The Long-Run Impact of Energy Storage on Electricity Prices and Generating Capacity

By Richard Green and Iain Staffell*

Energy storage technologies can potentially help with integrating variable renewable electricity generators such as wind farms and PV panels. At times of high generation and otherwise low demand, putting energy into storage is a valuable alternative to simply spilling excess power, and means that fossil generation can be displaced later at times of higher demand or lower renewable output. Increasing levels of variable renewable output have been associated with more volatile wholesale prices, which of course makes arbitrage strategies more profitable – the economic signal for energy storage complements the technical one. The use of storage to absorb excess renewable power could also counter the tendency for renewable output to become less valuable as more is produced (Swider and Weber, 2006; Lamont, 2008; Bushnell, 2010; Hirth, 2015).[1]

There is a natural limit on the amount of arbitrage that can be profitable, since it reduces the price differences that incentivise it. Furthermore, Green and Vasilakos (2011) have shown that the effect of renewables increasing price variability (and lowering average prices in some countries) is primarily a short-term phenomenon. Once the capacity mix has adjusted to the new shape of the load-duration curve (net of renewable output), the price-duration curve ought to revert to a similar form as without the renewable generators. We ask whether a similar result holds if energy storage technologies are widely deployed. If so, the need for energy storage might be quite limited.

Modelling the Impact of Storage on Generator Operations

A lot of papers in electricity economics (including many of our own) take a simplified approach to dispatching power stations, using the classic merit order stack. However, to get a full picture of how storage can affect the task of matching generation to demand over time, it is important to take intertemporal operating constraints into account. We use an open-source mixed-integer model – the Unit Commitment Capacity Optimiser (UCCO) – that decides which power stations to turn on and off over the course of a year, trading off the cost of starting a plant against the cost of keeping it running part-loaded, and the impossibility of running below its minimum stable level (Staffell and Green, 2015). UCCO calculates the marginal cost of energy in each hour, and hence the revenues that each type of station would earn over the year's operations, together with their costs. If the station is found to earn more than its costs, then UCCO will add more of that type of capacity and re-run the operating stage; if some stations are unable to recover their costs, then UCCO will reduce capacity. The process stops when every type of station is just breaking even (within model tolerances), thus giving the outcome a competitive market with perfect foresight would produce.

A fixed amount of storage, measured both in terms of power (MW) and energy (MWh) capacity, can be added to the model, and is dispatched as part of UCCO's cost-minimising operating stage. UCCO does not vary the amount of storage to meet a break-even constraint, but records the profits that it makes (net of energy purchase costs), and hence the fixed costs that these could cover.

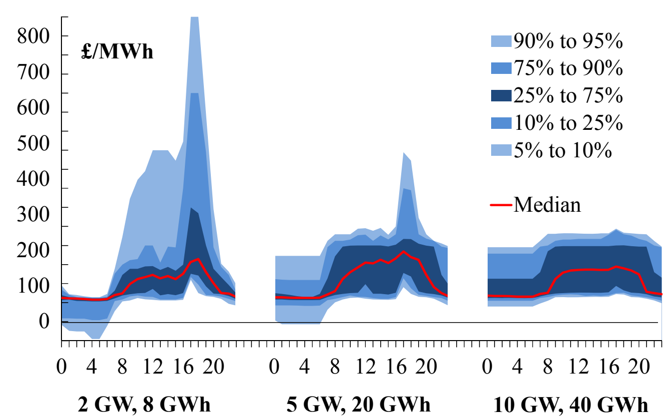

Figure 1: Distribution of prices over winter days.

We model the power system in Great Britain in 2030, assuming the demand level and renewable generation from the National Grid (2014) "Gone Green" scenario. This has 51 GW of wind, 16 GW of solar energy and total demand of 345 TWh – the same level as 2014. Demand is kept down by significant investments in energy efficiency and because the electrification of transport and heating is not assumed to take off until the 2030s. Our plant costs are taken from National Grid and DECC (2013), including a carbon price of £76/tonne. We follow the approach taken in DECC (2013), which is to take the expected net present value of the carbon price over the station's lifetime, a more relevant guide to investment than the current (low) value.

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See footnote at end of text.

Results

Figure 1 shows that as storage is added to the power system, the distribution of prices is compressed. The figure takes prices for 90 days between late November and the end of February (excluding the period around Christmas) – the very highest prices are suppressed as the amount of storage available increases. In contrast, the highest overnight prices increase – the effective demand rises as most power can be taken into storage at these times, and the plant mix is also changing – the storage actually displaces CCGT stations rather than the peaking plants that we might expect to be its direct competitors.

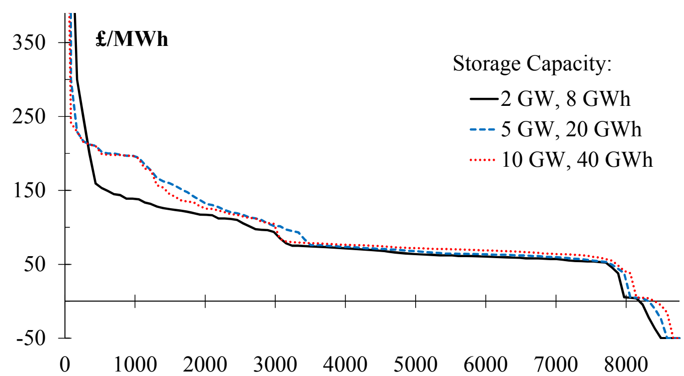

Figure 2: Price-duration curves

Figure 2 shows that the price-duration curve does not change significantly over the year as a whole – as Green and Vasilakos (2011) found, capacity will adjust so that the baseload technology continues to be able to cover its costs over the year as a whole, and this anchors the time-weighted price. Since storage cuts off some of the very highest prices, the new equilibrium requires higher prices than before in the near-peak hours: it also eliminates some (but not all) of the hours in which renewables have to be displaced and ask for a negative price to offset their lost subsidy. The demand-weighted average electricity price falls by 6% as storage is added, while the average market value of wind energy rises by 6%. The value of storage also falls; the energy arbitrage and peak capacity value captured in this work decreases by 60% as we move from 2 GW to 10 GW of storage power capacity. Storage has other uses, however, providing operating reserves and relaxing grid constraints; Strbac et al (2012) show that the marginal value of these is significant and not particularly sensitive to the amount deployed. Coordinating the use of storage between these different opportunities remains a challenge.

Footnote

[1] This is because power prices are positively correlated with the amount of thermal generation, which after correcting for the pattern of demand will be negatively correlated with the amount of renewable output. With enough renewable capacity, this can offset any tendency to have more output at times of high demand.

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