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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.

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 (HM Government, 2009).

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 centralised 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 need not 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 the latter 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 base-load 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.

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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.

Section 2 of the paper discusses previous work on generating hydrogen from surplus wind power. Section 3 outlines our model and data sources. Section 4 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-Langer 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 7000 h 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 operate for at least 7000 h, 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-minimising 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 the 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.

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