PENALTIES FOR INTERMITTENT SOURCES OF ENERGY

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SYNOPSIS

The integration of modest amounts of wind into an integrated electricity system does not incur any significant costs to a system operator - any extra perturbations in the supply/demand balance are small and difficult to detect. As the wind content rises, more significant - but still small - penalties may be incurred, as the system operator takes actions to secure system reliability. Nevertheless, the advent of the New Electricity Trading Arrangements has resulted in some wind generators incurring significant penalties (around £2.5-4/MWh with a £20/MWh spread between SBP and SSP, 3.5 hours before gate closure). These are higher than the actual penalties, given that there is less than 500 MW of wind in the country as a whole.

The "NETA penalties" arise due to the disaggregation which is a feature of the arrangements. This means that, viewed in isolation, a wind farm will sometimes increase its generation after gate closure, sometimes it will decline. The difference between System Buy and System Sell Prices means that penalties will be incurred which are a function of this difference and of gate closure time. Whether or not a wind generator incurs the full penalty depends on the nature of their contracts with suppliers. It is suggested that large-scale aggregation by wind generators might be a solution to the problem; it is shown this may ameliorate it but that significant penalties would still be incurred.

The technical penalties have been calculated on the basis of established procedures and with relevant costs and shown to rise to around £1.35/MWh with 10% of wind energy on the system. (This is consistent with the penalties being incurred in western Denmark). 50% wind energy will incur a penalty around £3/MWh, although this is less robust. Neither of these figures takes into account the significant improvements likely to be derived from better wind forecasting and/or demand-side management.

To resolve these problems the DTI appears to be suggesting aggregation be explored "at a cost of £3/MWh". As this is double the technical penalty at 10% wind penetration, and perhaps 30 times the penalty appropriate to the current level of wind generation (500 MW), it does not appear to be consistent with a level playing field for wind.

1. Introduction

Numerous studies have examined the feasibility of operating power systems with substantial amounts of intermittent sources - such as wind - in the UK, Europe and the United States. Most studies have concluded that there are no insuperable technical problems in assimilating wind energy. As the wind capacity rises, however, measures must be taken to ensure the wind variations do not reduce the reliability with which demand is met and that frequency and voltage tolerances are not exceeded.

When wind is introduced on a utility network: -

Additional flexibility of various sorts must be acquired in order to compensate for possible fluctuations in the level of wind generation. Costs may be incurred as follows:

1. To keep additional generation capacity in readiness (to meet demand if wind is unavailable);

2. To obtain additional flexibility from generators or demands to maintain energy balance in each metered period (half-hourly in the UK);
3. To obtain additional flexibility from generators or demands to maintain power balance continuously within half-hourly trading periods. This will be a mixture of response (automatic frequency sensitive action) and reserve (manually instructed action) of various speeds of delivery and endurance.

At low penetration levels the flexibility costs are not significant. However, as the amount of intermittent production increases, these costs will increase. The studies mostly suggest that the costs of these services add up to about £0.5/MWh at 2% wind, rising to around £1/MWh at 10% penetration. This is termed the "real penalty", or the "technical penalty" in this note, and all costs are debited to the wind generation.

It is also commonly acknowledged that when the wind capacity reaches around 15% to 20% of system peak demand, the costs are more significant and actions are likely to be needed to ensure sufficient flexibility is available. In addition, there may be times when not all the available wind energy can be assimilated on to the system, as the most economic option is to reduce the output of some wind plant.

1.1 UK Costs under NETA

The New Electricity Trading Arrangements (NETA) can introduce artificial penalties if imbalance prices are not cost-reflective and if diversifiable risks are not eliminated by appropriate aggregatation/consolidation. Electricity suppliers are now responsible for buying the energy required by their customers. Unlike the Pool system, they cannot automatically share out risks arising from their individual contracting decisions. Suppliers therefore tend to look at wind projects and other intermittent sources not offering firm volumes with some concern and discount the prices they are willing to pay, sharing the consequences of the risk with the producer.

Individual wind producers, on the other hand, cannot automatically obtain the benefits arising from the country-wide physical aggregation by the transmission network which was inherent under the Pool. Under NETA, such benefits must be realised by explicit consolidation of individual producers in a portfolio. These actions are not without cost, which will fall directly to wind producers if they use consolidators, or indirectly to them in the form of lower energy prices if they use their supplier as a consolidator.

In the UK market, the costs described above will be reflected in wholesale market prices (including their volatility) as individual suppliers and generators seek to maintain balance between their contracts and physical positions. The system operator performs residual energy balancing and also despatches other balancing services. The costs incurred by the system operator are passed to transmission users (demands and large generators) via the Balancing Services and Use of System Charge (BSUoS). The NETA imbalance charges reallocate some of the balancing costs incurred by the system operator (and passed in BSUoS) to those parties who are out of balance. In this way NETA seeks to pass all costs associated with each market participant’s energy volumes to that participant.

The requirements for additional flexibility costs arising from wind purchases are unlikely to be separately identified because they will form part of either the distribution of wholesale prices or the basket of costs incurred by the system operator.

If the costs of flexibility measures are debited to the wind plant (in accordance with the NETA philosophy), wind will trade at a discount to the market wholesale prices. This discount is partly a question of perception, partly due to the fact that wind projects, viewed in isolation, incur penalties associated with the spread between system sell and system buy prices. Typical penalties are around £8-9/MWh - several times the technical penalty[1].

There is widespread concern across the renewable energy industry that the NETA penalties, or discounts, are potentially discriminatory and the government has responded with a consultation document, suggesting possible solutions[2]. The Government response observes: - "We believe it is necessary that NETA operates to target costs accurately, fairly and proportionately. A truly cost-reflective system should benefit all participants, and smaller generators in particular".

2. Objectives of Study

This note examines the "real" flexibility costs which wind incurs and compares these with the penalties that wind energy is likely to incur under NETA - the "NETA penalties". The root cause of the problem - especially for wind - is that NETA, in some respects, tends to disregard the advantages of aggregation in the network as a whole. Each supplier is encouraged to balance his position and system-wide aggregation occurs separately, in the balancing market. One side effect of this is that suppliers are tending to maintain their own holdings of spinning reserve, which is less efficient than if the system operator performs that function[3]. "Aggregation means that the system operator need not offset wind on a megawatt-for-megawatt basis"[4], but, under NETA, the advantages of aggregation may be obscured or lost. NETA aims to work in a cost-reflective manner and the key question is whether it is unduly penalising intermittent generation.

The objectives of this study, in more detail, are: -

- Critically review well-founded studies of wind integration, particularly those of the CEGB, ESB (Ireland) and elsewhere, where it is possible to extract information on the operational penalties due to increasing amounts of wind energy. Compare and contrast the results.
- Discuss and quantify, wherever possible, revisions to the penalty estimates in the light of the latest information on plant costs, fuel costs and our knowledge of wind variability.
- Critically review the (fewer) studies of wind integration which take the amount of wind energy above the 20% mark, with a view to formulating further estimates of system penalties at these high penetration levels.
- Discuss the techniques which can be used to absorb wind energy at a high penetration levels and revise, if necessary, the penalty estimates in the light of present-day information on the costs of peaking plant and storage.
- Working from first principles, produce estimates of the likely NETA penalties - for single wind farms and for "England-wide consolidation" - under the New Electricity Trading Arrangements, as a function of the difference between System Sell and System Buy Prices and gate closure time.

3. Studies of utility networks

3.1 Early studies

The analysis of Farmer et al[5] laid the foundations for an analytical approach to the question of wind integration. He was one of the first to quote 20% of (maximum) demand as a rough benchmark for wind integration, above which significant operational changes may be needed. He actually concluded "...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". (Throughout this paper, wind capacities are "rated" values; the "Declared Net Capacity" concept, used under the NFFO, is not used). Another benchmark - the level at which wind is rejected - is similar. Both depend on the particular mix of plant in the utility concerned, but 20% is not a ceiling on wind energy penetration.

Farmer's analysis of the CEGB network was essentially technical in nature and its methodology is essentially valid today, due to the generic nature of his approach. There are some economic ratios in his analysis but these are only used to optimise the cost of holding and utilising spare capacity. Some of his assumptions re wind are inaccurate, but the general methodology can be used with suitably updated parameters.

3.2 Later work

Subsequently, two very detailed assessments of the impact of wind energy on the CEGB system were made (both with CEC support); by Gardner & Thorpe[6] and Holt, Milborrow & Thorpe[7]. Each of the later studies yielded similar results to those of Farmer's original analysis and the last one was completed in the run-up to privatisation.

The latter study used wind data from 12 coastal and upland sites - mostly close to locations where wind farms have subsequently been built - in Cornwall, mid-Wales, the Pennines, East Anglia and elsewhere - to obtain a time series of "wind farm" power outputs - for onshore and offshore locations - at hourly intervals over a year. Using similar time series for the system demand, and plant characteristics for the nuclear, coal and other units, the "system" was operated with increasing amounts of wind, up to 16 GW. The simulation showed that 5% of wind energy could easily be assimilated; at the 10% level[1], economic operation led to a tiny amount of wind being rejected (0.07%), and the need for extra part-loading of the thermal plant incurred extra operational costs which, if debited to the wind plant, equated to about £1.2p/MWh.

The CEGB study was one of ten such analyses of European electricity networks all part-funded by the European Commission. Most yielded very similar results, but only the ESB study presents the findings in a way that enables the operational penalties to be inferred with confidence.

The National Grid Company has recently suggested "thresholds" which are similar to those discussed above, and these are set out in Table 1, below[8]: -

Table 1 Factors influencing absorption of renewable energy

Impact	Threshold	Mitigation options
Change in renewable generation output	Generation subject to fluctuation>20% of peak demand	Purchase additional controllable output
Unpredictable instantaneous reduction in generation output	Potential instantaneous loss >2% of peak demand	Purchase additional frequency control measures
Unpredictable short-notice reduction in output	Potential loss >3% of peak demand in an hour	Purchase additional reserve services

As far as wind is concerned, the third threshold appears to be more stringent. Using actual power data from Western Denmark, described later in this paper, the author has suggested

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[1] As the load factor of wind plant is roughly half that of a thermal power station, 10% of wind, on an energy basis, corresponds to about 20% of wind on a capacity basis. Wind plant capacity is often quoted, for system studies, relative to maximum demand on a power system.

that the threshold may be reached with around 8800 MW of wind[9]. It must be emphasised these thresholds are not ceilings - merely markers. More wind can be accommodated - but at increased cost.

3.3 Results

None of the CEC-funded studies examined the implications of operating with small amounts of wind energy, but the analysis of Farmer can be used to do so. It can also be used to examine whether his general principles can be used to reproduce the results obtained in the much more sophisticated CEGB study mentioned above. Appendix 1 discusses the methodology and figure 1 demonstrates that his approach can reproduce the results from the CEGB study with reasonable accuracy. It must be emphasised, however, that the use of meteorological data to simulate wind power variations exaggerates these (as explained later) and so the penalties must be regarded as indicative only.

Results from the analytical technique tie in well with the more rigorous estimates from the CEGB study; the Irish penalty is lower at the 5% penetration level and higher at the 15% level. At the higher level, this is not surprising, as the results are very dependent on the assumptions which are made concerning additional needs for peaking plant.

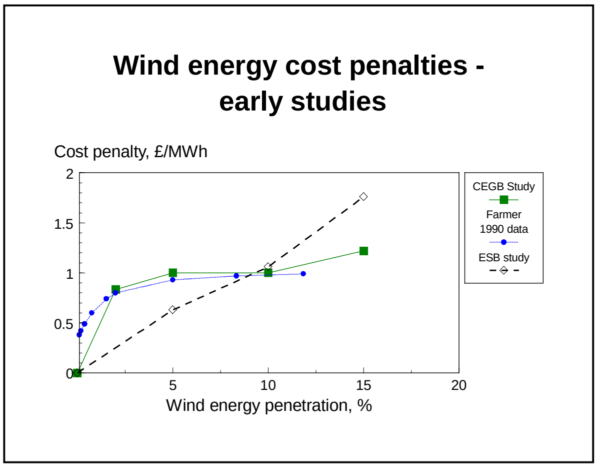
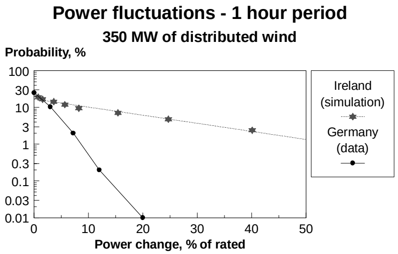


Figure 1 System penalties for wind energy - early studies

3.4 Accuracy of the simulation techniques

Now that information is available on the actual wind power fluctuations in Germany and Denmark, it is possible to test the accuracy of the various simulations which have been carried out.

By coincidence, one of the simulation exercises in the ESB study involved 350 MW of distributed wind -- almost exactly the same amount as currently monitored in Germany. As wind characteristics are similar across most of Europe, the power fluctuations modelled in Ireland can be compared with those observed in Germany, and this is the basis of Figure 2. It is clear that the simulation techniques exaggerate the fluctuations. Further evidence of this is provided in table 2, which compares the extreme fluctuations from several studies with the German data[10]. Here, again, the early modelled excursions are much higher than the measured ones, although it should be noted that the NGC modelling results agree well with observed fluctuations.



Sources: Irish data from ESB study for CEC, DGXII
German data (adapted) from ISET, Kassel

Figure 2 A comparison of power fluctuations – real and simulated

Table 2 Maximum power excursions

Source	Description	Maximum excursion, % rated wind power, **1hr**	Maximum excursion, % rated wind power, **4 hr**
Germany	**Single turbines**	**+ 60, -90**	**100**
	350 MW, distributed	**+15, -22**	**+46, -52**
Simulations			
NGC[11]	5600 MW	+ 18, -14	+ 29, -21 (3 hours)
ESB	4 sites	- 41	
Ireland	5 sites	+ 60, - 50	+ 80, - 80
Netherlands	11 sites	+/- 36	

It is clear that the use of wind data to produce simulated wind power fluctuations may lead to the magnitude of these fluctuations being exaggerated.

3.5 Analysis of actual power data

Further insights into the behaviour of distributed wind power may be derived from analysis of data recorded by the Danish (west) grid operator, Eltra. For the purposes of this study, the output of 1860 MW of wind in western Denmark between January and March 2001 was used. This was analysed to determine the power changes over timescales of 1,2 and four hours, as shown in figure 3. Not surprisingly, the longer the time period, the greater the spread. The analysis used 2% intervals of rated wind power and shows that with a "gate closure" period of 4 hours, wind is likely to be within plus or minus 1% of the "zero hours" level with a probability of 21%. If gate closure were reduced to 1 hour, the probability of the same power output being generated is 47%.

Reduced gate closure periods are discussed in the Government response to Renewable Generators. It is an option under consideration which may be implemented during the coming year - although not necessarily for the purpose of assisting renewable generation.

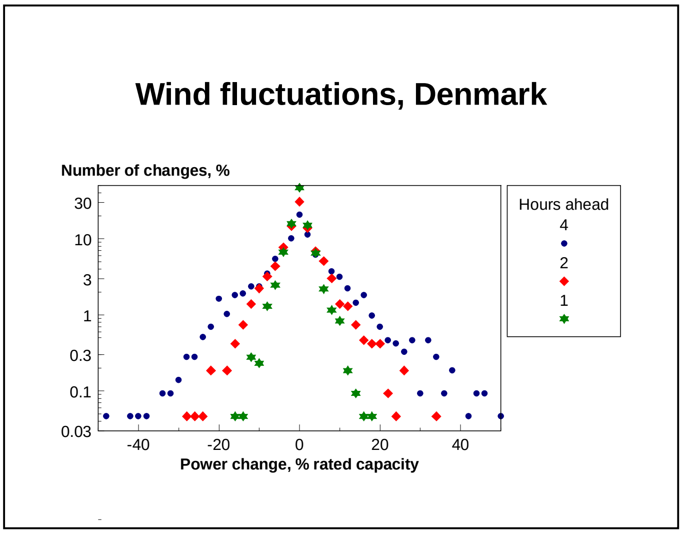


Figure 3 **Measured power fluctuations in Western Denmark**

This analysis provided further data to test the validity of the modelling exercises, in particular the standard deviation of the power swings, shown in Table 3, below.

Table 3 Standard deviation of wind power fluctuations (%)

Lead time, hr	1	2	4
Nation-wide			
Farmer	9.4	13	17
NGC[12]	3.1		6.0 (at 3.5 hr)
Danish data	3	5.6	10
Single wind farm (author)	11.8	16.0	20.8

[NB UK gate closure is at 3.5 hrs]

This comparison again suggests that the NGC modelling gives an accurate representation of the wind fluctuations on the one-hour timescale. On the four-hour timescale, the standard deviation is significantly less than that of the Danish data. Although this is to be expected, as England is bigger than Denmark, the difference is perhaps more than might be expected.

To complete the picture, data for a single wind farm are included in Table 3, based on power measurements from Bessy Bell wind farm in Northern Island, by kind permission of Prof B Fox, of Queen's University Belfast, and N.I.E.. These were analysed in the same way as the Danish data to show the power swings and the data are shown in Figure 4.

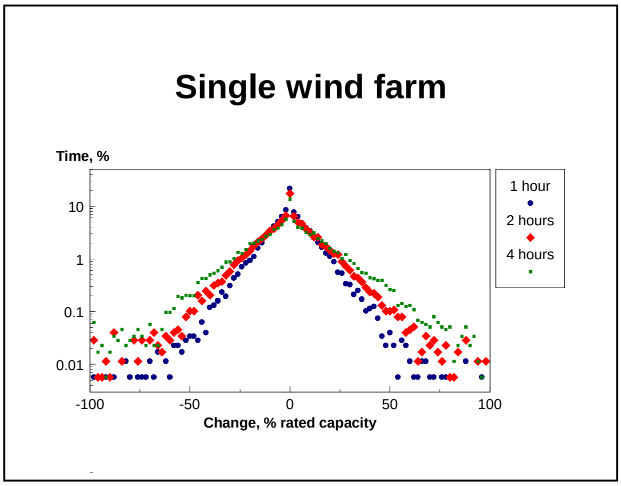


Figure 4 Wind fluctuations from a single farm

4 Present-day estimate of "real" technical penalties

Given that measured power fluctuations turn out to be significantly lower than those predicted by the early simulation studies, revised estimates of technical penalties applicable to present-day operation can be derived. Two sets are presented in the figure below. The first set, labeled "energy" uses the principles set out by Farmer, but with current prices for fast response and reserve plant[13]. In a further modification, the theoretical level of extra reserve required by wind has been multiplied by 3, following guidance from NGC. It may be noted that the extra reserve required at the 10% penetration level is around 735 MW. There seems little doubt that this would be readily available, for several reasons: -

- There is a desirable plant margin of around 20% (~10,000 MW), - to maintain system reliability.
- The actual UK plant margin is considerably more than this.
- Extra reserves, post-Neta, are used being used by suppliers to limit their exposure to the balancing market[14].
- NGC has observed "sufficient fast response and reserve services will be available for a situation in which the entire 2010 renewables target is met by wind[15]".
- None of the utility studies cited in the next section identified the need for extra reserve at low penetration levels - see Table 4

In the unlikely event of an extra 735 MW of reserve not being available to meet the requirements of 10% of wind energy, an alternative approach can be used, which assumes all the extra reserve needs new build. The methodology of an American study[16] has been followed closely for this case and the assumption concerning capacity cost is a pessimistic figure for Regenesys of £750/kW. As it would not be needed before about 2015, a lower figure might be more appropriate - another study has suggested £450/kW might be appropriate[17]. The annual costs of the capacity have been calculated using an 8% project test discount rate and a 15-year life. This curve is labeled "Capacity".

These analyses suggests that the present-day technical level of wind penalty (for around 500 MW of wind) is between £0.09 and £0.18/MWh. With 10% wind energy, the penalty is between £1.35/MWh and £2.25/MWh, as shown in Figure 5. This figure also includes the penalty recently quoted by the Danish grid operator, Eltra, who absorbed 16.3% of wind energy on their system in 2000 at a cost of £1.58/MWh[18]. This figure, which has not been challenged by the Danish wind industry, is consistent with the lower set of calculated values.

A further comparison can be made - with a result from the American study, cited above. This derived an estimate of £0.041/MWh at a wind penetration of around 2%, which compares with a value around £0.4/MWh, from the "Energy" method. This suggests that the latter may exaggerate the real penalties.

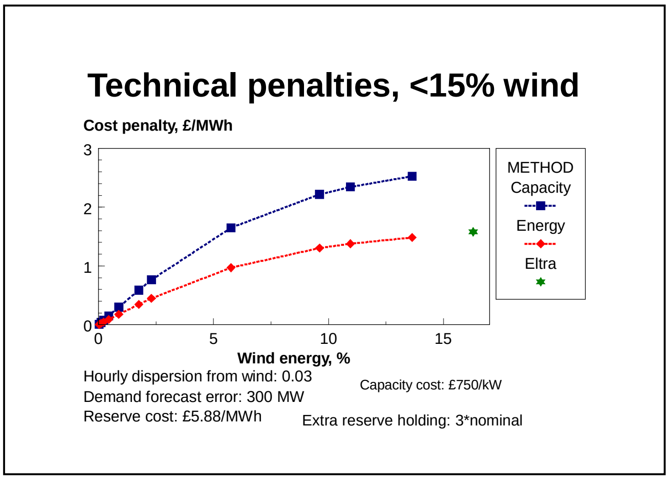


Figure 5 Estimated technical penalties:

The "Energy" method is essentially that of Farmer, with the modifications outlined above; the "Capacity" method assumes new build Regenesys plant is needed, at £750/kW.

4.1 Capacity credits

Few topics generate more controversy than capacity credits for wind plant. The capacity credit of any power plant may be defined as a measure of the ability of the plant to contribute to the peak demands of a power system. Capacity credit is often defined as the ratio (firm power capability)/(rated output). As thermal plant is not 100% reliable, values for all plant are less than unity. To a first order, 1000 MW of nuclear plant corresponds to about 850 MW of firm power and hence has a capacity credit of 0.85; coal plant has a capacity credit of about 0.75. These figures are, roughly, the statistical probability of the plant being available at times of peak demand.

Almost every authoritative utility study of wind energy has concluded that wind can provide firm capacity - roughly equal, in northern Europe, to the capacity factor in the winter quarter[19]. This implies that if, say, 1000 MW of wind plant was operating on the UK network, it might be expected to displace around 350 MW of thermal plant. It is difficult to say whether this would happen in a privatised and fragmented electricity industry but, ideally, the market signals should encourage it to happen, as this would lead to a technically optimised system.

In a worst-case scenario, where no thermal generation at all was displaced, system reliability would increase but the average load factor of all the thermal plant would decrease slightly. This implies that the capital element of the generation costs from this plant would increase. An estimate of the corresponding penalty may be derived by noting that the total capital value of the generation sector of the UK electricity industry is £10 billion[20]. If depreciation and interest charges are such that the annual charge rate is 10%, then the average capital contribution to the generators' electricity costs is £3/MWh. (Taking total generation as 360

TWh, and rounding up slightly). A 10% contribution from wind energy would then, to first-order, increase generators' costs by £0.3/MWh.

Although it could be argued that this penalty (which, of course, decreases with decreasing wind penetration) should be added to the penalties shown in the lower curve of figure 5, there are two factors which will mitigate the penalties, namely better wind predictability and the possibilities for demand-side management.

4.2 Better Wind predictability

Methods of improving wind predictability, specifically geared towards wind-generated electricity, have been developed in both Europe and America and further studies are in progress. The Danish grid operator, for example, uses wind prediction methods and a small levy has recently been agreed with Californian wind developers to fund further studies. As an indication of the improvements that can be secured, a British study has estimated that the needs for extra spinning reserve can be reduced by over 30% (with 10% of wind) using these methods[21]. If the conclusions from this study are reflected across to the system penalties calculated in figure 5, it is estimated that these could be reduced by about £0.45/MWh at the 10% wind energy penetration level.

Another study has estimated that revenues under NETA could be increased by up to 7.5% by appropriate forecasting methods[22].

4.3 Demand-side Management

The potential for load management in association with wind energy has been investigated and found to be a viable way of increasing the amount of wind generation which can be accepted onto a weak network[23]. It follows that load management could attenuate the power fluctuations "seen" by a supplier or grid operator and these techniques can also be used to reduce the magnitude of the real technical penalties.

5. Penalties at high penetrations

5.1 10-50%, approximately

As the level of wind energy on an electricity system increases, there will come a point at which the existing reserves on the system are not sufficient to provide the extra cover for wind that is needed. Additional peaking capacity (possibly secured by retaining plant on the system), storage or demand-side management will therefore be needed. The level of wind generation at which this additional capacity is required will depend on the reserves already held.

The economically optimum level of reserves depends on the characteristics of the generating plant and on the criteria which are laid down for system reliability. By way of example, the "plant margin" (the difference between total capacity and maximum demand) during the final days of the CEGB should have been 23.7%[24]. The precise figure comes from an elegant statistical analysis but a key assumption - the forced outage rate of the thermal plant - is difficult to quantify with great precision. Since CEGB days the reliability of plant has improved and a better estimate under today's conditions - assuming a forced outage rate of 8%, instead of 15% - would be around 20%. It should be noted that the UK plant margin has risen steadily during the past few years and now stands at 35%[25], almost double that which is required.

It follows that the present-day electricity network in the UK could almost certainly absorb well over 10% of its electricity from wind energy, without the need for extra plant. Whether this level of surplus capacity will continue, post-NETA, is difficult to forecast. However, given that many suppliers are now acting as "mini National Grids" and scheduling their own reserves, it is quite possible that high plant margins will be a feature of the electricity network for some time in the future.

Table 4, below, summarises information from authoritative integration studies on the level at or above which extra plant would need to be procured to provide sufficient reserves. It should be noted that few of these quantified the exact level, as most carried out simulations for various stepwise increments of wind energy.

Table 4 Estimates of the wind energy level beyond which extra reserves needed

Study	Threshold	Comments
CEC-funded studies: CEGB	> 15%	No mention of extra storage/peaking plant
(Greece) PPC[26]	> 15%	Ditto
ESB	> 10%	Costs included in Figure 1 data
(Netherlands) SEP[27]	> 10%	Note that NL has little storage
DK[28]	> 5%	DK also has little storage
P[29]	> 9%	No mention of need up to this level
Study for IEA Greenhouse Gas Programme[30]	> 10%	Extra peaking plant needed above this level

The pessimistic assumption has been made that extra capacity would need to be secured - above that existing - once wind energy production exceeded 10%. This enables penalty estimates to be derived, as shown in Figure 6. The assumptions are: -

- Enough reserve is available up to the 10% level, the penalties can be calculated using the "Energy" method (lower curve of Figure 5), as comparisons with recent Danish and American estimates show this to be robust
- Beyond 10%, some existing plant can be retained at a cost of £133/kW, calculated from the capitalised value of all UK generation, as described in Section 4.1, but
- These possibilities are gradually exhausted and so new peaking plant (costing around £400/kW) must then be built, and so the price gradually increases, and
- Towards the high end of the curve, new Regenesys plant needs to be built, raising the average plant cost to £610/kW.

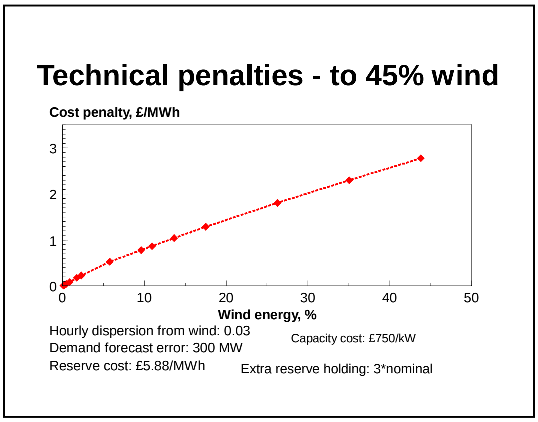


Figure 6 Technical penalties for wind energy penetration levels up to 45%

These assumptions are quite severe, i.e. not favourable to wind, and suggest a penalty of just under £3/MWh at 45% wind penetration

5.2 Very high wind scenarios

Although the prospect of 100% wind energy penetration for the UK is probably somewhat remote, there is interest in such a concept for small islands and the author recently completed a calculation to estimate the applicable costs for such a system[31].

The basis of the analysis was the time series of power generation in western Denmark for the first quarter of 2001. This system has characteristics similar to the UK, with the ratio of peak to average demand being about 1.5. It was found that a continuous supply could be achieved provided the wind plant had a rating five times the average demand and the store was rated at three times average demand. The store would need a capacity of 60 hours. Although this is higher than the current specification for Regenesys, extra storage can be acquired at low cost, as it simply means increasing the size of the electrolyte storage tanks.

The calculations are set out in Appendix 2. This shows that the concept is not totally unrealistic, as the extra cost of generation - the technical penalty, in this case - is around £10/MWh. 100% wind could be realised for a generation cost of just over £45/MWh. The present-day average cost of all generation is about £35/MWh. This puts the premium for 100% wind generation at just over £10/MWh.

6 NETA penalties

This analysis considers first the case of a single wind farm and secondly the corresponding penalties, under NETA, assuming country-wide consolidation were possible. As no consolidation at the supplier level is taken into account, the figures calculated here may be "upper bound" levels. However, penalties at the levels calculated here are being levied on some wind generators, and the DTI itself implies a penalty of £3/MWh may be inevitably incurred, although, with present levels of wind generation, it greatly exceeds the technical penalty; a "real" penalty of £3/MWh may not be incurred until the wind energy content reaches about 45%, as noted earlier.

Wind forecasting tends to be challenging on short timescales and so this analysis simply assumes "persistence", in other words the wind power 1,2 or four hours ahead will be identical to the "zero hours" level. The same assumption was implicit in the calculation of the technical penalties.

The power changes shown in Figures 3 and 4 enable the magnitude of the wind power shortfalls or surpluses to be determined over a period of time, say a year. For the purposes of this analysis, it was assumed that all shortfalls in power were made good at the same average “top up price” price (System Buy Price under NETA) and that surpluses were also sold at an average “spill price” (System Sell Price under NETA). A summation of all the cash inputs and outputs from surpluses and efficiencies enabled the total "penalty" to be determined. The analysis assumes effectively constant values of average SSP and SBP. While these averages may be affected by wind imbalances in practice, this effect has not been explicitly represented in the particular values used. For simplicity, the analysis also assumes that all the expected output from wind is traded at gate closure and so no attempt is made to reduce imbalance payments by reducing exposure to the higher SBP at the expense of more spill at SSP.

Once the total monetary penalty has been determined, the effective penalty, per unit of wind energy, can simply be determined by dividing this penalty by the energy generated during the period. The results of this analysis, for a range of differences (SBP minus SSP) from

£15/MWh to £50/MWh, are shown in figures 7 and 8. Assuming SSP and SBP are not affected by adopting a shorter gate closure, the smaller imbalance volumes over a shorter "gate closure" period give lower penalties.

6.1 Single wind farms

Operators of single wind farms are incurring the highest penalties under NETA, as the fluctuations are significantly greater than those of operators with several wind farms. The analysis assumes the supplier does not aggregate the output with other generation or demand, but this is representative of the situation facing some wind farm operators.

The graph shows a single wind farm, with a 4-hour gate closure, would occur penalties ranging from £3.4/MWh (for a system buy/sell spread of £16/MWh) to £9.75/MWh (for a buy/sell spread of £46/MWh).

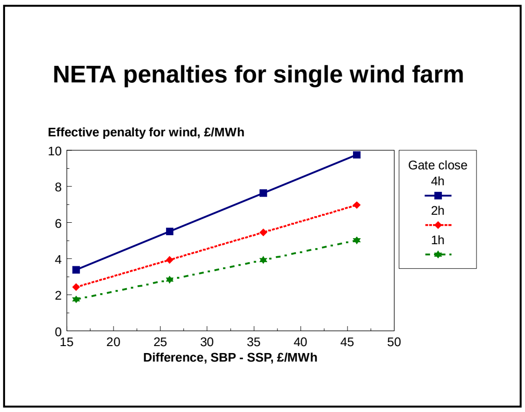


Figure 7 **NETA penalties for a range of gate closure and imbalance differences**

6.2 Country-wide consolidation

It appears that country-wide consolidation may be difficult to organize, as the Government response (ref 2) notes that "consolidation services are still at an embryonic stage", and potential consolidators suggest that institutional overheads and data handling may be costly. Even if it could be achieved, as the following analysis shows, it simply reduces the scale of the penalties but does not reduce them to the level of the technical penalties. The concept does not, therefore, achieve a situation where the cost penalties for wind are cost-reflective.

For this analysis, the wind power data for Western Denmark, mentioned earlier, were used and a similar procedure followed. The results are shown in Figure 8. With a 4-hour gate closure, the penalty rises from just over £2/MWh (with SBP minus SSP of £16/MWh), to £3.5/MWh (for a difference of £26/MWh). With a 3.5 hr gate closure the penalties would be slightly less.

As England and Wales are bigger than western Denmark, the wind output may be smoother and so the penalties may be expected to be slightly less; the Government response (ref 2) implies that country-wide consolidation would lead to a penalty around £3/MWh. This is several times the current level of "real" penalty, so NETA does not appear to reach its desired goal of cost-reflectivity. Even with 10% wind, £3/MWh is still double the technical penalty.

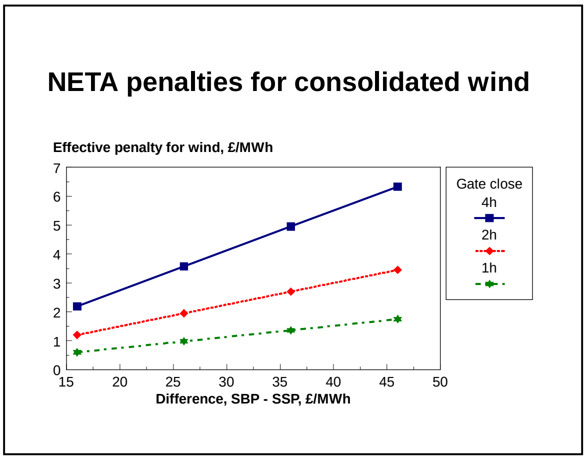


Figure 8 **NETA penalties for a range of gate closure and imbalance differences**

7. Surplus Wind Energy

At 10 and 15% wind energy penetration, the CEGB study (ref 7) suggested that some wind energy may need to be rejected. These amounts are shown in Table 5, together with the corresponding levels of the cost penalty. For the purposes of this analysis the value of wind energy has been taken as 5p/kWh and the value of the "lost" energy has been spread over the total wind generation.

Table 5 Cost Penalty due to lost generation

Energy Penetration, %	Wind Energy GWh	Energy Rejected GWh	Cost penalty p/kWh
10.00	28920	20	0.00
15.00	43380	300	0.04

Similar levels of wind rejection were reported in most of the CEC-funded studies which dealt with systems having similar characteristics.

As these penalties are not associated with the system, they are not considered further here.

8 Conclusions

While the output level of an individual wind farm will undoubtedly be subject to fluctuations, this lack of determinism does not, as is commonly assumed, imply the need to parallel wind farms with an equivalent level of conventional generating capacity. All integrated electricity systems are essentially stochastic in nature, and depend on the aggregation of instantaneous variations in supply and demand for their efficient operation. National Grid has indicated that sufficient fast response and reserve services will be available for a situation in which the entire 2010 renewables target (10% of electricity) is met by wind.

An analysis of the technical cost penalties associated with wind energy suggests it may be around £1.35/MWh at the 10% level, which is consistent with a level of £1.75/MWh for 17% of wind in Denmark. The former value takes no account of the benefits which may be derived from better wind predictability or demand management.

As the New Electricity Trading Arrangements tend to disaggregate both demand and generation, forcing each supplier to achieve a balance, they set aside the benefits of an integrated electricity system, to a certain extent. Each supplier must cope with the costs that arise from their contracting decisions. Under these circumstances, it appears that some suppliers tend to discount the value of the intermittent sources of renewable energy. These discounts - the NETA penalties - are partly a question of perception, partly due to the likely penalties a supplier with wind may incur under the new arrangements.

An analysis of the likely penalties which wind installations may incur under NETA show that they range up to £10/MWh - for a single wind farm, and a wide system buy/sell spread. Even if consolidation could be achieved over the whole of England and Wales, the penalty would be still higher than the technical penalty. Although these penalties can be reduced by consolidation at the supplier level, this does not always happen. This is not cost-reflective, which is the professed aim of NETA. Action is needed to remedy this situation, partly in the interests of securing a level playing field for wind, partly to ensure that a least-cost electricity system is achieved.

APPENDIX 1

The analysis of Farmer (simplified)

Farmer first assessed the r.m.s fluctuations from wind plant and estimated that these would amount to about 13% - on a 30-minute lead-time. If it is assumed that the errors in forecasting demand and wind are independent, the variances of the errors in demand and wind prediction add to give the total scheduling dispersion. For example, with 2000 MW of wind plant the r.m.s variation over 30 minutes would be 0.13 x 2000 = 260 MW. The corresponding daytime dispersion, due to normal fluctuations in demand, quoted by Farmer is 266 MW, and hence the dispersion with wind is $(260^2 + 266^2)$^0.5 = 372 MW, an additional requirement for part-load plant of 106 MW

The additional part-loading costs can be derived by noting that plant which is part-loaded operates at a lower efficiency and that the extra costs of operating in this way can be derived part-load energy loss is equivalent to 15% of the full load heat rate (**3**). This energy penalty can be converted to a monetary value using appropriate values of coal cost and thermal efficiency. Finally, this penalty can be translated to a "Wind energy cost penalty" using the corresponding level of wind generation.

To ensure consistency with the results from the CEC-funded studies, a coal cost of £1.55/GJ has been assumed for the test of the method; the night-time scheduling error was set at zero, and the daytime scheduling error was set at 176 MW.

This is a simplified description of Farmer's methodology and the penalties calculated using this approach are compared with those derived from the CEGB and the ESB studies in figure 1.

APPENDIX 2

Assimilating 100% wind energy

The calculation proceeds as follows: --

Cost of wind -- £500/kW (quite realistic for a 2025, say, as one wind farm has reportedly already been built at this price).

Cost of a nominal 5 MW (to supply 1 MW average load) -- £2.5 million

Cost of a nominal 3 MW of storage to support the same load (at £500/kW) -- £1.5 million
Total cost of wind plus storage = £4 million

Assuming a 10% annual charge rate - yearly cost: £400,000
Annual generation - 8760 MWh

Cost of electricity: £45.6/MWh

This shows that the concept is not totally unrealistic, as this price is £10/MWh higher than the present-day average cost of generation - about £35/MWh. This puts the premium for 100% wind generation at £10.6/MWh.

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