Spotted: How varying fuel prices affected British electricity wholesale prices

Richard Green
Imperial College Business School
r.green@imperial.ac.uk

Liliana Nowakowska
Imperial College Business School
ldn18@ic.ac.uk

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1 Overview

Wholesale electricity prices are unpredictable and volatile but essential for all market participants. The major factors driving this volatility are changes in fuel and carbon prices, volatility in energy demand and variable renewable generation. Understanding this price development process is becoming increasingly important to all market participants in the competitive electric power markets. Not only does the expected spot price have a strong impact on the contract price (Bessembinder & Lemmon 2002) but price volatility also brings uncertainty to energy suppliers about their costs and revenues (Robinson 2000). According to (Grubb & Drummond 2018) gas-powered generators have been helping to set the wholesale price in Britain for two decades, with power prices rising from 2004 onwards due to the increase in fossil fuel prices. However, coal-fired generators also have a role, particularly in the period since 2015 when the UK's Carbon Price Support (a tax) raised their cost above that of the gas-fired stations. Most papers studying electricity wholesale prices use fuel prices as inputs, but we argue that many do not capture the way in which they interact in a market with a mixture of coal and gas-fired stations. All in all, British energy market can be summed up as being fully market-driven and despite long-term contracts there is still extreme volatility in the electricity price and any change in fossil fuel prices is directly reflected in wholesale electricity prices. Another aspect crucial to the organization of British electricity spot market is the decarbonisation policy. Initially the carbon pricing was introduced by the European Commission in 2005 with the EU ETS (Emissions Trading System). As ETS prices fell after the financial crisis of 2008, the UK supplemented it with a domestic policy, the Carbon Price Floor (CPF), which added an additional tax on fossil fuels. Both these policies greatly impacted the generation mix in UK. Coal was dragged down the merit order stack, which made the coal-powered generators price setters at higher-demand times, while dramatically decreasing its share of thermal output. Along with regulation aiming to decrease the dependence on fossil fuels we have seen dramatic growth (by 400%) of renewable generation capacity between 2009 and 2017. There are plenty of papers that show the expansion of renewable capacity can depress electricity prices: (Munksgaard & Morthorst 2008), (Cludius et al. 2014), (Ketterer 2014),(Woo et al. 2013) to name a few.

The goal of this paper is to understand what caused the changes in British electricity spot prices, using a new methodology that concentrates on the interaction between the costs of coal- and gas-fired stations when both are available to meet demand. Profound understanding of such dependencies is essential for authorities that implement regulations especially for predicting the results of policies such as how the electricity generators react to economic events like increase of fuel and carbon prices.

1.1 Merit Order Principle

The merit order principle of operation means that after sorting the power stations according to the lowest marginal cost rule (cheapest offer starting the sequence with the most expensive one in the end), the stations with lowest variable costs tend to produce the most power over a year (Figure 1). Higher cost stations are on the margin, producing less but setting the price in the spot market.

That also means that an expensive power generator is at risk of being pushed out of the

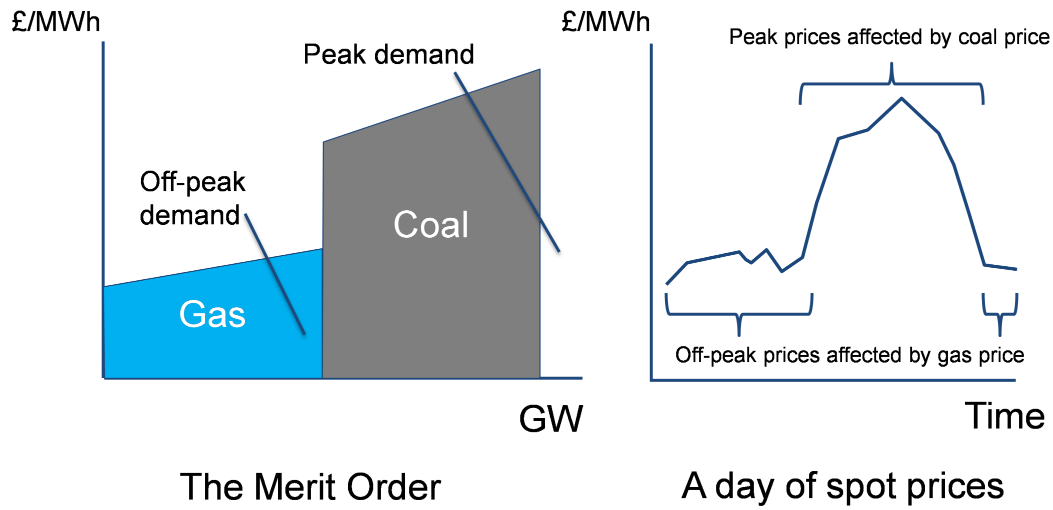

Figure 1: The Mechanism of the Merit order effect

market when the demand is low enough to be satisfied by cheaper sources. In a country with a mix of coal- and gas-fired stations, like GB, their relative variable costs depend on the interaction of coal, gas and carbon prices. It is also worth to note that gas-fired generators are much more flexible than coal-fired ones which are usually operating on a constant basis as they cannot be adjusted promptly to the changing demand. The left-hand graph in Figure 1 presents the merit order stack in a case when the electricity from coal is more expensive than that coming from gas. It is shown that in case of the lower demand (off peak) the load is satisfied with cheaper fuel only and thus the gas price will set the final price. During the peak times on the other hand, when demand is high, we need to move along the merit order to satisfy it, meaning that coal will set the spot price at that time. The right-hand graph in Figure 1 presents a stylised day of spot prices for the merit order stack presented on the left-hand side. For that particular case, we can see that gas price will affect off-peak prices (when prices are usually lower) and coal will be setting the price during the day. It has to be noted that the merit order changes whenever fuel prices change and that means different fuels may set peak and off-peak prices at different times. In our research period, the case illustrated in Figure 1 was happening in the years 2016-2018 when the UK CO2 costs grew significantly.

2 Methodology

We propose an econometric methodology which captures the endogenous switching between coal- and gas-fired power stations - the structural model of electricity prices that vary hour-by-hour without time series effects. In general, marginal cost depends on the fuel cost of the marginal unit, which in turn depends on fuel prices and level of demand less renewable generation.

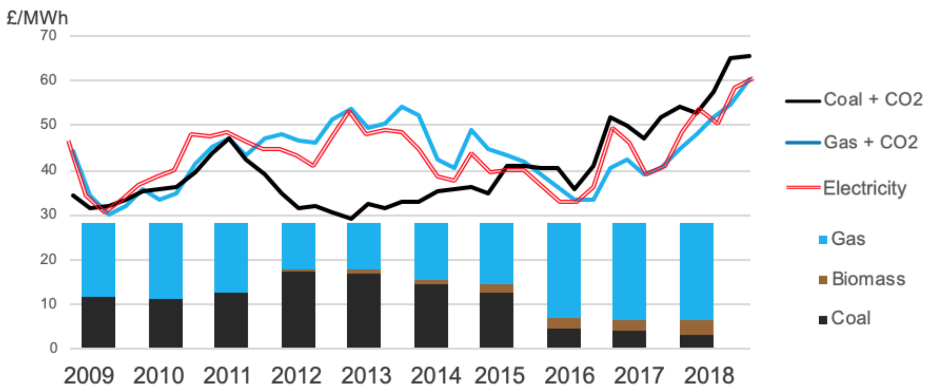

Figure 2: Fuel Prices incl. carbon price and share of thermal output

In the Figure 2 we can see that, the electricity price follows the gas price pattern and there is also period (mainly year 2010-2011) where the average electricity price is bigger than the most expensive fuel. Although it is not congruent with typical market behaviour, such case could have happened due to market power which dragged the prices above the marginal costs

In general, the British power sector had large amounts of both gas- and coal-fired generating capacity for most of this period, and relative fuel costs largely determined which type of stations were used more intensively. This means that when the gas price is relatively high, it will tend to affect the electricity prices set at peak times, whereas when the gas price is relatively low (or the carbon price is high) gas prices will have a stronger influence on off-peak prices than coal prices do (after taking into account the current demand). We capture this effect by constructing variables not for the variable costs of gas generation and of coal generation *per se*, but for whichever plant type is cheaper, and whichever is more expensive. This allows us to automatically capture the effects of fuel switching in a way that regressions with the raw fuel prices would not.

The main specification includes the switching-fuel method as well as the squared and cubed demand variables and has the following form:

$$P_t = \alpha_t + \beta \cdot Dem_t + \beta_1 \cdot {Dem_t}^2 + \beta_2 \cdot {Dem_t}^3 + \gamma \cdot Renewables_t + \gamma_1 \cdot PeakHours_t + \delta_1 \cdot CheaperFuel_t + \delta_2 \cdot CostlierFuel_t + \delta_3 \cdot CostlierDemand_t + \boldsymbol{\Theta} \cdot \boldsymbol{V_t} + \epsilon_t \quad (1)$$

where t indexes each half-hour of the day from January 1, 2009 through December 31, 2017. $P_{t,d}$ is a half-hourly day ahead electricity price (£/MWh) in the UK market for time t. In order to control for the wholesale price shifts we included demand as well as squared and cubic demand to control for any change in demand-price relationship. We included renewable generation, a dummy for peak hours variable where 1 is for peak times during the working day (8 a.m.-8 p.m). Fuel and carbon prices do not enter the regression directly, but we first calculate the average fuel and carbon cost of a gas-fired plant with 46.7 per cent thermal efficiency, and a coal plant with 34.3 per cent thermal efficiency (based on UK fleet-wide averages). On any given day, the lower of these is used for our variable CheaperFuel, and the more expensive is used as CostlierFuel. We expect CheaperFuel to have more effect on prices when demand is low, and CostlierFuel to have more impact when demand is high, and so we also interact each of these variables with the level of demand, its square and its cube (6 interactions in total), which we denote in the equation by $\boldsymbol{V_t}$. We define CostlierDemand to be demand, less the available capacity of the technology using CheaperFuel. We assume 80 per cent availability, but also test alternative values. We also interact CostlierFuel and CostlierDemand. As a part of further analysis and to compare the models' performance we also run three shorter versions of the model (1) starting with the basic OLS model.

3 Results

We chose the model with nonlinear relationship of demand towards price as our main specification as we suspect this relationship to be complex. Firstly, to check if our assumptions of non-linearity is correct we run the model without interaction effects with demand to see clearly the relationship. Indeed, the coefficients of demand squared and demand cubed are statistically significant which indicates the relationship between demand and price is not linear. The signs of these coefficients show their rough form - the positive sign for demand and negative sign for demand squared suggest a monotonic increasing function of price by demand until a turning point is reached and then it very slightly turns upward again as coefficient for demand cubed is small but positive and significant. To make the interpretation more clear, instead of describing the coefficients of our polynomial specification we decided to present graphs showing the marginal impact of fuel prices on price for different levels of demand in both a standard model with fuel prices in levels - Figure 3 and our fuel-switching model - Figure 4.

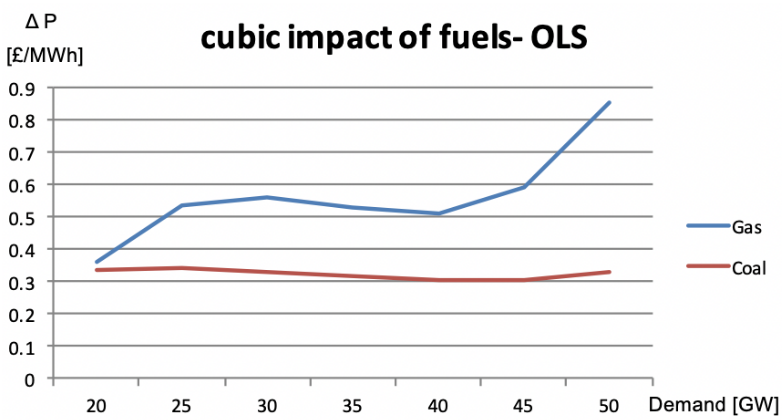

Figure 3: Marginal impact of fuel prices on the electricity price in a standard model (without fuel-switching).

In the standard model, the coal price seems to have a similar impact on prices at all levels of demand. This may have been affected by averaging potentially time-varying effects across all the years in our sample. Gas, on the other hand, changes its marginal impact and grows significantly once the demand passes the 45GW threshold. That high value may be caused by the need of burning more fuel - plants are less thermally efficient when running close to maximal capacity. In Figure 4 on the other hand, we can see the marginal impact of fuel and carbon costs on the electricity price for different levels of demand using our fuel-switching polynomial model. This suggests that the cheaper fuel has very little

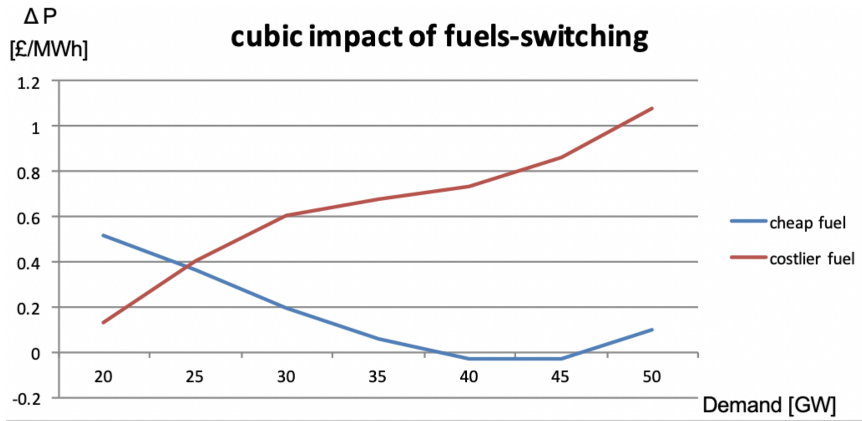

Figure 4: Marginal impact of fuel prices on the electricity price in our fuel-switching model

effect on the level of electricity prices when demand is relatively high, and that the more expensive fuel has much less impact when demand is low. We note that the cheaper fuel does appear to have a growing impact at the highest demand levels, but these have relatively few observations, implying that this effect may just come from continuing the curvature of a cubic function that was based on the bulk of our data, with too few observations to moderate it at high demand levels. We will consider adding further terms in demand in the next stage of our research. The marginal impact of the more expensive fuel becomes ever-stronger as demand increases, reflecting the facts that more and more of the plants likely to be setting the price are those using the more expensive fuel, and that the marginal stations will be the less efficient ones.

We also performed several counter-factual calculations, setting various elements of the data to their 2009 values and using the regression equation to estimate the resulting electricity prices. For some factors (EU carbon prices and demand) the values in 2009 were actually higher than in 2017. By repeating this process one at a time, we could produce Figure 5 which is based on the annual average prices.

We can see that more renewables and less demand would have reduced prices, but fuel prices went up, and the UK Carbon Price went up more than the EU price went down. There are also interaction effects, which meant the overall price impact was bigger than the one we get from only changing one thing at a time.

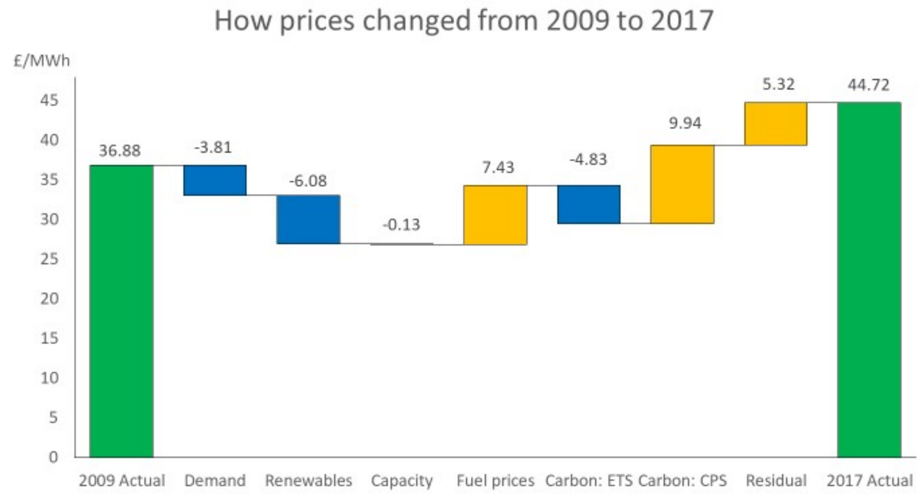

Figure 5: How prices changed from 2009 to 2017

4 Conclusions

In this research we aimed at understanding what shaped the electricity prices in UK in years 2009-2017. The average price increased in this period from 36 to 44£/MWh. The answer is definitely not straightforward as there were many changes in this period that impacted the price simultaneously: changes in fuel prices, rise of carbon costs, decrease of demand, increase of renewable output and also significant changes in shared thermal output of each energy sources. After thorough investigation, we concluded that the lower demand and increasing output of renewables contributed to the decrease in final electricity price by around 11£/MWh and carbon and fuel prices which increased in this period (particularly carbon price) increased the electricity price by around 16£/MWh. Particularly this high rise in UK carbon price triggered the electricity price to increase while the rest of Europe experienced (on average) falling electricity prices. What we have learnt is the fact that electricity prices in UK tend to follow the gas price as gas constituted significant part of shared output throughout the whole period. Coal, which was relatively expensive in the recent years was setting the price merely during some peak hours and constituted only around 5-7% of the overall output in years 2016-2018 thus, cannot be blamed for driving the prices so high. We believe that our fuel-switching approach is a useful way of analysing electricity prices in systems with both coal and gas-fired plants; a useful next step would be to see whether it also represents price patterns well in other electricity markets.

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