Journal of Energy Storage 8 (2016) 212–225

Contents lists available at ScienceDirect

Journal of Energy Storage

journal homepage: www.elsevier.com/locate/est

Maximising the value of electricity storage

Iain Staffell[a,*], Mazda Rustomji[b]

[a] Centre for Environmental Policy, Imperial College London, SW7 1NA, UK
[b] Energy Futures Lab, Faculty of Engineering, Imperial College London, SW7 2AZ, UK

ARTICLE INFO

Article history:
Received 16 March 2016
Received in revised form 18 July 2016
Accepted 18 August 2016
Available online 27 August 2016

Keywords:
Storage
Battery
Electricity market
Arbitrage
Reserve
Economics

ABSTRACT

Grid-scale energy storage promises to reduce the cost of decarbonising electricity, but is not yet economically viable. Either costs must fall, or revenue must be extracted from more of the services that storage provides the electricity system. To help understand the economic prospects for storage, we review the sources of revenue available and the barriers faced in accessing them. We then demonstrate a simple algorithm that maximises the profit from storage providing arbitrage with reserve under both perfect and no foresight, which avoids complex linear programming techniques. This is made open source and freely available to help promote further research.

We demonstrate that battery systems in the UK could triple their profits by participating in the reserve market rather than just providing arbitrage. With no foresight of future prices, 75–95% of the optimal profits are gained. In addition, we model a battery combined with a 322 MW wind farm to evaluate the benefits of shifting time of delivery. The revenues currently available are not sufficient to justify the current investment costs for battery technologies, and so further revenue streams and cost reductions are required.

1. Introduction

The world's leaders have now pledged to limit global warming to well below 2 °C, which will require significant increases in the penetration of intermittent renewables, inflexible nuclear generation and carbon capture and storage, together with electrification of heat and transport sectors. This raises considerable challenges in operating future electrical grids both efficiently and reliably. Electricity storage, demand side response, flexible generation and interconnection all offer methods to alleviate these issues [1]. Currently, storage is proving too expensive to make a significant contribution. Whilst much work is being carried out to reduce costs and improve efficiencies, this paper explores how storage can maximise its revenues through operating in multiple markets. Previous works have (1) focused on optimising for a single revenue stream such as arbitrage, (2) use global optimisation tools on specific cases, and (3) typically require perfect or very good foresight of future prices.

This work takes an existing algorithm for arbitrage from the EnergyPLAN software by Lund et al. [2] and extends it to co-optimise the provision of reserve, which we show can increase storage revenue by an order of magnitude. A full mathematical description and an open source implementation in MATLAB are given as Supplementary material.

The following section evaluates the revenue streams available to storage (focussing on the British market), barriers to its uptake, and the various technologies available. Section 3 describes the algorithm to optimise the operation of storage for arbitrage, with or without reserve services, under perfect and no foresight of future spot market prices and reserve utilisation. Section 4 gives a demonstration of the algorithm, simulating lithium ion and sodium sulphur batteries operating in the British electricity market. The results evaluate the attainable profits and rates of return within the current UK market, together with a sensitivity analysis of various model inputs and an assessment of storage integrated with a wind farm.

2. Background and literature review

2.1. Sources of revenue for storage

Storage has the flexibility to operate within energy market, trading energy to gain from arbitrage, and in ancillary markets, offering reserve, power quality and reliability services. It can also be integrated with existing infrastructure: generators such as wind farms (to reduce balancing costs, time-shift delivery or manage

* Corresponding author.
E-mail address: i.staffell@imperial.ac.uk (I. Staffell).

http://dx.doi.org/10.1016/j.est.2016.08.010
2352-152X/

Nomenclature

ArbOnly	The arbitrage only scenario
ArbAv	The arbitrage with availability (but no utilisation) scenario
ArbAvUt	The arbitrage with availability and utilisation scenario

constraints); demand centres (to reduce network service charges, e.g. triad avoidance); or networks (deferring costly upgrades to transmission and distribution systems).

2.1.1. The potential and future of arbitrage

The spread between daily peak and off-peak electricity prices depends on a multitude of factors: the difference in fuel costs of baseload and peaking generation, the carbon price, the difference in peak and baseload demand, the penetration of renewables and flexible technologies [3]. Similarly, future electrification of heat and transport has the potential to increase or decrease the spread, dependant on the extent to which the demand is managed in terms of spreading the peaks [4].

Storage that relies on daily energy arbitrage is susceptible to changes in the daily spread. Renewables may affect the spread by reducing prices when their output is high [5]. Some storage schemes, such as pumped hydro with very large reservoirs, may be capable of arbitrage over longer timescales, perhaps taking advantage of weekly spreads which are driven by lower demand over weekends, rather than renewable penetration [6].

Wind or PV which coincides with peak demand can reduce the spread. This appears to be the case in Germany, where PV coincides with peak daytime demand and suppresses prices during the day, resulting in lower peak prices which now occur in the morning and evening [7]. British peak prices occur in the evening, and so PV may instead increase the daily spread. Wind power has a less systematic diurnal pattern, but the penetrations seen in Germany and Britain are now sufficient to cause negative electricity prices, and thus increase the daily spread.

Fig. 1 displays the average daily spread in Germany since 2002 (peak minus baseload price) as a proportion of the median spot price, against the growth of solar PV and wind penetration. Before the rise in PV capacity, the cost difference between coal and gas plants was the main driver [3]; however, since 2008, the spread has consistently reduced, as the penetration of PV has dramatically increased.

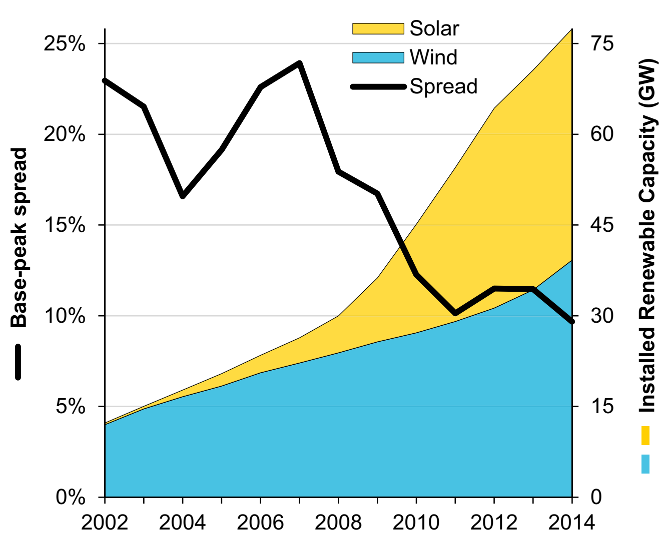

Fig. 1. Variation of average daily price spreads, gas-coal fuel price spreads and growth of wind and solar PV in Germany. Based on data from [3,7,8].

The daily demand profile varies significantly between countries. For example, the UK's peak demand is typically in the evenings, when solar is less likely to displace conventional generation. This greatly reduces its impact on the price spread, though it may still depress average wholesale prices.

2.1.2. The structure of balancing services in the UK

A second type of revenue that storage can access is from balancing services. In the UK, there are three types [9]:

- Ancillary and Commercial Services
- Contract Notifications Ahead of Gate Closure
- Bid – Offer Acceptances (also known as the 'balancing mechanism')

The first includes specific services that are contracted for in advance, namely reserve, response, power quality and reliability services. The income is typically based on utilisation volumes (MWh of energy) and/or availability offerings (MW of capacity). The second enables National Grid (Britain's transmission system operator) to contract directly with parties to purchase or sell electricity ahead of gate closure, typically when it predicts system imbalances may occur [9]; however, it is rarely used (most recently in 2012) and is hence not considered further [10]. The third type, the 'balancing mechanism', operated post gate closure (i.e. less than an hour ahead of real-time). Generators and consumers can submit bids to buy electricity (increase demand or reduce generation) and offers to sell electricity (reduce demand or increase generation), indicating the price at which they are willing to deviate from their preferred schedule [9].

The contracted nature of ancillary services results in income streams that are typically more predictable or at least offer some level of certainty, and hence these are considered further for the remainder of this study. Ancillary services consist of frequency response, reserve, black start and reactive power services [9]. In a broad sense, response services balance the power demanded with generation on a second by second basis, whereas reserve provides energy balancing during unforeseen events of longer duration, such as a tripped generator or incorrectly forecast demand. Black start is required in case of total or partial transmission system failure, to gradually start up power stations and link together in an island system. Finally reactive power services involve maintaining adequate voltages across the transmission network, though such a service may also be useful on distribution networks. A more detailed description of these is given in the online supplement.

2.1.3. Short term operating reserve

It is likely that storage has roles to play in all four elements of ancillary services; however, we focus on the provision of reserve, and specifically short term operating reserve (STOR) for reasons of data availability. STOR is a commercially tendered service, where a constant contracted level of active power (or demand reduction) is delivered on instruction from National Grid, typically when demand is greater than forecast or to cover for unforeseen generation unavailability. The service only requires participants to be available during predefined availability windows, with typically two to three occurring per day [11].

Participants are expected to deliver within 4 h of instruction (though most tenders could within 20 min), with a minimum capability of delivering 3 MW for 2 h, followed by a maximum 20 h recovery period [12]. In 2012/13, the majority of units were less than 10 MW in capacity, with typical utilisation times of 90 min