ECONOMICS OF GRID SCALE LITHIUM-ION BATTERY STORAGE

5/5/2017
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Economics of grid scale lithium-ion battery storage

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INTRODUCTION
Increasing intermittent generation is being connected to grids around the world, often via inverter connections, which have very different characteristics to the dwindling numbers of traditional large rotating machines. There are potential roles for lithium ion batteries (LIBs) in providing a range of services; replacing the capability of older generation plant, adding new faster response to offset the loss of inertia from fewer large machines, and helping to match the supply from intermittent sources to demand profiles.

The question arises as to what capital, operating and maintenance costs must be achieved in order to render LIB economically attractive against more conventional options such as stand-by fossil fuel plant.

AIMS AND OBJECTIVES
The aim of this project was to identify the range of services that grid-scale LIBs could provide, where possible to establish the costs and revenues associated with those services and to develop a model that could be used to evaluate the performance of a LIB under various scenarios.

The objective was to establish an understanding of the economic viability of LIB systems under current grid arrangements, identify possible service combinations and specifically to consider how Sheffield University’s Willenhall battery could generate revenue.

METHODS
To achieve the stated aims, a review of currently contracted National Grid Company (NGC) and other services was undertaken to understand the scope and potential revenues that are available.

A model was constructed using a combination of Goldsim (a Monte-Carlo based continuous and discrete simulation tool) and Excel.
DELIVERABLES

SOURCES OF REVENUE

The services that a LIB can provide can be divided up by market participant type as described below.

Embedded Generator

An energy storage provider can provide services to a distribution connected (embedded) generator to maintain its output during grid constraints or to arbitrage generated power; principally to shift power from a low to high export value period. Accessing half-hourly export tariffs is, however, quite challenging. Following a discussion with Flextricity [1] it appears possible to access day-ahead pricing, although it would be problematic to predict volumes with sufficient accuracy. Figure 1 illustrates wholesale day-ahead market prices with a differential of c£40/MWh between early morning lows and evening highs. However, it must be borne in mind that distribution charges will erode this differential and differences vary daily and over the course of a year.

![Figure 1 - Day Ahead UK Hourly Spot Prices][2]

Some embedded sites are also subject to location specific distribution network operator (DNO) constraints. Typically, these are expressed as a power threshold, but in practice the constraint may be the result of thermal limits on cables or voltage constraints. A LIB could thus either shift generated power into an unconstrained period or supply reactive power to maintain network voltages within Quality of Supply tolerances.
Supplier Services

Suppliers are the retailers of electricity in the UK; they must manage their half hourly electricity positions to minimise the difference between the volume they actually sell and the volume they notify to the grid operator. If their contracted position does not match their actual volume, they will subject to settlement of the non-contracted volumes at the calculated System Buy/Sell price [3].

Thus suppliers may wish to use battery storage to help manage their exposure to imbalance, particularly over short time horizons. This is equally true for licensed generators; a generator that does not deliver its contracted volume is also subject to payments at the system buy/sell price.

Suppliers also make payments to National Grid for use of the transmission system [4] based on their demand during the three highest demand half hour periods (triads) between November and end of February. Suppliers are keen to minimise their demand during anticipated triad periods and will pay generators to increase generation or consumers of power to decrease demand at these times. Triad periods are not known in advance, but typically occur between 4pm and 7pm on cold winter evenings. Triad payments can be worth as much as £45,000/MW/year depending on location [3]. Embedded benefits are currently under review by Ofgem and may be reduced substantially in the near future [3].

DNO Services (Location Specific)

These are similar to those noted under ‘Embedded Generator’ and will not be considered further due to their location specific nature.

National Grid Services

National Grid (NGC) procures services to manage system imbalance, load pick-ups (e.g. TV induced), network constraints and contingency events such as generator trips.

The services required are partly procured through bilateral contracts with generators and mandatory requirements on market participants, but NGC also tenders for specific services or groups thereof. Many services include minimum volumes, though recently there has been a move to reduce the minimum thresholds with many now at 1MW. It is usually possible to ‘aggregate’ multiple sites to deliver the minimum volume required.

The services below can generally be tendered across several operational ‘windows’; this allows for the possibility of sequentially stacking different services at different times of the day when they are at their highest value to the system operator.

Firm Frequency Response (FFR)

This set of services comprises various high and low frequencies responses. The differences between each relate to the trigger frequency, time to full output and duration for which it must be delivered. The capacity contracted varies according to the month and trading period and providers can nominate which periods they will be available for. Providers are paid an availability price and may elect to be paid an initiation and nomination fee, although few providers appear to do this. Typical prices are around £35/MW/hour with non-
balancing mechanism units (most likely for LIB systems) receiving revenue for power supplied at perhaps around £40-60/MWh [7].

NGC also procures ‘static’ FFR services with set triggered volumes, but these are less suited to LIB systems.

**Enhanced Frequency Response (EFR)**

This service is expected to provide a key market for LIB systems; to date there has been only one tender, which procured around 200MW of battery storage operating within a tight frequency control envelope. NGC expect to launch additional tenders to compensate for a reduction in system inertia as more large synchronous generators are decommissioned. Timing remains uncertain and the prices accepted in the first round were much lower than many expected, averaging less than £10/MW/h of availability [8].

**Short Term Operating Reserve (STOR)**

STOR is contracted by NGC to provide extra power at relatively short notice (under 4 hours). The capacity procured is set out for different availability windows depending on time of year, weekday vs weekend and time of day. Generators or consumers (through demand reduction) can bid in at different prices for different windows and provide different levels of guarantee as to availability, though these must always be firmed on the Friday before the delivery week. Providers are paid an availability price for each window and utilisation price for the energy supplied. STOR contract prices are some of the most variable with availability payments ranging from £1.50 to £22.50/MW/hour and utilisation charges from £63.00 to £220/MWh [9].

**Fast Reserve**

This is a quick start, high ramp rate service that must be delivered for up to 15 minutes. This is restricted to plants with a minimum capacity of 50MW and is not considered further.

**Demand Turn-Up (DTU)**

Demand Turn-Up is a new ‘Footroom’ service aimed at procuring additional demand as a lower cost option to curtailing generation in constraint conditions. The service availability windows occur overnight 23.30-08.30 in March, April, May, September and October, 23.30-09.00 June, July and August and during the day on weekends and bank holidays 13.00-16.00, although it can be procured at other times [6]. Prices paid were £1.50-£1.75/MW/h availability and £60-97/MWh.

**STACKING OF SERVICES**

In order to obtain the best return on investment a LIB needs to maximise revenue whilst minimising cycling in order to reduce degradation. There are two possible ways to stack services; concurrently or sequentially. Figure 2 lists each of the services that might be contracted and how they can be stacked with other services.

**Concurrent Stacking**

This involves offering two services at the same time and generating revenue from both. Within groupings of NGC FFR services it is often possible to have concurrent bids, but concurrent services (including with DNOs) are generally not permitted under current standard contract terms (e.g. see under [4]). This applies also to STOR and Fast Reserve and EFR.
Figure 2 indicates that, most frequently, it is generator/supplier/DNO services that can be stacked concurrently. It is likely that a LIB could provide voltage control with a reasonable amount of reactive power being supplied across quite a large load range, and in principle, phase balancing could also be provided.

DNO constraints will often coincide with generator constraints and therefore it should be possible to offer services to the DNO that also benefit the embedded generator.

**Sequential Stacking**

NGC publish forward data covering expected requirements for different services, making it possible to judge periods of high service demand and thus potential scarcity and higher pricing. Figure 3 plots the volumes of FFR sought by NGC in March against half-hourly period together with the average Noordpool day ahead spot price for w/c 16th March 2017. This suggests that the highest price paid for FFR is likely to be between 10.30pm and midnight, which does not conflict with selling power under an arbitrage model between 5.30pm and 8.00pm.
Figure 4 illustrates how services might be stacked sequentially through a Winter day. Starting in the early hours of the morning, the battery is charged at low market price, through the day the battery provides EFR services and the assumption is made that the SoC remains close to 50%. At 16.00 the battery is switched to a discharge mode to take advantage of arbitrage and potential triad avoidance. At the end of the peak pricing period, the battery is recharged to 50% SoC to provide FFR services from 22.00 when these are expected to be highly priced.
Modelling Approach

A model was produced using Goldsim [6] with an Excel input spreadsheet that defines which services are to be provided at what capacity in each half-hour trading period for 10 different day types. These day types cover typical days such as a winter weekday or a summer Saturday. Day types can either be combined into a contiguous sequence to represent a complete year or the model can run one of each day type with multiple model realisations to extract a probabilistic outcome for each type of day; the Excel sheet will then multiply these up to generate a ‘year equivalent’ output. Day-type appropriate market data ([11], [12]) is selected at random for each model realisation or change in day. Goldsim conditionally enables functionality representing each of the different services according to the spreadsheet schedule. The power demands from each are summed and presented to a simple battery model to determine SoC and equivalent complete cycles (a simple proxy for state of health).

Modelling Results

Five scenarios, listed below, were considered. All use the rating and capacity of the Willenhall battery (2MW, 1MWh) and are focused on EFR, although scenario 5 uses current FFR services for comparison. FFR high was used in scenario 4 to attempt to charge the battery prior to arbitrage periods.

1. Enhanced Frequency Response Only
2. Enhanced Frequency Response and Short Term Operating Reserve
3. Enhanced Frequency Response and Arbitrage
4. Enhanced Frequency Response, Firm Frequency Response (FFR High), Footroom (DTU) and Arbitrage
5. Firm Frequency Response (Low and High), Footroom (DTU) and Arbitrage

The results are summarised in Table 1. Service warning hours are the number of hours for which the service could not be provided if called on (i.e. unexposed failure), whilst ‘failure hours’ are penalty-attracting actual incidents of failure (costs not modelled). Detailed results are available in separate spreadsheets; an example of a summary report for scenario 4 is included as Figure 5.

<table>
<thead>
<tr>
<th>Ref</th>
<th>Services Scenario</th>
<th>Annual Revenue (GBP)</th>
<th>Annual full-cycle equivalent</th>
<th>Service warning hours</th>
<th>Service failure hours</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>EFR Only</td>
<td>158,465</td>
<td>721</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2</td>
<td>EFR, STOR</td>
<td>144,918</td>
<td>1017</td>
<td>1,969</td>
<td>38</td>
</tr>
<tr>
<td>3</td>
<td>EFR, Arbitrage</td>
<td>124,332</td>
<td>870</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>EFR, FFR (High), DTU, Arbitrage</td>
<td>121,401</td>
<td>763</td>
<td>28.5</td>
<td>0</td>
</tr>
<tr>
<td>5</td>
<td>FFR (Low and High), DTU, Arbitrage</td>
<td>121,217</td>
<td>223</td>
<td>1,029</td>
<td>5</td>
</tr>
</tbody>
</table>

Notes:
(1) an error was found in the dead band function for EFR which resulted in excessive cycling, a revised calculation gives annual cycles as 475 for EFR only, however, since this wasn’t run on other scenarios, the number shown has been left at 721.
(2) Service warning hours exclude EFR due to way contract works and Arbitrage as not contractual.
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<table>
<thead>
<tr>
<th>Day Type</th>
<th>Days</th>
<th>Daily Total</th>
<th>Annual Total</th>
<th>£P Revenue per MW x hour of service offered</th>
<th>% of Trading Periods for which service is active</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter Weekday</td>
<td>82</td>
<td>336.22</td>
<td>27,569.80</td>
<td>- 9.51 - - - - 1.50</td>
<td>8% 75% 0% 0% 0% 0% 13%</td>
</tr>
<tr>
<td>Winter Saturday</td>
<td>17</td>
<td>339.82</td>
<td>5,776.90</td>
<td>- 9.45 - - - - 1.71</td>
<td>8% 75% 0% 0% 0% 0% 13%</td>
</tr>
<tr>
<td>Shoulder Weekday</td>
<td>107</td>
<td>335.56</td>
<td>33,858.94</td>
<td>- 9.53 - - - - 2.23</td>
<td>6% 8% 0% 10% 0% 0% 13%</td>
</tr>
<tr>
<td>Shoulder Saturday</td>
<td>22</td>
<td>319.32</td>
<td>7,070.56</td>
<td>- 9.45 - - - - 1.50</td>
<td>2% 8% 0% 10% 0% 0% 13%</td>
</tr>
<tr>
<td>Summer Weekday</td>
<td>74</td>
<td>326.74</td>
<td>23,667.28</td>
<td>- 9.23 - - - - 1.50</td>
<td>6% 8% 0% 10% 0% 0% 13%</td>
</tr>
<tr>
<td>Summer Saturday</td>
<td>13</td>
<td>319.32</td>
<td>4,118.13</td>
<td>- 9.23 - - - - 1.50</td>
<td>6% 8% 0% 10% 0% 0% 13%</td>
</tr>
<tr>
<td>Public Holiday</td>
<td>8</td>
<td>424.92</td>
<td>3,399.40</td>
<td>- 9.92 - - - - 3.04</td>
<td>6% 8% 0% 0% 0% 0% 13%</td>
</tr>
<tr>
<td>Totals/Averages</td>
<td>365</td>
<td>3,369.21</td>
<td>121,401.33</td>
<td>- 9.55 - - - - 1.50</td>
<td>6% 64% 0% 6% 0% 12% 10%</td>
</tr>
</tbody>
</table>

(a) Average revenues by service and day type (rebalance not reallocated)
(b) Net revenue by service MWh of availability (rebalance not reallocated)
(c) Net revenue by service MWh of availability (rebalance reallocated)
(d) Hours for which each service is in a warning or failed state
(e) Number of charge cycles per service GWh and rebalanced revenue per charge cycle

Notes:

FIGURE 5: EFR, FFR HIGH, DTU (FOOTROOM) AND ARBITRAGE
DISCUSSION & CHALLENGES

Model Limitations
Some of the limitations in the model are listed below.

- Only limited testing was carried out on the model, and that largely whilst running scenarios, thus there are potentially some errors and inconsistencies in model functionality between the different scenarios.
- The model has been run as multiple realisations of single days, this means the LIB SoC is not accurately carried forward to the next day-type.
- The function that reallocates rebalance costs cannot handle situations where only export occurs and does not reallocate re-balance costs incurred the day after the service was provided, so re-allocated revenues (such as Figure 5c) may not always be accurate.
- The charge cycle counting methodology may not accurately distribute cycles between services, particularly where concurrent stacking occurs.
- The approach to EFR operation and use of dead bands has a significant impact on cycle count and needs further consideration.
- Only a limited amount of market data has been used.

Model Results
EFR, FFR and STOR all have rather similar availability payments of around £10/MW/hour and thus all offer similar revenue streams. The difference comes in the degree to which the battery is cycled in delivering the services, the time for which the service must be maintained and the costs/revenues of any import or export. The EFR service requires only a short service time of 15 minutes; the 2MW, 1MWh LIB modelled is appropriately designed to provide this service. Providing other services such as STOR or FFR requires longer operating windows. This can be achieved by reducing the capacity bid (for the same energy stored), but that has the consequence of reducing availability payments.

Although STOR appears problematic in regard to the number of cycles achieved against revenue, an option would be to bid a much smaller capacity to match the nominal 50% SoC 2 hour capacity. This would reduce the cost of operating the service and the number of battery cycles, but would also reduce availability payments; this would be a trade off against potentially high export revenues if dispatched.

The FFR service does not impose such a tight frequency control window as EFR and this is clearly illustrated in the much lower number of battery cycles over an operational year.

This small number of scenarios illustrates the complexity of the optimisation problem; there is a need to optimise the power to energy ratio of the battery system according to the services that are to be provided. The services then offered, and the strategy for ensuring they can be delivered (i.e. the approach to maintaining the necessary SoC) must be scheduled appropriately for each different day type considering expected market prices and, for some services, the likelihood of dispatch. All those choices will have an impact on the revenue streams and the number of cycles to which the battery is exposed and hence the ‘cost of degradation’ in providing the services.
Overall the analysis suggest that stacking services is not beneficial for a battery system of this power/energy ratio, but that may not be the case for systems with more energy capacity.

**Willenhall**

Although the number of scenarios modelled is small, it seems clear that the Willenhall battery, with its Power to Energy Ratio, is most suited to providing EFR. It wasn’t clear from the site visit whether the connection configuration provides ‘N-1’ reliability required for the service. If not, it might be possible to incorporate the system in an aggregated portfolio, such that equivalent reliability is provided. The maximum revenue available (before deducting maintenance and network charges) is around £160,000 per year under EFR. Given the circa £3M cost of the installation [11], the payback period would be about 19 years. Over this period, the number of full equivalent cycles would be circa 10,000, which is well within the stated cycle life [13] for the type of battery used.

**Considerations for LIB Developers**

Commercial developers will often need a firm contract to obtain finance; the maximum length of the NGC contracts is 4 years (for EFR [7]). Clearly the Willenhall battery does not offer a sufficiently attractive return on investment, but it does use expensive long life batteries. To offer a return within 4 years would require a system installed cost of well under £640,000. Assuming, taking into account maintenance and network costs, that the installed cost would need to be around £500k for a scheme this size then that equates to £250/kW or £500/kWh. Lower cycle-life batteries (4 years would require around 2000 cycles) are available at £200/kWh [14], leaving around £300k for inverters, battery management system, ancillaries and grid connection costs. Given an average high voltage connection cost of £450k [16], it is perhaps easy to understand why the first tranche of EFR projects went largely to sites with existing grid infrastructure. It also reinforces the potential advantages of working with DNOs to locate storage where it provides strategic advantage to them.

Large commercial systems are likely to involve multiple LIB units of perhaps a few MW capacity each. This opens up the possibility of transferring contracted services between different units according to their SoC at the start of any given service window presenting considerably more opportunity for revenue optimisation in systems with higher energy storage capacity.
REFERENCES


