Turning the wind into hydrogen: The long-run impact on electricity prices and generating capacity

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Abstract

Hydrogen production via electrolysis has been proposed as a way of absorbing the fluctuating electricity generated by wind power, potentially allowing the use of cheap electricity at times when it would otherwise be in surplus. We show that large-scale adoption of electrolysers would change the shape of the load-duration curve for electricity, affecting the optimal capacity mix. Nuclear power stations will replace gas-fired power stations, as they are able to run for longer periods of time. Changes in the electricity capacity mix will be much greater than changes to the pattern of prices. The long-run supply price of hydrogen will thus tend to be insensitive to the amount produced.

Keywords: Electricity markets, Wind Generation, Hydrogen electrolysis, Capacity Mix, Electricity Prices.

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1. INTRODUCTION

This paper asks whether electrolysis, on a large scale, can be a cost-effective way of producing hydrogen and managing the intermittency of wind energy, taking into account the long-term impact on the optimal capacity mix of power stations. As part of the EU's Climate-Energy Package, the UK has accepted a target for 15% of its energy demand to come from renewables by 2020. Along with the development of biomass, hydro and wave and tidal energy, wind power will provide a significant proportion of this. The UK's plans assume that more than 30% of electricity will be generated by renewables by 2020, sharply raised from the current level of 5%, and most of it will come from offshore and onshore wind generators (DECC, 2010).

Using a high proportion of wind generation leads to the problem of intermittency, for the output of wind power stations depends on the strength of the wind, which is variable and hard to forecast. This brings significant volatility to electricity markets as it becomes harder to match supply and demand. A system with a high penetration of wind power needs more reserve capacity as backup to deal with short-run fluctuations in the level of wind output. The fluctuating level of demand on the conventional power stations can make the market price of electricity very volatile, which brings challenges to the companies which need to trade it. In some countries, energy storage in hydro plants can be used to offset the fluctuations in wind output; Denmark does this by trading with its neighbours (Green and Vasilakos, 2010c).

In future, hydrogen production could also be used to even out the wind-induced fluctuations in the load on thermal power plants, therefore reducing volatility in wholesale prices. Hydrogen can be produced by electrolysis in centralized or dispersed plants at times when there is excessive wind output (relative to the demand for electricity), and stored until it is needed. The demand for hydrogen may be for transport, for combined heat and power, or simply to generate electricity at a time when prices are higher. Several papers (summarised in the next section) discuss the opportunity and benefits of this mode of hydrogen production. Some of them point out that hydrogen could be produced relatively cheaply at times with a surplus of wind energy, assuming that the demand from electrolysers is not great enough to absorb this surplus.

If hydrogen is to make a significant contribution to a low-carbon economy, this assumption may well be incorrect. If a large amount of electrolyser capacity is running at times when the wind is strong, it will tend to absorb the resulting power, and so wholesale prices will not need to fall to signal that conventional generators should reduce output. The presence of more electrolysers will therefore raise the average price of electricity. As we show in a later part of this paper, this correlation is evident in our simulations. Once we control for the effect of hydrogen production on the price of electricity, we get an upwards-sloping supply curve for hydrogen.

Large-scale hydrogen production will have a second effect on the electricity market, however. As the shape of the load-duration curve changes, with the demand for hydrogen production raising the lower levels of electricity consumption, the optimal mix of power stations is likely to change. There will be room for more baseload capacity, cheapest at running for long periods without interruption, and less need for the mid-merit and peaking capacity that balances somewhat higher variable costs against lower fixed costs.

These interactions between hydrogen production and the electricity market are the subject of this paper. We modify a long-term equilibrium model for the British electricity industry (Green and Vasilakos, 2010a) to find the impact of an increasing demand for electricity from hydrogen production on the equilibrium capacity mix of generation types. This model is based on a perfectly competitive electricity supply market in which prices are equal to marginal cost (or the level needed to bring demand down to the level of available capacity) and each type of power station makes zero profits. We add different levels of hydrogen electrolyser capacity to derive the long-run supply curve for a competitive electrolyser industry. The demand from the electrolysers affects the load-duration curve, and hence the equilibrium capacity mix.

The next section of the paper discusses previous work on generating hydrogen from surplus wind power. Section 3 outlines our model and data sources. The fourth section discusses the impact of hydrogen production on the electricity system in our base case, deriving a (gently) upwards-sloping long-run supply curve when both markets are in equilibrium. Section 5 presents sensitivity analysis, and section 6 concludes. Our main result is that the short-term opportunity to generate cheap hydrogen at times of excess wind will be eroded in a long-term equilibrium, once the generation capacity mix has been adjusted to the presence of wind generation and hydrogen electrolysers.

2. PREVIOUS WORK

The challenges due to the intermittency of wind output are well-known, and a summary of the likely costs (in a UK context) can be found in Gross et al (2006). The studies summarised in that paper mainly considered the cost of running thermal plant part-loaded to compensate for variations in wind output, but this is not the only way of dealing with the problem. Troncoso and Newborough (2007) find that electrolysers can be used to increase the penetration of wind power while still maintaining a high load factor for thermal plants and avoiding the need to spill excess wind output. Korpås and Greiner (2008) show that hydrogen production can reduce the loads placed on a weak electricity grid by smoothing the net export of power, although Greiner et al (2007) have shown that the cost of hydrogen will be lower in a system that benefits from a strong connection to the transmission grid, as an isolated system will need additional backup for longer periods of low wind speeds. Aguado et al (2009) show that a wind farm can smooth its power sales by storing hydrogen and generating electricity from it later, but found that this would not be economic with the (Spanish) price data they used. This might not matter if the hydrogen is actually more valuable when sold as such than when converted (inefficiently) back into grid electricity.

Many other papers have considered the cost of hydrogen produced in this way. Mueller-Lange et al (2007) conclude that hydrogen produced via electrolysis will [only] be competitive in niche applications compared to other hydrogen production methods in the short term, due to the relatively high cost of electricity. They base their comparison on the average cost of various types of generator. Other authors assume that electrolysers would only run at times of (relative) surplus generation, when electricity prices are low, which would significantly reduce the cost of the hydrogen they produce. Oi and Wada (2004) found that off-peak electricity tariffs in Japan would allow hydrogen to be produced at a price competitive with that of gasoline, while improving the load factor on the electricity system. Jørgensen and Ropenus (2008) show how the (hourly) wholesale price of electricity in Denmark varies inversely with the (concurrent) amount of wind generation, and model this relationship for four scenarios with different levels of wind penetration to estimate the cost of hydrogen production.

Floch et al. (2007) use spot prices on the French electricity market, PowerNext, to show how the cost of hydrogen production varies with the maximum electricity price that the operator is willing to pay. An operator willing to pay high prices benefits from a high load factor, whereas a decision to pay less for power reduces the electrolyser's hours of operation and raises its fixed cost per kg of hydrogen produced. They find an optimum load factor of about 64%, corresponding to a maximum willingness to pay of €48/MWh of electricity, and giving a hydrogen cost of €2.56/kg. Both studies implicitly assume that the total capacity of electrolysers is low and therefore cannot have a significant effect on the pattern of electricity prices. That is an assumption which this paper does not make.

This paper builds on Green and Vasilakos (2010a). That paper models the electricity market in Great Britain, with and without 30 GW of wind generation (roughly the level implied by national targets for 2020) and finds the equilibrium level of capacity and pattern of prices.[1] The capacity mix changes dramatically in the presence of wind generation, with more flexible gas-fired generators and fewer nuclear stations. The price-duration curves which are consistent with these capacities are remarkably similar.

The reason for this is that in a zero-profit equilibrium, the average price over the period for which any given station is operating has to equal its average costs. Furthermore, each station must be operating for a number of hours such that it has lower costs than any other type available would have over the same period. Following the addition of wind generation, the capacity mix adjusts so that each type of station can continue to operate for the same amounts of time as before. If nuclear stations are the least-cost option to meet demands that last for 7,000 hours a year or more, then when the growth of wind generation reduces the size of the load that lasts that long, fewer nuclear stations are needed. All of the stations that remain can now

[1] Bushnell (2010) carries out a similar exercise for the western United States.

operate for at least 7,000 hours, and will earn average revenues equal to the cost of running them for this period. This “anchors” the pattern of prices in a competitive market and ensures that it is largely unaffected by the growth of wind generation. We will find a similar effect when we change the load-duration curve for thermal generation by using electricity to produce hydrogen.

3. MODEL AND DATA

The model in this paper is based on the traditional cost-minimizing approach that combines a screening curve (giving the costs of different power stations if they run for different numbers of hours per year) and a load-duration curve (giving the number of hours for which demand is greater than or equal to a given level) to find the optimal capacity mix. We use cost data taken from the recently published UK Electricity Generation Costs Update prepared for the UK government (Mott Macdonald, 2010). The fixed cost is calculated as sum of the fixed operation and maintenance (O&M) costs and the annuity required to pay back the capital cost for each technology. The variable costs are determined by the plant’s thermal efficiency and the cost of its fuel, together with variable O&M costs. We consider five plant types: nuclear, combined cycle gas turbines (CCGT), supercritical coal (with and without carbon capture and sequestration) and open cycle gas turbines (OCGT). In each case, we use the figures for “n of a kind” new build plant ordered in 2017 (i.e., after the first of a kind costs have been incurred). Our intention is to study the costs of the marginal plants of each type, that is the ones that would determine the long-run equilibrium capacity mix.

The average prices for fossil fuels are taken as £27.0/MWh for gas and £6.0/MWh for coal. (We assume that the price of gas is 7% above this annual average in winter, and 7% below it in summer.)We assume that all carbon permits are auctioned, which obviously increases the variable costs of all the fossil-fuelled plant. In our main simulation, we set the carbon price at £50 per tonne of CO_2, which is similar to the central value of 'non-tradable carbon price' used by the Department of Energy and Climate Change (2009). The key figures for each plant type are shown in Table 1.

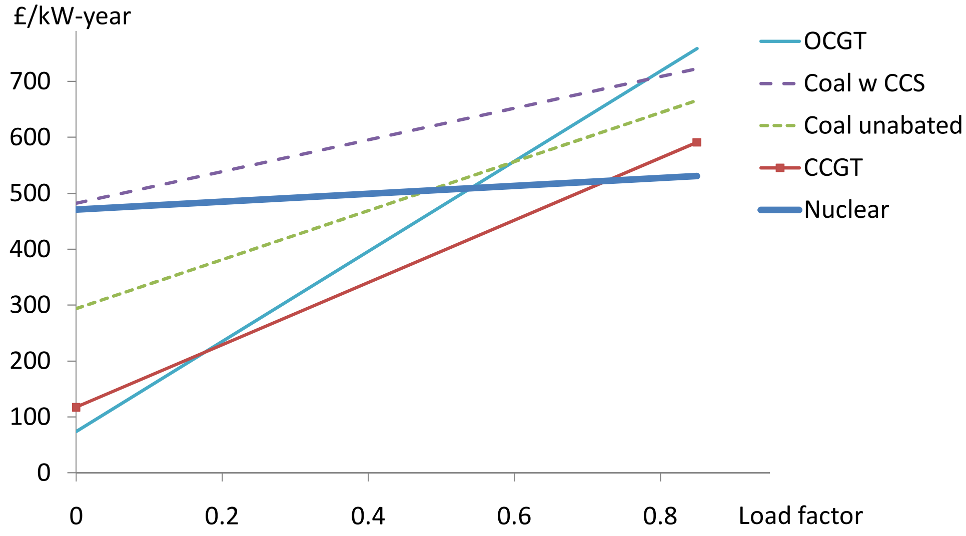
Table 1: The costs of generation

Plant type	Thermal efficiency	Variable cost (£/MWh)		Fixed cost (£/kW per year)
		Fuel	Non-fuel	
Nuclear	n/a	6.20	1.80	471
CCGT	0.59	64.52	2.20	117
Coal unabated	0.45	47.78	2.30	294
Coal with CCS	0.36	20.97	11.30	483
OCGT	0.40	95.17	1.50	74

Variable costs are given with our central case for fuel prices; nuclear waste management and decommissioning costs are split 50:50 between fuel and fixed costs

Figure 1 gives a screening curve diagram, showing the relationship between the load factor over the year for each type of technology and its total costs per kW per year. At the left-hand end of each panel, stations which generate for (practically) no time at all incur only their fixed costs, giving the intercept of each line. The slope of the line for each plant type is given by its variable costs. Due to outages for maintenance (planned and unplanned) we assume that no plants would be able to generate for more than 85% of the time. Given these costs, nuclear is the cheapest choice when it runs almost throughout the year. CCGT plants are the best choice for load factors of between roughly 20% and 70%, while OCGT stations are the cheapest for very low load factors. Coal stations are uneconomic for a carbon price of £50/tonne, whether or not their emissions are abated through carbon capture and storage.

Figure 1: Screening curves for generation costs



The load which these stations have to meet is equal to the overall demand for electricity (including that to be used in electrolysers), less the predicted output from wind power. The data for (non-electrolyser) demand and wind output are taken from Green and Vasilakos (2010b), which gives full details of the methodology used to derive it. In brief, the hourly wind speed data is taken from the British Atmospheric Data Centre from 1993 to 2005, using weather stations around the country. They are converted to electricity outputs using a standard wind turbine power curve, and assuming that 11 GW of onshore and 19 GW of offshore wind are distributed around the country and its surrounding waters, in proportion to the projects in the British Wind Energy Association’s database. The projected wind outputs are matched with the gross electricity demand from the same hour (obtained from National Grid), but scaled up to predicted 2020 levels, assuming demand growth of 1.1% per year from 2008 onwards. This effectively gives us 13 possible versions of each day in 2020, each corresponding to the weather and other conditions that would have affected electricity demand and wind output on a particular day, but based on the same underlying annual level of electricity demand. As we are looking for the long-term equilibrium, we cumulate the data into a single load-duration curve for each season (winter and summer).

There are 119 points in each of our load-duration curves (winter and summer) – we take demand levels every 0.1% of hours for the top and bottom percentile, and then every percentile – each with its own demand curve. Demand is (slightly) price-sensitive, with a slope of -2 MW per £/MWh in the base case. We add 5,000 MW of demand for reserve capacity in each hour (either spinning reserve, or available at reasonably short notice) which we assume has to be met by fossil-fuelled plant.

For each demand curve, the equilibrium price is given by its intersection with the industry's marginal cost curve. In hours when the nuclear stations are running at full capacity, this is generally the variable cost of the most expensive fossil-fuelled plant required (for reserve). If demand is so high that all plants are running at full capacity, then the price rises to reduce the quantity demanded to the available capacity (both net of reserve requirements). For relatively low levels of demand (net of wind generation) not all nuclear capacity is required, and we assume that competition between these stations would drive the wholesale price down to the level of their variable costs.

For very low levels of (net) demand, the load may be less than the minimum amount of generation that nuclear stations can supply. We follow Pouret et al (2009) in assuming that pressurised water reactors can operate at 60% of their capacity, but no less. If there is so much wind generation that it cannot all be accepted without forcing some nuclear stations below this level, we assume that some of the wind generators would have to be constrained off. The wholesale price would then fall to the opportunity cost of wind generation, which is minus the price of the tradable green certificates (Renewables Obligation Certificates) that they would have to give up. We assume that this price will be £40/MWh in 2020, somewhat below its current level, if renewable generation rises closer to the UK's target level and the gap between the demand for certificates and their supply falls.

We have taken our electrolyser cost estimates from spreadsheets produced by Ramsden (2008). Our base case uses a prediction for the future costs of electrolysers, at £75,000 per MW of electricity demand, with an efficiency of 74% (based on the lower heating value of the hydrogen produced). These electrolysers require 46 kWh of electricity per kg of hydrogen produced. We assume that the cost of electricity transmission and distribution, and of support for renewable energy, adds £25/MWh to the wholesale cost of power.

We assume that hydrogen production is a perfectly competitive industry. Each electrolyser will take the wholesale price of power as given, producing in those hours when it is low enough for the resulting marginal cost of hydrogen to be less than the market price. (Since hydrogen is a storable product, we assume that this price does not vary over time.) In the long-run equilibrium, this market price must also equal the average cost of hydrogen production, or firms would wish to enter or leave the industry. For each (given) amount of electrolyser capacity, we therefore find the maximum willingness to pay for electricity which gives us an equal average and marginal cost of hydrogen. Finally, we note that given a maximum willingness to pay for electricity, it will not always be possible for the full capacity of every electrolyser to be used without sending the price of power above this level, and we assume that the amount of electrolyser capacity in use is adjusted to keep the price from rising too high. Once there is a significant amount of electrolyser capacity, this effectively means that their willingness to pay for power will set the price for a number of hours, starting with an hour in which practically all electrolysers can be used, and ending with one in which very little hydrogen production takes place.

4. SIMULATION RESULTS: BASE CASE

Given the screening curve of generation costs, we find the equilibrium, for a given amount of electrolyser capacity, as follows. First, we select those plant types on the lower envelope of the screening curve, setting the capacity of any plant that is not the cheapest option for any load factor effectively to zero.[2] Second, we choose a value for the highest electricity price that electrolysers are willing to pay – this will feed in to our demand curves, creating a horizontal shift outwards at this price. Third, we choose the total amount of capacity so as to give the plants with the highest variable costs profits as close to zero as possible.[3] Fourth, we then choose the amount of peaking capacity so that the plants with the next highest variable costs also make profits as close to zero as possible. This is equivalent to ensuring that the peaking plant with the highest load factor can run for exactly the number of hours where its

[2] We actually set it to 1 MW (which makes no practical difference for a system with a peak demand of 60 GW) to avoid inadvertently dividing by zero at any point.

[3] This caveat is important, for the discrete steps in the load-duration curve mean that a small change in capacity can lead to a change in price which, when multiplied by several hours of operation, gives a non-marginal change in profitability.

costs would be just equal to those of the next type of plant. We continue the exercise for the other types of power station with non-zero capacity, until each has zero profits.

We then compare the average cost of the electrolysers with our initial choice of their maximum willingness to pay for power. In a long-run equilibrium for a competitive hydrogen industry, the market price for hydrogen, average cost and marginal cost (given by this maximum willingness to pay) must be equal. We do not of course know this market price – what we are doing is estimating the supply curve. If the marginal cost is less than the average cost, we increase the electrolysers' maximum willingness to pay (and vice versa) and find a new set of generating capacities until the process converges on an equilibrium for both electricity and hydrogen.

Figure 2 shows the resulting load-duration curve for summer, with 4,000 MW of hydrogen production capacity. The solid black line gives the demand for electricity, net of wind output, and ignoring the power used to make hydrogen. The solid areas show the generation from different types of thermal plant – only nuclear, CCGT and OCGT are used in this example. The shaded areas show the amount of CCGT and OCGT capacity used for reserve – we are assuming nuclear capacity is not suitable for this. At the right hand end of the diagram, when demand is low, some nuclear capacity is not required (the area with horizontal bars), and at the far right hand end, some wind output has to be constrained off to avoid running nuclear stations at less than their (assumed) minimum level.

The solid area above the demand line shows the amount of power being used to produce hydrogen, from nuclear plants when demand is low, and from CCGT stations when demand is somewhat higher. Once all the CCGT stations are in use, for either power or reserve, further increases in the demand for electricity lead to reductions in the demand for hydrogen, in order to avoid using OCGT stations and raising the price of power. This happens between the hour with the 1500th-highest demand and the hour with the 800th-highest demand for power.

Figure 2: Summer Load-Duration curve

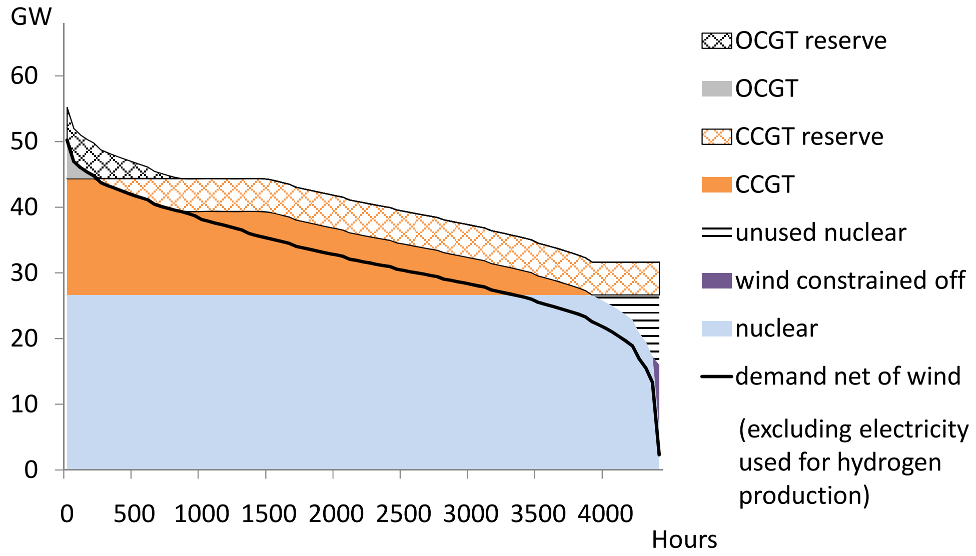


Figure 3 shows the corresponding load-duration curve for winter. In this example, the average cost of hydrogen corresponds to an electricity price between the marginal cost of CCGT stations in summer and in winter (given that we model the seasonal increase in gas prices). In figure 3, therefore, the electrolysers are only used for the hours with the lowest net demand for power, and are turned off when it is necessary to generate electricity from CCGT stations.

Figure 3: Winter Load-Duration curve

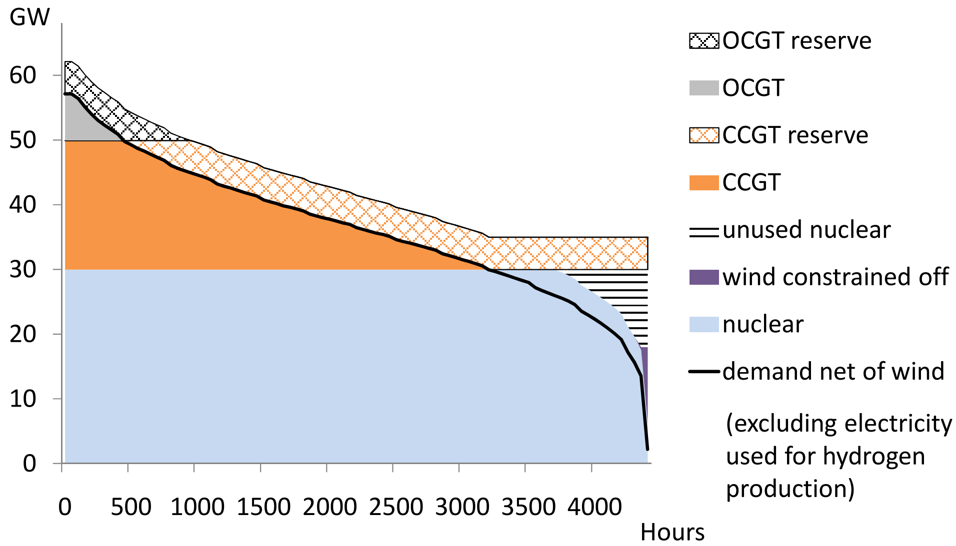


Figure 4 demonstrates how the generation capacity mix changes as the potential extra electricity demand from hydrogen production rises. With an increase in the capacity for hydrogen production, nuclear power plants are able to run for longer, and replace CCGT and OCGT stations. Note that the installed capacity of nuclear plants rises more than the installed capacity of electrolysers (shown by the diagonal line) as the (lower) available capacity of nuclear plants is matched to the ability of electrolysers to absorb their output. For most levels of hydrogen production, the total capacity remains constant – the price set by OCGT stations is too high for hydrogen production, and so the demand and marginal cost of power in peak hours is unaffected by the electrolysers. As electrolyser capacity increases, however, it reaches a level where it can support a greater capacity of CCGT and nuclear stations than the total generation capacity needed without electrolysers. This effectively crowds OCGT stations out of the market – the load-duration curve (including demand for hydrogen production) would have a flat segment from the vertical axis until past the point at which CCGTs become more economic than OCGT stations.

Figure 4: The generation capacity mix

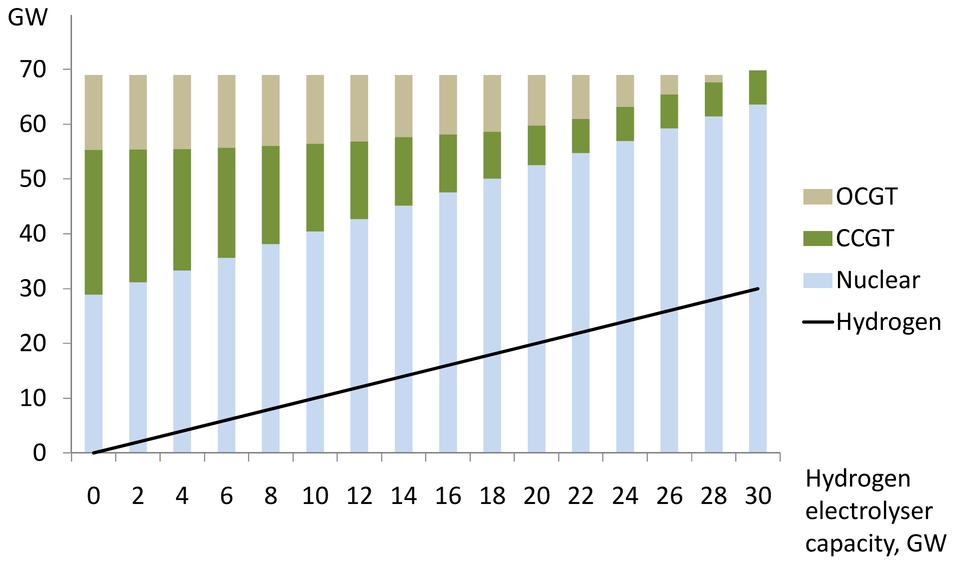
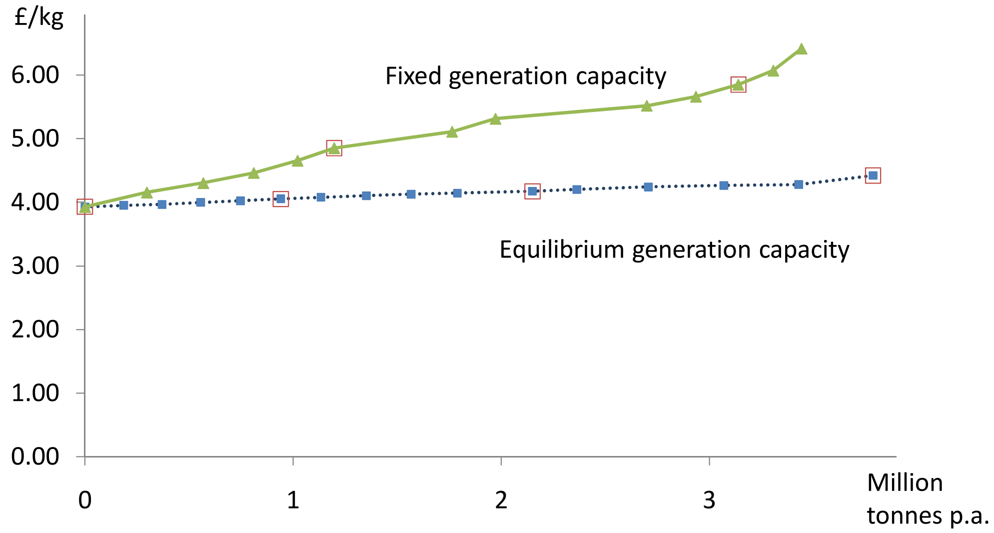


Figure 5 gives us the average cost of hydrogen production as a function of its output level: in other words, its long-run equilibrium supply curve. The horizontal axis is drawn in terms of millions of tonnes of hydrogen, but each point on the curves represents an additional 2 GWe of electrolyser capacity, with capacities of 10 GWe, 20 GWe and 30GWe highlighted. To put the scale into perspective, Offer et al (2010) predict that hydrogen-powered cars would achieve 72 miles (119 km) per kg of hydrogen, and the 400 billion km currently driven in the UK each year would thus need around 3.4 million tonnes – if it were all powered by hydrogen.

The upper line represents an equilibrium in the hydrogen industry (with marginal and average cost equal) but assumes that the generating capacity mix does not change in response to the additional demand from electrolysers. This additional demand raises the price of electricity and hence the cost of electrolysers quite steeply.

The lower line shows that once generating capacity is allowed to adjust, and if both industries achieve a long-run equilibrium, the price of hydrogen will be much less sensitive to the quantity required, although the long-run supply curve is still upwards-sloping.

Figure 5: Hydrogen supply curves



5. SIMULATION RESULTS: SENSITIVITY ANALYSIS

How sensitive is the long-run supply curve for hydrogen to the assumptions we have made? We have assumed that electrolysers would become cheaper and more efficient over time, following Ramsden (2008b), but this assumption may be too optimistic. Ramsden (2008a) contains data for present-day electrolysers, with a fixed cost of £150,000 per MW of electrical demand per year, and an efficiency of 63% - numbers consistent with those used by Greiner et al (2007) and by Jørgensen and Ropenus (2008). Figure 6 presents the hydrogen supply curve for this case, but still using our base assumptions for power station and fuel costs. In the long-run equilibrium in both markets, the price for one million tonnes of hydrogen would be £5.40/kg, as opposed to £4.06/kg with the lower cost of electrolysers.

Figure 6: Supply curves for hydrogen: higher electrolyser costs

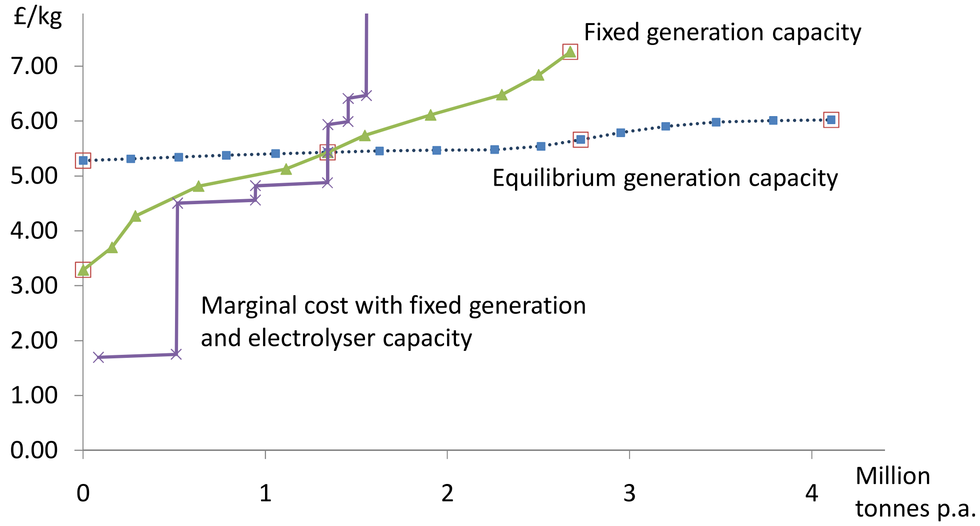
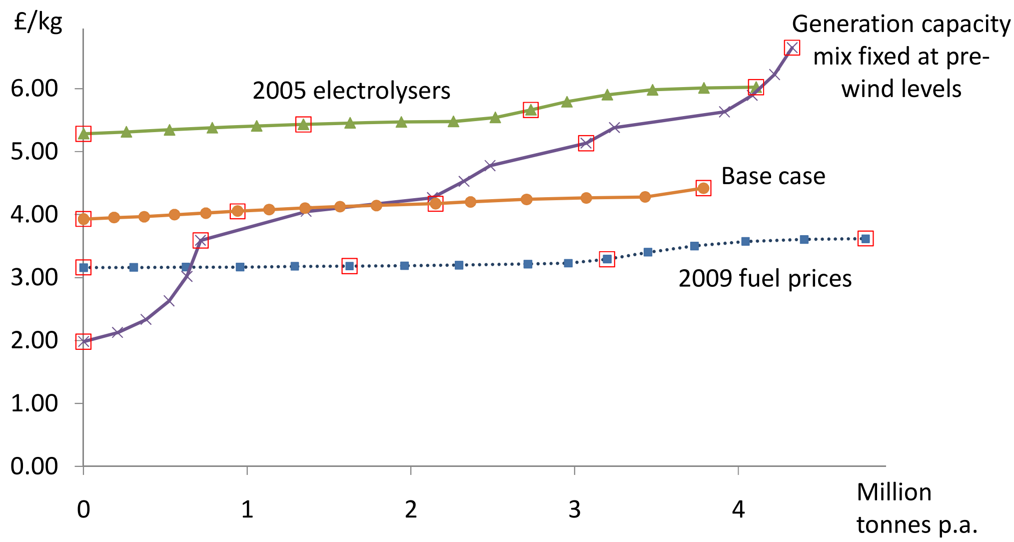


Figure 6 also presents the supply curve for hydrogen, assuming that the hydrogen market is in long-run equilibrium, but that the electricity market is not, with its generation capacity fixed at the amount suitable for an electrolyser capacity of 10 GWe. As before, this slopes more steeply upwards than the full equilibrium supply curve. The third line, the steepest (a step function), shows the short-run supply curve for hydrogen (its marginal cost) on the assumption that both electrolyser and power station capacities are fixed. As our generation model uses a small number of plant types with distinct costs, the electrolysers are able to run for a significant number of additional hours each time they raise their willingness to pay from just below to just above the marginal cost of one of our plant types. The marginal cost would be smoother if we had more plant types in our model (with less capacity of each).

Figure 7 considers alternative fuel prices, using those paid by UK generators in 2009 (£14.03/MWh for gas, £7.84/MWh for coal, and £15 per tonne for carbon dioxide). The lowest of the three parallel lines shows that these lower prices would reduce the cost of hydrogen by about one quarter – the cost for one million tonnes a year falls from £4.06/kg to £3.17/kg. The middle line is our base case, and the top line is the hydrogen supply curve using current electrolyser technology. We also calculated a supply curve using current electrolysers and fuel prices – this is very close to (but slightly above) the base case supply curve and is omitted for clarity.

Figure 7: Hydrogen supply curves



The final line in figure 7 slopes steeply upwards. This gives the supply curve for hydrogen, assuming that the hydrogen market is in equilibrium, but that generation capacity is fixed at the levels suitable for an industry without any wind generation. This implies significant excess capacity, overall and in terms of the amount of nuclear power that can be accommodated without having to constrain off wind generators from time to time. At those times, the opportunity cost of hydrogen production is very low, and small amounts of hydrogen can be produced very cheaply. This is not an equilibrium for the overall energy system, however, as all power stations are losing money. Furthermore, larger amounts of electrolyser capacity are more than enough to absorb any surplus of wind or nuclear power, and the cost of hydrogen rises steeply if larger quantities are required. At the right-hand end of the curve, the cost of hydrogen is high, electrolysers are buying electricity at high prices, and electricity generation is very profitable for most stations, which again means that the situation is not an equilibrium.

6. CONCLUSIONS

In a long-term equilibrium, adding hydrogen electrolysers to the energy system will change the capacity mix in generation, partly offsetting changes due to the large-scale adoption of wind power. To accommodate wind power, the capacity of base-load conventional and nuclear generators has to fall, but adding electrolysers will increase the viable capacity of these stations, allowing a given number of them to operate for longer periods. We have shown that the long-run supply curve of hydrogen is fairly flat, once the impact on the generation capacity mix is considered.

Our analysis is based on annual load-duration curves, and we have not considered the operational challenge of scheduling thermal stations to meet the fluctuating demand for electricity net of wind. In our base case, the electrolysers have a load factor of around 50% (slightly greater for large capacities when the hydrogen supply price and hence maximum price they pay for power are higher), but in most hours they are either running at full capacity or not in use. If electrolysers can be scheduled in a flexible way to offset the fluctuations in wind power, this will have a value which our static simulations are unable to model.

Our base estimate for the cost of hydrogen production, around £4 per kg, is comparable with other values in the literature (Floch et al, 2007; Jørgensen and

Ropenus, 2008). As long as the generation capacity mix is able to adjust to changing patterns of overall demand, increasing hydrogen production does not lead to a sharp increase in cost. The capacity mix should change to remove most of the opportunities given by the combination of large amounts of wind power and inflexible baseload plant forcing negative prices, but it should also change to allow increasing demands for power for hydrogen production without raising prices.

Will this be a competitive way of producing hydrogen? The main method used at present is steam reforming of methane. The cost of natural gas is a high proportion of the total cost, making estimates sensitive to the future price of natural gas. Ball et al (2007) predict a hydrogen cost of around €1/kg, and US DOE/NETL (2008) a cost of $1.65/kg (including the cost of carbon capture and sequestration), but both use gas prices well below those that we have assumed. Using our natural gas price, their estimates would both be approximately £2/kg, still significantly below our estimates. This implies that electrolysis remains a relatively expensive way of producing hydrogen, once the impact of hydrogen production on the electricity price and capacity mix is taken into account. It may still be worthwhile, however, as a way of integrating large amounts of wind power.

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