A Second Look at Wind-Related Electricity Costs
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Ruth Lea's paper, '*Electricity Costs: The Folly of Wind Power*', was published by Civitas in January 2012[1]. Although they do not call into doubt the author's conclusion that wind power (especially offshore wind) is more costly than gas- and nuclear-powered electricity generation, some specific criticisms of the report merit a response. The detail very quickly becomes technical. The substance of this review is that:

- The report's claim that wind power raises carbon emissions, on further examination, has been effectively challenged. At worst, wind power does not alleviate carbon emissions by as much as would a low-carbon energy source that is available on-demand.
- Wind is an intermittent source of energy, producing energy when it can, rather than when people want it.
- Lower, cogently argued estimates of the costs of intermittency exist. A lower-range cost estimate for additional costs attributable to wind-power by 2020 is £20/MWh.
- Experts continue to make different assumptions, particularly about how much back-up plant is needed to maintain security of supply and how to apportion the cost.
- Offshore wind remains an expensive option, whatever the conclusions about additional costs.
- Onshore wind, though much cheaper than offshore, still compares unfavourably with gas-powered or nuclear-powered generation. Even with the lower estimates of additional costs put forward in this review, gas- and nuclear-powered generation are economically preferable.

Adjustments to Levelised Costs Can be Non-Linear

The debate about '*Electricity Costs*' centred around what adjustments should reasonably be made to estimates of levelised costs in the Mott MacDonald report 'UK electricity generation costs update'. That report focused on costs to the generator, whereas different means of producing electricity could have further consequences for the costs met by the consumer.

Levelised costs have become the favoured basis for comparing different forms of generation. Yet they contain an inherent contradiction with regard to intermittency. A methodology that calculates the cost of each unit of energy produced is problematic when costs arise from the energy that is not produced. If an intermittent generator is not producing enough to satisfy demand, other means have to be employed to make up the difference, with costs that are usually greater than if they were operating without reference to an intermittent supplier. Under the levelised costs approach, these extra costs vary in a non-linear way. If the intermittent supplier produces more energy, the complementary, conventional suppliers are required to produce less, with the result that their own

[1] Ruth Lea, 'Electricity Costs: The Folly of Wind Power', http://www.civitas.org.uk/economy/electricitycosts2012.pdf

costs are spread across fewer units and their unit cost becomes higher. The cost estimates in the report, '*Electricity Costs*', depend largely on the work of Colin Gibson. He has set out some of the areas where costs vary because of intermittency, but stresses that 'total system costs', a more detailed exercise looking at all generation and consumption together, is a superior methodology for making economic judgements.

Advice from Phil Lawton of the National Grid is that it pays not to overstate the proportion of costs that are attributable to a single means of generation. For the purpose of supplying customers, an ideal electricity source is one that can produce economically whenever demand exists and be reduced as demand falls. Supply from nuclear stations is kept fairly constant because it is a long process to vary it. Conversely the issue with having too much wind energy is the lost opportunity to generate low carbon electricity, but it cannot be summoned at will. Even different kinds of fossil-fuel plant are better suited either for steady supply or for short-term response. There are many ways of matching supply and demand. It is usually easier to store energy as raw fuel than after producing electricity, although methods such as compressed-air and pumped storage have significant value, particularly when there is a rapid change in demand, or sudden loss of generation. Forecasting the level of wind more accurately gives longer to prepare extra generators, allowing them to respond more economically. European interconnectors, connecting the UK to France, Ireland, the Netherlands and, in future, Norway and elsewhere, provide a flexible way to smooth out fluctuations, just as the National Grid was devised to do for domestic supply.

Extra System Operation Costs

Table 1 of Chapter 2 of '*Electricity Costs*' quoted £16/MWh as the cost of extra system operation costs. This was an estimate only, to cover items specifically beyond the scope of the Mott MacDonald study[2], under headings such as 'extra response, operational reserve and part loading of thermal plant' as described in Colin Gibson's work, or 'impacts on the wider electricity system (such as reserve and balancing requirements) as Mott MacDonald themselves put it. These costs are distinct from 'planning reserve'.

The model in the 2003 paper '*A shift to wind is not unfeasible*' allows some costs to be wind-only and others to be spread across the whole system.[3] That paper's £2.85/MWh for balancing has already been charged solely to wind and does not need to be scaled up. David Handley of Renewable Energy Developers, RES, reasonably suggests instead using the National Grid forecast for 2020 of £4/MWh, calculated in 2011. Beside overall volume of energy, the grid maintains a steady voltage and frequency. All these costs, where they reflect the special case of wind power are reflected in the estimate of 'Reserve for Wind' on page 74 of 'Operating the Electricity Transmission Networks in 2020'. The estimate of an annual £286 million in 2020 for an installed capacity of 27GW is equivalent to costs of £4 per MWh of wind-generated electricity. It is above the Power UK figure and higher than estimates for current levels of wind penetration, but still £12/MWh below the estimate in '*Electricity Costs*'. Potentially, there may be an additional cost element to cater for sudden supply

[2] '*UK Electricity Generation Costs Update, June 2010*',
http://www.decc.gov.uk/assets/decc/Statistics/Projections/71-uk-electricity-generation-costs-update-.pdf

[3] Lewis Dale, David Milborrow, Richard Slark and Goran Strbac, '*A Shift to Wind is Not Unfeasible*', Power UK, March 2003, available from http://www.bwea.com/pdf/PowerUK-March2003-page17-25.pdf

losses when wind speeds exceed the maximum for safe operation. This will be minor by comparison and will generally be addressed by better forecasting rather than extra reserve.

Contribution to Security of Supply

One drawback of using an estimate derived from '*A Shift to Wind is not unfeasible*' for an estimate of costs of balancing and operating reserve is that that paper also examined planning reserve and transmission costs. In these areas, 'Electricity Costs' used a different set of assumptions, leading to suggestions of double-counting. Planning reserve is the means by which issues of security of supply are addressed so the same costs cover both terms.

Capacity Credit

With traditional thermal generation, the security of supply is pretty dependable. A high proportion may be considered available at times of maximum demand. Some back-up capacity is also maintained so that it would be a rare occurrence for supply not to meet demand. As an intermittent source, wind is different. Extra resource is needed if wind farms are to match the contribution of thermal power stations. It is not finally settled how to apportion the costs of this extra resource to each unit of energy. The quantity of back-up capacity needed depends on the difference between the capacity credit for wind and that for gas turbines. The workings are set out in Colin Gibson's spreadsheet, to which '*Electricity Costs*' makes reference.[4] Wind earns a low capacity credit between the average load factor and the minimum at times of high demand. UKERC posits a higher capacity credit[5] for low levels of penetration of the UK market. The higher the penetration of wind, the lower the proportion of its capacity that may be treated as 'firm'.

A capacity credit of 30 per cent (after UKERC) instead of 8 per cent (after E-On) would make a difference of £6/MWh to the extra costs. The more pessimistic assumption still appears justified, even allowing that thermal plants also have their failures, periods of maintenance and occasional problems with fuel supply. The actual level of wind's intermittency depends, obviously, on the weather. This can be followed on the '*New Electricity Trading Arrangements*' website,[6] where figures for 'generation by fuel type' may be compared with the forecast 'output usable by fuel type' at the half-hour level of detail.

Definition of 'Equivalent'

A lower estimate of wind-related costs results if the reserve does not need to match the maximum output of the wind farm but only its average. The reserve plant needs to be energy-equivalent, allowing for a capacity factor (or load factor), rather than power-equivalent, looking only at the maximum power of the intermittent plant. This finds support in the working paper by Professor Dennis Anderson to UKERC's The Costs and Impacts of Intermittency:

The capacity of the thermal plant displaced by the intermittent generation, excluding provisions for new reserves.... is the capacity of the thermal plant capable of providing the same amount of energy

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[4] Levelised cost estimates for electricity generation http://www.iesisenergy.org/lcost/Lcost.xls

[5] '*Costs and Impacts of Intermittency*', UKERC, Paragraph 21, http://www.ukerc.ac.uk/Downloads/PDF/06/0604Intermittency/0604IntermittencyReport.pdf

[6] http://www.bmreports.com/bsp/bsp_home.htm , as recommended by Straight Statistics, 10th February 2012, http://www.straightstatistics.org/article/spinning-wind-powered-future

as the intermittent generators; this is equal to the capacity of the renewable energy generators times their capacity factor. [7]

That assumption would amount to a difference in the region of £13/MWh. '*Electricity Costs*' has opted both for a low-end estimate for wind's capacity credit, whereby only about 8 per cent of its aggregated maximum output may be regarded as 'firm', but also for a contribution to security of supply equivalent to its maximum output, not its average. This is the approach used in '*The Cost of Generating Electricity*' published by the Royal Academy of Engineering in 2004.[8] In this area, the approach of total system costs is more likely to provide answers to which all sides can agree.

The planning reserve implications of wind-generated electricity are likely to remain the greatest area of disagreement. Table 2 in '*Power System Reserves and Costs with Intermittent Generation*' shows differences between high-profile studies.[9] Where the emphasis is on replacing fuel consumption, the important equivalence is with the plant needed to generate the same number of MWh. Where the emphasis is on maintaining supply, the equivalence must be with plant always able to deliver the same number of MW. '*Electricity Costs*' is firmly on the side of maintaining supply.

Table 1

Proportions of maximum output	Wind	Gas (CCGT)	Gas (OCGT)
Load Factor	0.35	0.85	0.85
Capacity Credit	0.08	0.85	0.85

To model energy supply without regard to security, load factor is all that matters. 100 MW of installed wind plant with a load factor (or capacity factor) of 35 per cent can generate an average of 35 MW. 100 MW of installed gas (either form) can generate an average of 85 MW. Therefore every 85 MW of wind installation can displace 35 MW of gas installation. In both cases, they would generate at an average rate of 85 × 35 ÷ 100 MW, or 29.75 MW. For security, extra gas plant is required. Capacity credit is the parameter that describes contribution to security. 100 MW of installed gas plant contributes 85 MW of system security ('firm capacity'). 100 MW of installed wind plant contributes 8 MW of system security. So in security of supply terms, 85 MW of wind installation is equivalent to 8 MW of gas. Either way contributes 85 × 8 ÷ 100 MW, or 6.8 MW, to system security.

If wind is installed to displace gas on the basis of equivalent energy production, 85 MW of installed wind displaces 35 MW of installed gas. That is 27 MW gas plant more than may be displaced in security terms, so that is the quantity of planning reserve that has to be kept ready for the occasions when the supply from wind falls short of the level of demand. Because they will not be used continuously, the OCGT is more suited than the CCGT and the energy generated by this gas plant is not considered part of the system.

[7] Professor Dennis Anderson, '*Power System Reserves And Costs With Intermittent Generation*', page 7. http://www.ukerc.ac.uk/support/tiki-download_file.php?fileId=232

[8] '*The Cost of Generating Electricity*', Royal Academy of Engineering and PB Power, 2004

[9] Professor Dennis Anderson, '*Power System Reserves And Costs With Intermittent Generation*', Table 2, page 17, http://www.ukerc.ac.uk/support/tiki-download_file.php?fileId=232

The equivalence now is:

35MW of CCGT, providing 29.75 MW both of generation and security.

Or

85 MW of wind, providing 29.75 MW of generation and 6.8 MW of security
and
27 MW of OCGT, providing an immaterial quantity of generation and 22.95 MW of security.

A version of these figures, scaled up to 100 MW of installed wind, is in Table 3.

Using *L* to denote Load factor and *C* for Capacity credit, *I* for capacity installed, and subscripts *C*, *O* and *W* for Combined and Open cycle Gas and Wind, the required Open-Cycle back-up per unit of wind installed is:

$$\frac{I_O}{I_W} = \frac{(L_W \times C_C) - (L_C \times C_W)}{L_C \times C_O}$$

'*Electricity Costs*' follows a different formula:

$$\frac{I_O}{I_W} = \frac{C_C - C_W}{C_O}$$

This works on the understanding that installed wind replaces an equivalent capacity of installed gas plant.

As assumed in '*Electricity Costs*'

Table 2

MW	**Wind**	**Gas (CCGT)**	**Gas (OCGT)**	**Total**
Installed	100	-100	91	91
Generating average	35	-85	77	27
Security	8	-85	77	0

In calculating planning reserve costs in '*Electricity Costs*', new wind plant is taken to displace an equal quantity of installed combined-cycle gas plant, CCGT. With a capacity credit of 8 per cent, the wind only contributes 8 MW of security of supply, whereas 85 MW are lost by retiring or not building the gas plant. To make up for the lost 77 MW of security, it budgets for 91 MW of installed new open-cycle gas. The effect on generation is to raise the average by 27 MW per 100 MW, and to raise the maximum by 91. Most of this excess will not be utilised, because the nature of intermittent supply is that electricity will often be available at times when it is not required.

For comparison, displacing only enough combined-cycle gas plant to match average generation, following UKERC, appears thus:

Table 3

MW	Wind	Gas (CCGT)	Gas (OCGT)	Total
Installed	100	-41	32	91
Generating average	35	-35	27	27
Security	8	-35	27	0

The difference is that the scenario in '*Electricity Costs*' retires or displaces 59 MW more combined-cycle plant and replaces it with open-cycle. The capital costs of the open-cycle plant, though not the capital savings on combined-cycle, are attributed to wind generation. The two gas types are regarded as equivalent for security of supply, so there is no difference in security between the two assumptions. Another way of looking at it is that if the wind plant requires 91 MW of thermal back-up per 100 MW of installed wind, 59 MW of the back-up may produce usable, saleable electricity so its capital costs do not need to be attributed to wind. The difference in costs is approximately £13/MWh of wind.

Transmission Costs

The third item concerns transmission. This is particularly awkward to apportion between generators so that each pays a fair share. Mott MacDonald's levelised cost analysis specifically excludes 'transmission network reinforcement impacts', but adds an element to running costs for connection to the onshore transmission network and for use- of-system charges. National Grid divides its charges into several sections, covering connection, balancing and general use of the transmission network with generator-specific costs and demand-specific costs. Some of these are caused equally by any generation or demand, but some are more costly with some forms of generation than with others. For example, a distributor is charged more and a generator less for using the system in the south of England, to make up for local surpluses of demand over supply. Wind generation contributes, though not uniquely, to this imbalance. Of the general charges, only 27 per cent are recovered from generators and the rest from distributors.[10] But they do include an element of zonal charging for necessary reinforcement. The estimate of those transmission costs in excess of these use-of-system charges in Colin Gibson's paper for the IESIS is necessarily imprecise, but the central basis is reasonable. Wind farms provide a large source of energy at a distance from its major users, so the cost of a major transmission project is a good indicator of the overall cost. As always, levelised costs from a generator's perspective are distinct from, and usually lower than, the prices paid by the customer. If connection charges are included already, then £6/MWh can be subtracted from the

[10] *2011 NETS Seven Year Statement*: Chapter 10 – Market Overview, National Grid, page 10, http://www.nationalgrid.com/NR/rdonlyres/8BE52C07-A3DF-4E28-B682-C1266D6EDE22/47007/NETSSYS2011Chapter10.pdf

additional costs, but '*Electricity Costs*' already substituted a lower than maximum value for this aspect of the cost.

Lower estimates exist for the cost of reinforcing the transmission and are based on broader data. According to their eight-year business plan and their estimate of 2020 wind capacity above where it stands in 2012[11], National Grid intend to spend in the order of £8.4 billion by 2020, connecting a further 40GW of power from all sources. Roughly half of this will be for connecting new wind capacity. It becomes a matter of judgement how much of the cost may be apportioned to wind. Transmission lines may be used for electricity from any source, regardless of the original reason for constructing them. The existence of a line may make a location more economically attractive for a new thermal installation. If the costs are evenly spread, then the adjustment to levelised cost is around £8.50/MWh. Given that wind farms are usually in remote sites, the unit costs will be slightly higher at around £10/MWh. This is based on capital expenditure approaching 60 per cent of £14 billion, following the National Grid eight-year business plan and their estimate of 2020 wind capacity above where it stands in 2012. It is still £10 to £13/MWh lower than the figure used in '*Electricity Costs*'. Some disagreement remains over how much the cost of reinforcement lies within the Mott MacDonald levelised costs, with the implication that there is scope to reduce the figure still further.

Effect on CO_2 emissions

The cited paper by C. le Pair posits single wind farm with back-up gas-fired generation. It is not appropriate to scale up the results from that to cover a national generation strategy. As long as the need for fossil-fuel back-up remains, wind-powered generation will require other components to emit more greenhouse gases than they optimally might, but the net effect remains that wind power reduces CO_2 emissions within a large, managed system.

Effect on Costs Overall

Identifying the nature and applicability of costs associated with wind-generated electricity retains an element of subjectivity. Experts using differing assumptions have produced very different estimates of the additional costs.

It is possible to derive lower estimates for all elements of these additional costs by starting from different assumptions. Balancing may be as low as £3/MWh, transmission £8.4 to £12/MWh, and planning reserve (with the most seriously different assumption) as low as £6/MWh, making a total in the region of £20/MWh.

Estimates even lower exist, but with contested assumptions. Differences arise where different levels of wind penetration have been assumed or where there is subjectivity surrounding how to apportion a shared cost between several components. David Handley of RES describes his combined estimate of £18/MWH as 'pessimistic', but its assumptions about wind penetration are consistent.

[11] National Grid Electricity Transmission's RIIO-T1 Business Plan Headlines, Page 8, http://www.nationalgrid.com/NR/rdonlyres/A7691393-6DCB-4849-8C0D-DCACEB2004A9/48221/NGET_Headlines.pdf

The disputed costs are presented as adjustments to the Mott MacDonald study, but the same case can be made without them. In the Mott MacDonald analysis, offshore wind remains an expensive large-scale generation option, whether projects start in 2009 or 2017[12]. Onshore wind is more costly than gas or nuclear, depending on the start date. Adding £20/MWh of costs for the consumer takes its cost above both alternatives. Wind power certainly makes a contribution to reducing Britain's carbon footprint, but it is far from being a cheap option.

[12] '*UK Electricity Generation Costs Update, June 2010',* Appendix B, Table B1, cases 2 and 5. http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf