Supplementary evidence to the Energy and Climate Change Select Committee on the economics of wind energy

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Preamble

This note is in addendum to the written and oral evidence Dr Gross submitted to the 10th July one off hearing on this topic. It addresses some of the specific contentions made by Professor Gordon Hughes on behalf of the Global Warming Policy Foundation (GWPF). The main issue the note addresses is the system implications of integrating wind, including Prof. Hughes' contention that meeting the UK's renewable energy targets using wind power will require up to 21GW of dedicated back up plant and do little or nothing to reduce CO_2 emissions. However, a number of additional errors and misapprehensions in Prof. Hughes evidence to the Committee are also addressed.

The note provides a high level overview of key issues. Readers who wish to understand the grid implications of integrating renewables are referred to the authors' review and meta-analysis of existing estimates on this topic for the UK Energy Research Centre (UKERC), and to a number of recent publications commissioned by the Committee on Climate Change and the Department of Energy and Climate Change (DECC)[1]. The UKERC review provides a bibliography of over 100 international peer reviewed academic, system operator and government papers and reports dealing with this important topic. Readers who wish to understand the optimisation problem associated with investment in various types of new power stations are referred to the authors' recent conference paper for the British Institute for Energy Economics (BIEE)[2].

The sections that follow deal with key problems with the GWPF evidence to the Committee in the following order: The volume of wind needed to meet targets; the cost of wind; the potential for the system to absorb wind; the carbon abatement implications of a system containing substantial wind power. This order has been chosen because Prof Hughes' contentions about system balancing requirements and carbon abatement follow in part from his view of wind capacity requirements. In order to assess Prof Hughes assertions about CO_2 emissions we also discuss his paper for the GWPF, which describes three 'scenarios' related to wind power and power system operation (Annex 1). We then use an economic model of the energy system to show what an economically rational approach would suggest (Annex 2). Finally, we provide some relevant background information in the form of statistics and explanation around wind speeds (Annex 3).

The authors have no connection with the wind industry and no vested interest in the debate. This addendum has been prepared to correct a series of misrepresentations related to the cost of wind, operation of power systems and the impact of wind power thereon.

[1] http://www.ukerc.ac.uk/TPA Intermittency Project
http://www.decc.gov.uk/en/content/cms/meeting_energy/network/strategy/strategy.aspx

[2] Staffell, I. & Green, R. 2012, 'Is there still merit in the merit order stack', BIEE September 2012 Conference Proceedings. See also Stoft, S. 2002. 'Power System Economics - Designing Markets for Electricity', IEEE Press, Piscataway, NJ.

Meeting the UK targets: How much wind is needed?

Prof Hughes suggests that 36 GW of wind will need to be installed to meet UK renewable energy targets in 2020. The government has not set a specific target for wind (onshore or offshore). Various scenarios exist, usually derived from cost-optimising models of the power system which seek to determine a likely electricity supply mix consistent with meeting targets at least cost. National Grid's 'gone green' scenario, used to assess requirements for transmission network upgrading, suggests that up-to 26 GW of wind could be installed by 2020[3]. DECC's latest 'roadmap' for renewable energy suggests that by 2020 some 10 to 19 GW of onshore wind and 13 to 26 GW offshore could be installed, with mid ranges of 13 GW onshore and 18 GW offshore (31 GW in total)[4]. Previous DECC estimates have suggested that some 15 GW onshore and 13 GW offshore could be installed in 2020[5], 28 GW in total. The Committee on Climate change (CCC) also offer deployment estimates equivalent to around 27 GW[6]. The CCC has further recommended that the offshore target should be limited to 13 GW unless costs fall[7].

Hence, at least three credible sources provide estimates for installed wind in 2020. The range of estimates is between 26 GW and 31 GW, with most below 30 GW. Currently there is a total of around 20 GW (both on and offshore) in the development pipeline, with about 7 GW installed to date. Hence a plausible outcome based upon *actual* plans and proposals for 2020 is approximately 27 GW.

Prof. Hughes overstates the volume of wind anticipated in 2020. His estimate is 10 GW higher than the estimate used by National Grid to plan for network expansion and at least 5 GW higher than the central range of the DECC figures. It is 9 GW above current plus planned projects.

What are the capital costs of wind to meet 2020 targets?

Prof. Hughes also suggests that the capital cost of installing wind to meet 2020 targets, including transmission upgrades, will be £124 billion.

As noted, approximately 7 GW of wind is already installed in the UK. Assuming that a ballpark 27 GW is consistent with the range of studies reviewed above then some 20 GW is needed to 2020. 10 GW onshore would cost approximately £13 billion. A further 10 GW offshore would cost £31 billion – assuming no cost reductions[8]. The Electricity Networks Strategy Group[9] has estimated that the transmission upgrades needed to meet renewable energy targets will be £8.8 billion – giving

[3] http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/
[4] http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/re_roadmap/re_roadmap.aspx
[5] DECC Renewable Energy Strategy, cited by the Committee on Climate Change http://hmccc.s3.amazonaws.com/Renewables%20Review/CCC_Chapter%202.pdf
[6] 22 GW from 2010 to 2020, with around 5 GW installed in 2010 http://hmccc.s3.amazonaws.com/Renewables%20Review/CCC_Chapter%202.pdf
[7] http://www.theccc.org.uk/reports/renewable-energy-review
[8] Costs approximated, based upon forthcoming UKERC research into the ranges of estimates of the costs of generation, cited in the author's previous submission to the ECC on the economics of wind. See http://www.ukerc.ac.uk/TPA Costs Project and also http://www.ukerc.ac.uk/TPA Offshore Wind Project
[9] http://www.decc.gov.uk/en/content/cms/meeting_energy/network/ensg/ensg.aspx

approximately £53 billion in total for new construction. This does not account for cost reductions, but recent studies suggest the costs of offshore wind could come down by 10–30% over the years to 2020[10]. Existing capacity will have been built at a range of costs, generally below current levels (the costs of power generation escalated during the 2000s[11]). We assume £5 billion to date.

Our rough estimate of the costs of wind to 2020, including projects already constructed, but not allowing for cost reductions in future, is therefore below £60 billion, less than half the figure suggested by the GWPF.

Prof Hughes appears to have costed the entirety of his 36 GW at current *offshore wind* costs. His costing of transmission upgrading is not consistent with National Grid. For reasons discussed below, his estimate of 'back-up' costs is questionable. He suggests that the capital costs for wind should be increased because wind farms are expected to have shorter operating lives than CCGT stations. This is questionable, but making an appropriate adjustment for this adds less than 10% to the wind costs, and nothing to the costs of longer-lived transmission assets[12].

Prof. Hughes estimate of capital costs of wind to 2020 appears to be some <u>£64 billion above</u> what the available evidence suggests, even without allowing for the possibility of cost reductions.

Is there an impending threshold on how much wind the system can absorb?

Prof. Hughes states that wind will "begin to impose increasingly heavy costs on system operation as the share of wind power in total system capacity approaches or exceeds the minimum level of demand during the year (base load). This threshold is due to be passed in the UK shortly after 2015."

Prof. Hughes makes a further contention that wind would need to be permanently constrained, to the effect that no more than 20 GW of 36 GW could be fed into the grid at any one time. His calculations of wind farm economics are predicated on the basis that wind would therefore need to be substantially curtailed, which affects the load factor assumptions he uses[13].

Both comments show a fundamental misunderstanding of the statistics of wind output, and the means by which engineers assess power system balancing requirements.

In layman's terms the key question is as follows - how often does wind generate at maximum capacity, and how often does this coincide with minimum demand? In even more parochial terms, how often is it extremely windy across the UK on a warm night in August?

With 20 to 30 GW of wind installed, statistically the answer is close to zero[14]. The reason is found within the wind output statistics. Wind farms can operate in a range of wind speeds, but wind

[10] http://www.decc.gov.uk/en/content/cms/meeting_energy/wind/offshore/owcrtf/owcrtf.aspx
[11] http://www.ukerc.ac.uk/TPA Offshore Wind Project
[12] The shorter lifetime of wind turbines should be taken into account by charging a proportion of the cost of a replacement station in each of the years after the original wind farm would have closed and then discounting the payments back to the present. .
[13] http://www.thegwpf.org/wp-content/uploads/2012/08/Hughes-Windpower.pdf
[14] See the UKERC review for an exposition of the key principles employed in power system operation http://www.ukerc.ac.uk/TPA Intermittency Project

speeds are most frequently found to be towards the lower to middle of this operational range (in statistical terms, wind speeds approximate to a Weibull distribution). This means that wind farms most often operate at a range of outputs between 10% and 50% of peak output and a diversified fleet of wind farms in different geographical locations would very seldom, if ever all operate at peak output at once. In fact the data show that the output of a UK wind fleet would almost never exceed 75% of rated capacity. It is also unusual for outputs to fall below 5% of installed capacity. This output range is consistent with both weather station data and data from operating turbines[15]. Annex 3 provides a review of wind output data.

In very simple terms, we can therefore assume that with 30 GW installed, wind power will produce, for much of the time, between 3 GW and 15 GW of power. Peak British demand exceeds 60 GW. Daytime demand in winter is typically about 45 GW, peaking to above 60 GW in the early evening. Minimum night time demand in winter is usually above 35 GW. In summer, daytime demand is usually around 35 GW and minimum night time demand about 25 GW. Wind speeds tend to be lower in summer, and higher in winter and autumn. Simply put, when wind data and demand data are looked at carefully we find that there is very seldom any need to spill wind[16].

A more technical explanation can also be provided. In order to determine whether wind power will exceed demand, it is necessary to model wind farm outputs and compare these to demand profiles across the diurnal and annual cycles. This can be done using a system simulation or a statistical simplification thereof. As already discussed, numerous studies have done this for the UK and elsewhere, and detailed statistical studies and simulation models find there is very seldom any need to curtail wind due to insufficient demand. The amount of wind 'wasted' is very small.

Power system control requires that wind cannot be the *only* generation on the network, so the threshold for spilling wind also needs to allow for a minimum amount of conventional plant. Some plants are costly to shut down and restart, and these may need to be given priority over wind at times. Even with these constraints however, Prof. Hughes 'threshold' is misleading. Power system simulations run by the Department of Electrical Engineering at Imperial College suggest that, with renewables targets met, and with nuclear and other 'must run' plants factored in, the need to spill wind is insignificant in 2020[17]. The same study goes onto assess impacts to 2030, concluding that the UK system is well able to absorb a combination of nuclear and new wind, well beyond the 2020 target for wind, with minimal energy spilled. This is consistent with the UKERC review of over 100 international modelling and statistical studies, which indicated that large modern power systems are seldom unable to absorb wind output until wind output is well in excess of 25% of annual demand[18]. Modelling of the British system undertaken by the authors indicates that in 2020, with 22 GW of

[15] Staffell, I. & Green, R. 2012, 'Is there still merit in the merit order stack', BIEE September 2012 Conference Proceedings

[16] 'Spill' is a short-hand term used in the power system modelling community to refer to available wind output that cannot be absorbed by the electricity network and that is wasted, by reducing the physical output of wind turbines

[17] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/future-elec-network/5767-understanding-the-balancing-challenge.pdf - the proportion of wind energy spilled ranges from zero to 0.6%

[18] http://www.ukerc.ac.uk/TPA Intermittency Project - exceptions to this rule occur for small, island systems, for wind-farms located in remote regions with limited grid capacity and if maximum wind output and minimum demand are strongly positively correlated.

nuclear, 30 GW wind and operational constraints accounted for, only 1 to 2 TWh of wind will be spilled, in a system generating around 350 TWh of electricity[19].

In short, Hughes' contention of a 20 GW cap on the input of wind to the GB power grid makes no sense at all. Curtailment will be required extremely infrequently, and the notion of a generalised 20 GW limit on the amount of wind the grid can absorb is baseless. It does not align with the evidence from simulation studies or indeed a commonsense investigation of the basic statistics.

Does the need for dedicated open cycle gas turbine back-up undermine CO_2 savings?

One of Prof. Hughes most startling assertions is that wind needs 21 GW of dedicated gas fired back-up, all of which would be 'open cycle' plant and that if the combination of wind and back-up plant is used to replace conventional gas-fired power stations then carbon emissions would *rise* relative to an all-gas equivalent.

Hughes' notion of a wind-gas system that is less efficient than an all-gas system might appear compelling. It has been widely reported in newspapers and websites hostile to wind power[20]. However it is *economically irrational*, a nonsense scenario that could not come into being if markets and regulation function as they should to minimise costs and ensure that a sensible mix of power stations gets built. Once built, markets and regulation also ensure that the power stations are *used* efficiently. Again, the idea that OCGT would displace the output of the most efficient base-load CCGT plant is economically absurd. The least efficient plants have a role, but the role is restricted to short term balancing or peaking. Only if the market and regulatory systems totally fail could Hughes' scenario of 21 GW of the least efficient gas plants replacing and displacing the most efficient gas plants come to pass. In what follows we try to explain this in lay terms. Annex 1 explains in more detail why the scenarios Hughes describes in his GWPF paper are wrong. Annex 2 provides a more appropriate estimation, using a 'despatch' model of the British electricity system.

Open cycle gas turbines – jet engines connected to generators – are only used on a small scale in Britain. They are typically small units of up to 50 MW, much smaller than conventional power stations.. The potential to be stopped and started very quickly also equips them to provide short term system balancing services. The System Operator (National Grid) might contract them to be available to cover for unexpected events, such as a power station breakdown or power line failure. The idea of such plant is that they are used for a short period of time (if used at all), whilst more efficient power stations are made ready, or the fault is repaired, or demand drops. They are also used as 'peaking' plant, operating for very short periods when demands are highest and the more efficient plants are already at full stretch. Around 1.5 GW of OCGT is currently installed in Britain[21], and such plants are generally operated at very low load factors – in 2011 they generated less than 25

[19] Staffell, I. & Green, R. 2012, 'Is there still merit in the merit order stack', BIEE September 2012 Conference Proceedings
[20] For example, *Daily Mail*, 7 March 2012 and 7 August 2012; European Platform Against Windfarms, http://www.epaw.org/documents.php?lang=en&article=cost5
[21] Digest of UK Energy Statistics 2012

GWh (0.025 TWh) of electricity (the equivalent of running a mere 16 hours at full load over the whole year).[22]

Power system modelling undertaken by the authors suggests that the amount of OCGT installed in Britain would be expected to go up in future, in part because of the variable output of wind, which increases the need for short term balancing plant, in part because old coal or oil power stations currently used infrequently to meet peak demands are set to close down. The modelling suggests that in 2020 approximately 10 to 12 GW of OCGT would be needed, used exclusively as peaking/fast response plant and producing for an average of 30 full-load hours per year[23]. This compares to the 21 GW, running for long periods, that Prof. Hughes cites in his evidence. We are not able to determine the basis on which Prof. Hughes calculates his estimate for the Committee. We note that it is not consistent with his paper for the Global Warming Policy Foundation, in which he contends that the UK will require some 13 GW of OCGT in 2020[24].

Investment in power generation is a complicated optimisation problem; simplistic assumptions, such as those that Hughes makes in his scenario where wind and OCGT replace base-load (see Annex 1) misrepresent reality, and misinform. Under conditions of central planning, monopoly power utilities sought to optimise investment in a mix of power stations such that they constructed the best mix of plants that are expensive to build but cheap to run (nuclear power, more recently wind), and cheap to build but expensive to run (gas OCGT, oil)[25]. An optimised mix would have just the right amount of inflexible 'base-load', the right amount of 'mid-merit' and the right amount of 'peaking plant' to meet demand variations and minimise overall capital and running costs. Annex 2 shows how the plant mix might typically meet demand – now and in future. The mix also needs to include plants that are fast responding – OCGTs can fulfil this role, so can hydro, and the latest designs of CCGT. Once plants are built, planners/markets come in play to ensure that power stations are used rationally. OCGTs are considerably less efficient than conventional (combined cycle, CCGT) gas fired power stations. Whilst they are also cheaper to build, the capital cost savings are quickly overwhelmed by increased fuel costs, for anything other than the most short term uses.

Under highly competitive liberalised markets investment by private companies should approximate to the planners' optimum. In the current UK environment, policymakers seeking to assess the plant mix and policy needs of the future might run an investment decisions model that tries to represent how an oligopoly functions[26]. With liberalised markets important judgements are needed about what is needed from regulation, for example on whether power price signals alone do enough to promote investment in new power stations, or whether some form of capacity incentive might be needed as well. This goes to the heart of the debate around Electricity Market Reform and is beyond the scope of this note.

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[22] Data obtained from Elexon's TIBCO service.

[23] Staffell, I. & Green, R. 2012, 'Is there still merit in the merit order stack', BIEE September 2012 Conference Proceedings

[24] http://www.thegwpf.org/wp-content/uploads/2012/08/Hughes-Windpower.pdf

[25] Stoft, S. 2002. 'Power System Economics - Designing Markets for Electricity', IEEE Press, Piscataway, NJ. Conventional coal and gas plants fall somewhere in between nuclear and OCGT in the spectrum between cheap to run and expensive to build

[26] This is done in, for example, Redpoint Energy and Trilemma UK (2010) 'Electricity Market Reform Analysis of Policy Options' http://www.decc.gov.uk/assets/decc/Consultations/emr/1043-emr-analysis-policy-options.pdf

However, investors and regulators in power generation would have to act extremely irrationally if they were to both make an excessive investment in OCGT, and then to *use* OCGT extensively to replace the output of more efficient plants. This is the key problem with Hughes' analysis – irrespective of how much OCGT might be needed to maintain reliable supplies, his scenario where emissions rises vastly exaggerates the extent to which OCGT would be *used*. Hughes is using OCGT as if it were conventional plant, not specialist, low load factor plant used for short periods when demand is high and wind output low, or when other plants could not come into operation fast enough.

The suggestion that as much as 21 GW of open cycle gas turbine plant would need to be built to back-up wind power in Britain is extremely questionable. *Using* OCGT *extensively* in place of more efficient and cost effective plant is economically absurd. Hughes suggestion that wind could lead emissions to rise is therefore spurious and misleading. It misrepresents how power systems are operated to maximise efficiency and minimise costs.

Annexes 1 and 2 deal with this topic in more depth.

Innovative solutions and the long term

In closing this discussion, we also note that the GWPF dismiss the possibility that demand response, storage and transmission upgrades will be able to assist with the integration of wind. This is because Professor Hughes contends "if the economics of such options were genuinely attractive, they would already be adopted on a much larger scale today".

We note the following: Extensive transmission integration already exists between France, Germany and Scandinavia. This allows a more efficient integration of nuclear, coal and hydro. In other words, transmission has already been adopted because it already is economically attractive. The electricity grid in England has long been connected to France, and the Scottish grid to Northern Ireland. Moreover, since the 1970s the French demand profile has been smoothed, using time of day metering and other measures, to help accommodate the output of relatively inflexible nuclear. However, the potential role of demand response will become larger in future because of technological innovation that makes it possible, notably smart meters and appliances.

Finally, it seems rather strange to suggest that options that are currently little needed (because to date there has been very little wind power to integrate) would have been adopted ahead of time. It is precisely *because* wind will create significant challenges for power system operation that innovative solutions need to be sought. Analysis by colleagues at Imperial College indicates that the potential for storage, transmission upgrade and demand response to reduce costs increases considerably as we look out to the longer term, to 2030 and beyond, and to a largely decarbonised power system[27]. The BritNed interconnector to The Netherlands opened in April 2011, and the EirGrid East West Interconnector to the Republic of Ireland in September 2012. National Grid is proposing a line to Belgium that would be ready in 2018.[28] In other words, the UK's interconnection

[27] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/future-elec-network/5767-understanding-the-balancing-challenge.pdf
[28] http://uk.reuters.com/article/2012/03/14/britain-belgium-electricity-idUKL5E8EE5Y020120314

capacity is being increased, strongly suggesting that the extra capacity will be more useful in the near future than it would have been in the past.

Decarbonising the power system is a challenging task, one that will of course impose costs. It is important therefore to accurately and fairly represent costs now, in the medium term and in the long term future. Exaggeration and oversimplification do not aid understanding or decision-making. We hope that this note provides helpful clarification of key issues.

Annex 1: Nonsense scenarios, and why they make no sense

The GWPF[29] presents three scenarios that ostensibly question the emission savings from wind power. None of them makes sense in terms of power system economics and investment.

The scenario: A. Base load generation

"Suppose that 10 GW of wind turbines substitute for 10 GW of gas combined cycle plant operating on base load. The average in-feed factor for new gas plants is about 92.6% (95% availability & 2.5% of gross output for internal consumption), so the net output from 10 GW of nameplate capacity would be about 81,100 GWh per year. The typical thermal efficiency for a modern CCGT is 59%, so total CO2 emissions would be 26.9 Mt of CO2 per year. In recent years, the average in-feed factor for UK wind generation has been 27% which gives an average output of 23,650 GWh per year from 10 GW of nominal wind capacity. The remainder would have to be provided by gas OCGT plants operating on a stand-by basis. Under such a regime the thermal efficiency of the plants is unlikely to be higher than 35%, so total CO2 emissions would be 32.1 Mt of CO2 per year. When wind generation displaces efficient base load plants it is correct to claim that more wind capacity leads to increased – not reduced – emissions of CO2. Indeed, the situation is much worse if wind generation displaces nuclear power with minimal CO2 emissions."

Why the scenario makes no sense

- Comparing wind and gas on a capacity basis is not sensible.
- OCGT would not be used to fill the gap in output.

10 GW of wind turbines are not comparable to 10 GW of gas turbines. This is because the nameplate capacity of wind turbines is simply a function of how much output they will produce at a maximum output that they seldom reach. Indeed, in wind farms around the world the ratio of blade size to generator output will be tailored to specific wind conditions, which will affect the relationship between energy output and nameplate capacity in complex ways. By contrast a gas turbine can be operated at maximum rated capacity for long periods if desired. This doesn't mean one is 'better', simply that one is optimised to capture wind power and the other to convert fossil fuel into electricity. The only sensible way to compare wind and gas turbines operating is on an equivalent energy basis, comparing costs on a levelised (£/MWh) basis. This means we will need a higher nameplate capacity of wind to produce the same amount of electricity as we would from a given nameplate of gas, it means nothing else and most definitely gives no insight into the amount of

[29] http://www.thegwpf.org/wp-content/uploads/2012/08/Hughes-Windpower.pdf

‘back-up’ needed or what form that plant should take. It does not imply – and the notion is utterly false – that we must back-up the wind on a *capacity* basis[30]. It certainly does not imply that the plant used alongside wind must all be low efficiency OCGT.

The objective function is to deliver a given quantity of energy, if the objective is to produce 81,100 GWh per year, and wind can provide 23,650 GWh, then why would the remainder have to be provided by OCGT? The remainder would be provided by the most cost effective mix of plant, of which a fraction might indeed be OCGT but the majority would more likely be CCGT, depending on the system size, demand profile and existing power mix. In Britain, if wind displaces CCGT on base-load, then the differential will be almost entirely made up by CCGT, on base-load. The way the ‘merit’ system works is to shift each least cost marginal plant ‘up’ the merit, with the most expensive and least efficient plants used last, and least frequently. This is why Hughes’ contention of a wind-OCGT hybrid running base-load is so absurd. It is utterly irrational to replace base-load or mid merit CCGT with OCGT that sits at the very top end of the merit ranking, and so best serves fast response and peaking functions only. For this reason Hughes scenario is a total fiction, not relevant at all to least cost integration of wind in the 2020s in Britain – or anywhere else.

The scenario B. Mid-merit generation

“Using the same capacity figures as in example A above, suppose that wind generation substitutes for mid-merit gas CCGT plants with an in-feed factor of 55% (typical for mid-merit plants). The thermal efficiency would be somewhat lower because of start-up and run-down periods plus periods as spinning reserve. It is reasonable to use a figure of 55% for thermal efficiency yielding total CO2 emissions of 16.0 Mt of CO2 per year. The in-feed factor for wind generation in recent years reflects the fact that wind plants displace base load plants whenever they are available. The appropriate in-feed factor when they displace mid-merit generation will be much lower and will depend on the correlation between availability and demand. It is simplest to assume that in-feed ratio is 14.9%, i.e. 55% of the base load in-feed factor of 27%. Again, gas OCGT is used as backup. In this scenario total emissions with wind generation are 18.2 Mt of CO2 per year, still higher than with no wind generation.”

Why the scenario makes no sense

- The capacity factor of wind does not fall just because it displaces mid-merit plant.
- Lower efficiency causes older CCGT to be mid-merit, not the other way around.

The first error in the scenario is in conflating cause and effect in terms of which CCGT plant operate at which point in the ‘merit order’. CGGT plant efficiency lies in a range, with 1990s plant typically around 50% efficient and brand new plant approaching 60% efficient. Older, less efficient plant tends to be used less than the latest and highest efficiency plant as its fuel costs are higher. Mid-merit plant is likely to be operating at 50% efficiency or below, if it is load following extensively. This is a trivial assertion compared to the one that follows. Hughes assumes that 45% of the energy

[30] This misconception is discussed at length by the author and colleagues in Skea J, Anderson D, Green T, et al, **Intermittent renewable generation and maintaining power system reliability**, Generation, Transmission & Distribution, 2008, Vol:2, Pages:82-89, ISSN:1751-8695 (http://dx.doi.org/10.1049/iet-gtd:20070023)

available from wind turbines will be wasted because it occurs at an inconvenient moment compared to a 'mid-merit' CCGT. Again, this is a silly and economically inefficient misrepresentation. It suggests in particular that zero marginal cost wind would be rejected from the system in favour of a variety of fuel burning plants, with *higher marginal costs* whether on baseload, in mid-merit or (potentially as the simplification is so crude) those on peaking/high merit duty. As with the first scenario, Hughes is also assuming that OCGT would be used exclusively alongside the wind plant in favour of CCGT, again for reasons that are not possible to explain because it is not an economically rational way to operate.

Scenario C. Peak load generation

"There is little to say when wind generation displaces peak load generation from gas OCGT used in the current system, since there is no difference between the efficiency and emissions for regular peak load plants and those used as backup for wind generation. Hence, there will be a reduction in CO2 emissions equal to the amount associated with the gas generation that is displaced."

Why the scenario makes no sense

For reasons already explained this scenario, though less misleading in terms of CO_2 emissions, is just as strange. It would appear to assume that wind is only allowed onto the system if it coincides with peak demands. Are we to assume that at all levels of demand below this wind is constrained off, in favour of plant with higher marginal costs and higher CO_2 emissions? This can only be described as a strange Alice in Wonderland inversion of economic efficiency and good sense.

Annex 2: Scenarios to illustrate efficient operation with and without wind power

The demand for electricity varies over time and it must be generated (or taken from expensive storage devices) at the moment it is consumed. This means that some power stations will have to run for most of the year, meeting the base load demand, while other peaking stations are only needed at times of high demand. The electricity markets in Great Britain allow generators to choose when to run their plants, but the economic incentives are clear. Given the mix of stations currently available, it should be obvious that the stations with relatively low variable costs should be used as much as possible to meet the base load demands, while those with high variable costs should only be used when all the available cheaper stations are already in use.

Figure 1 shows what happened during the first week of November 2011, with data taken from National Grid. At the bottom of the graph, nuclear power stations have the lowest variable costs and run continuously whenever they are technically available[31]. The next area in the graph shows the generation by CCGT stations burning gas, which was also maintained at a high level over the week. The dark area above the CCGT stations represents the generation from coal-fired stations, which varies much more over the period. This suggests that this was a period when the prices of coal, gas and carbon permits were such that it was more expensive (in terms of variable costs) to

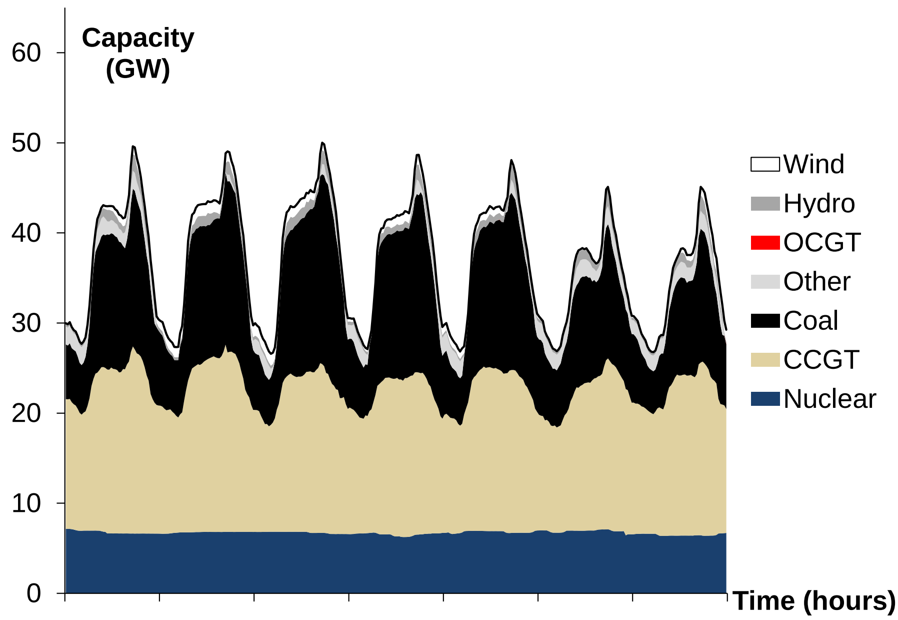
[31] The total costs of building and decommissioning nuclear facilities may be very high, but this does not affect whether it is sensible to use a station which has already been started up.

generate electricity from a coal-fired station than from a CCGT. The coal-fired stations accordingly reduce their output significantly overnight, and increase it once demand rises again the next day.

Note that the CCGT stations also reduce output overnight. This allows the coal-fired stations to continue running at a low load until the morning, rather than having to turn off and re-start the next day. Starting a coal-fired station is expensive, and turning it off and on again too quickly reduces the station's life. A possible analogy is that it rarely makes sense to turn off a car engine for a short delay at a traffic light.

The top bands in Figure 1 show imports from France and The Netherlands and a small amount of generation from oil-fired power stations (grouped together as "other") – cheap power in those countries allowed the UK to import for much of this particular week, even when our demand was low. Output from hydro-electric stations (both the conventional stations in Scotland, and the pumped storage stations in Scotland and Wales) was concentrated at times of high demand. The graph also shows a small amount of wind output, which comes from the larger wind farms which are connected to the national transmission system (rather than low voltage distribution systems).

Fig. 1: Output by power stations in the GB system, November 2011 (National Grid)



These power stations were able to increase and decrease output very rapidly in the early morning and in the evening, meeting significant changes in the level of demand. Some of this demand may have been unanticipated, and the system controllers employed by National Grid had to buy power at short notice to ensure that generation was actually equal to demand. The system controllers also made sure that a number of stations were running with spare capacity, able to respond instantly if there was a fault at another plant, and that some were available to start at short notice if needed. All of these balancing costs are collected by National Grid and (in due course) paid by consumers.

Figure 2 shows a similar picture, but based on the authors' simulation rather than history. It uses an economic-engineering model presented at the British Institute for Energy Economics conference, September 2012. The model selects the cheapest combination of plants able to meet the demand for electricity and for reserve capacity, optimising over the year. This means that it will reduce output overnight from plants with relatively low variable costs if this allows other stations to avoid the cost of shutting down and starting up the next morning, just as shown in Figure 1.

The model is calibrated for a possible level of demand in 2020, some 350 TWh of output per year (including losses in the transmission and distribution system). Hourly demands from 2010 have been scaled up to give this annual total. The demands have been matched with wind speed data from the same hours to simulate the output from 7 GW of wind turbines spread around Great Britain – roughly the current amount of wind capacity. The model assumes that there will be 11 GW of nuclear capacity (current stock, minus some retirements, plus some new build), 12 GW of existing coal capacity and 4 GW of existing hydro (including pumped storage). The model optimises the number of CCGT and OCGT stations to ensure that demand (and reserve requirements) can be met, choosing the combination that best minimises capacity costs and running costs.

Fig. 2: Optimal dispatch for a system with 7 GW of wind capacity (calculations from the model reported by Staffell and Green, BIEE Conference 2012)

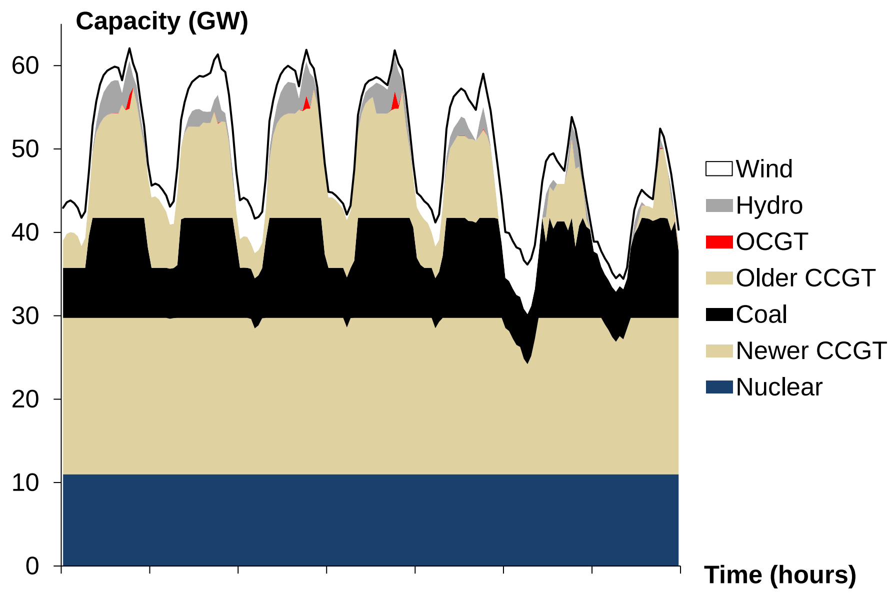
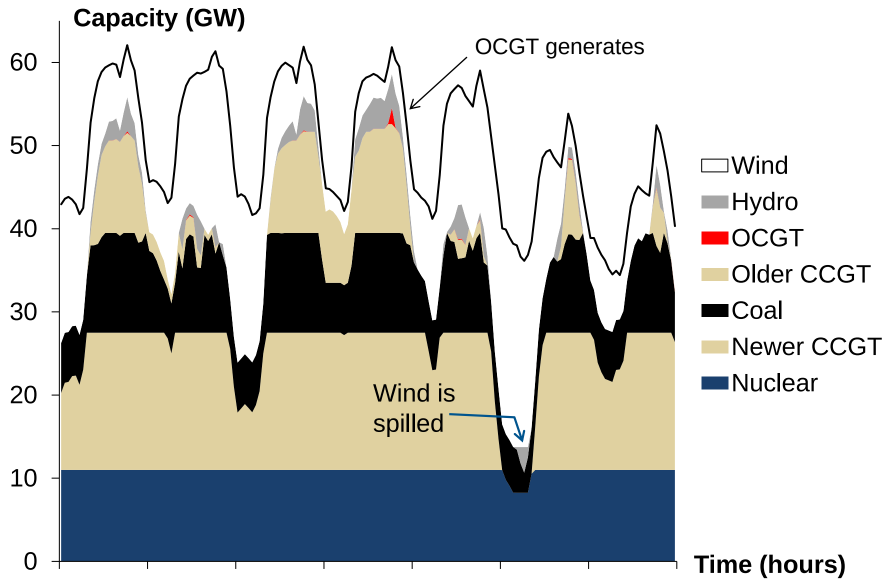


Figure 2 shows a broadly similar pattern to Figure 1, except that there is less coal-fired plant, as some is due to retire before 2016. Because the older CCGT stations are expected to have higher variable costs than the coal-fired stations (using DECC's central predictions for fuel and carbon prices), they are shown separately from the low-cost new stations. The model mainly chooses to build CCGT stations, and rarely runs OCGT stations – their high fuel costs offset the reduction in capital costs that they offer. The OCGT stations only provide noticeable amounts of output in the early evening of the first, third and fourth days of the week we model (based on demand and wind conditions for the week commencing 11 January 2010).

Figure 3 repeats the exercise using the same demand and wind speed data, but with 30 GW of wind capacity. The wind output (shown in white) is noticeably greater, leading to bigger variations in the demand placed on the thermal power stations – which they are still able to meet. Comparing Figure 2 and Figure 3, it is clear that the extra wind output mostly displaces energy from the older CCGT stations, the coal stations and, overnight between the fifth and sixth days, the newer CCGT stations. Indeed, there is so much wind at that time of (relatively) low demand that it makes sense to spill a small amount of wind energy (shown in a medium shade) to allow more coal stations to continue running through the night at minimum load. The amount of wind output spilled is tiny compared to the amount produced during the week. The amount of energy produced by OCGT stations is also tiny, and less than in the simulations with 7 GW of wind.

Fig. 3: Optimal despatch with a system with 30 GW of wind capacity (calculations from the model reported by Staffell and Green, BIEE Conference 2012)



Over the whole year, roughly 60% of the energy produced by the additional wind capacity (comparing 30 GW and 7 GW) displaces output from CCGT stations, and 40% displaces coal output. There is a small reduction in nuclear output (less than 1% of the wind output) and 0.3% of the wind output has to be spilled. The output from OCGT stations is almost unchanged.

The particular numbers in these simulations depend upon the assumptions made. Different fuel prices could lead to a different pattern of generation; different assumptions about the capital costs of power stations would affect the capacity mix. The simulations do not consider congestion on the transmission lines between Scotland and England, which can lead to wind being spilled (although new transmission lines are being planned to reduce these problems). They do not deal with the unpredictability of wind power (beyond requiring the system operators to keep plant in reserve to respond to this).

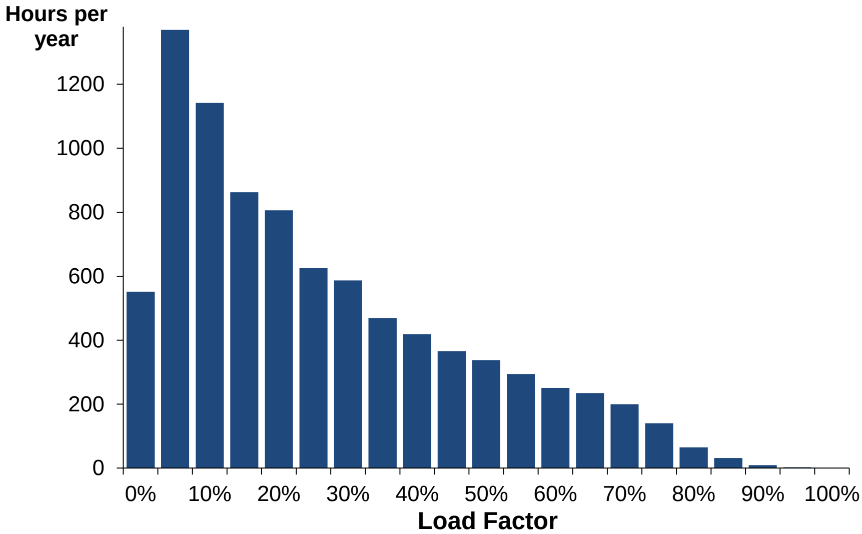
The broad conclusions of this work, however, are likely to be robust to a wide range of assumptions. Additional wind output in Great Britain will generally displace energy from coal- and gas-fired power stations in the years to 2020, reducing CO_2 emissions, and there will not be a significant change in the use of OCGT plant.

It is clear that in a least-cost scenario, we do not see the massive expansion of OCGT capacity and output that Hughes proposes.

Annex 3: Wind output patterns

We commented on the level of output that would be expected from a diversified fleet of wind turbines in Great Britain. National Grid reports the half-hourly output from all the stations that interact directly with its system, either because they are relatively large or they are directly connected to the transmission system – as opposed to smaller wind farms connected to the distribution networks at lower voltages. In practice, this means that a small number of offshore stations and a large number of stations in Scotland (where the transmission system includes lower voltage cables) are included in the data. Figure 4 shows the distribution of outputs over the three years from 2009-11. It shows that very high outputs are quite unusual, but also shows nearly 600 hours a year in which the load factor was 2.5% or less[32].

Fig. 4: The distribution of wind outputs across Great Britain. Collected from historic TIBCO data (courtesy of National Grid) 2009-2011.



National Grid's data are dominated by Scottish wind farms, and it is reasonable to expect that there would be a number of hours in which calm weather north of the border is offset by stronger winds further south. Figure 5 reports the results from a simulation[33] that uses hourly wind speed data for 2009-11 from the Meteorological Office (provided through the British Atmospheric Data Service) to estimate the output from a fleet of wind turbines spread across Great Britain, with a few offshore stations, as is currently the case. It shows a broadly similar pattern to Figure 4, except that the number of hours with very low outputs is significantly smaller – if it is calm in one part of the country, it may well be windy elsewhere. There are still an important number of hours in which outputs are very low, however, and our modelling (reported in Annex 2) takes account of the fact that some of the highest electricity demands occur at times of cold, calm, conditions.

[32] Each bar in the figure counts the number of hours in which the load factor was within plus or minus 2.5% of its central point.
[33] Staffell, I. & Green, R. 2012, 'Is there still merit in the merit order stack', BIEE September 2012 Conference Proceedings. Figure 5 is based on data used in that paper; Figure 6 uses the same data as the paper.

Fig. 5: Simulated distribution of wind outputs across Great Britain, estimated from wind speed data from 2009-2011, using the 2011 mix of onshore and offshore wind turbines.

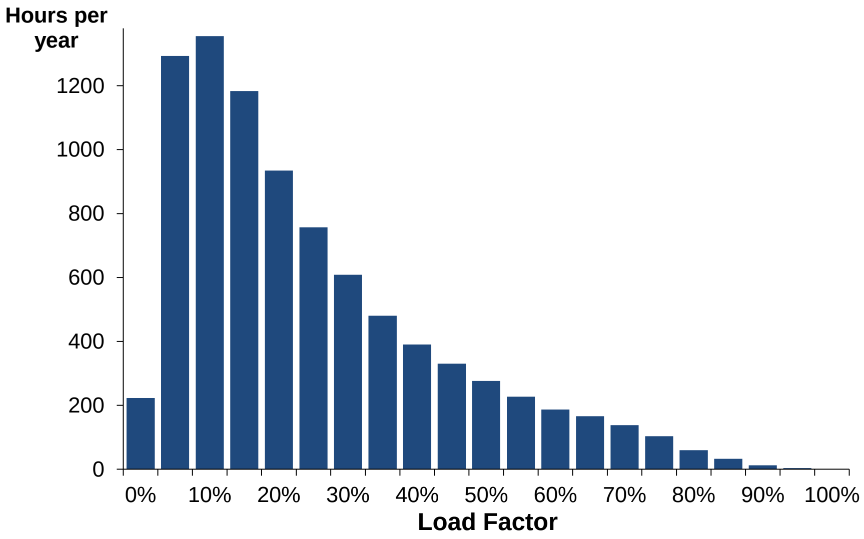


Figure 6 is a further simulation, using the same wind speed data but now assuming that far more of the wind stations would be offshore, where wind speeds (and therefore outputs) are higher. Once again, it is broadly similar to the earlier Figures (which helps to validate the model), with a further small reduction in the number of hours of very low load factors. Load factors of between 10% and 50% occur in two-thirds of the hours in the year, and it is still very unlikely that the total output will exceed 80% of installed capacity. This is the data used in the simulations reported in Annex 2.

Fig. 6: Simulated distribution of wind outputs across Great Britain, estimated from wind speed data from 2009-2011, using the potential 2020 mix of onshore and offshore wind turbines (11 GW onshore, 19 GW offshore).