SELECT COMMITTEE ON ECONOMIC AFFAIRS
The Economics of UK Energy Policy

Evidence submitted by Professor Richard Green

1. I am the Alan and Sabine Howard Professor of Sustainable Energy Business at Imperial College Business School. I have been studying the economics of the electricity industry since 1989. I am currently working on interdisciplinary projects, funded by the Engineering and Physical Sciences Research Council, investigating economic questions related to energy storage, international transmission, wind power and carbon capture and storage (CCS).

What are the key economic challenges for the energy market which the government must address over the next decade?

2. The decarbonisation strategy advocated by the Committee on Climate Change is to decarbonise the power sector by around 2030 and then increase the use of low-carbon electricity in heat and transport. This implies a significant increase in the demand for electricity, particularly during the peak winter months, and the capital stock must be sized to meet the peak demand. If the ratio of peak demand to average demand rises, asset utilisation falls, and this will raise the level of capital cost per kWh supplied. The capital-intensive nature of many low-carbon generating technologies will exacerbate this. **We need to design an electricity market that can support this capital-intensive production system**; the current trading arrangements were adopted when the system was fuel-intensive.

3. The government's Electricity Market Reform assumed that from the late 2020s, a high carbon price would support mature low-carbon technologies without requiring further intervention.[1] It should be noted that as their market shares rise, the average market prices received by wind and solar generators will fall, even if the closure of other plants keeps the market in overall balance. This is because wind and solar output is concentrated in particular periods when the weather is favourable, and those high levels of output mean less demand for other stations and a lower price at those times. The market is kept in balance by higher prices at other times, when wind and solar outputs are low. The renewable generators thus sell a disproportionate share of their output at times when market prices are low, depressing their revenues relative to the market average. This does not mean that those generators will never be competitive, but **wind and solar generators will need lower costs, or a higher carbon price, than in the absence of this effect**.

4. The costs quoted for low-carbon generators in the UK are often higher than those in other EU countries. Comparisons must be made with great care; the pattern of wind speeds or solar radiation determines the output available from a given investment, and the cost per unit generated from two solar farms with identical total costs would inevitably be higher in the UK than in a sunnier region. Offshore wind power will be more expensive, holding other things constant, the further from shore and the deeper the water. Some countries separate the cost of transmission from the price paid to

[1] See, for example, Table 1.1 of the *Implementing Electricity Market Reform* document published in June 2014, URN 14D/221

the generator (unlike the UK) and some carry out pre-development work before a tender is held. This transfers cost and risk from the developer, but does mean that a planner has to decide (at least roughly) what will be built.

5. Despite the caveats above, it is startling that Dong Energy has agreed to build two 350 MW offshore wind farms in the waters off the Netherlands at an average price of €72.70/MWh over 15-year contracts.[2] At today's exchange rate, that is £62.95/MWh. The Financial Times suggested that transmission costs would bring this up to €87/MWh, or £75/MWh.[3] Vattenfall has bid DKK475/MWh (€63.80, or £55.24) for two projects in Danish waters, again excluding transmission.[4]

6. The two projects that won the first Contracts for Differences in the UK bid £114.39 and £119.89/MWh, including transmission costs. The cheaper of these is currently the subject of legal action (following a complaint by the RSPB) and was unable to sign its CfD in time. The committee might wish to ask the four companies involved to explain the differences in their construction costs and cost of capital that have led to such a wide range of prices. **If there is something in the UK system that creates a genuinely higher cost of capital for otherwise similar projects, this will be a serious obstacle to the task of decarbonising our economy at reasonable cost.**

7. The less energy we use, the less it will cost to decarbonise that amount of energy. Many energy efficiency measures appear to be highly cost-effective,[5] although this is not inevitable and some rebound effects exist: for example, people choose higher temperatures once their homes have been insulated. In the UK, rebound is not generally strong enough to offset the benefits of energy efficiency. **Two major obstacles are that the business model of energy companies is traditionally based on selling more to their customers, not less, and that the party paying for the energy efficiency measure may not be the energy consumer.**

8. Developers pay the additional cost of building a more efficient home; landlords typically pay the cost of upgrades to tenanted homes. Lobbyists might protest that incurring these costs would drive up house prices and rents; it is likely that they are hired because some developers or landlords fear that they will *not*. Rents and house prices are determined by the amount that people are able and willing to pay for a largely fixed supply. When higher prices are paid for homes, this does not significantly change the amount paid for builders and materials, but it does increase the price of the land underneath them. Requiring better insulation for new buildings reduces land values, giving developers owning land an incentive to lobby against higher standards. Similarly, if landlords have to spend money upgrading their properties from the lowest standards before they can acquire a new tenant, this reduces the capital value of those properties (before they are refurbished).

9. Rents and house prices would rise (offsetting the cost to landlords and developers) if enough people were willing to pay more for an efficient home that was cheaper to run. If that culture change takes place, the split incentive between landlord and

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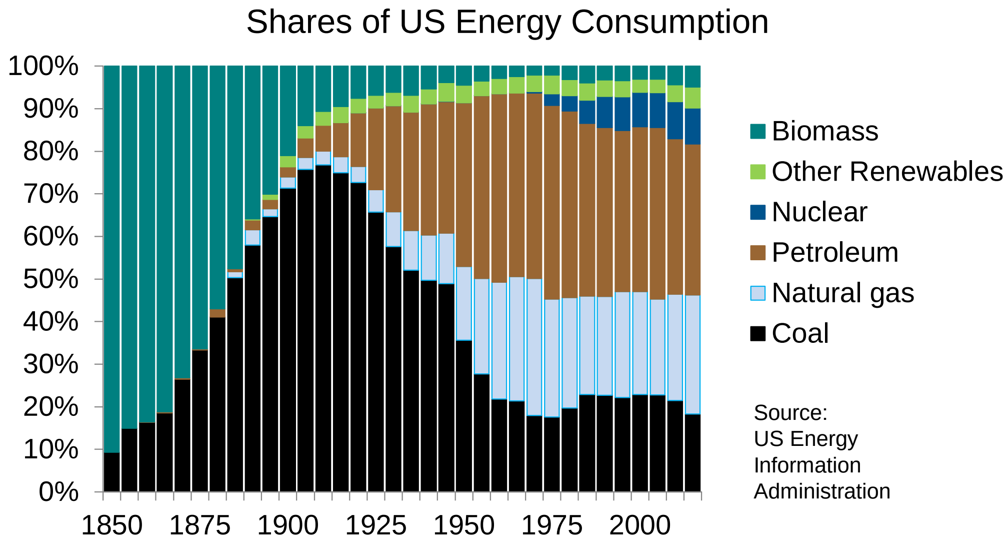
[2] http://www.dongenergy.com/en/media/newsroom/company-announcements-details?omxid=1472197
[3] https://www.ft.com/content/18b0f2b6-42db-11e6-b22f-79eb4891c97d
[4] https://corporate.vattenfall.com/press-and-media/press-releases/2016/vattenfall-wins-danish-near-shore-wind-tender/
[5] See, for example the impact assessment of the Energy Efficiency (Private Rented Property) (England and Wales) Regulations 2015 http://www.legislation.gov.uk/ukia/2015/60/pdfs/ukia_20150060_en.pdf

tenant would be greatly diminished. Prices would also rise, but harming households, if the supply of housing fell. This might happen involuntarily if it proves impossible to find enough skilled workers to build better homes and improve existing ones. It might happen voluntarily if landlords preferred to keep homes empty and developers preferred not to build on their land banks. This is more likely to happen in areas where rents and land values are low, and so the margin to pay for improvements is limited. It could also happen if politicians give the impression that they believe the lobbyists, so that a developer who refuses to build a high-quality building when that is the requirement thinks they might be rewarded with permission to build a low-quality building later. Similarly, landlords willing not to have warm tenants now might hope they will be allowed to have cold ones later.

How long might it take for new technologies to displace the established capital stock?

10. Energy infrastructure is typically long-lived, and it can take decades for a new technology to displace existing capital. The graph below shows the slow evolution of the energy mix in the United States, largely under normal market forces. Coal did not overtake biomass until around 1880; oil took until 1930 to reach one-quarter of consumption, and natural gas until 1960.



11. In the UK, gas took just a decade, from 1990 to 2000, to capture one-third of the electricity market, and peaked with a share of 47% in 2010. Its rise was helped by the change in industrial structure that came with privatisation; the Regional Electricity Companies had an incentive to enter the generation market and could do so on favourable terms, while the incumbents needed to reduce the sulphur emissions associated with coal generation and retired many coal plants during the 1990s. Renewable generation has risen from 4% in 2010 to 17% in 2015, driven by supportive policy; one-fifth of the UK's fossil fuel generators were closed in the same period. The proximate cause of most closures was the choice to opt out of the Large Combustion Plant Directive's controls on sulphur emissions, but the rise of renewable generation would have made much of this capacity surplus to requirements in any case.

12. Further increases in renewable generation are likely to be more challenging, and the ability of additional generators to drive out conventional stations may be reduced. The share of wind generation in the All-Island electricity market (covering Northern Ireland and the Republic of Ireland) is usually capped at around 50%. Large thermal generators have inertia due to the rotating mass of their turbines, which slows the speed at which power frequency falls after a fault and gives time for corrective action before it drops to critical levels. Solar PV and most wind generators have no inertia, and make the system more vulnerable to faults, in the sense that there is less time between a fault and the frequency dropping to the levels at which automatic cut-outs start to protect equipment but cause a black-out. The British electricity system may need to constrain off wind generators at times of high renewable output and low demand to reduce this vulnerability, rejecting some of this output. National Grid already rejects some renewable output because it is too far from consumers and the transmission system cannot cope. **Absent corrective measures, the more renewable capacity we have, the greater the output that will have to be rejected** for these reasons, and the more slowly its market share will grow. This reinforces the mechanism described in paragraph 3, which reduces the relative value of wind and solar power as its share rises, and may also impede its growth.

What are the emerging technologies which could materially change the energy market over the next decade and beyond?

13. Renewable generation is already having a dramatic impact on electricity markets in the UK and elsewhere. Energy storage (and particularly electricity storage) could have a material effect in offsetting the variability of wind and solar power. Similarly, technologies that promote demand response could help consumers to time their use of some energy services for when electricity is abundant. Few people would change their cooking or viewing habits in response to relatively small financial incentives; few would want to pay attention to electricity prices in order to time their water heating to the hours when power is cheapest, as the gain on each occasion is simply too small. We need "fit and forget" systems that will communicate between the power system and (for example) heating controls in order to respond to prices without troubling the consumer. Energy intensive companies adjust their demand as a matter of course, because the stakes are higher; others may have the same (non-) priorities as domestic customers and need the same assistance to save money.

14. In the absence of demand response, electricity storage can provide power when it is needed by consumers and absorb renewable generation at times of surplus. International transmission can help to offset shortages and export surplus power, as long as conditions in the systems at the other end of the line are different from those in the UK. There is no point trying to export power to a country experiencing the same high winds and surplus generation as us. International transmission could also facilitate the deployment of renewable generators across Europe in a way that placed a high proportion of solar systems in sunnier areas, and wind farms where it is windy.[6] The subsidies required would be lower overall but would need to be shared

[6] Green, R.J., D. Pudjianto, I. Staffell and G. Strbac (2016) "Market Design for Long-Distance Trade in Renewable Electricity" *The Energy Journal*, vol. 37, special issue on market design with high shares of renewable energy, pp. 5-22, http://www.iaee.org/en/publications/ejarticle.aspx?id=2727

across European countries, which would presumably be difficult to achieve in the current state of UK politics.

15. **Without demand response, storage or transmission, renewable deployment would require large amounts of back-up generation capacity, which could cost £8 billion a year more than the flexible alternative by 2030**. Work for the Committee on Climate Change suggested that a cost-minimising power system based on inflexible technologies would have a very different mix of generators from one which could draw on storage and demand response, with more nuclear and very little renewable generation.[7] Since the UK is already committed to large amounts of renewable power, this implies that the cost of not having the flexibility from demand response and storage will be even higher. **The National Infrastructure Commission has accepted the benefits of a flexible power system and made recommendations to encourage its development.**[8]

What alternate ways of pricing energy should be considered to reduce the burden of high energy bills, in particular on less well-off consumers?

16. Electricity bills typically consist of charges for each unit of power consumed (perhaps varying with the time of day) and (usually, but not always) a charge per day. This could reflect the marginal cost each consumer places on the system and encourage an efficient outcome.

17. One key question is how to recover the fixed costs of the network. In principle, economic efficiency requires those costs to be recovered in proportion to the demands made on it at peak times, but we have not metered domestic customers in a way that could identify those demands. In the 1970s, research by the Electricity Council showed that, on average, the peak demand imposed by each consumer was closely related to their annual energy demand, and so charges per unit consumed should be used to recover most of the costs of even the local network. Compared to an alternative in which the cost of the local network was shared evenly between households via the daily charge, this raises the bills of high-volume consumers, and reduces those of lower-volume consumers. The latter are typically, but not inevitably, poorer than high-volume customers.

18. Recovering network costs from per-unit charges increases the benefits from installing a solar PV panel, as the customer who does so cuts the amount that they are contributing towards the cost of the network. The panel is unlikely to be generating at the time of the peak demand on the system, which is usually during a dark winter evening, and so does not reduce the costs its owner is imposing on the network company. The latter then has to recoup the revenue lost to customers with solar power by raising its tariffs. This raises the bill of customers without solar panels (who are typically poorer) but increases the incentive to install a panel. In sunny areas where the proportion of panels is rising fast, this has become known as the utility

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[7] Imperial College London and NERA, "Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies", Report for the Committee on Climate Change, October 2015. https://www.theccc.org.uk/publication/value-of-flexibility-in-a-decarbonised-grid-and-system-externalities-of-low-carbon-generation-technologies/
[8] https://www.gov.uk/government/publications/smart-power-a-national-infrastructure-commission-report

death spiral. It is unlikely to have that dramatic an effect in the UK, but still represents a transfer from generally poorer to generally better-off consumers. Reducing per-unit rates and increasing the daily charge would offset this effect but be harmful for low-consumption, low-income customers. A special network contribution from the owners of solar panels has been proposed by some utilities in the US and might be introduced by a particularly courageous UK minister.

19. Smart meters offer the possibility of much more differentiated time-of-day charging, responding to actual conditions on the system. This is known as real-time pricing, in contrast to the time-of-day pricing based on the average anticipated conditions. The marginal costs of electricity will vary dramatically over time in a decarbonised system, and **customers who are able to shift their demands away from peak times could see significantly lower bills than those who do not.** This is not a pure redistribution effect but reflects the fact that every additional responsive consumer cuts the amount of expensive capacity needed.

20. Energy efficiency measures can also cut consumer bills. In the earliest days of the electricity industry, before the adoption of electricity meters, customers were charged according to the number of lights they had installed, or the size of their house. This method of charging was abandoned once metering allowed the industry to link bills to actual consumption, but that then creates an incentive for the company to encourage greater electricity use, and a disincentive to sponsor energy efficiency programmes. Regulatory pressure can be effective in making energy suppliers offer measures such as low-energy light bulbs and insulation to selected customers, but the UK has had a succession of schemes with varying results. If the committee would like a (very) radical alternative, electricity bills might be linked to the size of home being supplied, and perhaps the number of people living there. The supplier would then have a real incentive to install energy-saving measures, since these would reduce their costs and have no impact on their revenues.

21. The customer, however, would have no incentive to save energy. The “English thermostat” (also known as an open window) might be an attractive way to cool an over-heated room on a winter day. Moving from per-unit to fixed bills would be the exact opposite of several decades of policy in the water industry, where meters have replaced rateable values as the main basis of charging. To the extent that low-income people live in smaller homes, however, they would pay a smaller share of the total cost. If the fixed-bill scheme led to greater consumption, that cost would rise and even a smaller share of the cost might be higher than with per-unit charges. I would not recommend this billing scheme, but a carefully monitored, properly randomised, trial might reveal how much energy-wasting behaviour it would lead to.

22. Good public policy is generally that prices should reflect the true costs of goods and services. If this has undesired distributional consequences, taxes and transfers should be used to try to alleviate these. **Deliberately distorting prices away from costs is generally a higher-cost way of achieving a distributional goal.**

Richard Green

30 September 2016

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The Economics of UK Energy Policy

Supplementary evidence submitted by Professor Richard Green

Whether there should be a balance between the objectives of energy policy

1. During the evidence session, several members of the Committee queried whether there should be a balance between security of supply and the other objectives of energy policy, namely decarbonisation and providing energy at a reasonable cost. My position is that the government should aim for a very high level of security of supply, given the importance of energy to modern life. A high level of security of supply requires building enough infrastructure to meet the expected peak demands with a margin on top; holding fuel stocks sufficient to cope with unexpected interruptions to their supply; running the electricity system in a way that ensures its stability if any one generating unit or transmission line suddenly failed. However, it would be possible to run the system so that it was resilient to any two sudden failures, and this would be more secure. For example, parts of southern Sweden and eastern Denmark were blacked out in September 2003 because of the near-simultaneous failure of a generating unit and a transmission line, and this could have been avoided if the system operators had followed an “N-2” rather than an “N-1” rule. This typically involves having more stations running part-loaded, and reducing flows on critical parts of the transmission grid by restricting the output of cheap but inconveniently sited plants.

2. Most commentators believe that the costs of an “N-2” rule would outweigh its benefits, given that following the “N-1” rule delivers a very low risk of interruptions. Most power cuts in the UK are caused by faults on the distribution system, and in particular by wind damage to overhead power lines. It would be possible to bury these lines and avoid those power cuts, but the costs would be high. To say that we should prioritise security of supply rather than balancing it against the cost of energy might be taken to imply that we should be burying as many power lines as possible, and running the system in “N-2“, whatever the cost of doing so. The balance between security of supply and cost does not mean running the system without any spinning reserve, however, as the probability of a black-out would outweigh the undoubted cost savings.

3. At present, the critical issue related to security of supply is the level of generating capacity relative to electricity demand. It is necessary to have more capacity than the maximum demand expected during a normal year, since not all of that capacity will be available at any one time, and extreme weather can raise the demand. The Central Electricity Generating Board planned its investments to achieve a margin of 20% above Average Cold Spell[1] demand between 1970 and 1975. This was intended to ensure that it would only have to take emergency measures, such as reducing voltages or disconnecting a small number of customers, in nine winters in a

[1] This was the peak demand expected during a three-day period in which the temperature did not rise above freezing; the emphasis should be placed upon “Cold” rather than upon “Average”, as it represented the worst conditions that might be expected during a winter.

century. (Keeping the same reliability standard, it later revised the planning margin to 28%, but this was criticised by the Monopolies and Mergers Commission in 1981, implying that it was excessive.)

4. National Grid's latest Winter Outlook announces a capacity margin of 6.6%. This number is dramatically lower than that used by the CEGB, but it is calculated on a different basis. The CEGB took the actual capacity of all power stations, which needs to be much higher than expected demand in order to allow for breakdowns and maintenance. National Grid wants to include the contribution from all stations, including wind power, and has to make adjustments to take account of their different characteristics. National Grid counts between 84% and 96% of the capacity of "traditional" hydro and thermal power stations (biomass, coal, gas and nuclear); their gross capacity of 59.4 GW is 11% above the expected demand (including reserve[2]) under Average Cold Spell conditions of 53.6 GW.

5. The reason for de-rating the thermal capacity is that the expected contribution of wind can then be included in the calculations. Comparing historical patterns of demand with wind generation, National Grid has calculated that 1 GW of wind capacity would make the same contribution to system security as 0.21 GW of (hypothetical) stations with 100% reliability. Adding the 14.3 GW of transmission-connected wind on this basis would give a CEGB-equivalent capacity figure of 62.4 GW, 16% above the expected ACS demand.

6. National Grid also assumes that imports to Great Britain would contribute 2 GW of power at peak times (gross imports of 2.5 GW from the continent, and exports of 0.5 GW to Ireland). Counting this as additional generating capacity gives a total of 64.4 GW, or 20% greater than expected ACS demand. That is the same margin used by the CEGB when planning several years in advance, facing the risks that demand would grow faster than expected or stations would not be completed on time.

7. I hope this explains why apparently low "headline" capacity margins are consistent with National Grid's Loss of Load Expectation of 0.5 hours this winter. This gives the average number of hours, across a range of scenarios and probabilistic studies, in which emergency measures such as shedding small amounts of load would be needed. It implies that there is a good probability that no special measures would be required at any time this winter, but that there is a chance that emergency action will be needed several times in the face of severe weather or worse-than-normal station availability.

8. National Grid is paying £122.4 million to keep 4 GW of capacity at eight coal and gas power stations on the system this winter, through the Supplemental Balancing Reserve scheme. Without this scheme, the capacity margin (on the National Grid basis) would have been 1.1% (13% on the CEGB-equivalent basis) and the Loss of Load Expectation would have been 8.8 hours.

9. If any members of the Committee ask themselves whether it is worth paying £122.4 million to reduce the Loss of Load Expectation by 8.3 hours a year, they are

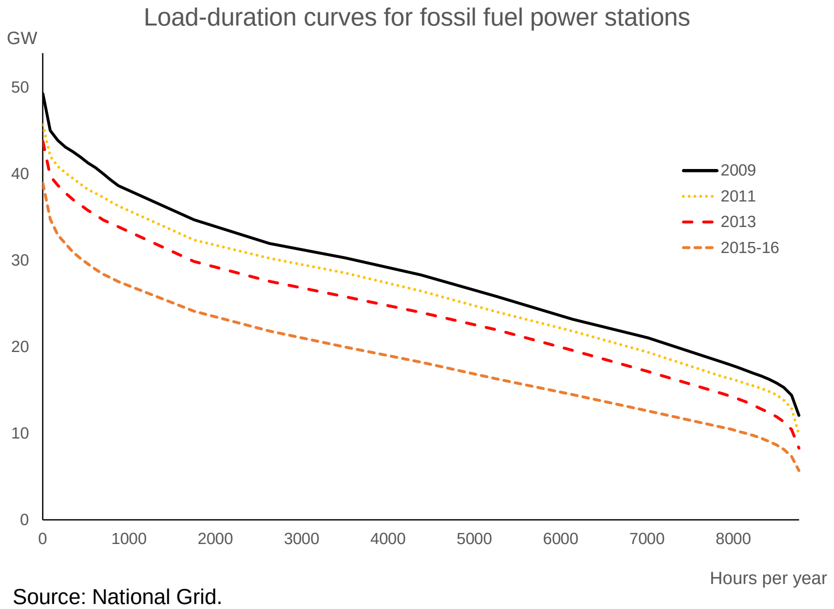
[2] I am not able to check whether the CEGB standard included the need for spinning reserve when estimating ACS demand for its planning standards. If reserve was not included in the past, then my "CEGB-equivalent" numbers in paragraphs 4-6 would each be 2% higher.

acknowledging that there is a trade-off between security of supply and the cost of electricity.

10. It is likely that as the Loss of Load Expectation rises, the size of the average shortfall between generation and demand at those times (and hence the number of customers affected by emergency measures) would increase, and possible that the (very low) probability of an uncontrolled failure and widespread blackout would also increase. In other words, the cost of not having enough capacity are non-linear in the Loss of Load Expectation, and I am not criticising the Supplemental Balancing Reserve scheme.

The Carbon Price Support and Power Station Closures

11. Figure 1 presents four load-duration curves for the coal and gas-fired power stations in Great Britain. It plots the number of hours in which their output was at least the level given on the vertical axis. It clearly shows that the amount of output needed from these stations has been steadily falling. Electricity demand has been declining (or met by stations not connected to the national transmission system) and output from renewable generators has been rising. Given this background, it is hardly surprising that generators have been closing older power stations, and have been reluctant to build new ones – the need for their output has been limited. Many of the coal and oil stations that closed were committed in 2012 to do so, under the Large Combustion Plant Directive, which combats acid rain.



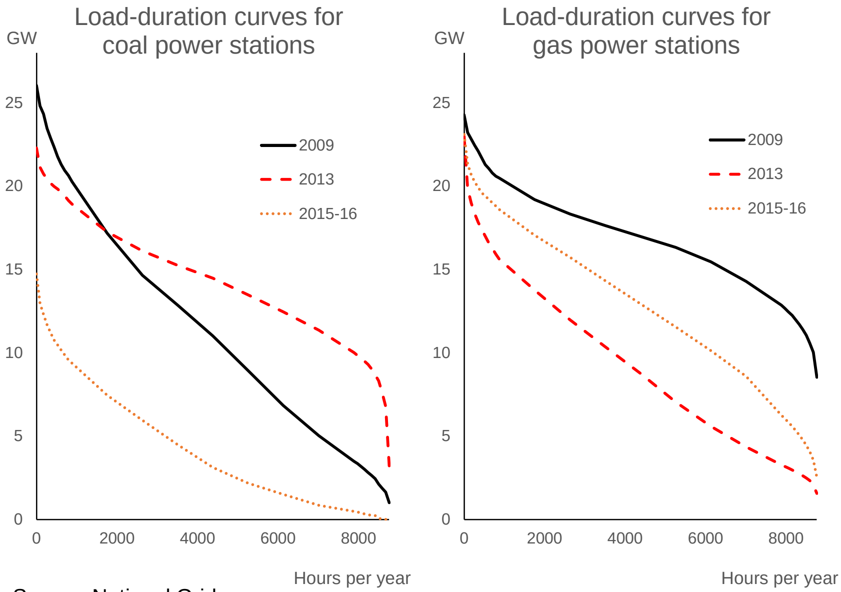
Source: National Grid.
2015-16 refers to the 12 months ending 30 September 2016

Figure 1: Load-duration curves for output from fossil fuel power stations

12. The right-hand end of a load-duration curve represents the peak demands, and these have fallen much less than overall output – we can be almost certain that there will be some hours with relatively high demands and relatively little renewable output. The Supplemental Balancing Reserve scheme is aimed at the stations needed (only) in these hours; from next year, the Capacity Mechanism under Electricity Market

Reform will take over. That mechanism has given contracts to new-build capacity, albeit much of it not of the kind expected when it was designed, but may have contributed to the recent hiatus in investment. While the market design was uncertain, potential investors would not wish to start construction if there was a chance that uncommitted plants would be treated more favourably than those already on the system. I do not know whether many projects were delayed by this effect, but I am aware that the Economic Affairs Committee warned against changing the basis of renewable energy support for just this reason in its 2007-8 report on the Economics of Renewable Energy (HL195 of 2007/8).

13. Figure 2 shows separate load-duration curves for coal (left-hand plot) and for gas stations. Many coal-fired stations ran more in 2013 than in 2009, since exports of American coal (driven out of that market by shale gas) were depressing its price. The corollary was that gas-fired stations were running much less, and some were closed or mothballed. In the year to 30 September 2016, however, the Carbon Price Support has been at a level, relative to fuel prices, that makes coal uneconomic compared to gas. The running hours of gas-fired power stations have improved, while there were nearly 200 hours that saw no coal-fired output. Carbon emissions have naturally fallen as a result of this.



Source: National Grid.
2015-16 refers to the 12 months ending 30 September 2016

Figure 2: Load-duration curves for output from coal and for gas stations

14. Between May 2014 and November 2016, there were net closures of 7.5 GW of thermal power station capacity. The last oil-fired station, Littlebrook D, closed because of the Large Combustion Plant Directive and the last nuclear unit at Wylfa shut down. Two gas-fired stations closed, Barking and Centrica's Killingholme, with press statements citing bad market conditions. The Longannet coal-fired station was closed by Scottish Power, with a statement blaming high transmission charges (which I suspect would not have been a problem for a station with high revenues), while Engie's 2016 statement announcing the closure of its Rugeley station explicitly

blamed increases in carbon costs. The relatively small station at Lynemouth was mothballed, but has received State Aid clearance to convert to biomass. Scottish and Southern closed the last two coal-fired units at Ferrybridge C, but re-commissioned a similar amount of gas-fired capacity at Keadby.

15. The Carbon Price Support would appear to have speeded the closure of some coal-fired power stations, but without the Carbon Price Support, gas would have remained more expensive than coal. That implies that coal and gas-fired stations would probably have had load-duration curves similar to (but lower than) those of 2013. It is quite likely that Ferrybridge, Longannet and Rugeley would still be open, but Keadby would probably be in mothballs, and other gas-fired stations would have proved uneconomic and closed. CO2 emissions would currently be higher, and the task of future decarbonisation made harder by the lower amount of gas capacity available to back up renewable stations. No-one who accepts the government's environmental objectives could think that it was better to close gas than coal stations.

The Cost and Carbon Savings of Renewable Energy

16. The Committee asked me to provide supplementary evidence on the cost per kWh of different kinds of power stations, and the carbon savings obtained from wind power. In its 2007-8 inquiry into The Economics of Renewable Energy (HL 195 of 2007-8), the Committee took the view that it was potentially misleading to compare the levelised cost of energy from conventional and renewable technologies, and instead published a system-wide comparison of the cost of generating and transmitting electricity from two different capacity mixes. One included the then-current amount of renewable generation (6% of output); the second raised this to the much higher proportion needed to meet the UK's 2020 target (34% of output), and was estimated to cost 38% more.

17. The levelised cost of energy from conventional power stations is generally calculated on the basis of base load, near-continuous, operation, but in fact many of these stations are only required to operate for part of the year and have to spread their fixed costs over a smaller volume of output. Levelised costs for renewable generators *are* calculated for the amounts of output they typically produce, but usually ignore the impact of their intermittency on other generators, and the additional costs that the system operator has to incur to manage this.

18. In 2006, the UK Energy Research Centre (UKERC) published a systematic review of studies on the cost of intermittency, concluding that balancing up to 20% of wind energy on the British electricity system would cost £2-3 per MWh of intermittent output (in 2006 prices). Additional capacity, over and above that which would have been required to generate the same amount of electricity, would cost £3-5 per MWh of intermittent output. UKERC is preparing an update to its earlier systematic review, but no results are available at this time.

19. In 2015 work for the Committee on Climate Change, Professor Goran Strbac and a team from Imperial College London, working with NERA Economic Consulting, calculated the system integration costs involved in increasing the amount of generation from wind, solar PV or fossil stations with CCS. It is only possible to think about system integration costs in the context of a specific system, and the report

takes a set of power stations able to deliver average emissions intensity of 100g/kWh in 2030 as its base case. When the share of one of the three options listed above is increased, an equivalent amount of nuclear generation capacity is taken off the system, and so the report estimates integration costs, relative to those of nuclear power as the change in total cost, over and above the direct cost of the stations brought in and out of the scenario. Wind and solar PV cost £6-9/MWh to integrate, compared to nuclear, while stations with CCS reduce system costs by up to £6/MWh as they are more flexible than nuclear power. Integration costs for wind and solar would be higher, the more capacity of each type is installed, and the more deeply the power system is decarbonised. https://www.theccc.org.uk/wp-content/uploads/2015/10/CCC_Externalities_report_Imperial_Final_21Oct20151.pdf

20. The Department for Business, Energy and Industrial Strategy has recently updated its estimates of future generation costs, and I do not have access to any figures that I believe to be superior. The table below gives the construction cost, estimated load factor, annual fixed cost (operations and maintenance, depreciation and return on capital), the variable costs per MWh and the Levelised Cost of Energy for several technologies. In each case, the figures are estimates for a project commissioning in 2025; the costs for nuclear and carbon capture and storage include a premium for first of a kind costs. The coal plant with CCS uses oxyfuel combustion (the plan for the aborted White Rose consortium); the CCGT has post-combustion capture of the kind that might be retrofitted to existing stations.

		Nuclear (PWR)	Coal with CCS	CCGT with CCS	CCGT (unabated)
Construction Cost (£/kW)		4,100	3,400	2,100	500
Fixed Cost (£/kW-year)		678	678	370	73
Load Factor		90%	91%	88%	93%
Variable Cost (£/MWh)	Operations	5	6	3	3
	Fuel	5	24	48	40
	Carbon	0	6	3	29
	CCS		17	7	
Levelised Cost of Energy (£/MWh)	Low	84	120	85	66
	Central	95	136	110	82
	High	124	169	132	90
			Offshore Wind	Onshore Wind	Large Scale Solar PV
Construction Cost (£/kW)			2,100	1,200	600
Fixed Cost (£/kW-year)			408	157	61
Load Factor			48%	32%	11%
Variable Cost (£/MWh)	Operations		3	5	
	Fuel and Carbon				
Levelised Cost of Energy (£/MWh)	Low		88	46	55
	Central		100	61	63
	High		113	74	76

Source: BEIS, Electricity Generation Costs, November 2016, Tables 4, 5 and 19

21. I have converted the costs presented in £/MWh for pre-construction, construction, fixed operation and decommissioning into a figure per kW per year, based on the load factors given in the report. The fuel and carbon costs are based on BEIS' forecasts of future prices, which rise significantly over time. For this reason, BEIS estimate that a 2020 CCGT would have costs of only £53-76/MWh. Their 2020 estimates for wind and solar plants are slightly higher, for there is less time for learning-by-doing to drive costs down. The "low" and "high" estimates for the levelised cost of energy include BEIS figures for variation in both capital and fuel costs (where applicable).

22. An unabated CCGT station with a thermal efficiency of 54% would have "headline" emissions of 0.34 tonnes of CO_2 per MWh. Adding CCS would decrease the thermal efficiency to 44%, but emissions would fall to 0.04 tonnes of CO_2 per MWh. The coal station with CCS would have a thermal efficiency of 32% and emissions of 0.08 tonnes of CO_2 per MWh.

23. While it would be straightforward to compare these emissions figures with the cost premia (or savings) from lower-carbon technologies, that calculation would not take account of any system-wide effects. The best study that I am aware of that include these is the University of Edinburgh PhD thesis of Dr Camilla Thomson. She compared changes in carbon emissions (calculated from the detailed operating patterns of individual generating units, and their estimated fuel consumption) with changes in wind generation, and found that each MWh of wind output between November 2008 and June 2013 saved an average of 0.562 tonnes of CO_2-equivalent (Thomson, 2014, p. 191). This figure was 11% below that from a simple calculation that ignored the effect of part-loading fossil-fuelled stations to provide reserve.

The Rebound Effect

24. While giving oral evidence, I mentioned, but could not recall the details of, work by the UK Energy Research Centre on the so-called rebound effect, the tendency to consume more energy services when improvements in energy efficiency reduce the cost of providing them. For example, following home insulation, the consumer may choose a higher indoor temperature and save less energy than an engineering estimate of the cost of providing a constant temperature would suggest.

25. The report was by Professor Steve Sorrell of the University of Sussex, published in 2007 and available at http://www.ukerc.ac.uk/asset/3B43125E%2DEEBD%2D4AB3%2DB06EA914C30F7B3E/. It reviewed existing studies and concluded that between 10% and 30% of the theoretical savings from energy efficiency measures might be given up in this way for household heating and cooling and personal transport. The impact of significant improvements in energy-intensive industries, however, could exceed 50% if greater competitiveness allowed large increases in production.

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