THE LONG-RUN IMPACT OF ENERGY STORAGE ON ELECTRICITY PRICES AND GENERATING CAPACITY

Richard Green, Imperial College Business School, +44 207 594 2611, r.green@imperial.ac.uk
Iain Staffell, Imperial College Business School, +44 207 594 2711, i.staffell@imperial.ac.uk

Overview

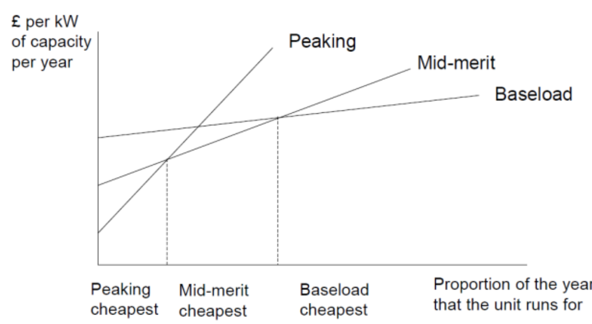
Energy storage technologies have the potential to help in the task of integrating variable renewable electricity generators such as wind farms and PV panels. The output from these becomes less valuable as the amount of renewable capacity increases, since the output from many generators is correlated, strengthening the negative correlation between renewable output and the remaining demand to be met by thermal (and hydro) generators, or weakening any positive correlation. Since wholesale electricity prices usually have a positive correlation with the amount of thermal generation needed, this explains why increasing amounts of renewable power become less and less valuable (Swider and Weber, 2006; Lamont, 2008; Bushnell, 2010; Hirth, 2015).

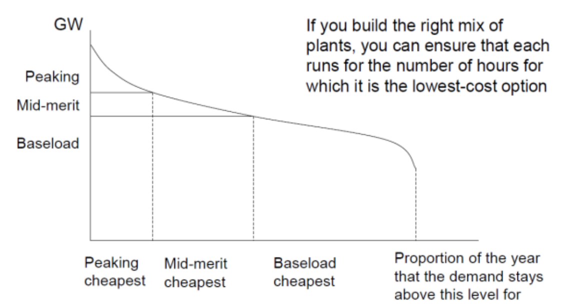
At the same time, if renewables make the pattern of electricity prices more variable over time, this increases the profitability of time-shifting arbitrage strategies by energy storage operators – they can buy power more cheaply at times of surplus renewable generation, and sell it later when the renewables are not running. This profitable activity would also help in the task of absorbing fluctuating renewable output into the power system.

Green and Vasilakos (2011) have shown that much of the increase in price variability (and lower average prices in some countries) due to renewable generation is in fact a short-term phenomenon, and that once the capacity mix has adjusted to the new shape of the load-duration curve (net of renewable output), the pattern of prices ought to return to something similar to the one that would have occurred without the renewable generators. This paper will ask whether the same result holds if energy storage technologies are widely deployed.

Methods

Green and Vasilakos (2011) and related work by Green et al (2011) was based on a simple merit order stack applied to an annual load-duration curve. A graphical version of the analysis would use a screening curve, which shows how the total costs of each type of power station over a year of operation vary with its load factor, to determine the optimal maximum and minimum hours of operation for each type. These critical lengths of time can then be compared with the load-duration curve to show the level of demand which is just equalled in those numbers of hours. The resulting demand levels give the cumulative capacity needed of each type. Changes in the load-duration curve as renewable generation is netted off from demand lead to a change in the optimal capacity mix of thermal plant. Prices are equal to the marginal cost of generation when there is spare capacity, and the level needed to ration demand to capacity when this is binding. The model was solved numerically because this allowed estimates of how the time-weighted and demand-weighted prices received by different kinds of generators would vary in equilibrium as the amount of wind power was increased. Green et al (2011) included energy storage, but as this was in the form of hydrogen produced by electrolysis for use in transport, the paper assumed that large quantities could be stored until it was needed and so the exact timing of its production was relatively unimportant.





When studying electricity-to-electricity storage, the timing of charging and discharging is important, because the energy storage capacity (MWh) is likely to be limited as well as the power capacity (MW). The model will therefore move from a load-duration curve approach to include the pattern of storage operation over time. The algorithm used in the DESTinEE model (Staffell and Green, 2014) allows for the rapid simulation of a year's operation, and the impact of start-up costs on the optimal capacity mix could be incorporated using the algorithms in Staffell and Green (under submission). These could also be verified with a full unit commitment approach, run on a suitable selection of days (Green et al, 2014). We have 20 years of historic demand and weather data against which the hourly wind output from a fleet of onshore and offshore farms can be simulated.

Results

This is work-in-progress and we do not yet have results to report. We will present the results from a market equilibrium in which the optimal capacities of generators and energy storage are jointly determined; we will be able to show how these capacities change as renewable output is added to the power system in Great Britain. The pattern of prices derived will be one in which each kind of capacity (including storage) just breaks even. In Green and Vasilakos (2011) we found that adding a large amount of renewable generation did not change the underlying time-weighted average electricity price (before subsidies) because it had to cover the costs of the base load technology. This logic suggests that time-weighted prices should also remain constant in the presence of energy storage devices, but they have the potential to significantly affect the pattern of prices over time, and the demand-weighted average price which is of greater importance to most customers than the time-weighted average.

The costs and efficiency of most kinds of energy storage are highly uncertain at present, since these are new technologies (with the exception of pumped storage, which requires suitable sites and has very project-specific costs). We will show how these variables affect the way in which storage can change investment and operating incentives within the power system, alongside the impact of varying fuel and carbon prices.

Conclusions

This paper lies at the junction of two streams of research. One stream assesses the value of renewable generation and its impact on investment incentives within the power system. The other stream is methodological, developing simplified techniques that can be used for rapid simulation of an electricity market, respecting an increasing number of engineering constraints while still allowing large numbers of Monte Carlo trials, for example, to capture the effects of uncertainty. We trust that the results on investment incentives will be of use to policy-makers and the energy industry, and that the methodological advances will be of interest to other modellers.

References

Bushnell, J. (2010). "Building Blocks: Investment in Renewable and Non-Renewable Technologies," in: B. Moselle, J. Padilla and R. Schmalensee: *Harnessing Renewable Energy in Electric Power Systems: Theory, Practice, Policy*, Washington, Resources for the Future Press.

Green, R.J., H.Hu and N. Vasilakos (2011) "Turning the Wind into Hydrogen: The long-run impact on electricity prices and generating capacity" *Energy Policy*, vol. 39, no. 7, pp. 3992-8

Green, R.J. and N. Vasilakos (2011) "*The Long-term impact of wind power on electricity prices and generating capacity*" CCP Working Paper 11-4, Centre for Competition Policy, University of East Anglia

Green, R.J., I. Staffell and N. Vasilakos (2014) "Divide and conquer? k-means clustering of demand data allows rapid and accurate simulations of the British electricity system" *IEEE Transactions on Engineering Management*, vol. 61, no. 2, pp. 251-260

Hirth, L. (2015) "The Optimal Share of Variable Renewables: How the Variability of Wind and Solar Power affects their Welfare-optimal Deployment" *Energy Journal*, vol. 36, no. 1, pp. 149-184

Lamont, A. (2008). "Assessing the Long-Term System Value of Intermittent Electric Generation Technologies" *Energy Economics* 30(3): 1208–1231.

Staffell, I. and R.J. Green (2014) "*How much transmission capacity will Europe need in 2050?*" Energy Institute Conference on Energy Systems

Staffell, I. and R.J. Green (under submission) *Is there merit in the Merit Order Stack?* 2012 BIEE Conference

Swider, D. & C. Weber (2006) "An Electricity Market Model to Estimate the Marginal Value of Wind in an Adapting System" Proceedings of the Power Engineering Society General Meeting, Montreal.