THE IMPACT OF WIND POWER ON HOUSEHOLD ENERGY BILLS

Evidence to the House of Commons Energy and Climate Change Committee

Gordon Hughes

The Global Warming Policy Foundation
Briefing Paper No 4

GWPF REPORTS

The Impact of Wind Power on Household Energy Bills

Evidence to the House of Commons Energy and Climate Change Committee

Professor Gordon Hughes
Dr Gordon Hughes is a Professor of Economics at the University of Edinburgh where he teaches courses in the Economics of Natural Resources and Public Economics. He was a senior adviser on energy and environmental policy at the World Bank until 2001. He has advised governments on the design and implementation of environmental policies and was responsible for some of the World Bank's most important environmental guidelines. Professor Hughes is the author of the GWPF reports *The Myth of Green Jobs* and *Why Is Wind Power So Expensive?*

The Economics Of Wind Power

The GWPF's submission, written by Professor Gordon Hughes, to the House of Commons Energy and Climate Change Committee for it public evidence session on the Economics of Wind Power on Tuesday 10 July 2012.[1]

1. The economics of wind (and solar) power depend upon two critical features which determine the contribution which they make to meeting overall demand for electricity. The first feature is that wind power has very high capital costs and low operating costs per MegaWatthour (MWh) of electricity generated. As such, it competes with electricity generated by nuclear or coal-fired generating plants (with or without carbon capture). The second feature is that the availability of wind power is both intermittent and random, so only a small portion of total wind capacity can be treated as being reliably available to meet peaks in electricity demand.

2. Neither of these features has a large impact on the operation of an electricity system when the level of installed wind capacity is less than 10% of peak demand, but they 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.

3. When wind power is available, its low operating cost and market arrangements mean that it displaces other forms of generation. Market prices are lower, so that other generators require higher prices during periods of low wind availability to cover their operating and capital costs. It is expensive and inefficient to run large nuclear or coal plants to match fluctuations in demand or wind availability, so that their operating and maintenance costs will be higher.

4. At the same time, the risks of investing in new generating capacity will be increased by the impact of wind power on market prices, so that the

1 http://www.parliament.uk/business/committees/committees-a-z/commons-select/energy-and-climate-change-committee/news/wind1/

cost of capital will be higher. Even if wind power was no more expensive per MWh than power from other sources its impact on other generators would still increase the aggregate cost of meeting the UK's electricity demand, probably by a substantial margin.

5. One way of minimising the impact of wind power on other generators would be to impose a constraint on the amount of wind capacity that can be despatched at any time, so that, for example, no more than 20 GW out of 36 GW of installed capacity can be fed into the grid. Of course, that would be resisted by wind operators as it would reduce the already low load factor for wind farms. The guaranteed price per MWh would have to increase to attract the investment required to meet the Government's targets for renewable generation in 2020, so that customers would have to foot even larger bills for wind power.

6. There is no escape from the consequences of the impact of wind power on other parts of the electricity system. In other areas of environmental policy this would be treated as a negative externality because the costs fall on electricity consumers as well non-wind generators. It follows that there is a prima facie case for taxing the source of the externality. Just as for fossil fuels, there would be strong arguments against the provision of subsidies designed to stimulate investment and output in wind generation.

7. A number of electricity markets outside Europe have developed arrangements to deal with intermittent or unreliable sources of generation, particularly hydro power. The most transparent approach is to require that there are long term contracts for the supply of reliable energy which in aggregate cover the predicted level of demand looking five or more years ahead. Hence, wind farms would have to either contract for storage and/or backup generation or absorb the cost of intermittency in some other way. Variants of this mechanism operate successfully in the US and Latin America (notably Brazil). They are more transparent and less likely to impose large costs on electricity customers than the hodge-podge of proposals for guaranteed prices (feed-in tariffs) and a capacity mechanism drafted by DECC. In addition, a proper market for long term reliable energy need not interfere with existing

market arrangements designed to optimize generation and despatch on a half-hourly or daily basis, whereas it is inevitable that DECC's proposals will compromise the efficient operation of such markets in the medium term.

8. Enthusiasts for wind power often suggest that the costs of intermittency can be reduced by (a) complementary investments in storage (pumped storage, compressed air, hydrogen, etc), and/or (b) long distance transmission to smooth out wind availability, and/or (c) transferring electricity demand from peak to off-peak periods by time of day pricing and related policies. However, if the economics of such options were genuinely attractive, they would already be adopted on a much larger scale today because similar incentives apply in any system with large amounts of either nuclear or run-of-river hydro power.

9. With sufficient commitment to research and development, some of these technologies may become economic within 20 or 30 years. However, up to 2030 and beyond it will remain much cheaper to transport and store natural gas, relying upon open cycle gas turbines to match supply and demand. As a consequence, any large scale investment in wind power up to 2020 will have to be backed up by investment in gas-fired open cycle plants. These are quite cheap to build but they operate at relatively low levels of thermal efficiency, so they emit considerably more CO2 per MWh of electricity than combined cycle gas plants.

10. The amount of investment in backup generation that will be required depends upon the minimum level of availability from wind farms spread over the UK. This is the amount of "reliable energy" offered by wind power. Calculations based on the geographical distribution of wind speeds have suggested that this might be as high as 25-30% of total wind capacity. Reality turns out to be rather different. In 2011-12 the minimum output from wind plants was less than 1% of actual installed capacity. This may rise as the share of offshore wind increases, but it would be unwise for any planner to rely upon this. For practical purposes, wind power in the UK must be discounted when considering the system requirement for reliable sources of generation. This means that all retirements of nuclear,

coal or gas-fired plants plus any growth in peak electricity demand must be matched exactly by investment in new non-wind plants, most of which will be gas-fired capacity.

11. Meeting the UK Government's target for renewable generation in 2020 will require total wind capacity of 36 GW backed up by 21 GW of open cycle gas plants plus large complementary investments in transmission capacity. Allowing for the shorter life of wind turbines, the investment outlay for this Wind scenario will be about £124 billion. The same electricity demand could be met from 21.5 GW of combined cycle gas plants with a capital cost of £13 billion – this is the Gas scenario.

12. Wind farms have relatively high operating and maintenance costs but they require no fuel. Overall, the net saving in fuel, operating and maintenance costs for the Wind scenario relative to the Gas scenario is less than £200 million per year, a very poor return on an additional investment of over £110 billion.

13. Further, there is a significant risk that annual CO2 emissions could be greater under the Wind scenario than the Gas scenario. The actual outcome will depend on how far wind power displaces gas generation used for either (a) base load demand, or (b) the middle of the daily demand curve, or (c) demand during peak hours of the day. Because of its intermittency, wind power combined with gas backup will certainly increase CO2 emissions when it displaces gas for base load demand, but it will reduce CO2 emissions when it displaces gas for peak load demand. The results can go either way for the middle of the demand curve according to the operating assumptions that are made.

14. Under the most favourable assumptions for wind power, the Wind scenario will reduce emissions of CO2 relative to the Gas scenario by 21 million metric tons in 2020 - 2.6% of the 1990 baseline ¬at an average cost of about £415 per metric ton at 2009 prices. The average cost is far higher than the average price under the EU's Emissions Trading Scheme or the floor carbon prices that have been proposed by the Department of Energy and Climate Change. If this is typical of the cost of reducing carbon emissions to meet the UK's 2020 target, then the total cost of meeting the target would be £120 billion in 2020, or about 6.8% of

projected GDP, far higher than the estimates that are usually given.

15. Wind power is an extraordinarily expensive and inefficient way of reducing CO2 emissions when compared with the option of investing in efficient and flexible gas combined cycle plants. Of course, this is not the way in which the case is usually presented. Instead, comparisons are made between wind power and old coal or gas-fired plants. Whatever happens, much of the coal capacity must be scrapped, while older gas plants will operate for fewer hours per year. It is not a matter of old vs new capacity. The correct comparison is between alternative ways of meeting the UK's future demand for electricity for both base and peak load, allowing for the backup necessary to deal with the intermittency of wind power.

16. In summary, wind generation imposes heavy costs on other parts of the electricity system which are not borne by wind operators. This gives rise to hidden subsidies that must be passed on to electricity consumers. In the interest of both transparency and efficiency, wind operators should be required to bear the costs of transmission, storage and backup capacity needed to meet electricity demand. Only then will it be possible to get a true picture of the costs and benefits of relying on wind power rather than alternative ways of reducing CO2 emissions.

Supplementary Evidence: The Impact of Wind Power on Household Energy Bills

Measuring the impact of wind power on system costs

1. The debate on the economics of wind power is often accompanied by claims about the impact that reliance on wind power to meet targets for renewable energy will have on household energy bills in the UK. Many of these claims should come with a large health warning because they rely upon calculations that are incomplete or relate to something else altogether.

2. Official estimates of the impact on household bills refer to the joint effect of a whole slew of policies and initiatives. It is almost impossible to determine whether the claims are reliable, because the nature and coverage of the policies changes frequently and some elements are either subjective or rely upon assumptions with large margins of error. In any case, the issue is the impact of deploying wind power to generate a lot of electricity rather than some alternative source of generation. The Green Deal, Electricity Market Reform, etc are all irrelevant, because each initiative is distinct and can be evaluated on its own merits. The fact that investments in energy efficiency may reduce household bills is a reason for going ahead with that program, but it has no bearing on the economics of wind power.

3. Another feature of official and non-official estimates is that they are backwardlooking. They compare the situation with the present fleet of generating plants if this were to continue in the future with system costs in which older, mostly coal, plants are replaced by wind generation. Again, this is irrelevant. A significant fraction of all generating capacity is due to be retired before 2020. So, the choice facing the UK is whether new investment to replace retired capacity and cater for demand growth should go to either (a) the lowest cost sources of generation – either gas CGTs or nuclear plants (depending on discount rates and expected gas prices), or (b) wind or other renewable generating plants.

4. Since there is little likelihood of any nuclear plants being completed before 2020, my analysis has focused on gas CCGTs as the low cost baseline scenario. The crucial point is that the analysis focuses on the impact of new investment on the electricity system. Investors will not build gas CCGTs to run with a load factor of less than 20% to back up wind generation, unless they are paid to do so

5. A rather different defect is that academic estimates of the costs of investing in wind power often neglect the wider impact of wind power on the economics of system operation and investment decisions. The reason is that it is difficult to quantify such effects in a precise manner. Even so, for policy analysis it is much more important to be approximately right than precisely wrong.

6. It is generally agreed that the introduction of a large volume of wind capacity into the existing electricity market will change the distribution of market prices over the year and probably discourage investment in other types of generation such as gas or nuclear. Non-wind generators will have to cope with great market volatility and will apply a higher cost of capital to their investments. The same would be true of wind generators if there is a risk of significant curtailment in windy periods because mustrun plus wind capacity exceeds base load demand, which will occur shortly after 2015.

7. The consequence is that an electricity market operating with a large share of wind capacity will require a higher cost of capital to compensate investors for the risks which they have to bear than one in which the share of wind is negligible. This will, of course, affect the cost of all capital-intensive forms of generation including nuclear, coal with CCS and solar power as well as wind power. Gas OCGTs and CCGTs have low capital costs and would not be affected to the same degree.

8. Of course, any reform that transfers market risks from producers to consumers will reduce the cost of capital and, thus, the cost of wind generation. The same is true for any profile of generation and is quite separate from the penalty attached to wind generation for a given market regime. Bringing back the CEGB in disguise may seem very attractive to those who advocate a centrally contracted market, but it

should be remembered that there are large hidden costs associated with such arrangements. The move to liberalised and decentralised electricity markets around the world has brought large gains in the performance of electricity generators which should not be given up lightly.

9. There is another feature of some levelised cost models which can have an impact similar to an increase in the cost of capital. The basic issue is how to allow for changes in technical parameters such as the average load factor, thermal efficiency, outage rates and maintenance costs as generation plants get older. DECC's levelised cost model incorporates an efficiency degradation factor which is applied selectively to fossil fuel plants in a manner that is not transparent and may not be plausible.

10. It is perfectly reasonable to assume that fuel and operating costs per MWh will increase for older plants while their load factors will be expected to decline. However, these changes will apply to all technologies, not just gas and coal-fired plants. Also, the date at which performance begins to tail off – and at what rates - is very important. Such details are rarely documented properly, even though they can have a significant impact on the results of levelised cost comparisons – as much as £10 per MWh.

11. Levelised cost calculations are inherently artificial. The perspective of investors and operators is rather different and this is what should underpin policy evaluations. Most operators would expect to follow a maintenance regime designed to ensure that a new plant will perform in accordance with its design specification for a period of 15-25 years depending upon the technology and expected plant life. After 60-65% of the expected plant life performance may start to degrade, even with good maintenance, and the operator will consider whether to carry out a major rehabilitation or life extension to reverse the impact of performance degradation. In effect there is a choice between (a) responding to a higher level of operating costs by reducing the load factor and running the plant when market prices are relatively high, or (b) making a significant investment to postpone performance degradation and continuing to run the plant with a relatively high load factor.

12. In technical terms an investment in a new power plant should be viewed as offering a combination of (i) a (relatively) reliable flow of

electricity for sale over an initial period of 15-25 years, plus (ii) a real option offered by the opportunity either to invest in rehabilitation or to operate the plant as peaking or mid-merit capacity for an additional 10-20 years. Assessing the residual (real option) value of the plant after the initial period is technically difficult and involves a variety of assumptions about probabilities and market conditions many years in the future. Few investors are inclined to do this, so the usual approach is to assign a conventional residual value to the power plant at the end of the initial period. The estimates reported below are based on a rather generous assumption that power plants are given a residual value of 20% of their original capital cost (in real terms) after an initial operating period of 60% of their maximum operating life. This provides the basis for using a simple annuity calculation to estimate the capital charge for a new power plant.

The extra cost of wind generation

13. Table 1 shows the total system costs in 2020 of the baseline Gas scenario and three alternative versions of the Wind scenario. The capacity of wind farms in each of the Wind scenarios is normalised so that total wind output in 2020 is 94.4 TWh as explained in Section 7 of *Why Is Wind Power So Expensive?*[2] The differences between the wind scenarios concern the degree to which future wind plants are located onshore or offshore.

a) Mixed - this is the main Wind scenario in which onshore wind capacity in 2020 is 12 GW while offshore capacity is 24 GW. This scenario corresponds to the likely outcome if most of the onshore wind farms that have planning permission go ahead, while the focus of future development shifts offshore.

(b) More onshore – this scenario assumes twice the amount of onshore wind capacity in 2020 as under the Mixed scenario – a total of 24 GW. Because of the lower load factor for onshore wind farms the total amount of wind capacity in 2020 to meet the output target would

2 http://thegwpf.org/images/stories/gwpf-reports/hughes-windpower.pdf

have to be about 39 GW. Given public opposition to the development of onshore wind farms and constraints on the availability of suitable sites this scenario is likely at or above the maximum amount of onshore wind capacity that could be achieved by 2020.

(c) Future offshore – this scenario examines the impact of cutting subsidies for onshore wind generation through the ROC regime substantially so that there is almost no further development of onshore wind farms. The system costs include the cost of backup generation, transmission and a CO2 floor price of £30 per tonne of CO2.

14. The pre-tax real cost of capital or hurdle rate of return, which is what determines the costs borne by consumers, for power projects is determined primarily by two sources of risk: (i) development risk associated with delays and cost overruns during project development, and (ii) market and operational risk after construction. Most analyses show that development risks have a large impact on the cost of capital and are considerably higher for wind power projects than for gas-fired power plants. Post-construction risks will be large for intermittent sources of generation and peaking or backup plants, because they are more exposed to volatility in market prices. Hence, the cost of capital for the wind scenarios will be considerably higher than for the gas scenario.

Table 1 – Comparisons of system costs by scenario (£ billion per year at 2010 prices including CO2 tax)

Real cost of capital	Gas scenario		Wind scenario	
		Mixed	More Onshore	Future Offshore
8%	8.1	15.4	14.0	15.8
9%	8.2	16.2	14.7	16.6
10%	8.3	16.9	15.5	17.5
11%	8.5	17.8	16.2	18.3
12%	8.6	18.6	17.0	19.1
Total wind capacity in 2020 (GW)				
Onshore		12	24	8
Offshore		24	15.25	27

Source: Author's calculations

15. Standard estimates of the real cost of capital for fossil-fuel generators under current market conditions tend to fall in the range 7-9%. The cost of capital for wind projects which rely on ROC subsidies is rather higher with a typical range of 9-12% with values for offshore wind at least 2% higher than the equivalent cost of capital for onshore wind. The ranges given below for the additional system costs associated with wind power are based on the assumption that the real cost of capital for the Gas scenario as the baseline is 8%, while the average real cost of capital for wind generation in the Wind scenarios is a minimum of 10% and a maximum of 12%.

16. Hence, the additional system cost for the Mixed Wind scenario is a minimum of £8.8 billion per year (= £16.9 billion for Mixed Wind at 10% cost of capital - £8.1 billion for Gas at 8% cost of capital) and a maximum of £10.5 billion per year (= £18.6 billion for Mixed Wind at 12% cost of capital

- £8.1 billion for Gas at 8% cost of capital). The differences in system costs would be rather lower for More Onshore wind scenario with a range of £7.4-8.1 billion per year, while the range would be £10.2-11.0 billion per year for the Future Offshore wind scenario in which all future wind farms are located offshore. Note also that total system costs would be much higher under the Mixed Wind scenario than under the Gas even if an identical cost of capital is used for all types of generation. The difference varies from £7.3 billion per year with a real cost of capital of 8% up to £10 billion per year with a real cost of capital of 12%.

17. For the main Mixed Wind scenario the additional system costs are equivalent to £90-110 per MWh of wind generation. Under the other wind scenarios the additional system costs vary from £78 per MWh for the More Onshore scenario to £117 per MWh for the Future Offshore scenario. As a reference point, the average cost of new generation under the Gas scenario is £72 per MWh for the middle of the cost of capital range. Clearly, the increase in system costs due to the introduction of substantial amounts of wind power is substantial, varying from 110% to 160% of costs under the baseline scenario.

18. Another point to note is that the system costs for the Gas scenario include about £1.1 billion per year of CO_2 floor price payments in 2020, whereas the equivalent figure for the Wind scenarios is £0.3 billion per year. Since the government can readily ensure that such payments accrue to the Exchequer, this means that other taxes can be lower while maintaining the same level of total tax revenue. This effect may be partly offset by higher corporation tax payments on profits accruing to wind generators under the Wind scenarios, but this is much more uncertain because it depends upon capital allowances, financial structures and other factors. With typical gearing ratios (i.e. the proportion of total capital costs financed by debt) of 60-80% the additional corporation tax revenue is unlikely to be more than £0.6 billion per year in 2020 and may be considerably lower.

Translating system costs to household bills

19. It is complicated to assess how any increase in the average cost of electricity generation will affect household electricity bills. Most of the calculations that gain widespread currency are misleading because they are incomplete. There are two critical issues that have to be considered:

(a) What will be the incidence on household and non-residential consumers? Industrial and large business customers are generally more sensitive to electricity prices than households. That is reinforced by the fact that the impact of wind generation on wholesale prices will be larger than the impact on retail prices, which include a larger element of distribution and retail costs. Under standard models of tax incidence, which apply in this case, the burden of higher system costs will not fall uniformly on all consumers. One mechanism by which this will happen is that any decline in industrial demand will fall disproportionately on base load demand and, thus, increase the differential between base load and daytime prices. Through such adjustments the average wholesale price paid by households – and probably small business customers – will increase by more than the average price paid by industrial and large business customers. The effect is likely to be even greater if either time of day or marginal cost pricing are adopted on a significant scale.

(b) What will be the impact on network costs and retail margins? Both will be affected by an increase in the average wholesale price of electricity. Transmission and distribution losses are equivalent to 7-8% of the total amount of electricity that is transferred over the network. The largest portion of these losses are "technical losses" due to heat and other losses in cables, transformers and other network equipment, while the remainder are "non-technical losses" due errors or mismatches in metering and billing. In principle, the level of technical losses will vary with the network load, but trying to identify how this might change in future is not practical. The costs of losses are borne by network operators and passed on to customers. Hence, a total increase in generation system costs of £8.8 billion will translate to a cost to all customers of £9.5 billion. On top of this it is also necessary to take account of an increase in retail margins. A part of this will be due to the commercial losses experienced by energy suppliers, but the largest component will be linked to the cost of hedging whose cost will increase substantially. The higher level of wholesale price volatility caused by wind power will have a direct effect on hedging costs which will be amplified by the indirect effect on the cost of capital employed in the supply business.

20. Households account for 36% of final electricity consumption after deducting losses and internal use for electricity generation and in the energy sector. Given the factors outlined above it is reasonable to assume that at least 40% of the total increase in system costs will fall on household customers with a high estimate of 50%. Similarly, the increase in market volatility is assumed to increase the supply markup on wholesale prices (including environmental costs and levies) from 28% in 2010 to 30-33% in 2020.

21. On this basis the average household electricity bill would increase from £528 per year at 2010 prices to a range from £730 to £840 in 2020 under the Mixed Wind scenario. These figures amount to increases of 38% to 58% in the average household bill relative to the baseline under the Gas scenario. The equivalent ranges for the other scenarios are 29-46% for the More Onshore Wind scenario and 40-62% for the Future Offshore Wind scenario.

Appendix A - Alternative assumptions

A1. The results reported above are based on assumptions that are rather favourable to wind power. The penalty associated with the Wind scenario would increase if less favourable assumption are made:

(a) Economic life. The analysis assumes that capital costs of wind plants are recovered uniformly over an economic life of 25 years. Experience shows that wind operators will expect to recover their costs over 15 years or less, since both downtime and maintenance costs rise sharply after 15 years. Some wind turbines have a life of less than 10 years. If the expected life of wind turbines is reduced by 5 years to 20 years, then the addition system cost for the Mixed Wind scenario would increase by £1.0 billion per year.

(b) Load factors. The load factors for onshore and offshore wind are based on current experience. In practice, the load factor for new onshore plants will fall as they are likely to be located in places with less favourable wind profiles. For example, the average load factor for onshore plants in both Denmark and Germany with much larger wind capacities relative to total capacities is well below 20%. The prospect of significant wind curtailment after 2020 would further reduce the expected load factor. If the actual load factors for onshore and offshore wind were 20% and 28% respectively, which is consistent with their performance in Denmark, then the additional system cost for the Mixed Wind scenario would increase by £1.6 billion per year.

(c) OCGT performance. The cost of operating gas turbines as backup is based on an estimate of thermal efficiency which can be achieved if plants are just switched on and off when extra capacity is required. In practice, the plants will not operate in this way. The volatility of wind generation from minute to minute or one 5 minute period to the next means that there is a significant requirement for spinning reserve, i.e. capacity that is running but which is not contributing power to the system. If this reserve is provided by OCGTs, their effective thermal efficiency will be lower than the theoretical figure. Alternatively, and perhaps more likely, existing coal plants or CCGTs will be used as spinning reserve, in which case there will be fuel consumption and CO2 emissions in the rest of the system that should be taken into account. If the actual thermal efficiency of OCGTs was 30% rather than the figure of 35% assumed in the main analysis, the additional system cost for the Mixed Wind scenario would increase by £0.3 billion per year.

A2. Adopting realistic but less favourable assumptions for these three sets of parameters increases the range of additional system costs for the Mixed Wind scenario from the range £8.8-10.5 billion reported in the text to £12.0-13.6 billion. The corresponding range for the impact on average household electricity bills would be from £275 to £400 per year.

A3. One of the major uncertainties about any projections of future system costs concerns the path of future gas prices. Most official estimates of the costs and benefits of wind power rely heavily upon a rather pessimistic forecast that gas prices will continue to increase as they have over the last 5-10 years. This is justified by reference to the supposed link to world oil prices. The factual and analytical basis for such forecasts is largely wrong, unless the UK were to pursue deliberately wrong-headed policies.

A4. Analysts hold very different views about the likelihood and/or desirability of large scale exploitation of unconventional gas in the UK – not just shale gas but also coal bed methane. The summary which follows does not rely upon any assumptions about the scale of such production. Nonetheless, the lesson from recent discoveries of both conventional and unconventional gas is that gas is an extremely abundant fuel on a global scale. In the medium and longer term the cost of gas in the international market is not driven by scarcity but by the costs of investing in the infrastructure required to extract and transport it. Shale gas has driven down the market price of gas in the US because the marginal cost of extraction is low and there is a large amount of pipeline capacity to transport the gas.

A5. There is no reason why gas prices in the UK should track global oil prices. The fact that this has happened in the recent past is a consequence of poorly designed contracts signed by Germany and other European countries for essentially political reasons. The same is true for the prices paid by countries such as Japan and Korea. Certainly, gas prices may rise in line with oil prices in future but the reason will be government failure not the logic of the international gas market. With an appropriate regime to produce and store gas – UK gas storage is woefully small – the market price of gas will be linked to the cost of building infrastructure to extract and transport gas. Despite the inevitable problems with large projects this is falling in real terms over time and will continue to do so as large new discoveries of gas come on-stream.

A6. If the levelised average gas price used in the calculation is 10% lower than the assumed value of £7.40 per GJ, then the additional system cost under the Mixed Wind scenario increases by about £0.4 billion per year. Because CCGTs are so much cheaper to install and operate than wind turbines, the expected future price of gas is much less important than the expected load factors for onshore and offshore wind turbines in assessing the additional system costs of relying upon wind power rather than gas. Focusing on energy security and independence from international energy prices makes little sense if the alternatives are very costly.

Appendix B – A non-technical overview of generation technologies

B1. Many non-specialists find the combination of acronyms and technical terms that is characteristic of many discussions of power generation confusing and difficult to grasp. Even consulting entries in Wikipedia may not provide much illumination since they are often written for people with a reasonable technical background. Hence, this appendix has been written for non-specialist readers who wish to understand the key concepts of the different technologies that are discussed in the debate about wind power. Specialist readers may consider that it relies upon gross over-simplification but that is an inevitable cost of providing a concise overview for a non-specialist audience.

B2. Most forms of electricity generation on a large scale (other than solar photo-voltaics) involve the conversion of energy into rotational force that drives an alternator in which a rotating magnetic field induces an alternating electric current in a stationary set of conductors that surround it. The number of magnets in the magnetic core and its speed of rotation determine the frequency of the alternating current (50 Hz in Europe, 60 Hz in North America). The voltage of the AC current that is produced by the generator is "stepped up" to match the voltage of the transmission grid and then "stepped down" for distribution to users connected to the electricity network.

B3. Wind turbines are very simple machines that are familiar to almost everyone. The flow of air over the blades of the turbine causes them to rotate. This mechanical energy is converted to electricity through a combination of gears and an electricity generator. While the blades, the rotor shaft and the supporting tower are the most visible components of a wind turbine, they account for only about 35-40% of the total cost. Other components include the civil works required for installation, gears, electrical generator, transformer, etc. The amount of electricity produced by a wind turbine depends strongly upon the wind speed since the potential wind energy available varies with the cube of wind speed. Modern wind turbines have an output profile that is zero below a cut-in speed of 3-4 metres per second (m/s) and reaches their maximum output in the range 12-15 m/s. For safety reasons there is a cut-out speed

– usually 25 m/s – above which the turbine has be closed down. [1 m/s converts to 2.24 mph, so the operating range of a modern wind turbine is approximately 8 to 56 mph, while rated output is only achieved for wind speeds greater than 27 mph or at least Force 6 (strong breeze) on the Beaufort Scale.]

B4. There are fundamentally two different ways of generating electricity from fossil fuels. The traditional way is to burn the fuel in a boiler which produces steam and then the steam is directed into a turbine whose rotation is used to generate electricity. Almost all coal and oil plants operate in this way, as do an older generation of gas plants. The thermal efficiency (i.e. the proportion of the energy content of the fuel that is converted into electricity) of such plants is limited by the engineering and thermal problems of converting fuel into steam and then steam into electricity. Even the most modern steam plants do not achieve a thermal efficiency of much more than 42%.

B5. The alternative is represented by a jet engine, which is technically a gas turbine. The fuel is burned in a compressed stream of air so that the resulting explosion expands the air and thereby drives a turbine directly. Most people are familiar with jet engines. What are called open or single cycle gas turbines (OCGTs) are often derivatives of jet engines with the turbines designed to power an electricity generator rather than provide backward thrust. On their own, gas turbines are less efficient than steam turbines in generating electricity but they are compact and flexible because they can start and stop quickly. Typically their thermal efficiency is 30-35% depending on how they are operated, though some new gas turbines are reported to achieve an efficiency of 38-40% when running at a steady rate.

B6. A combined cycle gas turbine (CCGT) literally combines the two technologies. The first stage consists of one or more gas turbines. Then, the hot gases from the first stage are used to produce steam which drives a second stage steam turbine. The combination of the two stages provides considerable flexibility because plants can be designed with the option of running the first stage only. While natural gas is the fuel of choice for CCGTs, they can run on most types of gas-oil such as kerosene, jet fuel or diesel.

B7. There are also a small number of coal-fired plants around the world which have an initial stage of coal gasification with the gas being used to feed the equivalent of a CCGT. Plants based on this technology, known as integrated gasification combined cycle (IGCC), are expensive to build and complex to operate, but they can achieve relatively high levels of thermal efficiency (about 50%) and they can be attractive where coal is cheap and environmental controls are strict.

B8. The thermal efficiency of CCGTs has steadily improved (along with the performance of jet engines) as designers have found ways of making each stage more efficient. When CCGTs were first introduced in the 1980s their typical thermal efficiency was less than 50% - the typical design level was 48% but achieved values were closer to 45%. Today the design specification of a modern CCGT will often be 60% or even higher and the achieved values will be about 58%. As a consequence, gas-fired CCGTs have overtaken coal-fired plants as the dominant technology for new fossil fuel plants providing that a reliable supply of gas is available. A further advantage is that the average capital cost of CCGTs per MW of capacity is much lower than for steam turbines and they can be constructed much more quickly - typically 2-3 years by comparison with 4-5 years for coal-fired plants.

B9. An alternative way of combining electricity generation with heat recovery is offered by combined heat and power (CHP) plants. Any steam or gas turbine can be converted to CHP operation by using the waste heat from the steam or gas turbine to heat water that can be used for industrial processes or residential use. In principle, the most efficient form of CHP is offered by tri-cycle operation which combines a CCGT with a final stage of heat recovery to produce hot water. The thermal efficiency of such plants can exceed 80%. However, the high efficiency of CHP plants involves a significant loss of flexibility and requires large complementary investments to distribute hot water. Heat losses, even from insulated pipes, mean that it is rarely sensible to transport hot water over a distance of more than 10-20 km. For a temperate country such as the UK, unless circumstances are particularly favourable, it is usually more efficient to transport gas which can be burned to produce hot water in high efficiency boilers in situ than to invest in the distribution of hot water from centralised heating or CHP boilers.

B10. Maintenance costs for all gas or steam turbines are strongly linked to the number of start and stop cycles they experience (because the thermal stresses are greatest during cycling up or down). Because of their origin as jet engines, OCGTs are designed to start and stop quickly as well as to lower the maintenance cost of each cycle. That is why they are better suited to back up wind turbines than are conventional steam plants. In running electricity systems for which demand may vary a lot from one 5 or 30 min period to the next, the disadvantage of the low thermal efficiency of OCGTs is offset by their flexibility and responsiveness. On the other hand, it is not economic to run them continuously because their fuel cost per unit of electricity is too high.

The Global Warming Policy Foundation is an all-party and non-party think tank and a registered educational charity which, while open-minded on the contested science of global warming, is deeply concerned about the costs and other implications of many of the policies currently being advocated.

Our main focus is to analyse global warming policies and their economic and other implications. Our aim is to provide the most robust and reliable economic analysis and advice.

Above all we seek to inform the media, politicians and the public, in a newsworthy way, on the subject in general and on the misinformation to which they are all too frequently being subjected at the present time.

The key to the success of the GWPF is the trust and credibility that we have earned in the eyes of a growing number of policy makers, journalists and the interested public.

The GWPF is funded overwhelmingly by voluntary donations from a number of private individuals and charitable trusts. In order to make clear its complete independence, it does not accept gifts from either energy companies or anyone with a significant interest in an energy company.

Published by the Global Warming Policy Foundation

For further information about the GWPF or a print copy of this report contact:

The Global Warming Policy Foundation
1 Carlton House Terrace, London SW1Y 5DB
T 020 7930 6856
M 07553 361717
www.thegwpf.org

Registered in England, no 6962749
Registered with the Charity Commission, no 1131448