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Cost Pass-through in the British Wholesale Electricity Market

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Similarly to most European wholesale electricity markets, Great Britain (GB) has a small number of firms providing most of the country's electricity generation. For a long time, the six largest British electricity generation companies provided nearly 70% of all electricity generated nationally. CMA calculates that in 2015, the Herfindahl-Hirschman Index (HHI) in GB's wholesale electricity market was 1,269, suggesting a concentrated market. The company with the largest market share contributed to about a quarter of GB's total generation, with two thirds of its energy supply coming from nuclear, which generally runs at baseload with high-load factors. About 3.5% of the company's energy supply came from coal and 9.3% from gas.

The market structure of the British wholesale electricity market raises concerns of market power as it is highly profitable for the largest electricity generator to raise prices for their marginal units, which are most typically gas- or coal-powered plants. Competition in the wholesale market promotes lower electricity bills for consumers, while market power tends to make electricity more expensive.

Policymakers often rely on the Cost Pass-Through (CPT) rate to measure market competition since it is a measure of the degree to which a change in costs determines a change in prices. An increase in the input cost raises the marginal cost of electricity generation, but generators may absorb some of the increase by marking up their offer by a smaller or larger amount if the market is imperfectly competitive, depending on the shape of the residual demand (i.e. total demand minus renewable output) curve. The CPT would then differ from 100%. However, given that consumers are inelastic to wholesale electricity prices in the short-run, a CPT rate that is significantly different from 100% would cast doubt on the assumption of a competitive electricity market.

In estimating the CPT, we first apply a Vector Error Correction (VEC) model and use daily data to estimate the long-run effects of fuel and carbon costs on wholesale electricity prices. The effect of fuel (i.e. coal or gas) costs is then divided by the share of hours during which the corresponding technology supplies electricity at

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the margin, and the effect of carbon costs is divided by the Marginal Emission Factor (MEF) of electricity generation. The ratios are therefore the estimated CPT for fuel and carbon costs. If our estimated CPT rates are significantly different from 100% we find evidence supporting a competitive electricity market. However, it is also worth noting that it is possible to find the average daily CPT rates to be close to 100%, although rates may vary between peak and off-peak periods, indicating the existence of market power during different realised levels of demand.

We do not reject the hypothesis that gas costs and carbon prices were entirely passed on to the British wholesale electricity price. When removing electricity price outliers we do not reject the hypothesis of a 100% CPT rate. However, when the outliers are not removed, the estimated CPT rate for coal costs is substantially greater than 100%, confirming that extreme prices are due to the marginal coal plants exercising market power. Therefore, one of the main contributions of this article is to identify whether market power exists in the wholesale electricity market, which generators have market power, and how and when do they exercise it.

Another contribution is to enrich the literature on heterogeneous CPT. We find evidence that coal CPT rate is higher in peak compared to off-peak periods, which is in agreement with the argument that electricity generators tend to implement different bidding strategies over different hours of the day. One possible reason for this is that during off-peak periods coal plants are mostly operating at minimum load, hence the generator is incentivised to bid at a lower price level to avoid the costs of shutting down and starting back up. We also extend this argument by investigating marginal plants' (coal plants in this case) bidding based on the reduced form estimates and marginal market shares. From our results we infer that their off-peak bids are mainly subject to coal costs, while their peak bids depend on both coal and carbon costs.

Our analysis did not cover 2019 and beyond, or years where GB electricity generators were affected by major uncertainty around the payable carbon price and the terms of exit from the European Union. Future work should therefore be aimed at investigating the impact of politico-economic uncertainty on electricity generating firms' bidding decisions. If uncertainty were to have deviated generators' bidding outcomes from their optimal strategies, the market would be considered less efficient, resulting in deadweight losses and increased consumer bills. Policies to limit intra-daily market power remain critical to achieve affordable electricity prices for consumers, especially if Brexit were to reduce competition and increases domestic generators' price-setting ability.

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