WIND

Numerous electricity utilities around the world have examined the implications of absorbing wind energy and most have concluded that the additional costs are modest and there are no insuperable difficulties. The additional costs can be derived by looking at the overall uncertainty when supply fluctuations (due to plant breakdowns) are combined with demand uncertainty and wind uncertainty. That enables the amounts of additional short-term reserve to be derived. The costs of that reserve can then be calculated. National Grid estimates these additional costs for 40% wind will not exceed about £7/MWh of wind (roughly 10% extra on top of its generation cost).

Contrary, again, to popular perceptions, wind does not need to be 'backed up', megawatt for megawatt. Numerous authoritative studies have shown that it can displace thermal plant. At low penetration levels the volume of this thermal plant roughly equals the average power of the wind plant, but the volume declines -- in percentage terms -- with increasing amounts of wind energy. This does give rise to a small 'backup cost'. When this is added to the additional costs of operational reserve, the total extra cost to the consumer, with 20% wind, is expected to lie between £1.5/MWh and £2.5/MWh. With 40% wind, the additional cost is estimated to lie in the range £5-7/MWh. Higher penetration levels are feasible.

When considering the introduction of the variable renewable energy sources it is important to preserve the advantages of an integrated electricity network as that minimises the extra costs to electricity consumers. National Grid has made this point[13]: -

"However, based on recent analysis of the incidence and variation of wind speed we have found that the expected intermittency of wind does not pose such a major problem for stability and we are confident that this can be adequately managed…

It is a property of the interconnected transmission system that individual and local independent fluctuations in output are diversified and averaged out across the system.

The effects of adding wind to an electricity network may be illustrated by the case of western Denmark, and examining the changes in demand that need to be managed. If there had been no wind installed there in 2007, the maximum one-hour increase in system demand would have been 675 MW. With 26% wind (the amount on the system that year), sometimes the wind fluctuations augmented the demand fluctuations, sometimes they reduced them. The maximum increase in demand that the System Operator had to deal with went up from 675 MW to 900 MW. In that hour, there was an increase in demand at the same time as the output from the wind plant fell. However, the number of times that the net demand increased by more than 600 MW in an hour only went up from 55 (consumer demands only) to 63 (consumer demand net of wind production). Even with 39% wind (scaling up 2007 wind outputs by 50%), there would only be about 75 occasions when the net increase in demand exceeded 600 MW[14].

The impacts of variability and the corresponding possibilities for mitigation can be studied by examining the three principal 'cost centres': --

- The costs of extra operational reserves (balancing costs), which can be reduced by
    - Reducing the 'unpredictability' of wind (by better forecasting), or
    - Reducing the cost of balancing services
- 'Backup', which can be reduced if the capacity credit can be increased, and,
- 'Constraint costs', due to surplus wind, which can be reduced if the surpluses can be reduced.

4.1 Extra short-term reserve 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. An American author has made this point[15]: -

"A key feature of the present analysis [of the effects of variability] is its integration of wind with the overall electrical system. The uncontrollable, unpredictable, and variable nature of wind output is not analyzed in isolation. Rather, as is true for all loads and resources, the wind output is aggregated with all the other resources and loads to analyze the net effects of wind on the power system. Aggregation is a powerful mechanism used by the electricity industry to lower costs to all consumers. Such aggregation means that the system operator need not offset wind output on a megawatt-for-megawatt basis. Rather, all the operator need do, when unscheduled wind output appears on its system, is maintain its average reliability performance at the same level it would have without the wind resource."

The combined uncertainty is determined from a 'sum of squares' calculation that provides the basis for estimates of additional reserve needs: -

σ^2 (total) $= \sigma^2$ (demand) + σ^2 (wind)

σ is the standard deviation of the uncertainties.

Although the quantity of operational reserve rises with increasing amounts of wind energy, National Grid is confident that it will be able to procure the necessary amounts, and, moreover, that there is no 'ceiling' on the amount of wind-generated electricity that can be accommodated[16]: --
"Based on recent analysis of the incidence and variation of wind speed the expected intermittency of the national wind portfolio would not appear to pose a technical ceiling on the amount of wind generation that may be accommodated and adequately managed."

It may be noted that National Grid says nothing about the type of plant that may be needed for reserve - that is left for the market to decide, provided it can meet the technical specifications set by National Grid. In practice, it may be coal-fired plant, combined cycle gas turbines, or storage. The former tends to be the most economic option, whilst the latter tends to be the most expensive. However, pumped storage plant can respond extremely rapidly and so is well suited to a particular type of 'fast reserve'.

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 extra balancing costs for wind in the UK for 40% wind[17]. These would increase balancing costs in 2020 by £500-1000 million per annum (£3.5-7/MWh of wind). The uncertainty arises partly because the future trajectory of balancing services costs is uncertain (they are dependent on fuel prices), partly because increased use of the demand-side management could reduce the overall costs. The way in which balancing costs are likely to increase with wind penetration level is illustrated in figure 4. This makes use of the National Grid data as 'anchor points' and uses information on demand and wind uncertainty (discussed earlier) 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.

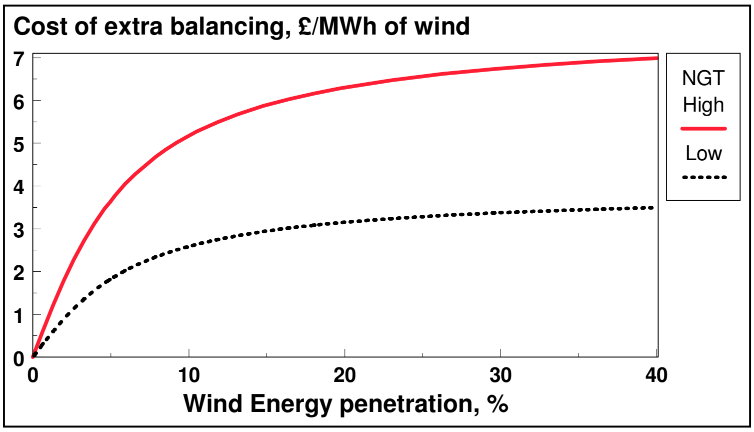

Figure 4. Estimates of additional balancing costs for Great Britain

A recent American review[18] quotes a study that looked at 30% penetration on a peak load basis (probably about 15% on an energy basis) and that suggested an extra balancing cost of $8.84/MWh – within the range of the National Grid data. Other international comparisons are discussed briefly in Section 4.5

4.1.1 Carbon dioxide savings

As the extra reserve operates at part-load, its lower thermal efficiency means that its emissions increase. The reserve still contributes useful energy to the system, so the extra emissions are those associated with the reduced efficiency of part-loaded plant. Taking a pessimistic estimate of 10% for the reduced efficiency, and taking into account the fact that the load factor of wind plant is just under half that of thermal plant, Dale et al suggested that this reduces the emission savings from the wind, at the 20% penetration level, by a little over 1%[22]. In other words if the displaced fuel is coal, for the sake of argument, with CO_2 emissions of 900 kg/MWh, then the effective CO_2 saving would be around 890 kg/MWh. If the displaced fuel were gas, with CO_2 emissions of 400 kg/MWh, the effective saving would be 395 kg/MWh. At higher penetration levels (40%, say), the non-linear increase in the necessary reserves brings these figures down to around 875 kg/MWh and 388 kg/MWh, respectively.

20% wind energy corresponds to around 80 TWh [iii] and so the carbon dioxide savings would be around 71 million tonnes per annum if coal is displaced (32 Mt if gas is displaced). With 40% wind, the savings would be about 140 Mt and 63 Mt, respectively.

[iii] The exact amount that corresponds to 20% wind depends on assumptions about electricity requirements in 2020 and these vary.

4.2 Extra back up and its costs

A distinction must be drawn between the extra reserves needed for short-term balancing in an electricity system with wind and the extra backup (if any) needed to guarantee the security of the system at all times. That means making sure that there is always enough power available to meet the peak demands of the system. Although some suggest that there is a need to provide 'backup for windless days' to ensure that demands are always met[19], this is misleading, on two counts: -

- When a new thermal power station is built there is no discussion as to how the electricity system will manage when the station is unexpectedly out of action for emergency repairs during the winter. The 'plant margin' is a common pool of 'extra' plant that ensures peak demands are met. No power stations are 100% reliable, as discussed earlier.
- Not even the most zealous of renewable energy enthusiasts would suggest that System Operators should rely on the full rated capacity of wind power plant. When wind is added to an electricity network, the situation is not fundamentally different from an addition of thermal plant. If the wind plant has some 'capacity credit' (discussed next) 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, either way, no new plant needs to be built for 'backup' – it already exists.

Estimates of capacity credit that are based on wind electricity production during a single winter are unlikely to provide accurate estimates. It is a statistical quantity that requires adequate data -- as for nuclear plant. During the winter of 2008/9, for example, at the time of peak demand, the metered wind electricity production was about 18% of its rated output[iv]. However, about 5000 MW of nuclear output was not available, for various reasons - nearly 50% of the total[20]. It would be misleading to assign a capacity credit of 18% to wind on the basis of this one instance, and equally misleading to assign a 'firm power' contribution from nuclear as 50% of its rated output.

It is important to emphasise that the capacity credit of wind will never be greater than the plant margin and even if the country had 26,000 MW of wind and had been completely becalmed at the time of the peak demand on 6 January 2009, the plant margin would not have been used up, despite the missing 5000 MW of nuclear. It is also worth reiterating that the plant margin is generally greater than the theoretically desirable minimum.

4.2.1 Capacity credit

The term 'capacity credit' for wind, introduced above, tends to be controversial. It may be defined[21] as follows: -

"The reduction, due to the introduction of wind energy conversion systems, in the capacity of conventional plant needed to provide reliable supplies of electricity."

Despite the controversy, numerous studies have confirmed that wind can substitute for thermal plant and enable the British power system to operate with the same level of reliability. The issues are discussed in more detail in appendix 1 and figure 5 shows how the capacity credit varies in megawatt terms, as a function of the installed wind capacity.

[iv] National Grid does not monitor all the wind plant output, so this applies to the metered capacity.

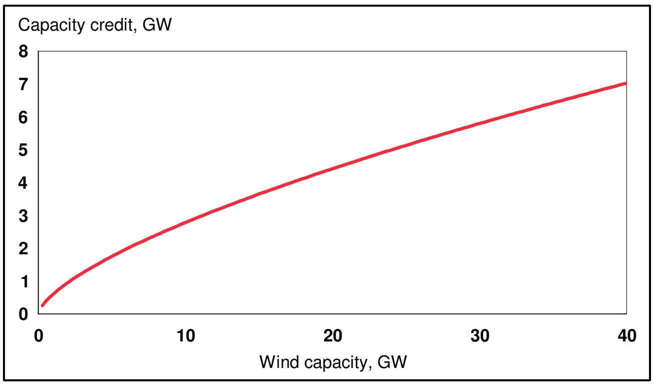

Figure 5. Capacity credits as a function of wind capacity

4.2.2 The cost of backup

Although the 'extra costs of backup' are not derived by assuming the whole of the wind plant capacity needs to be duplicated by standby thermal plant, there are extra costs associated with the low capacity credit of wind at penetration levels above about 8%. With thermal plant, the average power and the 'capacity credit' are the same, but wind energy is different. Above the 8% penetration level (approximately), 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 10,700 MW of thermal plant (assuming a wind capacity factor of 35% 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. Their generation costs increase, as capital cost repayments are spread over fewer kilowatt-hours. This provides a basis for estimating the 'additional costs of backup', using the methodology used by Dale et al[22]. Using an up to date price for combined cycle gas turbine plant of £700/kW, these amount to around £2.5/MWh of wind (at 20% penetration), rising to around £6/MWh of wind at 40% penetration.

Even if evidence should surface showing suggesting capacity credits are much lower than has been assumed, the effect on the variability costs would be modest. At 20% wind energy penetration level, for example, the additional variability cost would be about £1.7/MWh[20].

4.2.3 Transmission constraints

The foregoing discussion has implicitly assumed that the electricity network can be operated as a single unit, with unrestricted flows of energy. In practice, this is not always the case and there are sometimes occasions when the power production from renewable plant exceeds the transmission capacity that is required to deliver it to the demand centres. This means that there may be occasions when renewable plant may be required to cease generation, or be 'constrained off'. The effect of such constraints will be to increase the costs of the renewable plant, as the capital costs will be spread over fewer units of electricity than was anticipated. Whether or not these costs are borne by the renewable generator depends on the structure of the market as designed by the regulator and government.

In Britain, such constraints are likely to occur due to the large quantities of wind energy -- installed or planned -- in the north of England and Scotland. For many years there have been large North to South power flows, as generation capacity exceeds demand in the north, and vice versa. There is increasing concern over the cost of these constraints[23], although these can be alleviated by additional transmission connections at an estimated cost of £ 4,700 million[24].

These constraints are not, strictly speaking, a 'variability' issue, but more to do with the location of the best sources of renewable generation, relative to demand. Similar issues arose when the large concentrations of coal-fired power stations were built -- near to the coalfields -- and most significant expansions of large generating plant involve transmission reinforcements.

4.3 Wind surpluses at high penetration levels

The discussion so far has focused on wind energy penetration levels up to around 40%. In practice, as noted earlier, higher levels are achievable, albeit at increased cost. A detailed analysis by the Danish system operator, Energinet, has examined the implications of operating with 100% wind and quantified the additional costs[25]. The analysis was carried out for Western Denmark, but ignored the existence of the connections to Germany, Sweden and Norway and did not assume that any storage was available.

100% wind is not, of course, feasible but the System Operator assumed that sufficient wind power capacity was installed in order to meet 100% of the electricity requirements. With that level of capacity, around 30% of the wind energy had to be rejected when wind power production exceeded system demand. A similar amount of wind had to be supplied from thermal sources of generation when the system demand exceeded the wind power production.

The possibility that wind power production may occasionally exceed system demand first occurs at penetration levels around 25%. Figure 6, which shows actual data from Western Denmark, shows that it occurred twice during 13/14 January 2007. However, the amounts of 'surplus' wind energy are initially modest and similar estimates come from the Energinet study and from a British study[26].

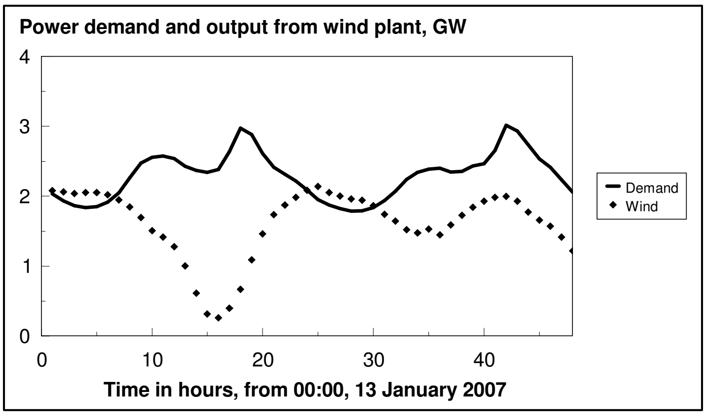

Figure 6. Demand and wind production in Western Denmark, 13/14 January 2007.

With 30% wind energy, the Danish study suggested around 1.7% would need to be constrained off or rejected and the SKM study a slightly lower level -- although the precise value depended on assumptions about interconnectors and pumped storage. With 40% wind, both studies projected about 4% would need to be rejected and at 50% wind about 7.5%. Data from the two studies are compared in figure 7.

If no market can be found for this 'surplus' wind energy, a small penalty is attached to this 'lost' electricity, as the fixed costs of the wind plant are spread over fewer units of electricity. With 30% wind, this amounts to around £0.6/MWh of wind, rising to around £1.5/MWh with 40% wind, based on current installed prices of around £1300/kW. Ways in which this 'surplus' may be utilised are discussed in the section 5.

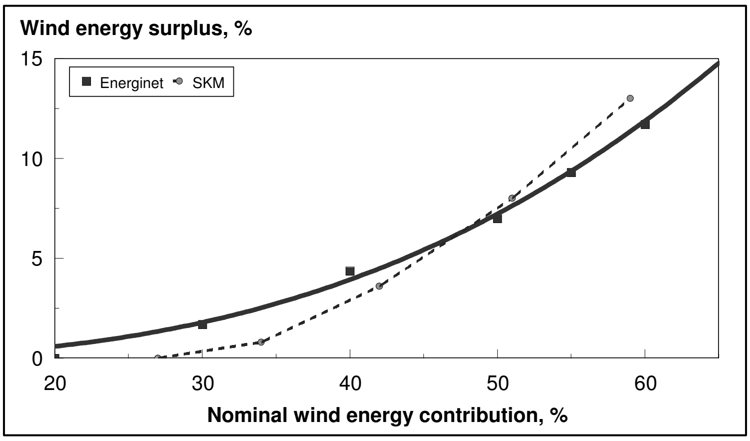

Figure 7. Estimates of surplus wind energy for contributions up to 60%.

4.3.1 Impact of new nuclear and coal-fired plant

The threshold at which wind energy may need to be rejected, and the corresponding amounts of surplus wind may change in the future if new nuclear and coal-fired plant is built in Britain. As wind, nuclear and coal-fired plants are 'capital intensive', all need to run as much as possible in order to repay their capital costs. This is unlikely to be a problem in the short to medium term as the build up of wind energy is likely to be accompanied by a decline in the capacity of nuclear and coal-fired plant as the old plants retire and close. If new nuclear and coal-fired plant are given consent and commissioned, however, then there will possibly be conflicts[27] and these are discussed in Appendix 2. Resolution of these is likely to be a matter for the regulator and government.

4.4 Total costs of variability

The total costs of variability to the electricity consumer -- defined as additional balancing costs, plus backup costs as discussed in section 4.2, plus constraint costs as discussed in section 4.3 - are shown in figure 8. The 'high' estimate uses National Grid's upper balancing cost estimate and an installed cost for combined cycle gas turbine plant (CCGT) of £700/kW in the calculation of backup costs. The 'low' estimate uses National Grid's lower balancing cost and an installed cost of £500/kW for a mixture of CCGT and open cycle gas turbine plant. To derive the constraint costs at penetration levels above 30%, it has been assumed that 12 GW of onshore wind costing £1100/kW has been installed and 45 GW of offshore wind costing £2000/kW. With 10% wind energy, the extra costs are below £1/MWh in each case; at the 20% level they rise to a little over £2/MWh in the 'high' case (£1.5/MWh in the 'low' case) and with 40% wind, the estimates are £7.3/MWh and £5.2/MWh, respectively. A 'central' figure would add about 5.5% to domestic electricity bills.

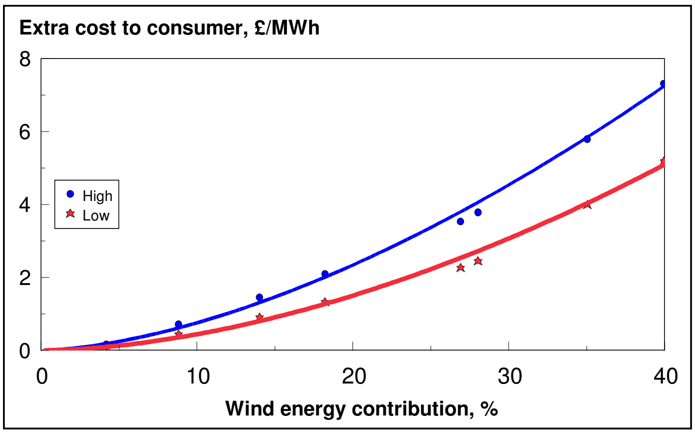

Figure 8. Additional costs associated with variability

It must be emphasised that this is the ‘cost of variability’ and the overall extra cost to the consumer may be greater or less than this figure, depending on the relative generation costs between wind and gas.

4.5 Types and costs of plant used for reserve

A substantial proportion of the additional reserve is likely to come from thermal plant in the short to medium term, so changes in fossil fuel prices will influence the cost of reserve and hence the cost of the additional reserve needed for wind energy. If carbon capture and storage (CCS) on coal and gas-fired power plant achieves technical and commercial viability, reserve prices are likely to be higher as their capital costs are higher and their thermal efficiency lower.

Other types of non-fossil generation could, however, provide frequency response and other reserve services. This could include anaerobic digestion plant, sustainable biomass or biogas.

5. MITIGATING THE EFFECTS OF VARIABILITY

Progress towards 20% -- or even 40% -- wind will inevitably be gradual and so it is highly likely that technologies and strategies will develop that will mitigate the impacts of variability.
Some of these are already in use, such as improved methods of wind forecasting and this is likely to have a significant impact. Numerous other ideas are under development or discussion and it is likely that increased use of demand-side management (possibly aided by the installation of ‘smart meters’) will also play a key role in reducing variability costs. The use of storage is often advocated, but its use for ‘levelling the output’ of wind power may be difficult to realise. However, it may have a role to play -- for the benefit of the electricity network as a whole -- in systems with a high penetration of variable renewables. The construction of more international transmission links should aid the assimilation of variable renewables -- and will also work to the benefit of the system as a whole. Further ahead, the widespread introduction of electric cars or a switch to electric heating would be beneficial to wind energy, as it would facilitate the absorption of ‘surplus’ wind at times of high wind and low demand.

Many of the ideas now under discussion for mitigating the extra costs of variability of wind aim to reduce the additional costs of operating electricity systems with high renewables input, rather than focusing exclusively on the wind itself. There is a further category of technologies that may come to fruition for other reasons that may ease the additional costs associated with high wind energy penetration levels. Table 2 summarises the various possibilities and their likely impacts.

	Lower reserve costs	Higher capacity. credit	Less rejection	Stage
Wind-related				
Better forecasting	Yes			Proven
High offshore productivity	Yes	Yes		Likely
System-related				
DSM	Yes			Proven
Storage	If price right	Too costly?	If economic	Proven/developing
More international connections	Probably		Likely	Some building, some conceptual
Other technologies				
Electric cars	Probably		Yes	Developing
Electric space and water heating	Likely			Feasible
Hydrogen economy	Uncertain		Probably	Conceptual

Table 2. Developments likely to reduce the additional costs of assimilating wind energy.

5.1 Wind forecasting

There is considerable work in progress on improvements in wind forecasting and the emergence of forecasting services, in both Europe and America, testifies to the fact that it is worthwhile improving the accuracy of projected power outputs. A large EU-funded R&D project involved a large number of contributors[28], and a utility-funded project has been completed in United States, managed by the Electric Power Research Institute[29]. Commercial forecasting services are also available, with software that improves forecasts up to 24 hours ahead. One company claims, for example, that the error in one-hour-ahead forecasts is typically 15 to 25% lower than that of persistence forecasts[30].

Much of this forecasting work is focused on providing services to operators of wind farms, rather than System Operators, but estimates are available of countrywide improvements that might be expected[31]. The analysis, for Germany, suggests that the standard deviation of the uncertainty one hour ahead might be reduced from 3% to below 2% and, similarly, the 4-hour uncertainty can be reduced from 6% to around 4%. This would reduce the estimates of balancing costs that were quoted earlier by about 30%, provided the System Operator felt that the forecasting accuracy was sufficiently robust.

5.2 Higher productivity from offshore wind

Most of the analysis in this paper assumes that the weighted average capacity factor of the wind power plant is around 30%. The latest available figure for onshore wind is 27%[50], which may decline as the better onshore sites are used up; on the other hand this may be more than offset by the higher productivity of offshore wind. Some of the most recent statistics from Denmark suggest that higher values are achievable offshore. With a higher capacity factor, the extra balancing costs come down -- as a lower total farm capacity is needed to produce a given output. A 10% increase in the capacity factor reduces the additional short-term balancing costs by a little over 10% and, by increasing the capacity credit, reduces the extra back-up costs.

5.3 Demand management

'Demand-side management' (DSM) has been an integral part of the load management strategies of system operators for many years. It has the potential both to reduce peak loads and lower the costs of reserve. The variable sources of renewable energy, such as wind, are likely to benefit from the wider adoption of load management in the future, although there are potential benefits for the electricity system as a whole.

There are various types of demand-side management, although the boundaries are not sharp: -

- Provision of reserve and frequency response under contract to the System Operator. In 2005/6, users, rather than generators provided about one-third of the 'standing reserve and 'frequency response' balancing service requirements of National Grid[32].
- Teleswitching. This technology has been slowly developing for around 40 years. It enables demands to be modulated in response to radio signals sent by the System Operator (or, more usually in the UK, by the Distribution Network Operator). The signals are sent to a special meter and the technology has the potential to control or modulate interruptible demands.
- Dynamic demand. Whilst tele-switching is actively (and remotely) controlled, Dynamic Demand is a passive system that relies on sensors in equipment used by consumers to modulate demands. If all domestic refrigerators, for example, included a frequency-sensitive device that inhibited its operation when the frequency fell below (say) 49.8 Hz and switched the fridge on (provided it was not already too cold) at, say 50.2 Hz, then this could substitute for between 728 and 1174 MW of frequency response plant[33].

- Smart Meters. These give electricity consumers access to information about the price of their electricity on a continuous basis. The government has announced its intention to facilitate their introduction on a widespread basis. The most common perception of such meters at present is to provide information to consumers, rather than intervene to restrict demand on a selective basis.
- 'Time of use' pricing. Smart Meters for domestic consumers, as presently envisaged in Britain, are a source of usage information and it is up to the consumer whether he responds or not. 'Time of use' tariffs have been in existence for many years in the industrial and commercial sectors, and, in simplified form, in the domestic sector. The tariffs aim to discourage use at peak demand times -- that normally coincide with peak prices -- and so iron out, to some extent, demand fluctuations. If that enables the quantity of rarely used (and expensive) 'peaking plant ' to be reduced, that reduces both costs and emissions. The most sophisticated development of 'time of use' pricing responds continuously to changes in market prices. Whether or not consumers can react to high or low prices depends on the type of electrical equipment they are using. 'Time of use' tariffs are common in France and their effectiveness appears to be reflected in a lower ratio between maximum and minimum demands. On 21 May 2009, for example, the French ratio was 1.39, whereas in Britain it was about 1.6.

All these concepts act to improve the efficiency of the electricity system as a whole. Any benefits to wind would come through reductions in the costs of balancing services. Some benefits are already being realised (first bullet point) but it is difficult to estimate the magnitude of any additional benefits.

One possible downside (from the point of view of wind) is that a reduction in the uncertainties in the supply/demand balance might mean that the uncertainties in wind power production would become more significant, thus increasing additional balancing costs.

5.4 Energy Storage

5.4.1 Dedicated storage

Energy storage is often seen as a means of 'levelling the output' variable renewables, possibly increasing its capacity credit and so increasing its value. Such 'dedicated storage' faces a number of challenges as it adds to the generation cost of the variable renewable. That additional cost needs to be less than the additional value of 'firm power' over variable power. There are additional challenges with dedicated storage, as the store needs to be very large to ensure that the 'levelling' continues during long periods of low wind.

An early integration study concluded[34]: --

"There is no operational necessity in associating storage plant with wind-power generation, up to a wind output capacity of at least 20% of system peak demand"

This does not imply that 20% is a ceiling, or threshold. It was simply the upper limit that was investigated in the study.

A later American study made the same point[35]: -

'Storage may increase the value of intermittent generation. However, studies generally show that dedicated storage systems for renewables are not viable options for utilities because of added capital costs of current storage technologies. Storage can add flexibility and value to utility operations, but it should generally be a system-wide consideration, based on the merit of the storage system'.

More recently the American Electric Power Institute suggested[36]: --

"Installing energy storage….. practically eliminates wind integration issues…. unfortunately the high cost of storage systems limits the situations in which they are useful."

In Britain, the cost threshold that storage would need to meet for viability in the current market can be gauged from the difference between 'continuous' and 'variable' power sources. The difference in the prices realised for landfill gas (firm power) and for wind energy (variable power) in the auctions conducted by the Non-Fossil Purchasing Agency is a guide. Between the summer of 2006 and the end of 2008, the minimum price difference was £1.1/MWh, the maximum £11.2/MWh, and the average £4.9/MWh. The average roughly corresponds to the theoretical 'capacity value', based on the replacement cost of combined cycle gas turbine plant.

5.4.2 System storage

There is a difference between 'dedicated storage' for variable renewables and storage for an electricity system -- with or without variable renewables. Storage has the potential to enable power systems to operate more efficiently -- absorbing power at periods of low demand and releasing it at periods of high demand that otherwise needs to be met by expensive generating plant. This is generally a less challenging role than 'dedicated storage'. However, storage has a generation cost, just like any other generation technology, and will only be economic if the differential between the energy prices paid to the storage operator at times of high demand, and by the operator for electricity at times of low demand, is sufficient to cover its costs.

A recent UK Select Committee observed[37]: -

"No evidence we received persuaded us that advances in storage technology would become available in time materially to affect the UK's generating requirements up to 2020."

A recent analysis that examined the prospects for western Denmark concluded[38]: -

"The conclusion is that energy storage systems are for most cases uneconomical for day-to-day trading in Western Denmark."

If the introduction of large quantities of wind energy into the UK electricity network (and elsewhere) widens the difference between 'high' and 'low' spot prices in the electricity market, that may facilitate the construction of cost-effective storage. Most of the technologies are able provide system services (short-term operating reserve, reactive power and 'black start' capability) and these can provide additional revenue. There are a number of technologies in existence and under development, with a wide range of applications, apart from those discussed here[39].

5.5 Additional international connections

Additional international connections give system operators access to more sources of power, effectively increasing the size of the system. The advantages of large systems were discussed in section 2.1 and perhaps the simplest way of looking at the effects of additional connections is to view them as additional plant. The 'effective' renewable energy penetration level then drops from, say, 30% -- with 80,000 MW of conventional plant -- to, say, 26.7% with 10,000 MW of additional connections. Reference to figure 6 suggests this brings down the 'costs of variability' from around £4/MWh to £3.2/MWh.

The next stage in the argument for additional interconnections is that, with the two interconnected systems operated as one, the wind variability comes down. However, the evidence on this point is not clear. On the one hand, the standard deviation of hourly wind fluctuations in Britain is similar to that in (smaller) Western Denmark (table 1). On the other hand, Foley and Leahy[40] combined British and Irish wind records and showed that the joint occurrence of wind speeds below 5 m/s was reduced to 16% of the time, whereas the individual occurrences were 22% (Britain) and 28% (Ireland).

5.5.1 European Supergrids

A number of proposals for more extensive international grid connections -- mostly using HVDC - have been put forward in recent years, mostly with some or all of the following objectives: --

- Facilitating the connection of offshore wind farms.
- Smoothing wind fluctuations on a continental (rather than national) scale.
- Facilitating progress towards very high proportions of renewable energy in the European network including, for example, concentrated solar power plant in Africa.

Hurley et al[41] provided data that illustrated the smoothing effects. They took data from 60 well-distributed sites over a 34-year period and showed, for example, that there were very few occasions when wind power production fell below 12% of rated output in the winter. This suggests that the capacity credit of this widely distributed wind might be higher than the values calculated from individual national studies. Similarly, their analysis of power swings also suggests that there would be a lower uncertainty, probably leading to lower additional balancing costs.

Decker et al[42] have recently summarised most of the proposals that are currently being discussed. Some cater, in the longer term, for up to 100 GW of offshore wind. They note that increased interconnections would be beneficial to European electricity networks as a whole, quite apart from their role in facilitating the connection and smoothing of renewable energy. They also provide data on the smoothing effects, suggesting that hourly variations in excess of plus or minus 10% appear to be negligible. (This may be compared with the maximum hourly swings around 14-18% observed in Western Denmark and estimated for Britain -- see table 1).

A simple cost benefit analysis suggests that significant savings from lower variability costs are needed to make the concept of European Supergrids attractive. Figure 6 suggested that the additional cost to the consumer of 40% wind might be just under £6/MWh. If a Supergrid enabled savings of £2/MWh to be made, then the net present value of these savings over 20 years, with a test discount rate of 10%, is around £6 billion. The projected costs quoted by Hurley et al., were €9.4 billion – nearly 50% higher. (Although supergrid construction costs may have increased since the estimate was made). However, this implicitly suggests that all the extra costs of the Supergrid are debited to wind energy whereas, in practice, there would be significant system benefits as well. Europe's Transmission System Operators already have plans for improved interconnections[43], most of which are likely to benefit wind energy.

There are, nevertheless, difficulties on the way to the construction of a European Supergrid. Several witnesses who appeared before the Energy and Climate Change Select Committee in April/May 2009 drew attention to technical and regulatory difficulties, although there was support for further analysis of the concept. Another possible difficulty is that national plans for the connection of offshore wind farms are already well advanced and so the possibility of looking at ‘the big picture’ may already have passed. Nevertheless, the broad concept has support at the European level, through the ‘Ten E’ programme of support for improved interconnections[44].

5.6 Electric cars

The prospects for electric cars are being studied with a view to reducing greenhouse gas emissions. There is a double benefit as air quality in cities will be improved and national emissions will be reduced, even though the electricity used to charge them at present comes from a mixture that includes lots of coal and gas-fired plant. The attraction from the standpoint of the electricity industry is that it may enable the more efficient use of generating plant, provided most of the charging takes place during the night. Reference to figure 1 shows that between 2230 hrs and 0630 hrs in the winter the demand dropped below 45,000 MW, whereas during the rest of the day it was above this level, peaking at just under 60,000 MW. Inspection of data for later in the year (21 May, 2009) suggests that there was a similar difference between the night time demand and the peak.

A margin of around 15,000 MW would be sufficient to charge the entire fleet of British cars if all were to be powered electrically (Appendix 3). The additional attraction, from the standpoint of integrating wind, is that this would enable surplus wind power to be utilised at times when wind power generation exceeded demand. There would be no guarantee, of course, that surplus wind would always be generated during the night, but that is a realistic scenario, given the lower demand. Daytime charging would be possible, provided it could be controlled by some form of 'smart meter', or by teleswitching.

The use of electric cars as a form of storage is also advocated, with electricity being fed back into the system when needed. The costs and benefits of this option need to be examined as the costs of reversible circuitry would be higher than those of simple 'charging' circuitry -- and the 'round trip' efficiency would also be lower. In addition, the System Operator would need to be assured that sufficient vehicles were likely to be connected during the day -- and vehicle owners would need some form of control over the process, otherwise there would be a danger of finding that the charge had been drained when the car was needed. Even if the 'charging' option were expensive, that would not necessarily preclude the System Operator from gaining comparable benefits. Provided that at least some of the charging load could be reduced, that would ease pressure on the system at times of peak demand. The beauty of using electric cars as a proxy for storage lies in the fact that the cost of the storage would not be borne by the electricity system, but by the car owners.

Although much of the discussion surrounding electric cars has focused on their use in high-wind scenarios, it is likely that they might be to provide reserve services at modest cost. As noted in the previous paragraph, control of the magnitude of the charging load is a strong possibility, and at modest cost.

5.7 'Smart grids' and the growth of de-centralised generation

The term 'Smart Grids' is used to describe various technologies that may need developed in the future to enable electricity networks to function more efficiently. Most of these have been covered already, with the exception of 'islands' of decentralised generation. These islands would not necessarily be permanently disconnected from the main network, but may be able to function independently from most of the time. A paper[45] that was commissioned by the Government Office for Science has discussed the issues surrounding the concept. The paper suggests, "*Fully decentralised energy supply is not currently possible or even truly desirable*", but that, "*current evidence points towards the deployment of an increasingly decentralised energy supply infrastructure, which will still rely on and benefit from common centralised infrastructures.*" The rate at which decentralised generation will grow is somewhat uncertain[46], although both PB Power[47] and National Grid[48] appear to be in broad agreement that the additional plant capacity will be in the range 3-5 GW by 2020. The present capacity of embedded generation is around 7500 MW.

If self-sufficient decentralised 'islands' do become established, this may reduce, slightly, the demand fluctuations on the network as a whole. This would, however, have a second-order effect on the estimates of variability costs that have been discussed. The 'islands' would, of course, face the same issues in coping with variable generation if some of their supplies come from such sources.

5.8 Electric space and water heating

At present, electric space and water heating is significantly more expensive than gas or oil-fired heating. If, however, there were a move towards more electric heating, this potentially would provide the System Operator with a large source of inexpensive demand-side management. Such a shift in emphasis might be the result of high fossil fuel prices, government incentives, or both. Electric water heating, and, to a lesser extent, space heating can be modulated without significantly affecting the comfort of the consumer, although wider dead bands may be necessary for central heating systems. The signals that would enable the System Operator to influence demand levels could be transmitted through 'smart controls' or one of the other technologies discussed in section 5.3. The concept is actively being considered in Denmark[49]

5.9 The Hydrogen economy

The hydrogen economy has been under discussion for some time but, apart from a few demonstration plants, has yet to become established. Most studies assume that the prime user of the hydrogen would be road transport and so its influence on variability costs would be similar to that of electric cars. At present, however, costs are very uncertain.

5.10 Overall effects

Precise estimates for impacts of the mitigation measures cannot easily be made in every instance. The prospects for improved methods of wind forecasting are good and allowance for these has already been incorporated into National Grid's 'low' estimate for additional reserve costs. The most significant impacts would be at the higher levels of wind energy penetration and so Table 3 includes conservative estimates for 40% wind, based on the assumption that electric cars and/or other demand side measures are able to offset the constraint costs that occur once wind energy penetration levels exceed about 20%. It is quite possible, however, that the various measures that have been discussed will reduce the extra costs at the 20% level by 10% or more.

Case	20% wind	40% wind	40%, mitigated
Lower bound	1.6	5.1	3.8
Upper bound	2.4	7.4	6.1

Table 3. Estimates of variability costs, in £/MWh. With average domestic prices in 2007[50] being just over £100/MWh, these also represent percentage additions to consumer bills.

6. EXPERIENCE ELSEWHERE

The characteristics of wind tend to be broadly similar the world over and the same applies to electricity networks -- but there are some differences. Two comprehensive reviews of a large number of studies, worldwide, showed that the additional reserve costs were very similar, with outlying values attributable to particular characteristics in the country concerned[2,51]. The analysis showed that almost all the estimates of additional reserve costs for 20% wind energy were below £3/MWh. It should be noted that fuel prices rose after the work was carried out; this influences the costs of frequency response plant and other operational reserves and so the values quoted in the previous section are now more relevant.

Wind is poised to become a major contributor to renewable energy targets in most of Europe and elsewhere. The 'top five' contributions expected in Europe range from 40% in Ireland, 33% in Denmark, 28% in Portugal, to 25% in Germany and Greece[52]. This suggests that assimilation of wind is not regarded as a serious problem.

6.1 Germany

With around 25,000 MW of wind installed, Germany come second to United States in terms of installed capacity, although the contribution to electricity consumption in 2008 was only around 6%. Some problems have been reported[53], leading some observers to assume that difficulties there reflect universal problems, but this is not the case. This is due partly to the way that the electricity network is operated, partly to the lower wind speeds that prevail there. In Germany, as well as in some other electricity jurisdictions, wind tends to be treated in the same way as gas or coal-fired plant and is required to forecast its output several hours ahead. If the plant schedules lack flexibility, it is quite likely that the actual output from the wind plant will differ from the commitment made, say, 24 hours ahead. That may mean that balancing power must be purchased to make up any power deficits or, alternatively, surplus wind may need to be sold for a low price. The more flexibility that is built into plant scheduling, the more efficiently can the system the operated.

The other reason why balancing costs for wind in Germany tends to be higher than elsewhere is that wind speeds are quite low. The average capacity factor of German wind is about 18%, 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 almost twice the capacity needed in Britain. The magnitude of the power swings from the plant will therefore be higher than those in Britain, and the additional uncertainty means that the system operator needs to schedule more reserve. The lower capacity factor means that the additional balancing costs associated with 5% wind energy penetration are around three times higher in Germany, compared with Britain[54].

Low capacity credits are also reported for Germany, but these tend to be system-specific. The capacity credit of German wind is low -- in percentage terms -- largely because the capacity factor is low, as noted above.

Nevertheless the German Transmission System Operators have examined the implications of operating their networks with up to 54 GW of wind by 2020[55]. The corresponding energy penetration level is not quoted in the report, and is estimated as around 15%.

6.2 Denmark

Denmark has, for many years, promoted decentralised electricity, particularly wind power and CHP. In 2007, wind energy accounted for around 26% of the electricity consumption in western Denmark. It is sometimes argued that this is a misleading statistic, as western Denmark has transmission links with Germany, Sweden and Norway and the power exported over these links often mirrors the wind energy production. The capacity of these links is 2900 MW, slightly less than the installed capacity of the thermal plant. Roughly speaking, therefore, the plant capacity available to the System Operator is almost doubled due to the existence of the links and so it could be argued that the 'effective' wind energy penetration level is halved -- to about 13%. This is still higher than anywhere else in the world.

The System Operator has made a number of estimates of the 'costs of variability'; the study that ignored the existence of the transmission links suggested that the extra cost to the electricity consumer of absorbing 50% wind was about €6/MWh[25], which is very close to the estimates for the GB system.

Although wind power growth in Denmark has slowed recently, it is not halting though and plans to increase its wind energy penetration level to 50% by 2025[56]. It is envisaged that electric vehicles and heat pumps will absorb wind power surpluses[57] and that demand-side response will be a crucial feature of the electricity system in the future. It is assumed that electric vehicles constitute 15% of the traffic.

7. CONCLUSIONS

This paper draws on only a small fraction of the references that were cited in two major literature reviews (the Carbon Trust/DTI 'Renewables Network Impacts Study'[58] and the UKERC study[2]). More information has been published since these reports were completed, and reinforces the conclusions that were drawn. Wind energy, worldwide, continues to grow at around 25% per annum, despite the recession, which suggests that utilities and governments see it as a reliable source of carbon-free electricity generation.

There are no significant barriers to the introduction of wind energy due to its variability, and contributions up to 40% or more of electricity consumption can be managed with quantifiable -- and modest -- 'variability costs'. Any study of the impacts of variability needs to take into account the characteristics of the electricity network within which wind plant operates. Thermal plant breakdowns generally pose more of a threat to the stability of electricity networks than the relatively benign variations in the output of wind plant. Aggregation of wind outputs over the whole country ensures that the fluctuations are smoothed, in exactly the same way as the demands from consumers.

The key parameter that determines the requirements for additional short-term reserves ('extra balancing') is the additional uncertainty in the electricity supply and demand balance. Contrary to popular perception, wind variations are not totally random and unpredictable and the likely changes in output, on various timescales, can be quantified. When the uncertainty linked to wind fluctuations is combined with the underlying uncertainties associated with the thermal plant breakdowns and with consumer demands, then the requirements for extra balancing, and the additional costs, can be derived. The costs of additional reserve in Great Britain amount to around £4/MWh of wind for 20% wind, which adds about 6% to its generation cost. The total costs of variability to the electricity consumer amount to around £2/MWh at this penetration level which would add about 2% to domestic electricity bills are. The latter figure takes into account the 'extra backup costs'. Again, contrary to popular perception, the latter are quite modest as there is a very large and robust body of evidence that points to the fact that wind can displace thermal plant, although not on a megawatt for megawatt basis. This issue tends to attract more interest than it deserves, but it is noted that the amount of 'backup' plant for the system a whole will always be greater than the capacity contribution expected from wind energy. Despite low winds during the cold winter of 2008/9 -- and a shortage of nuclear plant - the system demand was still met. There does not appear to be any firm statistical evidence that contradicts the large body of analysis on the capacity contribution to be expected from wind energy.

Penetration levels above 20% are quite feasible; although there is a danger of wind that wind will compete with nuclear and coal plant (with carbon capture and storage) for 'must run' status if these thermal plant types are sanctioned for construction. (Both types of thermal plants are capital-intensive and so need to run as often as possible to recoup their fixed costs). The additional costs to the consumer of 40% wind are likely to apply in the range £5-7/MWh; and even at the high end of this range the additional cost to the domestic electricity consumer would be around 6%.

These additional 'variability costs' are likely to fall for a number of reasons, some associated with the wind itself (such as better forecasting), others associated with efforts to improve the efficiency and economy of the electricity network. Further implementation of demand side management is likely as there are several possibilities, some existing, and some emerging. Passive methods, such as 'dynamic demand' are attractive and possibly low-cost. (This technology envisages frequency-sensitive sensors within plugs or appliances that increase or reduce demand, depending on system frequency).

Additional international connections -- already under discussion -- will also aid the assimilation of wind as well as facilitating more efficient operation of the electricity network. The most advanced of these concepts -- 'European supergrids' -- envisages sufficient additional connections to enable most of Europe's electricity supplies to be provided by renewable sources. Finally, other technical developments, unrelated to wind energy, may result in a lowering of variability costs, the development of electric cars and a possible shift towards electric space and water heating.

APPENDIX 1. Capacity Credit

The most rigorous method of calculation for capacity credit involves examining the loss of load probability for electricity system over a period of at least a year. The integrated value over this period is the 'the loss of load expectation'. When wind is added to the electricity system, more power is available and so the loss of load expectation is reduced. Conventional plant may therefore be notionally removed from the system to restore the original loss of load expectation. The capacity of this conventional plant, divided by the rated capacity of the wind plant is the capacity credit.

It may be apparent from this description that capacity credits are not universal but most studies that have been carried out for the British system suggest that the capacity credit at low levels of wind energy penetration is roughly equal to the 'winter quarter' capacity factor. It declines, in percentage terms, as the amount of wind energy increases but continues to increase in megawatt terms. There is a 'saturation' level that is probably around 7500 MW.

Figure 9 shows that four independent studies have reached very similar conclusions as to how the capacity credit declines with increased wind energy penetration. The capacity credits have been normalised with respect to the capacity factor. With 10% wind, for example, the ratio is about 0.8. If the average capacity factor of the wind plant is 0.3, then the capacity credit is 0.24. So 12,000 MW of wind would displace 0.24*12,000, or 2880 MW, of thermal plant.

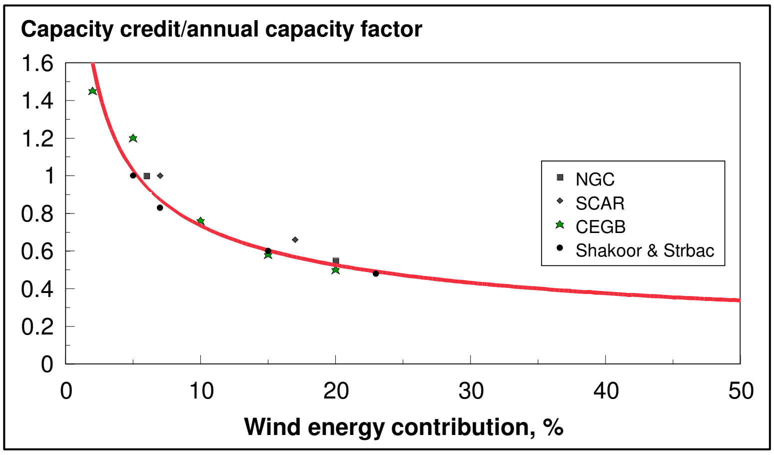

Figure 9. Capacity credits for the British system, derived from four independent studies, by NGC[59], the 'SCAR' report[12], the CEGB[60], and Shakoor and Strbac[61]. The capacity credits have been normalised with respect to the capacity factor to eliminate apparent distortions resulting from the differing assumptions about capacity factor. With 20% wind (for example) the ratio (from the graph) is about 0.55. If the capacity factor is 0.35, then the capacity credit is 0.192. 20% wind corresponds to about 26,000 MW and so the corresponding capacity credit is 5000 MW.

It is often suggested that large, high-pressure weather systems may prevent wind generation over the whole of Great Britain during times of peak demand. This, it is argued, means that substantial amounts of backup are required to replace the 'missing' wind generation.

There are several weaknesses in this hypothesis: --

1. System Operators do not rely on the full rated output of *any* plant being available at peak times. The expected contribution is quantified by the 'firm power'. With nuclear plant, for example, the average availability at times of peak demand is around 85% of its rated output. On some occasions it will be less, on other occasions, more. For wind, 10,000 MW of wind in the UK has a capacity credit of about 3,300 MW, so the 'firm power' equivalent is about 2,800 MW. On average, roughly that amount of wind will be available at times of peak

demand. On some occasions it will be less, on others will be more. This is no different from the approach to the capacity credit of nuclear plant.

2. There does not appear to be any evidence that the whole country is *regularly* becalmed at times of peak demand. On the contrary, work carried out at the University of East Anglia[62] suggested: "…peak demand times occur when cold weather is compounded by a wind chill factor, and low temperature alone appears insufficient to produce the highest demand of the year". Other work at Oxford University yielded similar conclusions[63]: - "There is an increased probability of high wind power output.... during periods of high electricity demand; this translates into a capacity factor during peak electricity demand hours that is around one-third higher than the annual average."

Numerous studies have shown that, statistically, wind *can* be expected to contribute to peak demands. The evidence is very robust and there are several approaches: -

1. The statistical approach[64]. This assumes winds are random in nature, with respect to electricity demand. Analysis has confirmed that this is the case.
2. Analyses of wind turbine output. Work at the University of East Anglia, cited above, is very relevant. Using just four sites, they showed that the summed average wind turbine outputs during 8 winter peak demands was about 32% of rated output. National Wind Power, similarly have found that "wind farm capacity factors during periods of peak demand are typically 50% higher than average all-year capacity factors"[65].
3. Power system simulations. These include those of the CEGB[60] and more recent work by National Grid Transco.

The UK studies have all yielded similar results, pointing to wind having a capacity credit roughly equal to the 'winter quarter' capacity factor, (around 30-40%) at low penetrations. Thereafter, it decreases, reaching around 20% with 20% wind on the network, as shown in figure 9. Increased use of offshore wind, with higher wind speeds and greater geographical diversity, is likely to increase the firm power contribution.

APPENDIX 2. Conflicts between Wind and Large Conventional Thermal Baseload Plant

Nuclear, wind and coal fired plant (especially coal with carbon capture and storage) are all 'capital intensive'; in other words the need to repay their capital costs (with interest) has a strong influence on their generation prices. Around 50-75% of the generation price is due to capital costs. Operators of these plants therefore aim to run whenever possible so as to spread these costs over as many units of electricity as possible, thus minimising prices. If output needs to be constrained, the price of electricity needs to increase, whereas if conventional gas or coal plant is constrained, fuel costs are avoided and the impact on electricity prices is less.

Noting that the minimum demand on the British electricity system is about 22 GW[66] it is possible to make sixth you are first order estimates of the way that constraints may be incurred. If there were no other capital-intensive plant on the network, then wind energy would need to be constrained once its output exceeded this level. Experience from Western Denmark shows that it is extremely rare for the wind output to exceed about 80% of its rated capacity. So, in theory, wind energy may need to be constrained once its capacity exceeds about 22/0.8, or 27.5 GW. This corresponds to an energy penetration level of about 20%.

As the penetration level of capital-intensive thermal plant rises, it is likely that some would need to be constrained off at times of low demand, and there would be no 'room' for any wind. With a load factor for thermal plant of 85%, the corresponding critical level of capacity would then be about 26 GW. This corresponds to an energy penetration level around 48%.

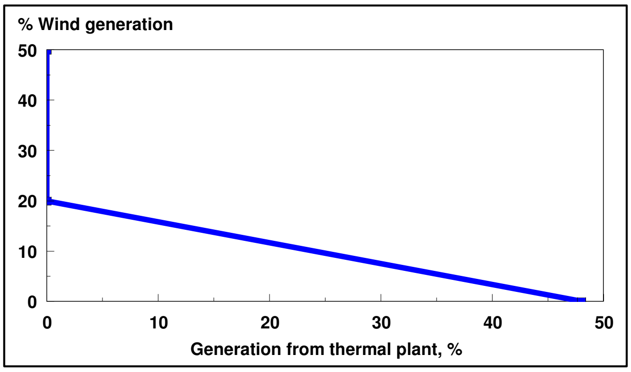

Figure 10. Indicative estimates of possible conflicts between wind and capital-intensive thermal plant. Above the line constraints are likely to occur and below the line they are not.

Figure 10 illustrates how capital-intensive thermal plant and wind may come into conflict. With no capital-intensive thermal plant, then, as outlined above wind can build up to about the 20% level without any constraints. With a 20% contribution from capital-intensive thermal plant, however, then with a wind contribution greater than about 10%, some constraints (one or the other) are likely to occur. Any capital-intensive thermal plant contribution over about 40% is likely to lead to constraints of either or both technologies.

This first-order assessment of the constraint boundaries does not identify the volume of constraints and this issue is discussed in more detail in section 4.3.

APPENDIX 3: Electric Cars

This appendix sets out the arithmetic that led to the estimate for the electricity requirement for electric cars.

	Unit	Amount	
Current fuel consumption, cars and taxis[67].	Mtoe	17	A
Energy content of fuel[50]	TWh/Mtoe	12.7	B
Total energy use	TWh	216	c = a*b
Overall efficiency of cars	%	15	D
Net energy requirement	TWh	32	e = c*d
Electric vehicle efficiency (Power station to road)	%	70	F
Electricity requirement, all cars and taxis	TWh	46	g = e/f
Corresponding average power need (continuous)	MW	5250	h = g/8760
Power need if all charged in 8 hours	MW	16750	i = h*3
Power need per car (28 million)	kW	0.6	j = i/28E6

The power need per car has been derived to check that the demand can be met on domestic circuits, without modification. 0.6 kW is well within the capabilities of domestic circuits. In practice, electric cars would properly be charged at around 2.5 kW, but not all would require charging every night.

APPENDIX 4. Glossary

Backup: spare generating plant, carried by all electricity networks, to ensure that peak demands always met, despite plant breakdowns.

Balancing costs: costs paid by the System Operator to owners of plant providing Operational Reserve (qv). In line with common practice, the extra costs for wind are generally expressed per MWh of wind generated.

Black start: power plant that has the ability to restart without needing a grid connection. This type of plant is necessary to ensure that electricity generation can resume after an incident that causes disconnection of large quantities of electricity demand.

Constraints: restrictions that may be imposed on power stations or wind farms, curtailing their output, due to a lack of transmission capacity or a potential surplus of generation over demand.

Demand-side management: provision of operational reserve to the System Operator by modulation of demands. It is also used to modulate system demand and customers generally receive favourable tariffs in return for agreements to reduce demands.

Frequency response (plant): see section 2.2.1

Operational reserve: a quantity of generating plant that is kept in readiness to deal with short-term mismatches between supply and demand. A description of the various categories is in section 2.2 .1

Plant margin: the magnitude (in MW) of backup plant (qv), over and above the expected peak demand of the electricity network. In UK expressed as a percentage of the peak demand.

S**hort term operational reserve:** This is the term preferred by National Grid for ‘ operational reserve’.

System operator: the entity that is responsible for operating a power system

Trip(s): a sudden loss of generation by thermal power stations, due to mechanical, electrical or electronic faults.

Thermal power stations: power stations that use gas, nuclear, oil or coal as fuel.

Variability costs: see discussion at the beginning of section 4.

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