# The economics of large-scale wind power in the UK

## A model of an optimally mixed CEGB electricity grid

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**Previous calculations of the economics of large-scale wind power have been generally limited to the evaluation of the marginal cost of energy, assuming that the addition of a wind farm to an electricity grid does not change the mix of base, intermediate and peak load plant in that grid. Here a simple but powerful numerical generation planning model has been constructed for grids containing wind farms and three classes of thermal power station, but no storage. Electricity demand and available power are specified by empirically based probability distribution functions and the plant mix which minimizes the total annualized costs of the generating system is determined. Capacity credit of wind power is automatically taken into account in the optimization. Using the model, the breakeven costs of wind energy in a model British CEGB grid, containing coal, nuclear, oil and wind driven power plant, are evaluated under various conditions. For a wide range of parameter values, large-scale wind power is likely to be economically competitive in this grid.**

Simple 'cost of energy' calculations provide a useful first approximation method for comparing the respective costs of energy (eg in p/kWh) from new wind and thermal power plant. However, they do not take account of the different economic values of energy and power produced by different types of power station and do not treat the economic impacts of the new stations on the grid as a whole.

An alternative approach is to perform detailed dynamic (eg hour-by-hour) computer simulations[1,2] of the operation and economics of the grid in the presence of either a new wind farm or a thermal power station. While this approach can provide detailed information about a specific grid with a fixed set of parameters, it uses such large amounts of computer time that it is extremely expensive to perform a sensitivity analysis of the results to changes in economic, grid and power station parameters, and it is difficult to reproduce or validate results obtained.

## Basic approach

The model formulated in this article is intermediate between the simple cost of energy calculations of single power stations and dynamic computer simulations of whole grids. The model grid comprises wind farms and, at most, three different classes of thermal power station which for convenience are labelled 'base', 'intermediate' and 'peak'. Each class is characterized by its annualized fixed and variable costs in constant currency, economic lifetime, rated power, minimum power output during operation, forced outage rate (the fraction of hours/year for which the plant is not available due to breakdowns) and planned outage rate (for maintenance). Within a particular class of power station, individual units are treated as being identical. The demand on the grid is characterized by an empirical probability distribution function, known to power system planners as the 'load duration curve'. The power available from the thermal power stations in the grid is characterized by an 'availability'

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probability distribution, which is derived from the respective outage rates of the three types of thermal power station units. Wind power is characterized by a probability distribution function of hourly averaged wind speeds which have been filtered by the response of a standard aerogenerator.

The method assumes that the random variables of load and availability are independent, an assumption which gives a good approximation in a grid for which contributions from hydroelectric storage (which introduces a 'memory' into the grid) and certain types of demand modification are relatively small. These assumptions are satisfied by the CEGB grid, to which the model will be applied below. A further assumption of this paper, that the random variables of load and wind power are independent, is likely to give an underestimate of the capacity credit (see below) and hence the economic value of wind power in the UK.

## Optimal mix

The annual economic cost of a configuration or mix of power stations is the sum of annualized capital costs (including interest during construction and provision for decommissioning where applicable) for each generating unit, plus the sum of fuel cycle costs per unit of energy times the energy generated per year by that generating unit.

The optimal mix is therefore the configuration of the three classes of thermal power unit which minimizes total annualized cost, subject to the constraint that grid reliability is not decreased. Thus, as well as placing the thermal power stations into three classes, our model simplifies the real grid by ignoring the time sequence of the random variables of load and availability, thereby reducing the problem to a simple numerical manipulation of three probability distributions (load, wind power, thermal power availability) and a straightforward optimization. Since the computation time is not excessive for this static probabilistic model, a sensitivity analysis can be performed so that the effects of the original simplifications can be tested. It is shown (see below) that the results are insensitive to most of the simplifying assumptions of the model. The definition of the optimization problem is a straightforward generalization of that given in an earlier paper.[3] Wind power plant is placed at the top of the merit order, followed by thermal base, intermediate and peak load plant.

## Numerical model

A numerical method for determining the optimal mix of an electricity grid containing two classes of thermal generating plant, 'base' and 'peak', and wind driven power plant has already been described in an earlier paper.[4] Then, a method was used for determining the optimal mix which is conceptually the easiest: namely evaluating the total (fixed plus variable) annualized cost for every possible mix of the two different classes of plant. The combination with the lowest total cost is the optimal mix. However, such an approach is highly inefficient in terms of computer time when there is an additional class of thermal power stations.

Therefore, in the present work an approximation to the optimal mix is obtained and then the costs of neighbouring mixes are checked. The initial approximation is obtained in the absence of wind power by starting with an 'empty' grid. One station at a time is added to the grid, choosing

[1]W.D. Marsh, *Requirements Assessment of Wind Power Plants in Electricity Utility Systems*, EPRI ER-978, Vols 1–3, Electric Power Research Institute, Palo Alto, California, 1979.
[2]L. Jarass, L. Hoffman, A. Jarass and G. Obermair, *Wind Energy*, Springer-Verlag, Berlin, 1981.
[3]B. Martin and M. Diesendorf, 'Optimal thermal mix in electricity grids containing wind power', *Electrical Power and Energy Systems*, Vol 4, No 3, 1982, pp 155–161.
[4]*Ibid.*

at each step that type of station which contributes the lowest marginal cost to the system. The resulting 'stepwise optimal mix' is often close to the actual optimal mix and would be identical, were it not for the following two factors which are not taken into account by the stepwise process.

- Each class of power station has its own value of capacity credit, which is a measure of its contribution to the reliability of the whole grid. Units with a higher forced outage rate have lower values of capacity credit. Contrary to popular belief, wind power has a non-negligible capacity credit, although its magnitude is generally lower than that of thermal power plant with the same annual energy output.[5,6] The total amount of rated capacity required to ensure a given value of grid reliability thus depends on characteristics of all the units and, hence, the total capital cost also depends on these characteristics. This global dependence is not taken into account by the stepwise process.
- The power output of each class of station can be regulated down to its own characteristic minimum level, $P_{min}$, during operation. For base load coal-fired plant, $P_{min}$ might be $\frac{1}{2}P_{max}$, for peak load gas turbines $P_{min}$ is typically close to zero, while for wind power $P_{min}$ equals the current power output. Particularly in grid configurations with large amounts of wind power or base load units with high $P_{min}$, minimum power output for the grid may be higher than load in periods of low load. This leads to additional fuel costs which may not be taken into account by the stepwise process.

Due to these two factors, mixes adjacent to the stepwise optimal mix are evaluated until a mix is found, the total cost of which is a local minimum. Usually this cost will also be the global minimum, but in a few cases – especially when the marginal costs of base and intermediate plant are nearly equal – the global minimum is found on a boundary in configuration space with a mix of only one or two classes of thermal plant. In a highly reliable grid some peak plant will always be economic, since units lowest in the merit order burn negligible fuel and, hence, the plant with lowest capital cost is preferred.

These considerations lead to the following efficient procedure for determining the optimal mix. First, the stepwise optimal mix is determined. Second, costs of mixes which are nearest neighbours to this mix are calculated until a local minimum cost is found. Third, reduced mixes of base and peak, intermediate and peak, and all peak are examined to ensure that the global minimum cost has been obtained.

For example, a grid which was shown to have a stepwise optimal mix of 15 base, 15 intermediate and 2 peak load stations was examined. Upon examining neighbouring configurations, the actual optimal mix was found to have 14 base, 14 intermediate and 4 peak. Interpolation involving the lowest cost mix and its nearest neighbours was then used to fix a more mathematically precise optimal mix which resulted in a mix containing fractions of a station: 14.1 base, 14.2 intermediate and 3.2 peak. Although it is not practical in reality, this fractional mix provides useful information when comparing the optimal mixes resulting from different choices of parameters. Mixes of base and peak, intermediate and peak, and all peak were checked but were found to have higher costs than the lowest cost mix of all three types of plant.

In the presence of wind power, an 'effective load distribution' is derived by 'subtracting' the wind power from the load. (The 'subtraction'

[5] B. Martin and M. Diesendorf, 'The capacity credit of wind power: a numerical model', *Proceedings of the Third International Symposium on Wind Energy Systems*, Copenhagen, August 1980, BHRA Fluid Engineering, Cranfield, England, 1980, pp 555–564.

[6] J. Haslett and M. Diesendorf, 'On the capacity credit of wind power: a theoretical analysis', *Solar Energy*, Vol 26, 1981, pp 391–401.

is actually a numerical convolution of the probability distributions of load and wind. Only in the case where there are simultaneous data sets of load and wind can one perform an ordinary subtraction of data points.) Thermal power stations are then added to the grid one by one as before, until the grid reliability reaches the same value as that specified by the utility in the absence of wind power plant. 'Loss of Load Probability' (LOLP) is used as the index of reliability, defined as the fraction of hours/year for which demand exceeds supply. In general it is found that the thermal power capacity installed in the presence of wind power plant is less than the thermal power capacity in the absence of wind power plant. This difference is a measure of the capacity credit of wind power.

## Model of the CEGB grid

Since Britain has significant wind power potential,[7] the numerical model for calculating optimal mix in an electricity grid with and without wind power has been applied to an idealized model of the CEGB grid. This model includes three types of new thermal power plant, which for the CEGB case are taken to have the cost and performance parameters of typical nuclear, coal and oil units. The numerical model is then used to obtain the optimal mix of these three types of units, with and without wind power plant, with specified parameters.

There are two important reasons for considering the optimal mix of *new* thermal plant, rather than incorporating some or all of presently operating plant. First, inclusion of present plant would make the calculation much messier and more difficult. Second, the change in optimal mix after introduction of wind power plant is what is sought through the calculation, and if the present grid mix is non-optimal – as is the case for the British grid – the meaning of the result of the calculation may be misleading.

In most cases, non-optimal mixes near to the optimal mix have only slightly higher total costs, while non-optimal mixes progressively farther from the optimal mix have disproportionately higher costs. This means that the further away the actual mix is from the optimal mix, the greater the savings to be made by changing it towards the optimal one. Therefore, if the actual mix is non-optimal and wind power is introduced while changing the mix towards the optimal mix (with wind), then this will show the economics of wind power in a more favourable light than the present calculation. That is, the breakeven costs of wind power plant presented in this article are likely to be lower (and hence less favourable to wind) than those obtained using a more realistic model of the grid.

One of the main difficulties in performing an evaluation of the economics of wind power in an electricity grid is finding a reasonably complete, accurate, authoritative published account of the economics of *thermal* power stations, particularly for nuclear power. However, the recent public and scientific debate in the UK has revealed much of the basic data and assumptions on economic method, plant operation and so forth for determining the costs of coal and nuclear power in the CEGB grid.[8,9,10,11,12]

Table 1 compares the current performance and cost parameters for the three main types of new thermal power plant in the CEGB grid, used as baseline values for the subsequent optimal mix calculation. The cost estimates are essentially those of the CEGB,[13] with some differences as noted in the appendix.

[7] *The Prospects for the Generation of Electricity from the Wind in the UK*, Energy Paper 21, HMSO, London, 1977.
[8] *Costs of Producing Electricity*, Central Electricity Generating Board (CEGB), Annual Report 1979/80, Appendix 3, July 1980.
[9] J.W. Jeffery, letter in *Nature*, Vol 287, 23 October 1980, p 674; J.W. Jeffery, letter in *Nature*, Vol 292, 27 August 1981, p 791.
[10] J.W. Jeffery, 'The real cost of nuclear power in the UK', *Energy Policy*, Vol 8, No 4, December 1980, pp 344–346; J.W. Jeffery, 'The real cost of nuclear electricity in the UK', *Energy Policy*, Vol 10, No 2, June 1982, pp 76–100.
[11] R. Marshall, letter in *Nature*, Vol 287, 18 September 1980, p 184.
[12] House of Commons Select Committee on Energy, *The Government's Statement on the New Nuclear Power Programme*, HC114–1, HMSO, London, February 1981.
[13] *Op cit*, Ref 8.

**Table 1. Baseline values of performance and cost parameters for three types of thermal power station in the UK.[a]**

| Type of plant | Nuclear | Coal | Oil (boiler) |
|---|---|---|---|
| Unit size (MWe)[b] | 500 | 500 | 250 |
| Minimum power output (MWe) | 500 | 200 | 0 |
| Economic lifetime[c] (years) | 25 | 30 | 30 |
| Availability[b,d] | 0.60 | 0.75 | 0.80 |
| Forced outage rate[b] | 0.20 | 0.15 | 0.10 |
| Planned outage rate[b] | 0.20 | 0.10 | 0.10 |
| Fixed cost[e] (£/kW) | 1 085 | 555 | 390 |
| annualized (£/kW/year) | 77 | 36 | 25 |
| annualized (p/kWh) | 1.46 | 0.55 | 0.36 |
| Variable cost[f] (p/kWh) | 0.83 | 1.49 | 1.86 |
| Total cost of energy (p/kWh) | 2.29 | 2.04 | 2.22 |

[a]All costs are measured in March 1980 currency. Power stations are assumed to be ordered in 1980 with immediate start in construction.

[b]To avoid serious truncation error in the numerical calculation, the unit sizes, and the unit sizes times either the forced or planned outage rates must all be multiples of the numerical mesh size, here taken as 25 MW, which is also one quarter of the mesh for the CEGB load data obtained for the calculation (see Ref 17). Since the peak load approaches 50 GW, there are about 2 000 intervals (0-25 MW, 25-50 MW, . . .) in the numerical mesh representing the load.

[c]Based on CEGB Report (see Ref 8). In the CEGB's subsequent Annual Report, the stated fossil plant lifetime has been changed to 40 years, reducing the annualized capital cost by 10%, but this decrease would be offset to some extent by an increase in maintenance cost.

[d]Each station can in principle compete for any position in the merit order. Hence availabilities rather than capacity factors are the appropriate basis for calculating total cost of energy. Availability is defined here as the fraction of time for which the power plant is available to deliver its rated power. For a plant run to the limit of its availability, 'availability' equals 'capacity factor' or 'load factor', which is defined as annual mean power output divided by rated power output.

[e]The fixed costs in £/kW and £/kW/year are identical to those given by the CEGB (see Ref 8) for the costs of future thermal power plant ordered in 1980 with immediate start in construction. These costs include interest during construction and a modest allowance of £28/kW or £2/kW/year for decommissioning a nuclear station. The real interest rate is 5% and so, from the levelized annuity formula, the real annual charge rate for a plant with a 25 year lifetime is 7.1%. Thus the nuclear capital cost of £1085/kW becomes £77/kW/year. Dividing this by 8760 (the number of hours per year), dividing again by the availability (0.60 for a nuclear station) and multiplying by 100 converts the fixed cost to p/kWh.

[f]These comprise fuel cycle plus operation and maintenance (O and M) costs and are based on 1980 costs, in March 1980 currency, reported by the CEGB (see Ref 8). The variable costs of nuclear power comprise a fuel cycle contribution of 0.61p/kWh (which includes the cost of the initial fuel charge and an allowance for the future cost of reprocessing) and an O and M contribution of 0.22p/kWh. The variable cost of coal power comprises a 1980 fuel cost of 1.35p/kWh plus an O and M cost of 0.14p/kWh. This latter figure equals 0.10p/kWh, as observed for Drax first half, times 73/54, to allow for operation to the limit of availability (namely with a load factor of 0.73, corresponding to base load operation, rather than with a load factor of 0.54, corresponding to intermediate load operation).

**Table 2. Availabilities and estimated cost of energy from a wind farm of mass-produced MOD-2 aerogenerators.[a]**

| | | | | | |
|---|---|---|---|---|---|
| Annual mean wind speed[b] $\bar{v}$ at 10 m height in m/s | 5.5 | 6.0 | 6.5 | 7.0 | 7.5 |
| Availability[c] | 0.26 | 0.31 | 0.35 | 0.39 | 0.42 |
| Projected capital cost in mass production in 1980 £/kW[d] | 500 | 500 | 500 | 500 | 500 |
| Cost of energy[e] in 1980 p/kWh | 1.88 | 1.57 | 1.37 | 1.24 | 1.16 |

[a]The start-up speed of the aerogenerators is $v_s$ = 6.3 m/s, with a linear increase in wind power from $v_s$ to the rated wind speed $v_r$ = 12.0 m/s.

[b]The aerogenerators are assumed to respond to winds at 60 m height which are 1.29 times the wind speed at 10 m (this assumes that the wind speed varies as the 1/7 power of the height). The wind speed is described by a Rayleigh distribution (see Ref 15).

[c]This assumes 10% of the aerogenerators are undergoing planned or forced outage at any given time.

[d]See Ref 14.

[e]This is calculated assuming a real interest rate of 5%, and an economic lifetime of 30 years, giving a real annual charge rate for capital of 6.5%, to which is added 2% for operation, maintenance and insurance.

Table 2 gives some basic parameters and some estimated future costs for a wind farm, comprising large mass-produced aerogenerators. The capital costs are approximate figures based on several US studies for the MOD-2 aerogenerator,[14] assuming that £1 ≅ US$2. In the optimal mix calculations below, the breakeven costs of wind power will be derived as an output of the problem rather than an input. For the purposes of standardization and convenience, it has been assumed that the hourly-averaged wind speeds at the wind farm site may be described by a Rayleigh distribution.[15] This distribution is completely specified by the annual mean wind speed $v$.

To estimate the capacity factor (annual average power output divided by rated power output) of the wind farm, it has been assumed that all aerogenerators experience the same wind regime and that each machine has the theoretical power response curve of the MOD-2. The effect of breakdowns has been taken into account by assuming an outage rate of 0.1 applied to the mean power output.

In Britain, large land-based wind farms can be sited in areas with $v$ in the range of 5.5–6.5m/s. There are fewer aerogenerator sites in higher wind speed areas such as hilltops or the Orkneys (apart from offshore). At very windy sites the high capacity factors may be offset to some extent by higher capital costs or lower machine lifetimes, and so it may be difficult to push the cost of energy below about 1.2p/kWh, even at the best sites.

Cost of energy figures for the US MOD-2 in the UK given by Lowe[16] are too low by a factor of about two, because they are based on an invalid

[14]The estimated 100th production unit cost for MOD-2, including site preparation, erection and installation in the USA, is $2.11 million or $840/rated kW (1980 dollars). The manufacturing costs are based upon a dedicated high rate production facility producing 20 units per month, with installation in farm sizes of 25 units. (See: *MOD-2 Wind Turbine Development Final Report*, Vol II, Detailed Report, NASA CR No 168007, September 1982.) Allowing for higher labour costs in the UK, £500/rated kW seems to be a reasonable approximate conversion.

[15]M. Diesendorf and G. Fulford, 'Optimal value of the rated speed of a wind generator', *Wind Engineering*, Vol 3, No 1, 1979, pp 62–68.

[16]R. Lowe, 'Expected electricity costs for the US Mod 2 Windmill', *Energy Policy*, Vol 8, No 4, December 1980, pp 347–348.

comparison of real (inflation corrected) interest rates in the UK with nominal interest rates in the USA.

The load–duration curve used here is that of the CEGB for 1978, given in a mesh of 100 MW.[17] For this load data the mean load is 24.9 GW, the standard deviation is 6.9 GW, the peak load is 44.1 GW and the minimum load is about 10 GW. A loss of load probability (LOLP) of $10^{-4}$ is assumed.

## Results

The breakeven cost for wind power plant in the idealized CEGB grid, with economic and wind parameters given in Tables 1 and 2 and with 1 GW of mean wind power, is £572/kW. If wind power plant can be obtained at or below this cost, it should be economically competitive for any future expansion or replacement of plant in the CEGB grid, according to the model.

The projected capital cost of the MOD-2 aerogenerator in mass production is about £500/kW. The *first* important result therefore is that mass-produced aerogenerators may be economically competitive for producing electricity in the CEGB grid. However, in assessing aerogenerators compared to thermal power plant, factors other than economics would need to be considered, including environmental effects, lead times, uncertainty about future cost changes and susceptibility to attack in war.

In Table 3 the breakeven wind power cost is given for a variety of cases in which economic, wind or grid parameters are changed. A glance at

[17]J.A. Halliday, private communication.

**Table 3. Breakeven costs in £/kW of wind power plant for an idealized model of the CEGB grid, for different values of economic, wind and grid parameters.[a]**

| Parameter changed | Breakeven wind power cost (£/kW) |
|---|---|
| *Economic parameters* | |
| Standard (see Table 1) | 572 |
| Nuclear capital up 50% | 572 |
| Coal capital up 50% | 631 |
| Oil capital up 50% | 466 |
| Nuclear fuel up 50% | 572 |
| Coal fuel up 50% | 631 |
| Oil fuel up 50% | 460 |
| All capital up 50% | 636 |
| All fuel up 50% | 717 |
| *Wind parameters* | |
| Standard (mean wind power $\bar{W}$ = 1 GW, $v$ = 6.0 m/s, $v_s$ = 6.3 m/s, $v_r$ = 12.0 m/s, linear wind power response) | 572 |
| $\bar{W}$ = 0.5 GW | 598 |
| $\bar{W}$ = 2 GW | 522 |
| $\bar{W}$ = 4 GW | 431 |
| $\bar{W}$ = 8 GW | 441 |
| $\bar{v}$ = 5.5 m/s | 469 |
| $\bar{v}$ = 6.5 m/s | 662 |
| $\bar{v}$ = 7.0 m/s | 736 |
| $\bar{v}$ = 7.5 m/s | 800 |
| $v_r$ = 10 m/s | 704 |
| $v_r$ = 14 m/s | 464 |
| wind power response cubic from zero wind power | 572 |
| wind power response cubic from cut-in wind power | 488 |
| $v_s$ = 5 m/s | 686 |
| *Grid parameters* | |
| Standard (LOLP = $10^{-4}$, 5% real interest rate) | 572 |
| LOLP = $10^{-6}$ | 566 |
| LOLP = $10^{-2}$ | 583 |
| 10% real interest rate | 439 |
| forced outage rate = planned outage rate = 10%, all units | 514 |
| Thermal unit sizes doubled | 587 |
| Thermal unit sizes quadrupled | 607 |

[a]Wind power is economically competitive if available at a cost less than or equal to the breakeven cost. The 'standard' result of £572/kW is for the set of parameters specified in Tables 1 and 2 and the text. Other results listed are for a change in the parameter listed, while all other parameters are taken from the 'standard set'.

Table 3 indicates the *second* important result: that the breakeven wind power cost is not highly sensitive to any of the economic, wind or grid parameters within their likely range of variability.

Among the economic parameters, it is clear that increases in coal costs raise the wind power breakeven cost, while increases in oil costs lower it. Among the wind parameters, increasing wind power penetration into the grid (larger $W$) lowers the breakeven cost, while increasing mean wind speeds $v$ increases the breakeven cost. These changes are as expected. Among the grid parameters, the only significant change in breakeven wind power cost results from changing the real interest rate. Since wind power costs are almost entirely capital costs, the decrease in wind power breakeven cost for a higher real interest rate is understandable.

In determining the optimal thermal mix for a variety of economic and other parameters, it was found that the optimal mix hardly ever consists of a mixture of all three types of units. Instead, it is almost always coal–oil, all oil, or nuclear–oil. The optimal mix for the 'standard' parameters is coal–oil, as expected from the total cost of energy figures in Table 1.[18] When the nuclear variable cost is reduced from 0.83p/kW to below 0.55p/kW,[19] the optimal mix suddenly switches from coal–oil to nuclear–oil. Only for a very small range of cost parameters – in an interval of about 0.02p/kW variable cost – is the optimal mix a mixture of nuclear, coal and oil. Similarly, the shift from coal–oil or nuclear–oil to an all oil optimal mix is very sudden as parameters are varied. Thus the *third* important result is that for performance and cost parameters similar to those in Table 1, the optimal mix almost always contains only one or two types of unit.

In Table 4 the optimal mix is given for the different penetrations of wind power into the grid. Since the average available power of coal units is 375 MW, it is apparent that, in a comparison of optimal mixes, wind power displaces considerably more than its average power in available coal plant, with a small increase in available power from oil units. Similarly, in a nuclear–oil mix wind power displaces nuclear power with some increase in oil units. This result is simply explained: in a grid with wind power, the variability of effective load (load minus wind) is greater, and peak plant satisfies this variability more economically. The *fourth* important result, therefore, is that in a comparison of optimal mixes, wind power displaces more than its average power in base plant, with a smaller increase in peak plant. The economic savings from wind power thus come primarily from lower base capital and fuel costs, counteracted by a slight increase in peak capital and fuel costs. This extra peak plant which is seldom used may be said to serve as reliability insurance with a low premium. The change in optimal mix with different wind penetrations also explains why increasing coal costs increase the breakeven cost of wind power, while increasing oil costs reduce it.

[18]This optimal mix explains why increasing nuclear costs do not affect the wind power breakdown cost.

[19]On strict cost of energy grounds, the nuclear variable cost required for total cost breakeven between nuclear and coal is 0.58p/kWh. The additional costs created by the minimum power output of 500 MW for nuclear plant reduces this by about 0.03p/kWh to 0.55p/kWh. A similar small change in breakeven cost would result from a doubling of unit size of nuclear (or coal) units from 500 MW to 1000 MW, due to reduced capacity credit for the larger units.

**Table 4. Optimal mix and cost savings for different penetrations of wind power (mean power $\bar{W}$) into an idealized CEGB grid.[a,b]**

| | Coal | | | Oil | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| $\bar{W}$ (GW) | Units | Capital savings | Fuel savings | Units | Capital savings | Fuel savings | Capital savings | Fuel savings | Total savings |
| 0 | 64.2 | – | – | 81.3 | – | – | – | – | – |
| 0.5 | 62.4 | 32 | 78 | 83.0 | –11 | –16 | 21 | 61 | 82 |
| 1 | 59.6 | 83 | 185 | 87.5 | –39 | –71 | 43 | 114 | 158 |
| 2 | 50.9 | 239 | 501 | 102.9 | –137 | –316 | 102 | 186 | 288 |
| 4 | 25.4 | 701 | 1 574 | 149.4 | –432 | –1 368 | 269 | 207 | 475 |
| 8 | 1.9 | 1 125 | 2 728 | 192.2 | –703 | –2 175 | 421 | 552 | 974 |

[a]Performance and cost parameters given in Table 1.
[b]Fractional units are obtained by interpolation near the optimal mix of integral numbers of units. Cost savings are in £ million (1980 currency) annually.

# Appendix

## Notes on use of CEGB cost estimates

As explained in the text, the computer programme used automatically determines the optimal plant mix for a given set of economic parameters. In the programme, each type of power plant competes for every position in the merit order. This is the appropriate method, since the analysis has been undertaken for planning purposes. The CEGB, in contrast, uses load factors in making comparative economic assessments of power plants, and so assigns coal-fired plant to an intermediate load position in the merit order.

The variable costs quoted in Table 1 are the 1980 costs quoted by the CEGB,[20] based on the assumption of immediate start of construction rather than their projected future costs. It should be noted that the CEGB's claim[21] that new nuclear stations are cheaper than new coal stations is based on two assumptions. Firstly, it is assumed that coal stations will be operated as intermediate load (see above) and, secondly, that there will be a specific real escalation in the cost of coal fuel but no future real escalations in the capital cost of nuclear plant and in nuclear fuel cycle costs. In this article the effects of real escalations in the capital and future fuel cycle costs of coal, oil and nuclear power are explored in a simple sensitivity analysis.

The CEGB report's[22] reference to Heysham II in section D of Appendix 3 suggests that its nuclear power cost estimates relate to the Advanced Gas Cooled Reactor (AGR). It should be noted that a nuclear power station constructed in Britain has a higher cost per kilowatt than one constructed in the USA. This is because the former has additional safety features, two 500–660 MW turbogenerators rather than a single 1000–1300 MW turbogenerator and a cost component for decommissioning. The British AGR also has more materials content than the US Pressurized Water Reactor (PWR). Commentators have suggested that a PWR constructed in Britain might cost about 70% of an AGR. If this could be achieved, then nuclear power would become cheaper than coal in the baseline case (see Table 1).

[20] *Op cit*, Ref 8.
[21] *Ibid*.
[22] *Ibid*.