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A Unit Commitment and Economic Dispatch Model of the GB electricity market – Formulation and Application to Hydro Pumped Storage

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This paper formulates a fairly simple unit commitment model of an electricity system and applies it to the GB. It demonstrates its use with a case study of the economics of pumped storage (PS). As part of this enterprise, the paper reports, documents and assesses the data sources used for calibrating the model to GB in 2015. The model is subjected to a sensitivity analysis to test its robustness and the data quality, finding that the model and its results are robust against some of the key input and structural assumptions.

First, we found that greater volatility of operating reserve requirements (for example as a result of increasing renewables penetration) leads to a higher utilization of PS. Higher wind and solar penetration increase the demand for electric energy storage, but more to provide balancing and ancillary services than as purely price arbitrage. Further, we found that PS and gas-fired stations compete in provision of flexibility services (e.g., spin-up reserve) - when we exclude non-synchronised gas-fired units from providing spinning up reserve, PS utilization increases, underlying the importance of PS in providing balancing and ancillary services. However, excluding non-synchronised gas-fired units from providing spinning up reserve means also very high volatility of system marginal price (SMP) as this puts substantial pressure on synchronized units (coal and gas units that have already been committed and are available) as well as PS to fulfil reserve requirements. In this case, the spin-up reserve market is roughly equally divided between online coal and gas units. But, in all our sensitivity cases, non-synchronized gas-fired capacity covers 99% of all spin-up reserve requirements. Our analysis shows that in response to variations in operating reserve requirements, the variations in the annual output of gas and coal is of order of 4% and 7% respectively but 80% for PS. Clearly the impact of operating reserve requirements on PS utilization is proportionately the greatest.

Further, we found that cycling characteristics of conventional generation (ramp rate and commitment time) can change the supply mix quite significantly. For example, the relative inflexibility (e.g., minimum up and down time requirement and ramp rate) of coal generation disadvantages gas in the supply mix. The total system operating cost under a simple economic dispatch model that ignores all the unit commitment (UC) and cycling constraints is 2.7% less than the operating cost of the system under a UC model. This is driven mainly by changes in the supply mix. The majority of cost savings is due to lower fuel and carbon costs. Start up and shut down costs represent just under 0.3% of total system operating cost. Hence, the impact of cycling is not so much on operating costs *per se* but on the way the plants react to changes in demand and supply conditions and, critically, on system marginal prices. However, a simpler economic dispatch model (ignoring binary start up and shut down variables) but a well-calibrated one could be well suited to address some questions such as long-term capacity expansion and could be more suitable for modelling market power.

More wind on the system increases PS arbitrage revenue – specifically, with every percentage point increase in wind capacity total PS arbitrage profit increases by 0.21 percentage points. However, under a range of wind capacities, the modelled revenue from price arbitrage is not enough to cover the ongoing fixed costs of PS. This reinforces the fact that PS storage relies on balancing and ancillary services revenue. Analysing the 2015-18 GB balancing and ancillary services data suggests that PS stations were not active in managing transmission constraints, which (about 60%) were supplied by gas-fired units. However, PS stations are active in providing ancillary services such as fast reserve, response and other reserve services with a combined market share of 30% in 2018. Stacking up the modelled revenue from price arbitrage with the 2018 balancing and ancillary services revenues against the ongoing fixed costs suggests that the four existing hydro PS stations are quite profitable. Most (about 75%) of the revenue comes from balancing and ancillary services whereas only 25% comes from price arbitrage. However, the revenues will not be enough to cover the cost of building a new 600 MW PS station. Investment in new PS in GB will be challenging with existing revenue opportunities, and even in balancing and ancillary service markets PS competes with gas. Most existing PS stations reduce gas and coal plant profitability, but also reduce the total system operating cost.

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