



Perspectives from Abroad

Assimilation of wind energy into the Irish electricity network

Prepared by

David Milborrow

Assimilation of wind energy into the Irish electricity network

David Milborrow

***The author:** the author has been involved in renewable energy studies since 1978, with a particular emphasis on economic and technical issues associated with wind energy. He has been an independent consultant since 1992 and has been associated with five major studies of the integration of wind energy into electricity networks: one in his CEGB days, two in partnership with the Science Policy Research Unit at the University of Sussex (with EU Funding), one for the UK Cabinet Office and one (just completed) for the UK DTI and Carbon Trust (As a Sub-Contractor to Mott MacDonald Ltd)*

Summary

This paper examines a number of issues associated with the introduction of increasing amounts of wind energy into the Irish electricity network. It draws upon international experience and, in particular, operational data from western Denmark, where wind produces 21% of total electricity consumption. Particular characteristics of the Irish network are identified and a mixture of empiricism and "first principles" analysis is used to derive estimates of the capacity credit of wind plant, the extra costs of operational reserve and the total extra costs of operating with increasing quantities of wind energy.

It is concluded that the total extra cost to the electricity consumer of installing enough wind to provide 10% of electricity consumption may be around €0.7/MWh, but much depends on timing (as wind costs are falling rapidly), and the mix between onshore and offshore wind. The need for market mechanisms to be cost-reflective and promote technical efficiency in electricity networks is emphasised, recognizing the advantages of integrated electricity systems. It is noted that this is not in conflict with the requirements for efficient assimilation of wind energy.

1. Introduction

The way in which the variability of wind energy impacts on the operation of electricity networks has been the focus of numerous studies over the last 30 years. There is, as a result, a considerable body of data on the topic and, broadly speaking, a good consensus between most of the authoritative studies. The characteristics of wind are much the same in Australia as they are in Ireland and, similarly, electricity networks are managed in much the same way so as to realise technical efficiency, security and low-cost electricity. The fundamental issues associated with efficient assimilation of wind are not in conflict with the delivery of the least-cost electricity to the consumer. Both demand that the benefits of an integrated electricity system are exploited to the full (1).

Nevertheless, the Irish electricity network does have particular characteristics. It is possibly the first isolated medium-sized network likely to operate with a significant percentage of wind energy. The electricity system in western Denmark is often held up as an example of the way in which high penetrations of wind energy can be managed (21% in 2003). In practice, however, that system has links with Norway, Sweden and Germany and when the capacity of these is taken into account, the effective wind energy penetration is about 10%. Nevertheless, wind power data from western Denmark is useful as it indicates the level of fluctuations likely to be incurred on the Irish network. (The two electricity systems have similar peak demands and electricity consumption). It is also important to note that Ireland has roughly twice the area as western Denmark. This means that "geographical diversity" is likely to result in power fluctuations from distributed wind in Ireland being less severe than those in western Denmark.

This paper addresses:

- Issues associated with intermittency from both technical and economic standpoints and issues discussed in a recent paper by ESB National Grid (2).
- The overall cost implications of absorbing increasing amounts of wind on the ESB system
- Brief comments on other issues such as carbon dioxide savings

2. Definitions and nomenclature

Capacity credit: the ability of wind plant to displace thermal plant, normally expressed as a percentage. If the capacity credit were 40%, 1000 MW of wind would displace 400 MW of thermal plant. For further discussion, see section 5.1 Capacity Credit

Geographical diversity: the greater the distance between two sites on which wind plant are installed, the lower the probability that the winds, at any given time, will be the same. This means that the wider the geographic distribution of sites, the lower the levels of wind power fluctuations.

Operational penalty: the extra cost of providing additional reserve (q.v.) on an electricity network to cope with the uncertainty of wind energy. When expressed in €/MWh the denominator is the wind energy generation.

Penetration level: unless otherwise stated, this refers to the (percentage) of wind energy delivered in a year, as a fraction of the total electricity consumption of the network concerned. As it is not always possible to derive this value, the parameter (wind capacity/peak demand) is used in places, in which case the context is made clear.

Plant margin: the difference between the installed capacity of all generation on an electricity network and the peak demand. Note that the plant margin *appears* to increase with wind on a network, due to the low load factor (usually termed "capacity factor") of the wind plant.

Reserve: plant held on part-load, or on "hot standby" so that its output can be increased or decreased at the request of the System Operator. There are various types of reserve, and definitions used in Ireland are quoted by Doherty and O'Malley (3).

3. Literature review: brief historical summary.

A short review of the principal sources of information serves to illustrate the wide diversity of electricity systems that have been studied, and also the degree of agreement between the results. One early American study (4) of a system similar in size to ESB (Kansas Gas and Electric company with an installed capacity of 3260 MW) suggested that the capacity credit of wind plant at low penetrations was about 55% of the rated capacity, falling to 30% at 20% penetration. This is a typical result.

Numerous studies have been made of the impacts of wind on the electricity network in the EU states. One early analysis for the UK set out the key aspects of the analytical procedures, which are valid everywhere (5). This has stood the test of time, although some of the results overestimated the impacts of wind, as they were based on simulations. Possibly the most definitive UK study was carried out by the CEGB itself and completed just before privatisation of the electricity industry (6). That study was one of ten, part-funded by the European Commission, and another of these was carried out by ESB (7). Although the CEGB network was much bigger, several of the results from the English and Irish studies were very similar. Both studies, for example, suggested that the operational penalty for a 10% wind penetration was about €1.5/MWh (1990 money valuesⁱ). In a later study, for the UK Cabinet office, Milborrow (8) reviewed a wide range of studies and drew a number of important conclusions which are summarised in the next section. That study was prompted by the realisation that the "institutional" penalties that wind energy projects were incurring under the New Electricity Trading Arrangements (NETA) were unrealistic. NETA was tending to force suppliers to view generation sources independently, rather than looking at demand and generation in an aggregated manner. The conclusion drawn was that it is important that market-based trading arrangements are cost-reflective; otherwise market distortions are liable to result.

The growing importance of wind energy in United States has spawned an increasing number of studies in recent years and a review of these has drawn attention to similarities in the results (9). These results are also in line with the most recent assessments of the impacts of wind in the UK. Typically, increased operational costs - due to the need to schedule additional reserves -- now are around €2.5-4.8/MWh for 10% wind, adding roughly 10% to its generation cost. The spread of estimates is due partly to differing characteristics of electricity networks and partly to differences in the costs of reserve.

3.1 Recent interest in wind forecasting and load management

In recent years, there has been considerable interest in developing better methods of forecasting wind power production. Numerous studies are in progress, aimed at providing power system operators with good forecasts of the wind power production in their area. The Danish grid operator uses wind prediction methods and a small levy has recently been agreed with Californian wind developers to fund further studies. Under the Californian plan, wind plant owners will develop a wind forecasting system and the ISO will operate it. If wind generators pay a forecasting fee of \$0.10/MWh and schedule according to the forecast, then

ⁱ *Strictly speaking, ecu, but the difference between ecu and euro is minimal.*

generation imbalance penalties are waived (10). As an indication of the improvements that can be secured, one study has estimated that the needs for extra spinning reserve can be reduced by over 30% (with 10% of wind) using these methods (11). If the conclusions from this study are reflected across to the system operating penalties, it is estimated that these could be reduced in the UK by about €0.7/MWh at the 10% wind energy penetration level.

The potential for load management, i.e. active control of customer loads, in association with wind energy is also under investigation and has been found to be a viable way of increasing the amount of wind generation which can be accepted onto a weak network (12). (The term "Interruptible Load Service" is used by ESBNG). The study concluded that such techniques might increase the uptake of onshore wind energy by around 1,600 MW in the area covered by Northern Electric in the UK. Load management could attenuate the power fluctuations "seen" by a supplier or grid operator, and so reduce the need for additional spinning reserves.

Any reduction in the cost of frequency control measures would also reduce the extra balancing costs for intermittent renewables and it has recently been suggested that responsive loads might be able to act as spinning reserve (13). It could be argued that this happens anyway, but the study advocates the use of better controls to secure a more positive link. The study focused on air conditioning loads in particular but identified other possible sources that would be equally suitable.

4. Technical and economic issues: Current status

Important "generic" conclusions from worldwide studies, plus particular data from northern Europe that is relevant to the Irish situation may be summarized: -

- Winds are stronger during the winter than the summer. For example, the average wind speed at Belmullet meteorological station during the winter quarter (DJF) is 27% higher than during the summer quarter (JJA) (14). It follows that: --
 - The likelihood of peak output from wind plant during the summer period, when consumer demand is low, is also low.
 - There is a strong likelihood that it will be windy on days of peak demand. This point is examined further in the context of the capacity credit of wind plant, section 5.1 Capacity Credit. Almost all studies in northern Europe have concluded that wind does have a capacity credit, which is roughly equal to the capacity factor of wind energy during the winter quarter.
- At low penetrations, the costs of additional reserve are very small
- Once the wind energy penetration level reaches about 10%, the most economic option, on a few occasions, may be to reduce the output of the wind plant
- Simulations of wind power fluctuations based on meteorological data tend to overestimate the magnitude of the power fluctuations. This is simply because "spot" measurements do not build in the smoothing effects of a wind farm on any given site. Evidence for this was provided in (8)
- Data from western Denmark, also in (8), and from Germany (15) on the variations in output from distributed wind plants, provide useful data. For example: -
 - The maximum hourly swing in output power from distributed wind rarely, if ever, exceeds 20% of the installed capacity of the wind plant. The standard deviation of the hourly swings is 3% (reference 8). This information is important in the context of assessing the needs for additional reserves.

- The maximum measured change in output from 2400 MW of wind in western Denmark is about 6 MW per minute (16).
- For 52% of the time, wind output and demand rise together, or fall together (author's analysis of Eltra data). Although this is not necessarily by the same amount, it illustrates the flaw in the argument that wind output should be "levelled".

Analysis of output changes over various timescales, taking into account the "normal" fluctuations in consumer demands, and in generation output, enables the additional reserve needs to be quantified.

4.1 Comparisons with western Denmark

As noted in the introduction, the Irish and western Danish electricity systems are similar in size, with similar annual energy consumption and peak demands in both systems. To illustrate the point more clearly, figure 1 shows demand fluctuations during the first ten days of February 2004.

Both the author and Holttinen (17) have examined the fluctuations seen by the grid operator in western Denmark, net of wind, over several months. Both analyses showed that the range of power excursions, with and without wind, is very similar. The results of the author's analysis (18) are shown in figure 2.

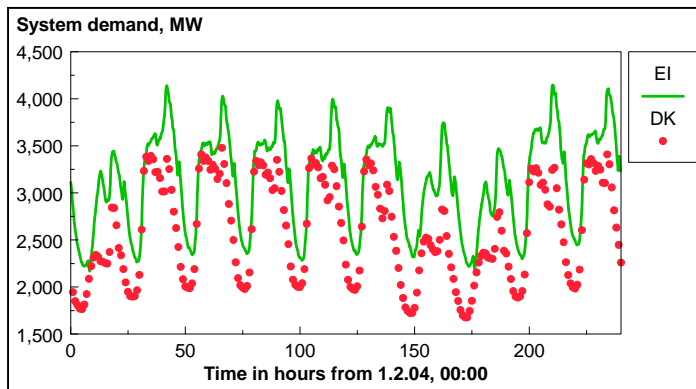


Figure 1 System demand variations in Ireland and western Denmark.

As the pattern of demand fluctuations, with the wind output netted off, is very similar to the "normal" fluctuations in consumer demand, this implies that the duty cycles of the load following units will also be similar. More load-following plant may be required, however, and this point is discussed later.

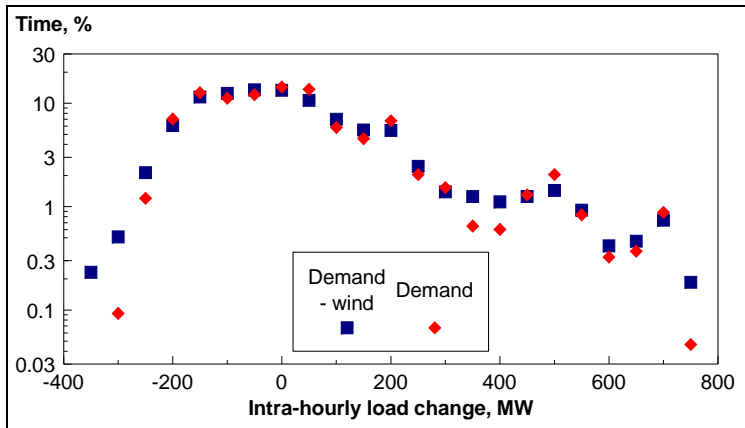


Figure 2 Intra-hourly load changes in western Denmark, with and without 20% wind

5 Key Economic Issues.

Wind energy is no different from any other generation option. It has a generation cost, and a value. If value exceeds cost, addition of a new generation source will lower overall system costs, and vice versa. In the case of wind energy, the additional costs of extra reserves must be taken into account. The extra cost of wind energy, which is of interest, can be simplified to: -

(Generation cost) + (intermittency costs) - (fuel saving value) - (capacity saving value)

This procedure has been used by Dale et al in the UK (19), and by Black and Veatch in Pennsylvania (20, to yield estimates of the extra cost of renewables.

The form of this expression indicates why there is considerable interest in both capacity credit – which is needed to estimate “capacity saving value” - and intermittency costs. In practice, neither is usually large and the recent ESBNG report (ref 2) is unusual in assigning a high value to so-called “backup costs”. This issue is explored further in section 5.2.1 Extra back-up capacity.

5.1 Capacity Credit

The capacity credit of wind plant tends to be controversial. This is not helped by a lack of uniformity over definitions. In this report, the capacity credit of any power plant is defined as

“A measure of the ability of the wind plant to displace conventional thermal plant, i.e., (thermal plant displaced/rated capacity of wind plant)”ⁱⁱ

ⁱⁱ Capacity credit is sometimes defined as the ratio (firm power capability)/(rated output). As no plant is 100% reliable, values using this definition are always 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. As CCGT plant has a credit, based on this definition, of about 0.85, credits based on firm power may be converted to “thermal plant credits” by dividing by 0.85.

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 (21). This implies that if, say, 1000 MW of wind plant was operating on the English or Irish network, it might be expected to displace around 350 MW of thermal plant.

Most of these analyses have used rigorous procedures for calculating capacity credit. Ref 22 gives a good description of these: "In general, the ["firm power"] must be calculated by considering hourly loads and hourly generating capabilities. This procedure can be carried out with an appropriate production-simulation or reliability model. The usual formulation is based on the hourly estimates of LOLP, and the LOLE is the sum of these probabilities, converted to the appropriate time scale".

Typical wind outputs over the course of a year (or longer) are "added" to the normal generation requirements so that there is a surplus of generation capacity at most times. Firm thermal capacity is then notionally subtracted until the original system Loss of Load Expectation (LOLE) is restored. As the LOLE tends to be strongly influenced by the availability of generation at the times of peak demand, a simpler, but less rigorous, method of estimating capacity credit is simply to examine wind power outputs at these times. The two methods yield very similar results.

Although it is argued that there is a danger of the electricity systems in Britain and Ireland becoming becalmed in midwinter, at times of peak demand, as far as is known, no evidence has been provided in support of this hypothesis. The work of Palutikof et al (23), for the UK system, is very relevant. They observe: "...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". 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" (24).

Results from the 1990 ESB study (7), the corresponding UK study (6), and the latest ESBNG study, "Impact of Wind Power Generation in Ireland" (2) are all very similar, as shown in Figure 3. In this figure, apparent inconsistencies due to the use of differing capacity factors have been eliminated by use of the ratio (capacity credit/annual capacity factor). In the latest ESBNG study, for example, wind is assumed to have a capacity factor of 34%. Reference to Figure 3 shows that, with 10% wind, the capacity credit was 83% of this value. So 1000 MW of wind will displace $0.83 \times 0.34 \times 1000$, or 282 MW of thermal plant.

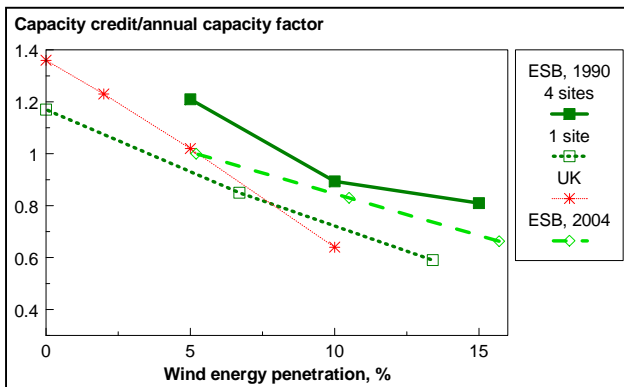


Figure 3 Comparison of capacity credits

It may be noted that capacity credits decline with increased wind penetration, due to the way in which the probabilities of wind and plant failures “add” together.

5.2 Requirements for Spinning Reserve and Associated Costs.

5.2.1 Extra back-up capacity

Looking at likely changes in wind output on various timescales and evaluating the additional uncertainty that this imposes on System Operators enables the needs for extra reserve – usually from conventional thermal sources or storage - to be quantified. The exact procedures were first laid down by Farmer et al (5) and have recently been restated, in the context of an analysis of the Irish system, by Doherty and O’Malley (3).

Drawing on several recent studies, many of which have used the parameter (wind capacity/peak demand) as a reference, Figure 4 shows that the back-up needs are modest: between 1-3% of wind capacity when that capacity is 10% of peak demand (about 5% penetration on an energy basis), rising to 2-6% of wind capacity, when the capacity is 30% of peak demand (15% penetration). It may be noted that Holttinen (17) estimates that the extra reserve needed for western Denmark is about 2% of the wind capacity, with 20% wind (energy basis) – nearly 50% of peak demand.

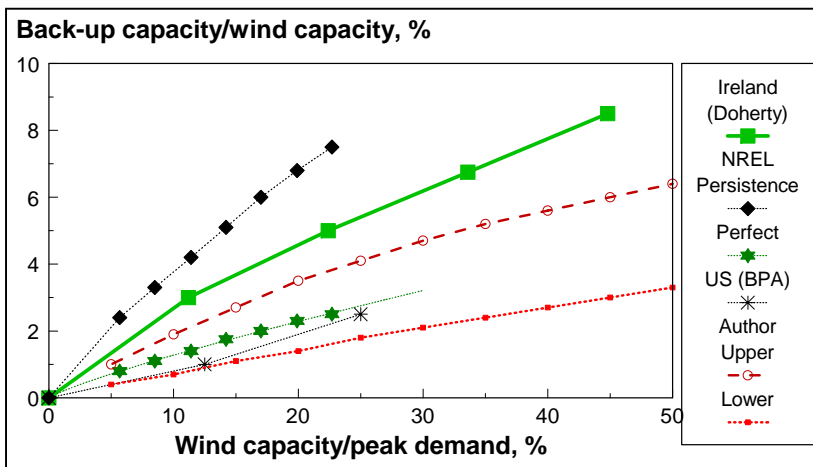


Figure 4 Estimates of backup requirements for wind energy

Additional data sources:

“NREL”: a study by the National Renewable Energy Laboratory in the US (25)

“US (BPA)”: a study for the Bonneville Power Authority, a system with a peak demand of 8054 MW (26)

"Author": these estimates have been derived assuming that the standard deviation of the intra-hourly power changes from wind in Ireland are the same as those in western Denmark. (This is probably a conservative assumption). The "upper" curve derives the combined uncertainty by assuming that the demand prediction error is the same, in percentage terms, as it is in it England. The "lower" curve takes into account the fact that more spinning reserve must be scheduled in Ireland than in England (allowing for the difference in system size), as the largest unit on the Irish system (~400 MW) is, proportionally, significantly bigger than the largest unit on the English system (1320 MW).

5.2.2 Extra costs of backup

The extra costs associated with intermittency have two components: the capital cost of the plant and the additional running cost that is incurred when this plant provides operational reserve. As such plant operates at part load, it runs at reduced efficiency and hence incurs higher costs. A "first order" estimate of the extra costs has been derived by taking the "upper" estimate of extra backup capacity, from figure 4 and building in the other assumptions that are shown in figure 5.

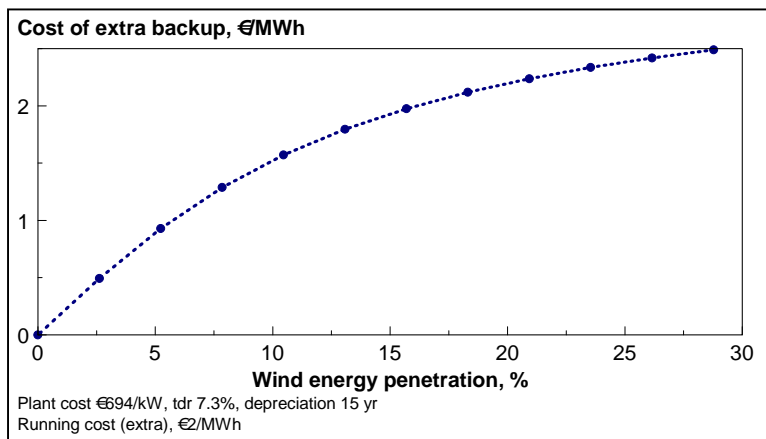


Figure 5. Estimate of additional costs associated with wind intermittency. Note that these extra costs are assigned to wind energy, and not spread across the network.

With 10% wind the extra costs are around €1.5/MWh, rising to €2.2/MWh with 20% wind. These figures are similar to estimates coming from other utility studies in Britain and America, several of which are collated in reference 9.

5.3 Total extra costs

As noted in the recent ESBNG report, a rigorous assessment of the extra costs of wind energy is quite complex, but the procedure can be simplified to yield estimates of acceptable accuracy by noting that most new plant would otherwise be gas-fired. The cost comparisons can then focus on the increased costs of wind energy over gas. The wind energy cost must include the extra costs of backup, discussed in previous section, but the concept of "capital cost for extra capacity", used in the ESBNG report, is not found in the literature. The concept appears to be based on the assumption that, at times of peak demand, 100% of the rated output of the wind plant is expected to be available and so, if the capacity credit is 35% of the

rated output, 65% of the rated output must be provided as backup. However, no plant is 100% reliable. The average capacity factor of nuclear in the UK over the past six years, for example, is about 75%. The reasoning put forward by ESBNG appears to demand, therefore, that nuclear has 25% backup. It may also be noted that forced outage rates for thermal plant in Ireland have increased in recent years.

The plant requirements are illustrated in figure 6, which shows the total capacity required to meet a peak demand of 6500 MW. It may be noted that the “apparent” plant margin increases when wind is installed.

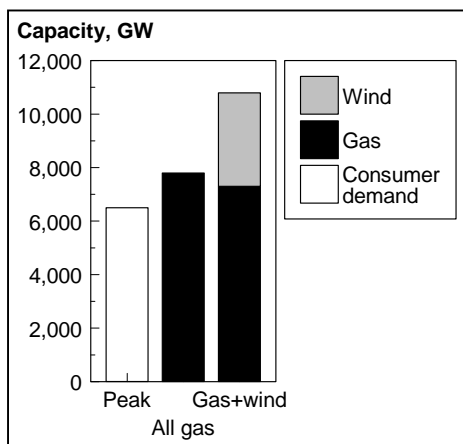


Figure 6 Illustrative plant requirements without/with 2500 MW of wind. To meet a peak demand of 6500 MW (first bar) requires around 7800 MW of thermal plant (2nd bar), assuming a plant margin of 20% is needed to meet the security standard. (The exact percentage is not important). If, say, 2500 MW of wind is installed, with a capacity credit of 429 MW – using ESBNG’s figure -- then only 7351 megawatts of thermal plant is needed.

Having established the plant needs, the extra cost of wind energy can then be computed as shown in Table 1. This uses ESBNG’s assumptions throughout. The procedure used here follows that described at the beginning of this section, and as used in the paper "A shift to wind is not unfeasible", published in Power UK, issue 109 (19).

Item	Assumptions	Cost, €M/yr
Annualised savings from gas plant not required	Capital cost €700/kW, Discount rate 7.3%, Depreciation 15 yr	-33.64
O&M of gas plant	€30/kW/yr	-12.87
Fuel savings	7.5 TWh, @€20/MWh	-150
Annualised cost of wind	2500 MW, @ €1450/kW	406
Wind O&M	2500 MW, @ €30/kW	75
Extra balancing	As for figure 7	13
TOTAL		297.49

Table 1 Sample calculation of extra costs due to wind.

Table 1 illustrates a “worst case” scenario, inasmuch as it assumes no increase in gas prices with time, and no drop in wind prices. Milborrow, Garrad (27), and others expect offshore wind prices to fall to 60% of their current levels by 2012 to 2020 (depending on development rates). Other studies by the EWEA and Forum for the Future (28) expect onshore prices to fall in a similar way.

Alternative estimates for future wind prices, together with possible future gas prices, are included in table 2. This table takes, as a starting point, the six scenarios used in the ESBNG report and assigns possible dates when they might be realised. The estimates of installed costs for wind are based on current price levels for onshore (for the first 500 MW). For later estimates a single source that is broadly representative of numerous studies has been used (29). The later estimates have also been weighted to allow for possible increases in the take-up of offshore wind (assumed 50% more expensive than onshore wind). This enables installed costs for wind energy costs to be assigned to each date.

The method of calculation is similar to that employed by Dale et al (19), and by Black and Veatch (20) and, in essence, works through each of the terms in the equation set out after the 1st paragraph of section 5. This enables the total extra yearly cost of various amounts of wind energy to be calculated (3rd line from bottom) and these numbers are then used to calculate the total extra cost per unit of wind energy (penultimate line) and, finally (last line) the total extra cost per unit of electricity delivered by the system.

This analysis suggests that the first 500 MW of wind will result in an extra cost to the electricity consumer of about €0.5/MWh. Thereafter the extra cost depends on the exact mix between onshore and offshore wind and on the way that prices – of wind and gas - behave. The assumptions that have been made suggest that the extra cost may not rise much above €1/MWh, even with significant wind penetrations. However, the numbers must be regarded as illustrative at this stage.

INDICATIVE ESTIMATES OF EXTRA COSTS DUE TO WIND

System MW		5000	5000	5000	6500	6500	6500	Source
Generation	TWh	28.9	28.9	28.9	38.3	38.3	38.3	ESB
Wind								
Date (est)		2005	2008	2010	2010	2017	2025	
Capacity		500	1000	1500	1500	2500	3500	ESB
C credit	MW	171	283	340	332	429	496	ESB
Energy	TWh	1.5	3	4.6	4.5	7.5	10.5	ESB
	%	5.19	10.38	15.92	11.75	19.58	27.42	ESB
Cap Cost, onshore	Euro/kW	771	667	633	633	542	500	CEC
Offshore %		25	30	40	40	45	50	Author
Weighted cost		867	767	760	760	664	625	
Annual cost	Meuro	48.58	85.93	127.64	127.64	185.95	245.05	
O&M	Euro/kW/yr	24	23	22	22	20	20	Author
O&M cost	Meuro/yr	12	23	33	33	50	70	
Balancing	Meuro/yr	1.4	4.8	9.1	9.1	18.5	28.4	Author
Gas								
Plant cost	Euro/kW	700	700	700	700	700	700	ESB
Saved	Meuro/yr	13.41	22.19	26.66	26.03	33.64	38.89	
O&M	Euro/kW/yr	30	30	30	30	30	30	Author
Saved	Meuro/yr	5.13	8.49	10.2	9.96	12.87	14.88	
Fuel	Euro/MWh	20	21	22	22	24	26	Author
Fuel cost	Meuro/yr	30.00	63.00	101.20	99.00	180.00	273.00	
Net cost	Meuro/yr	13.44	20.05	31.68	34.75	27.94	16.68	
....of wind	Euro/MWh	8.96	6.68	6.89	7.72	3.72	1.59	
.....to consumer	Euro/MWh	0.465	0.694	1.096	0.907	0.729	0.435	
	Test discount rate		%		7.32			ESB
	Life		yr		15			ESB

Table 2 Possible extra costs to the consumer of wind energy

5.4 Carbon dioxide savings

The carbon dioxide savings that result from the introduction of renewable energy depend on which fuel is displaced. As wind energy is invariably a "must run" technology, this implies that changes in output from wind plant are reflected in changes in output from the "load following" plant. In most of Europe, coal or oil-fired plant tends to be used for load following, which implies that each unit of renewable electricity displaces between 650 and 1000g of carbon dioxide (the lower figure applies to oil). However, as the amount of wind energy on the system rises, the carbon dioxide emissions from the additional reserve plant need to be taken into account and this means that the effective savings of CO₂ are reduced. Figure 7 uses the data that was used to estimate the reserve requirements in section 5.2.1 Extra back-up capacity to show the way that the generation from the additional reserve increases with increasing amounts of wind energy. With 2 TWh of wind, for example, the carbon dioxide savings would be scaled down by 10% and with 6 TWh say would be scaled down by about 20%. This assumes, however, that the same type of plant is used for reserve as for load following and this would not necessarily be the case.

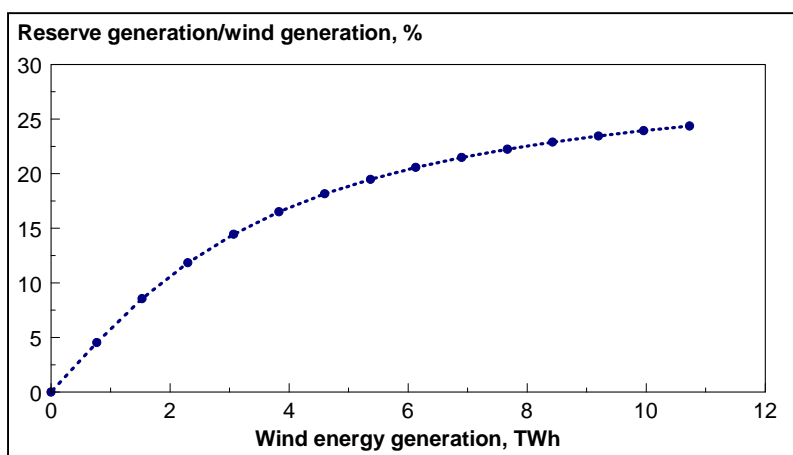


Figure 7 Amount of extra reserve generation needed for wind

Until recently, there was a reasonable consensus on the method of estimating carbon dioxide savings, based on the above reasoning. More recently, however, alternative approaches have been suggested, perhaps exemplified by the supporting analysis to the UK DTI Renewable Energy consultation document of 1999 (30), which proposed three possible scenarios for assessing the range of carbon savings from the UK renewables programme:

- "Renewables displace combined cycle gas turbines"
- "Renewables displace modern coal plant"; and
- "Renewables displace the current generating mix".

The document suggested that the first scenario was unlikely in practice, but did not comment further. Despite this, the DTI has since adopted "renewables displace gas" as its preferred approach, on the basis that renewables will inhibit the construction of new gas plant. Given that the construction of new gas plant in UK has slowed to a trickle, this argument now seems

more difficult to sustain. The alternative argument is that wind, like gas, forces the closure of old coal plant (31).

There appears little technical justification for "renewables displace current generating mix", although published studies of carbon dioxide savings follow each of the three options in roughly equal numbers.

6. Institutional Issues

There can sometimes be conflicts between the "rules and regulations" which govern the operation of an electricity network and the goal of operational efficiency and minimum cost to the consumer. This issue has come to the fore recently in the context of the UK's New Electricity Trading Arrangements (NETA) and some American operations. With the introduction of NETA, there has been a tendency to look at the performance of intermittent renewables in isolation. In the early days, this resulted in high penalties for intermittent generators. An analysis of the value of wind energy during the first week of NETA concluded, "the most profitable way of operating wind farms was to switch them off (32). Ironically, the demand prediction error has increased and so the amount and cost of spinning reserve being used has risen to well above the economic optimum. As more spinning reserve is being used than is needed – for reasons which are nothing to do with renewables - it will be some time before any extra needs due to wind become apparent.

Similar dichotomies have been recognised by the regulators in California (33) and Northern Ireland (34), who have acted to correct the anomalies. The approaches are similar, inasmuch as imbalances are no longer accounted for on an hour-by-hour basis, but averaged over longer periods, up to a year. This reduces the penalties considerably and, in each case, any residual costs are spread across all consumers. The principles of the Californian scheme seem likely to be adopted by the Federal Electricity Regulatory Commission.

The key issue here is that "market mechanisms" should not only be cost reflective, but should also encourage electricity networks to operate with high efficiency. Within these, the renewable energy industry simply asks for fair treatment.

7. Conclusions and recommendations

Within the context of a short study, it has not been possible to explore thoroughly all the issues involved, but a "first principles" approach, drawing on data from western Denmark, has been used to make estimates of some of the key parameters associated with increased amounts of wind energy. The key conclusions are: -

- Most utility studies have concluded that up to around 10% of wind energy can be absorbed without major technical changes and modest extra operational costs. Beyond 10% (which is only a rough benchmark) the requirements for additional reserve rise to around 5% of the installed wind capacity (at 20% penetration). The estimated costs of additional backup at 20% penetration are around €2/MWh, which is consistent with data from other studies.
- Useful information can be derived from western Denmark, where the network has a similar capacity. The data suggests, for example, that the distribution of power

- fluctuations, net of wind, are very similar to those due to consumer demands alone. This suggests that the extra demands on load-following plant may not be too onerous.
- Taking into account the cost of extra backup, present and future levels of wind plant costs, and possible changes in gas prices, a preliminary analysis suggests that the extra cost to the Irish electricity consumer may not exceed €1/MWh. Further analysis would help to quantify these figures more accurately.
 - Estimates of carbon dioxide savings indicate that some abatement occurs due to the operation of additional reserve plant. With 10% wind, this abatement is around 17.5%. As there is some uncertainty as to the most accurate method of calculating emissions savings, this issue needs to be examined further.

As this is a preliminary study, it has not been possible to produce estimates of additional reserves or extra costs with great accuracy. Further information and analysis, needed to enable a better understanding, includes: --

- Additional data covering the demand prediction errors; this has a strong influence on the estimates of additional reserve required.
- The estimates of total extra costs have been made using "best judgements" of future development in the capacity of onshore and offshore wind and these could be refined if there were agreed forecasts in the rate of wind development.
- It needs to be demonstrated that the current market mechanisms in Ireland will properly reflect what may be termed the "technical costs" outlined in this note.

7.1 The way forward

7.1.1 Technical Developments

Technical developments that are likely to ease the assimilation of wind into the Irish electricity network include: --

- Better forecasting techniques for wind power, since there is considerable activity, worldwide, in this area.
- More use of demand-side management. This has been discussed briefly and, in general, has been slow to develop in both Europe and America. New research may alter the picture.
- Construction of a connection from Ireland to Wales. This would effectively increase the size of the system into which wind is absorbed, in much the same way as in western Denmark.
- Storage: although the potential for storage is often discussed in the context of wind energy, no cost-effective technology has yet emerged. If it does emerge, however, it is best used for the system as a whole. The use of "dedicated" storage for wind energy is unlikely to be worthwhile, as it constrains the operation of the storage plant.

7.1.2 Institutional requirements

One of the key requirements for effective and fair utilisation of wind energy is that the advantages of an integrated electricity system are exploited to the full. This does not amount to "special pleading" for renewables, as low-cost electricity, even without renewables, also demands this. To illustrate the point, "side-effects" such as the increased (and unnecessary) part loading that has occurred in the UK since the introduction of the New Electricity Trading Arrangements are unacceptable. This pushes up both costs and carbon dioxide emissions, and is a consequence of the "compartmentalising" of the industry.

The potentially damaging effects of market mechanisms which treat each generator as an isolated entity, and so have an adverse effect on intermittent sources of renewable energy have been recognised by several regulatory authorities; it is important that the development of the electricity market in Ireland proceeds in a way that is "even -handed" towards intermittent renewables. Specifically, in the case of wind energy: -

- Wind should only be debited with the extra costs of reserve
- Capacity credit should be properly reflected, and
- Prices paid under renewable energy support mechanisms should be cost-reflective

This does not amount to "special pleading". It is quite possible that, on a level playing field and at some time in the future, generation costs from wind might undercut those from gas. In this case, wind should be the preferred choice, as it will deliver lower electricity costs to the consumer.

David Milborrow
Revised draft 12 April 2004

8 References

- 1 Milborrow, D J, 2001. Fading fears about fluctuations. *Windpower Monthly*, July.
- 2 ESB National Grid, 2004. Impact of wind power generation in Ireland on the operation of conventional plant and the economic implications.
- 3 Doherty, R and O'Malley, M, 2004. A new approach to quantify reserve demand in systems with significant installed wind capacity. Paper submitted to transactions of the IEEE.
- 4 Electric Power Research Institute, 1979. Requirements Assessment of Wind Power Plants in Electric Utility Systems. EPRI ER-978-SY
- 5 Farmer, E D, Newman, V G and Ashmole, P H, 1980, Economic and operational implications of a complex of wind-driven power generators on a power system. *IEE Proc A*, Vol 127, No 5
- 6 Holt, J S, Milborrow, D J and Thorpe, A, 1990 Assessment of the impact of wind energy on the CEGB system. CEC Brussels.
- 7 Electricity Supply Board, Ireland, 1990. CEC DG XII Wind Energy Penetration Study.

-
- 8 Milborrow, D, 2001. Penalties for intermittent sources of energy. Working Paper for PIU Energy Review
 - 9 Parsons, B, Milligan, M, Zavaldi, B, Brooks, D, Kirby, B, Dragoon, K and Caldwell, J, 2003. Grid impacts of wind power: a summary of recent studies in United States. European Wind Energy Conference, Madrid.
 - 10 O'Bryant, M, 2002. Favourable ruling on imbalance. Windpower Monthly, May, 28
 - 11 Watson, S J, Landberg, L and Halliday, J A, 1993. Wind speed forecasting and its application to wind power integration. Proceedings, 16th British Wind Energy Association Conference, York. MEP Ltd, London
 - 12 Econnect Ltd, 1996. Wind turbines and load management on weak networks. ETSU W/33/00421/REP
 - 13 Kirby, B, 2003. Spinning Reserve from Responsive Loads. Oak Ridge National Laboratory, ORNL/TM-2003/19
 - 14 Troen, I, and Petersen, E L, 1989. European Wind Atlas. Commission of the European Communities, Brussels
 - 15 Institut fur Solare Energieversorgungstechnik, 2002. Wind Energy Report Germany 2002. ISET, Kassel
 - 16 Christensen, H C, 2003. General introduction to wind power in the Eltra area. Wind Conference, Billund, 20-22 October.
 - 17 Holttinen, H, 2003. Hourly wind power variations and their impact on the Nordic power system operation. PhD Thesis, Helsinki University of Technology
 - 18 Milborrow, D J, 2004. The real cost of integrating wind. Wind Power Monthly, 20, 2. (February)
 - 19 Dale, L, Milborrow, D, Slark, R and Strbac, G, 2003. "A shift to wind is not unfeasible". Power UK, issue 109.
 - 20 Black and Veatch Corporation, 2004. Economic impact of renewable energy in Pennsylvania.
 - 21 Milborrow, D J, 1996. Capacity credits - clarifying the issues. British Wind Energy Association, 18th Annual Conference, Exeter, 25-27 September, 1996. MEP Ltd, London
 - 22 Kirby, B, Milligan, M, Makarov, Y, Hawkins, D, Jackson, K and Shiu, H, 2003. California renewables portfolio standard renewable generation integration analysis. Phase 1: Analysis of integration costs for existing generation. California Wind Energy Collaborative, CWEC-2003-02.
 - 23 Palutikof, J, Cook, H and Davies, T, 1990. Effects of geographical dispersion on wind turbine performance in England: a simulation. Atmospheric Environment, Vol 24A, No 1.
 - 24 Warren, J, Hannah, P, Hoskin, R, Lindley, D and Musgrove, P, 1995. Performance of wind farms in complex terrain. Proceedings of the 1995 British Wind Energy Association Conference, Warwick. Mechanical Engineering Publications Ltd, London.

-
- 25 Hudson, H, Kirby, B and Wan, Y, 2001. The impact of wind generation on system regulation requirements. American Wind Energy Association Conference, Washington, DC, 3-7 June. AWEA
- 26 Hirst, E, 2002. Integrating wind energy with the BPA power system: preliminary study. Consulting in Electric-Industry Restructuring, Oak Ridge, Tennessee.
- 27 Both authors gave presentations to the BWEA Conference “UK Offshore Wind 2004” suggesting that offshore prices will fall to 60% of their current level by around 2015/2020.
- 28 Ekins, P, 2001. The UK’s transition to a low-carbon economy. Forum for the Future
- 29 California Energy Commission, 2003. Renewable resources development report. Ref 500-03-080F
- 30 DTI/ETSU, 1999. New and renewable energy: Prospects for the 21st century; supporting analysis.
- 31 Milborrow, DJ, 2001. Memorandum submitted to the House of Commons Environmental Audit Committee. HC-334
- 32 Bathurst, G and Strbac, G, 2001. The value of intermittent renewable sources in the first week of NETA. Tyndall Centre, Briefing Note no 2.
- 33 O’Bryant, M, 2002. New rules remove transmission barriers. Windpower Monthly, 18, 9, 49-50
- 34 Ofreg, 2002. Trading in Renewable Electricity. www.nics.gov.uk