Applied Energy 206 (2017) 12–21

Contents lists available at ScienceDirect

Applied Energy

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

Techno-economic analysis of the viability of residential photovoltaic systems using lithium-ion batteries for energy storage in the United Kingdom

Kotub Uddin[a,*], Rebecca Gough[b], Jonathan Radcliffe[c], James Marco[a], Paul Jennings[a]

[a] WMG, The University of Warwick, Coventry CV4 7AL, United Kingdom
[b] Cenex – The Centre of Excellence for Low Carbon and Fuel Cell Technologies, Loughborough LE11 3QF, United Kingdom
[c] School of Chemical Engineering, University of Birmingham, Edgbaston, Birmingham B15 2TT, United Kingdom

HIGHLIGHTS

- Commercially available PV-battery system is installed in mid-sized UK home.
- PV generation and household electricity demand recorded for one year.
- More than fifty long-term ageing experiments on commercial batteries undertaken.
- Comprehensive battery degradation model based on long-term ageing data validated.
- PV-Battery system is shown not be economically viable.

ARTICLE INFO

Keywords:
Photovoltaic
Lithium ion battery
Solar power
Battery degradation

ABSTRACT

Rooftop photovoltaic systems integrated with lithium-ion battery storage are a promising route for the decarbonisation of the UK's power sector. From a consumer perspective, the financial benefits of lower utility costs and the potential of a financial return through providing grid services is a strong incentive to invest in PV-battery systems. Although battery storage is generally considered an effective means for reducing the energy mismatch between photovoltaic supply and building demand, it remains unclear when and under which conditions battery storage can be profitably operated within residential photovoltaic systems. This fact is particularly pertinent when battery degradation is considered within the decision framework. In this work, a commercially available coupled photovoltaic lithium-ion battery system is installed within a mid-sized UK family home. Photovoltaic energy generation and household electricity demand is recorded for more than one year. A comprehensive battery degradation model based on long-term ageing data collected from more than fifty long-term degradation experiments on commercial Lithium-ion batteries is developed. The comprehensive model accounts for all established modes of degradation including calendar ageing, capacity throughput, ambient temperature, state of charge, depth of discharge and current rate. The model is validated using cycling data and exhibited an average maximum transient error of 7.4% in capacity loss estimates and 7.3% in resistance rise estimates for over a year of cycling. The battery ageing model is used to estimate the cost of battery degradation associated with cycling the battery according to the power profile logged from the residential property. A detailed cost-benefit analysis using the data collected from the property and the battery degradation model shows that, in terms of utility savings and export revenue, the integration of a battery yields no added benefit. This result was, in-part, attributed to the relatively basic control strategy and efficiency of the system. Furthermore, when the cost of battery degradation is included, the homeowner is subject to a significant financial loss.

1. Introduction

The United Kingdom (UK) Government set a carbon dioxide (CO_2) emission reduction target of at least 80% by 2050 from 1990 levels [1] which became legally binding through The Climate Change Act [2]. Given that the UK power sector accounts for one-fifth of the total final energy demand, contributing 35% of total CO_2 emissions [3], with demand projected to increase under many scenarios [4] it is identified

* Corresponding author.
E-mail address: k.uddin@warwick.ac.uk (K. Uddin).

http://dx.doi.org/10.1016/j.apenergy.2017.08.170
Received 6 June 2017; Received in revised form 27 July 2017; Accepted 16 August 2017

as the single most important route for decarbonisation [3]. Since 55% of electricity, within the UK, is generated from fossil fuels (with 21% Nuclear and 25% renewable) [5], the obvious route to decarbonisation is by reducing energy consumption. However, the possible negative impacts on economic growth and living standards arising from cutting back energy demand, means that many authors advocate the greater deployment of more environmentally clean alternative energy resources [6].

Renewable energy technologies are expected to play a major role in the decarbonisation of the UK power sector [7], while contributing to domestic energy security. Among the many options available, solar photovoltaic (PV) power is found to have substantial potential for electricity generation [8]. A challenge with PV generated electrical power is the flexibility needed to match demand and supply such that supply needs to match at each time point [9]. Electrical energy storage is one option to mitigate the supply/demand mismatches.

Recent developments that reduce the cost of solar PV panels [10,11] combined with a 59–70% (per kWh) reduction in the cost of lithium ion batteries in the last decade [12,13] have acted as catalysts in stimulating interest in solar home systems (SHS). Significant uptake of combined PV-battery units is now increasingly seen as a possible future, which would lead to increased decentralised generation and higher self-consumption levels [14]. If current battery cost reduction trends persist, it is predicted that these systems could ultimately disconnect from the grid and lead to autonomous homes or micro-grids [14].

In assessing the economic viability of solar home systems, PV-battery storage systems were shown to be profitable for small residential PV systems in Germany [8], although the assumption for battery costs in that study were deemed to be extremely ambitions (EUR 171/kWh). Other studies, also focussing on the German market, found that the profitability of PV-battery systems are dependent on significant reductions in battery price and the favourable German regulatory framework [15]. Corroborating the results of Ref. [15], Truong et al. [16] conclude that the viability of SHS is dependent on both an increasing retail price of electricity and financial subsidies. Such subsidies include, for example, feed-in-tariffs, green certificates or favourable net metering schemes [17]. The economic benefits of SHS is also correlated with the increased usage of on-site solar energy within the home, a practice termed self-consumption [14–16].

A limitation of such previous studies however, is that their assessment of economic viability did not consider the impact of battery degradation. Within the context of this study, battery degradation is characterised by a reduction in the useable energy capacity of the battery (e.g. capacity fade) and a reduction in the ability of the battery to deliver sustained power (e.g. power fade) resulting from an increase in battery impedance. For example, although studies such as [8] considered numerous forward-looking electricity pricing scenarios and the impact of subsidies, their work neglected the cost associated with battery degradation. Given that the daily capacity throughput for a battery in an SHS is almost twice the battery rated capacity [14] – approximately ten times larger than a typical electric vehicle, assuming daily recharging [18] – the impact of battery degradation is expected to be significant [19–21].

In this work therefore, we address the economic viability of solar home systems within the UK considering battery degradation. For this, we develop and employ a comprehensive battery degradation model based on long-term ageing data collected from more than fifty degradation experiments conducted on commercially available lithium ion batteries. This comprehensive model accounts for all established modes of degradation including calendar ageing, capacity throughput, ambient temperature (T), state of charge (SoC), depth of discharge (DoD) and the applied current (I) [21]. The model is validated using highly transient real-world usage cycles for various environmental conditions corresponding to different geographical regions of the UK.

Original data for PV generation and electricity consumption in an occupied UK family home is collected for an entire year. Previous studies which have reported consumption data have either been synthetic, i.e., modelled consumption estimates [22] or did not consider on-site generation [23–26]. Using this typical domestic electricity profile for a household in the UK and the detailed battery degradation model, the economic viability for PV battery systems in the UK is addressed.

This paper is outlined as follows: In Section 2, the PV-battery system is introduced and electricity profiles for an occupied family home is presented. The development and validation of the battery degradation model is presented in Section 3. Cost benefit analysis of SHS, considering battery degradation, is presented in Section 4. Analysis and discussion including the impact of future policy and pricing scenarios are presented in Section 5. Finally, conclusion and further work is presented in Section 6.

2. PV generation and electricity demand for a mid-size UK family household

2.1. Data collection

The domestic property explored here is based in Loughborough, Leicestershire, UK and is a three bedroomed, detached property in a domestic district of the town. Occupancy is a young family of four, with two children under the age of six and an approximate building size of 83 m^2. A number of low carbon and energy saving measures are installed in the property, including LED lighting, solar PV, battery storage and the family also own an electric vehicle (EV) which is regularly charged at the property. Based on the properties Energy Performance Certificate (EPC – which is an assessment of key items such as loft insulation, and the operating efficiency of household appliances, such as: the domestic boiler, hot water tank, radiators and windows, etc. The assessment provides a single number for the rating of energy efficiency, and a recommended value of the potential for improvement) the house is placed in band C, with an efficiency rating of 69–80% which is above the England and Wales average of band D [27]. The specifications for the commercially available PV and battery storage system installed in the property are given in Table 1 and a system schematic for the property is given in Fig. 1. Data collection has a 5-min sample period for all of the systems installed in the property, with the EV demand included in the total building demand value which is measured by a current sensor integrated within the supply meter.

2.2. Electricity demand and PV generation

The average annual electricity consumption for UK domestic properties is 3100 kWh for standard customers and 4300 kWh for customers on an Economy 7 tariff [28,29] (which is a differential tariff provided

Table 1
Technology and data collection specification for the domestic property in Loughborough.

Item	Specification	Data collected	Units	Frequency
PV array	4 kW monocrystalline PV array (20.4% efficiency, 327 W nominal power rating)	Solar generation Solar export to the grid House import House usage	kWh	5-min
Battery storage	2 kWh rated (1.6 kWh actual); 400 W inverter; lithium-ion battery	SoC over time Energy flow in/out	% kWh	5-min
Electric vehicle	2015 Nissan Leaf; 24 kWh lithium-ion battery	N/A	N/A	N/A
Building demand		Energy flow in/out	kWh	5-min
Charge point	13 Amp plug	Included as part of building energy demand	kWh	5-min

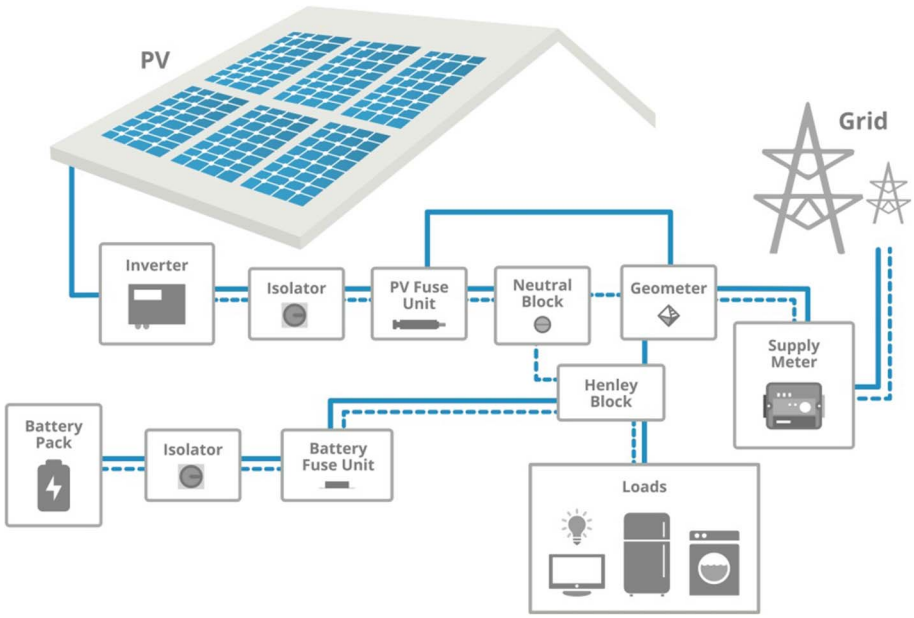

Fig. 1. System schematic for domestic property with static storage and PV. The Solid lines indicate Live connections while the dashed lines indicate Neutral connections.

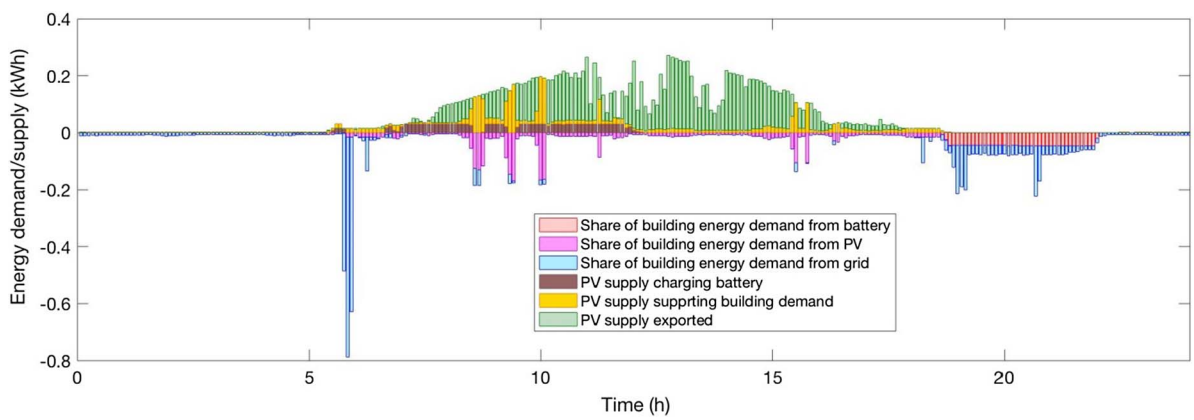

Fig. 2. Stacked bar chart showing the 5-min resolution breakdown of the total energy demand and the total PV supply for a typical day in April 2016. Positive values show the breakdown of total PV supply usage while negative values show the breakdown of how the buildings total demand is met.

by UK electricity suppliers that uses base load generation to provide cheap off-peak electricity during the night). The annual electricity consumption of the domestic property evaluated in this work was 4142 kWh for 2016, with the five-minute demand profile in Fig. 2 matching those generated by the CREST demand model [30]. The total electricity generated by the PV panels for the year was 3691 kWh and the grid imported electricity was 2771 kWh, therefore, only 33% of the PV generated electricity is consumed within the home and 2344 kWh is exported out. The energy generated through the PV cells are used to charge up the battery and support the buildings energy demand, with excess PV supply exported to the grid. As shown in Fig. 2, battery storage is used to distribute some of the PV generation to a period in the day when demand exceeds generation, for example during the evening.

The 24-h profile presented in Fig. 2 is relatively regular over a month. There are certain peaks in demand during the day, seen in Fig. 2, where demand exceeds PV production. Even if the battery has sufficient charge to support this demand, because the basic control algorithm adopted by the manufacturer is set based on the previous day's operation, such peaks are not reinforced. Given the regularity of the daily demand profiles across the year, it is noteworthy, that losses due to this control algorithm limitation are deemed to be negligible.

The half-hourly power throughput for an entire year (from the beginning of April 2016 to the end of March 2017) for the battery system is presented in Fig. 3. For a typical day, the capacity throughput is 160% of the batteries rated capacity, i.e., 80% of the battery's state of charge (SoC) is depleted (from 100% SoC to 20% SoC) in supporting the building's electricity load, which is subsequently replaced through the PV supply the following day. An 80% depth of discharge (ΔSoC) is significant. Continuous cycling of $\Delta SoC = 80\%$ is known to lead to a large, non-negligible volumetric change in the electrode due to lithium intercalation [31] leading to contact loss between the electrode active material and the current collector and hence an increase in cell impedance due to the decrease in electron conducting pathways [21]. In addition, the formation of large intercalation gradients will cause the disordering of crystal structures and hence particle cracking [32]. If persistent, this degradation mode will lead to the isolation of electrode material and a partial loss of cell capacity [33].

3. Battery degradation model

It is well established within the academic literature that lithium ion batteries are subject to degradation [34–41]. This degradation is generally governed by the age of the battery and the frequency of use. In addition, battery degradation is accelerated by elevated temperature, high states of charge, large swings in state of charge during cycling and the use of high current charge/discharge rates [19,21]. These factors are collectively referred to as ageing stress factors. In many applications, these ageing stress factors are convoluted and result in non-linear

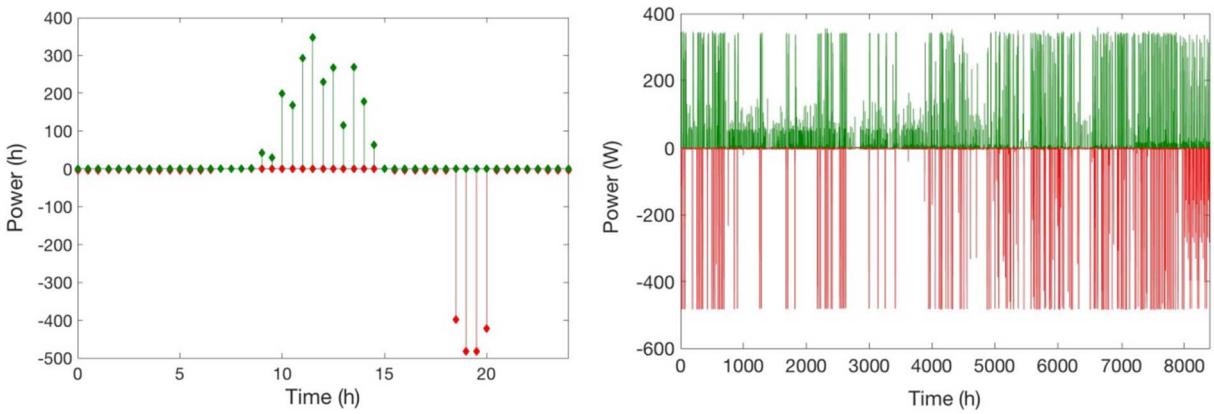

Fig. 3. Showing half-hourly electricity data for the battery which is operating to displace the building's electricity demand of a typical April day. Positive values (green) indicates battery is charging from the PV supply while negative values (red) show the battery discharging to support the buildings electricity demand. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

accelerated degradation of the battery. In this section, the development of a lithium-ion battery ageing model (degradation model) is presented. In what follows, the details of the battery ageing model development are presented. This commences with the ageing tests carried out to parametrise the ageing model, a discussion on the model structure and finally the validation of the model.

3.1. Lithium-ion cell used in ageing tests

Within this study, 45 commercially available 3 A h 18650-type cells were used [54]. Each cell comprises of a LiC_6 negative electrode, $LiNiCoAlO_2$ positive electrode, separated by a polyethylene separator, sandwiched between an aluminium current collector at the cathode and a copper current collector at the anode, all immersed within an electrolyte solution. The manufacturers recommended maximum continuous charge and discharge current rates are defined as 1.2 C and 0.3 C respectively. The maximum instantaneous charge and discharge current rates are defined as 5 C and 1.5 C respectively. The nominal internal resistance at 25 °C and 50% SoC is stated as 36 mΩ.

3.2. Ageing tests

The ageing tests are divided into two groups: storage and cycling. Storage tests entailed storing the cells at different SoC and temperature combinations. To adjust the SoC to the required level, the cells were first discharged at a 1 C constant current discharge rate to a cut-off voltage of 2.5 V using a commercial cell cycler (Bitrode MCV 16-100-5). Subsequently, the cells were allowed to rest for 3 h before being fully recharged according to the manufacturer's recommended charge protocol of constant current charge of 1 C until 4.2 V is measured and then a constant voltage of 4.2 V until the current fell below 0.15 A. Following the completion of charge, the cells were again allowed to rest for 3 h prior to being discharged at 1 C constant current for 6 min s, 30 min or 48 min which brought the cells to 90%, 50% or 20% SoC respectively. To control cell temperature, the cells were placed in a Vötsch thermal chamber at either 10 °C, 25 °C or 45 °C. The nine combinations of temperature and SoC were studied in this work, with three cells tested per combination [54].

Cycling tests were all carried out at 25 °C with one of two depths of discharge 30% or 80% and one of three discharging rates 0.4 C, 0.8 C or 1.2 C. All cycling tests were limited to a charging rate of 0.3 C for safety (i.e., to within manufacturers limit for continuous charging). Cell cycling was achieved using a commercial cell cycler (Bitrode MCV 16-100-5) and the ambient temperature was controlled using an Espec thermal chamber. Again, three cells are tested for each depth of discharge and discharging rate combination [54].

3.3. Ageing characterisation tests

Ageing stress factors lead to the activation or enhancement of various degradation modes and mechanism [19,21]. The resulting physical effects are typically quantified by energy storage systems engineers using two metrics: capacity fade that affects the amount of capacity a battery can hold and power fade, which is the increase in the internal resistance or impedance of the cell and limits the power capability of the system and decreases the efficiency of the battery. To quantify capacity fade, a retained capacity measurement at a temperature of 25 °C for a constant discharge current of 1 C is undertaken. To estimate resistance rise, power pulse tests were employed, where the voltage response of each cell is measured for a 10 s current pulse at 20%, 40%, 60%, 80% and 100% of the manufacturers recommended maximum continuous charge and discharge current. Pulses are applied to each cell when preconditioned to a SOC of 90%, 50% and 20% respectively, with all tests conducted at an ambient temperature of 25 °C.

3.4. Ageing degradation results

Capacity loss (from an initial 3 A h at 25 °C and resistance rise (from an initial 36 mΩ at 25 °C and 50% SoC) for storage and cycling tests are presented in Fig. 4 for 550 days of storage and 3800 A h of cycling. Results show that storing at progressively higher temperatures cause higher capacity fade and resistance rise. Resistance rise was highest for high SoC storage, although storing at 50% SoC was found to be better than at 20%. Despite higher discharge rates and $DoD(=\Delta SoC)$ globally exhibiting more degradation, the almost flat surfaces for cycle ageing capacity loss and resistance rise suggests that capacity loss and resistance rise are indifferent to (or lacks strong correlation with) the discharge current rate and DoD. For a more detailed discussion on degradation mechanism, readers are directed to Ref. [19].

3.5. Battery ageing model

An equivalent circuit model (ECM), shown in Fig. 5, of the form used in Ref. [20] is adopted for this work. Such models are well established in the field of battery modelling [43–45]. The Open Circuit Voltage (V_{OC}) represents the equilibrium potential of the system, i.e., the potential difference between the negative and positive electrodes when no current is applied and the system is at rest. The pure Ohmic resistance R_0 represents the electronic resistances of the battery and corresponds to the instantaneous voltage drop when a battery is connected to a load. The parallel resistor-capacitor (RC) network connected in series with R_0 represents the charge transfer process which is attributed to the charge transfer reaction at the electrode/electrolyte

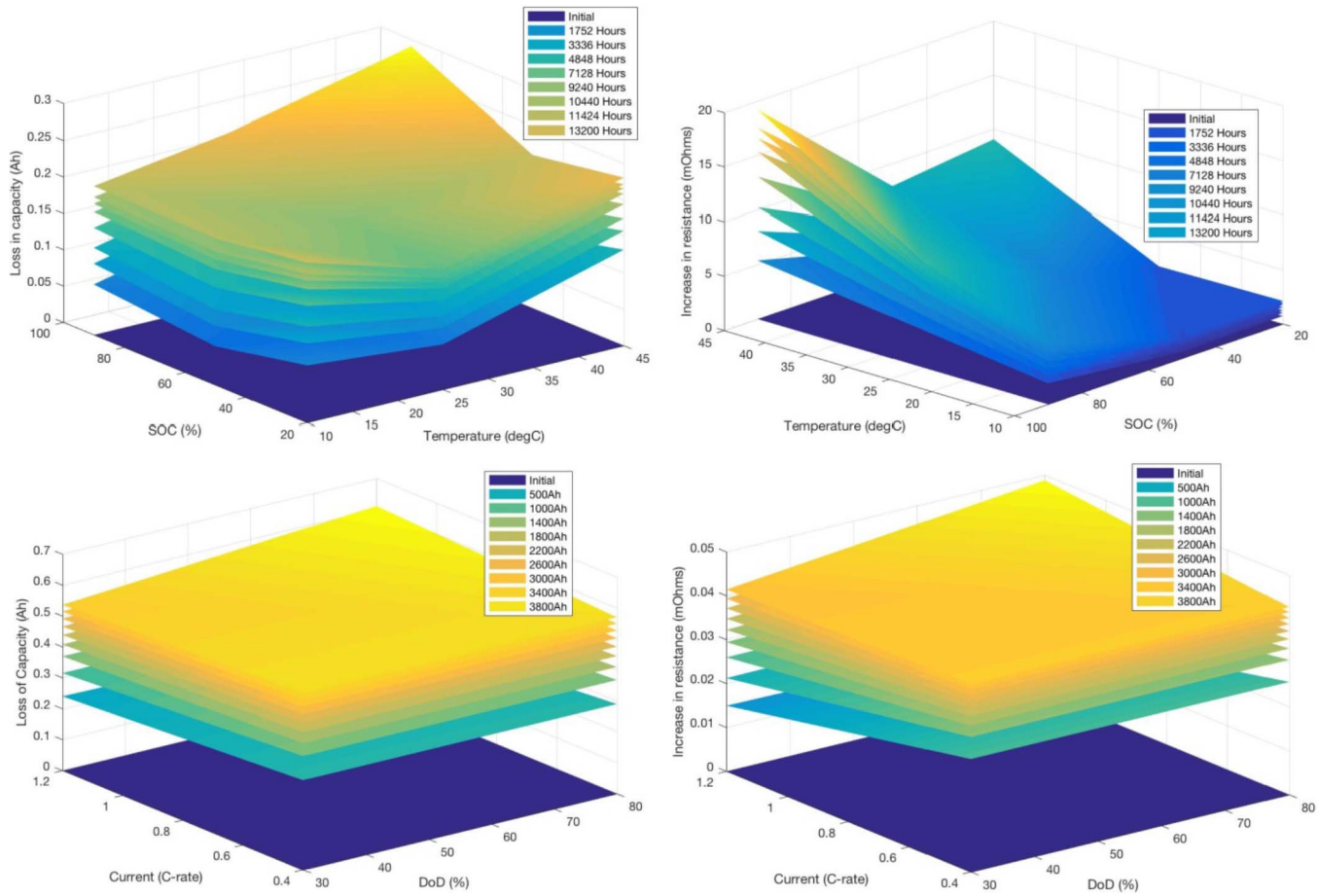

Fig. 4. Showing decrease in capacity (A h) and increase in cell resistance (mΩ) for storage (top panel) and cycling (bottom panel) ageing tests. Interpolation between data points is achieved using fractional polynomials of the form Y= $Y_0 \pm \alpha X^{\beta}$ where Y is either capacity or resistance, Y_0 is the corresponding initial value, X is either cell age or capacity-throughout, and α and β are fitting parameters.

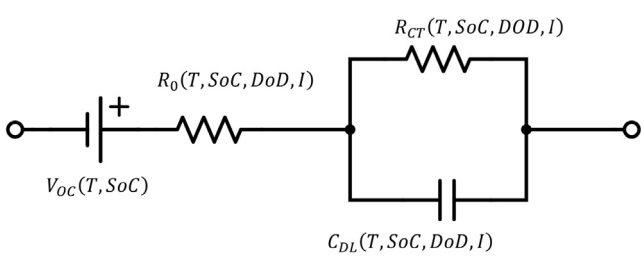

Fig. 5. Equivalent Circuit Model for a lithium Ion battery.

interface with an associated resistance R_{CT} and the double layer capacitance C_{DL}. The resistance elements, as well as the cell capacity (Q) are dependent on the varying time history of $T(t)$, $SoC(t)$, $DoD(t)$ and $I(t)$. The parameters of the ECM, namely the cell capacity and the sum of Ohmic resistance and charge-transfer resistance $R_0 + R_{CT}$ are therefore updated using results presented in Fig. 4 as the cell ages. To predict the evolution of the temperature under load, a bulk thermal model is employed:

$$mc_p \frac{d}{dt} T(t) + hA(T(t) - T_{amb}) = I(V - V_{OC}) \tag{1}$$

where T_{amb} is the ambient temperature, m is the cell mass, c_p is the heat capacity of the cell, A is the surface area of the cell, h is the heat transfer coefficient of the cell to the environment and $I(V - V_{OC})$ represents irreversible joule heating caused by Li-ion transport under cycling, where V is the terminal voltage. The performance of the ECM for a highly transient load in cold climates ($T_{amb} = 0$) is illustrated in Fig. 6, which shows very good agreement between predicted and simulated voltage. Under high current loads and low ambient temperatures, the lithium ion battery displays nonlinear characteristics. The maximum transient difference between the simulated and measured voltage and temperature presented in Fig. 6 is 6% and 11% respectively, which is considered to be low and therefore appropriate for use within this study [42–44]. In-fact, the difference between simulated and measured temperature rise is below the accuracy of the T-type thermocouples used to make temperature measurements.

The battery ageing model is validated with highly dynamic annual charge/discharge usage cycles, akin to an automotive battery connected to the electricity grid. Such a highly dynamic usage cycle was chosen for validation because under these circumstances, the battery is highly stressed and therefore the model is exercised at its operational boundary. The ambient conditions chosen for the validation cycles correspond to London (18 °C), Durham (10 °C) and the mountain peaks in Cairngorm National Park in the Eastern Highlands of Scotland (1.1 °C). The ambient temperatures therefore capture the breadth of climates within the UK. The 30-min resolution temperature profiles were controlled within the laboratory using commercially available LAUDA heating and cooling units. The load profiles for each validation cycle is unique and corresponds to a weekly capacity throughput of 12.8 A h, 7.3 A h and 5.2 A h for London, Durham and Cairngorm, respectively.

The validation results are summarised in Table 2. The estimated degradation corresponding to Durham exhibited least deviation from the measured degradation, while for Cairngorm it was the highest. This result is attributed to the ambient temperature for Durham that corresponds directly with a temperature point used for parametrisation while

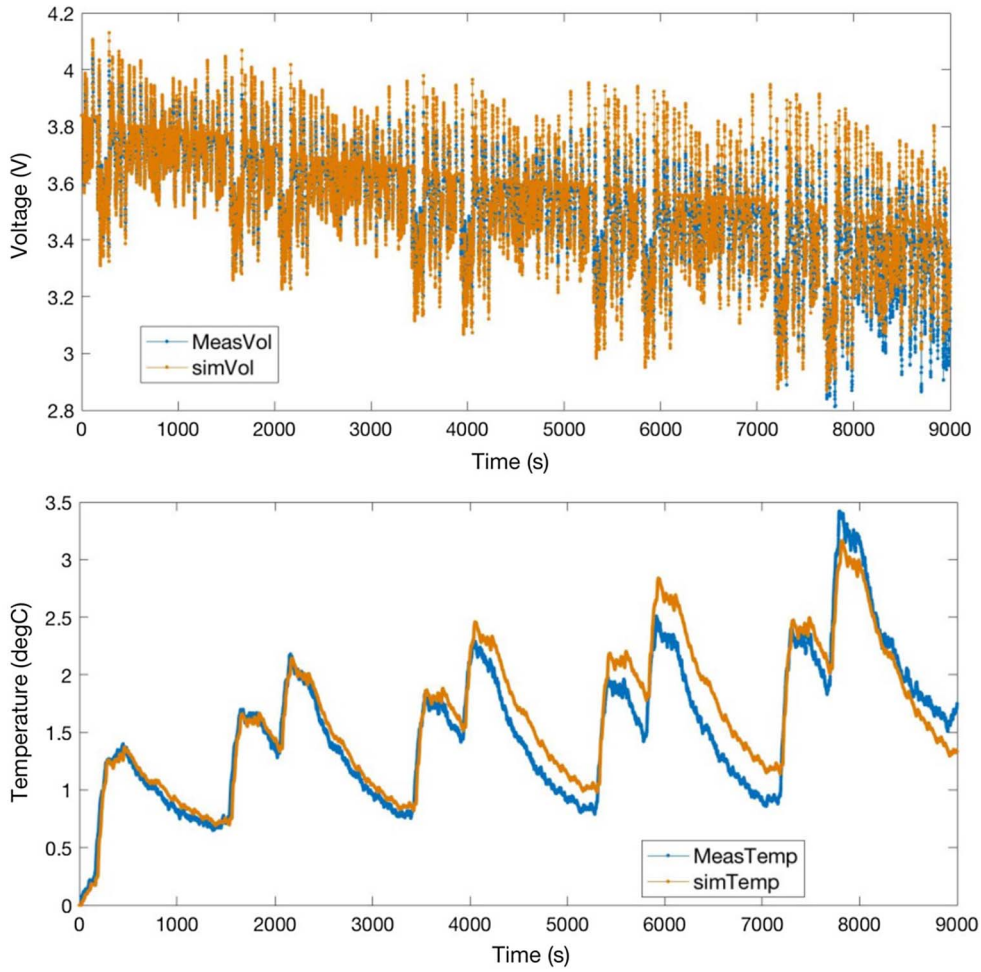

Fig. 6. Showing simulated (orange) and measured (blue) voltage (top panel) and temperature (bottom panel) for a dynamic current cycle. The ECM simulation ran for 2.5 h. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

the ambient temperature for Cairngorm is considerably different from temperatures considered for parametrisation (c.f., Section 3.2). In addition to these three ambient conditions, validation cycles were also carried out at temperatures of 27 °C, 32 °C, and 37 °C, with weekly capacity throughputs of 12.8 A h, 10.3 A h and 10.6 A h, respectively. The corresponding error in CF and PF were −3.82% and 5.85%; 7.26% and 7.79% and, −2.62% and −3.36%, respectively. The maximum error for capacity and power fade is below 7.8%, which is lower than

Table 2
Capacity fade and resistance rise validation results for the ageing model after 1 year of cycling. Note, the errors are calculated using discrepancies in absolute capacity and resistance values and not change in capacity and resistance values. Also, the cycling capacity throughput for each validation cycle is different because the weekly throughput is different.

		Initial	69 A h	128 A h	252 A h	376 A h
London	Capacity loss measured (A h)	0	0.201	0.243	0.279	0.310
South East England	Capacity loss estimated (A h)	0	0.213	0.265	0.338	0.386
Mean annual temp. 18 °C	Error in total capacity estimate (%)	0	−0.40	−0.73	−1.97	−2.53
Weekly throughput 10.7 A h	Resistance rise estimated (mΩ)	0	6.79	7.83	10.07	12.09
	Resistance rise measured (mΩ)	0	7.79	10.43	12.42	14.73
	Error in total resistance estimate (%)	0	−2.78	−7.22	−6.53	−7.33
		Initial	46 A h	89 A h	172 A h	254 A h
Durham	Capacity loss measured (A h)	0	0.228	0.261	0.294	0.324
North East England	Capacity loss estimated (A h)	0	0.180	0.220	0.273	0.316
Mean annual temp. 10 °C	Error in total capacity estimate (%)	0	1.60	1.37	0.70	0.27
Weekly throughput 7.3 A h	Resistance rise estimated (mΩ)	0	5.33	6.68	9.13	11.13
	Resistance rise measured (mΩ)	0	4.33	6.35	8.73	10.27
	Error in total resistance estimate (%)	0	1.43	0.43	−0.77	−1.43
		Initial	35 A h	91 A h	148 A h	177 A h
Cairngorm (mt. peaks)	Capacity loss measured (Ah)	0	0.412	0.467	0.499	0.504
Eastern Highlands, Scotland	Capacity loss estimated (Ah)	0	0.188	0.247	0.285	0.302
Mean annual temp. 1.1 °C	Error in total capacity estimate (%)	0	7.47	7.33	7.13	6.73
Weekly throughput 5.2 A h	Resistance rise estimated (mΩ)	0	13.73	17.66	21.12	21.66
	Resistance rise measured (mΩ)	0	15.17	19.46	21.78	22.99
	Error in total resistance estimate (%)	0	1.43	0.43	−0.77	−1.43

the established and well reputed model reported within [40].

4. Cost benefit analysis of electrical storage

4.1. Calculating cost savings due to battery storage

Energy cost savings as a result of the battery storage operation are calculated based on the total energy imported with and without the battery and the export Feed-In Tariff paid to the homeowner for PV export. In the UK, a Feed-In Tariff is a rate of money paid by the government to homeowners, business and organisations to generate their own electricity through small-scale sustainable energy installations such as solar panels. Under the scheme, homeowners can receive up to £1000 a year. One can receive feed-in tariffs for both the generation of electricity (a generation tariff) and for giving unused generated electricity back to the National Grid (an export tariff). The level of payment depends upon the technology employed and whether it is being fitted to an existing home, or installed as part of a new build. The reduction in imported electricity (ΔE [kWh]) due to integrating battery storage with the PV system is given by:

$$\Delta E = E_{-batt} - E_{+batt} \tag{2}$$

where E_{-batt} is the electricity exported without battery storage and E_{+batt} is the electricity exported with battery storage. The income paid for energy export without battery storage (G^{ex}_{-batt} [£]) is a product of E_{-batt} and the export tariff C^{ex} [£/kWh]:

$$G^{ex}_{-batt}(£) = E_{-batt} \times C^{ex} \tag{3}$$

while the export income with battery storage (G^{ex}_{+batt} [£]) is given by:

$$G^{ex}_{+batt}(£) = E_{+batt} \times C^{ex} \tag{4}$$

The cost savings as a result of battery storage S (£) is therefore:

$$S = \Delta E \times C^{im} - (G^{ex}_{-batt} - G^{ex}_{+batt}) = \Delta E(C^{im} - C^{ex}) \tag{5}$$

where C^{im} [£/kWh] is the electricity import price.

4.2. Cost benefit analysis

Using the annual usage data presented in Section 2 and the battery degradation model presented in Section 3, the capacity fade (CF) and power fade (PF) was estimated (see Fig. 7), where CF and PF are defined as:

$$CF = 1 - \frac{Q - \mu_{CF} Q_{rated}}{Q_{rated} - \mu_{CF} Q_{rated}} \tag{6}$$

$$PF = \frac{1}{\mu_{PF} - 1}\left(\frac{R_0 + R_{CT}}{R_0(0) + R_{CT}(0)} - 1\right) \tag{7}$$

where Q_{rated} is the rated capacity of the battery, μ_{CF} is the factor of the cells rated capacity at which point the battery is considered not fit for purpose (taken to be zero for this work) and μ_{PF} is the factor of the cells total resistance at which point the battery is considered not fit for purpose (taken to be 2 in this work, although this is arbitrary in the case of SHS applications).

The estimated battery degradation (Fig. 7) shows that the battery resistance almost doubled (100% PF) over five years while in the same time 20% of the initial battery capacity was lost. Although for the automotive industry the end of life of a lithium-ion battery is defined as 20% CF and a doubling of PF, for SHS applications there is no equivalent standard. According to the manufacturer of the commercial SHS installed in the home considered in this study, the battery end of life is defined by a CF of 30%. Given that the logged usage of the battery system installed in the property (Section 2.2) showed a daily $\Delta SoC = 80\%$, arguably, a more appropriate definition for end of life is a CF of 20% since a capacity fade of more than 20% would noticeably impact daily usage.

Estimated annual revenue from installing a PV-battery unit into a typical UK home is summarised in Table 3. The estimates assume that the annual electricity generation and usage remains the same over five years. The savings from utility bills amounted to £193 annually, given a fixed rate with a unit electricity cost of £0.1374/kWh. The generation and export income was £533 annually based on a generation tariff of £0.1339/kWh and an export tariff of £0.0485/kWh. This remained constant over five years, because the manufacturers of the installed PV-battery system limited SoC to 20%. Since SoC is estimated by the control system via coulomb counting (rather than matching open circuit voltage with SoC), as long as CF is below 20%, there is no noticeable operational effect because the CF acts to erode the 20% 'buffer.' Beyond a CF of 20%, there is a tangible loss in electricity generation and export revenue due to CF. Furthermore, with the addition of the battery operation, the export income is reduced as more energy is used within the home. Without battery storage, the sum of utility savings and electricity export profits is £727, meaning the battery costs the home owner £1/annum. When the cost of battery degradation is included, the annual loss to the home owner is significant as per Table 3 and the economic viability of SHS with electricity storage using lithium ion batteries is totally diminished.

The cost of battery degradation is taken to be governed by capacity fade, this is because there is no industry standard for defining a PF threshold that renders the battery *not fit for purpose*. Given that the

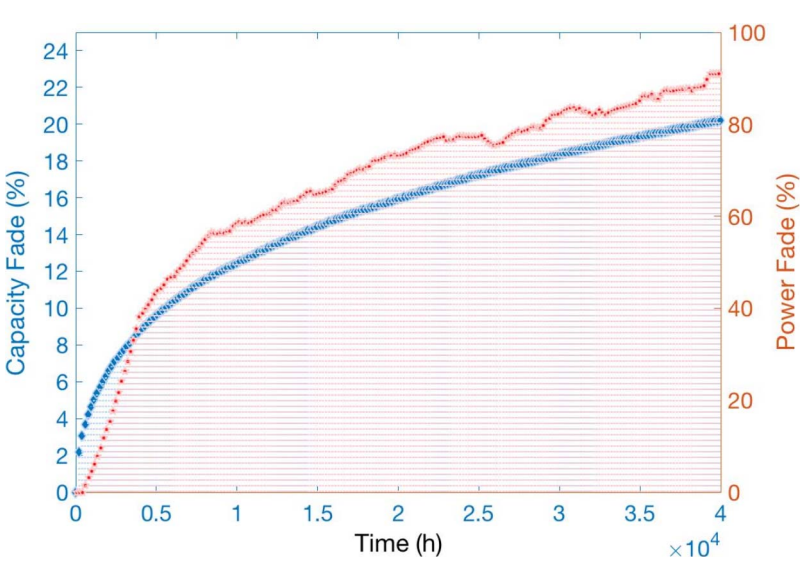

Fig. 7. Showing capacity fade (blue-diamonds) and power fade (red-stars) for 5 years of cycling under the measured residential load profile shown in Fig. 3. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Table 3
Summarising the cost benefits of SHS in a typical UK home. The Year 1 CO_2 savings estimate assumes the 2016 conversion factor; Year 2 assumes the 2017 DECC projection and so on [46].

Year	Electricity generation and export revenue without battery	Electricity generation and export revenue with battery	Savings on electricity without battery	Savings on electricity with battery	Estimated battery degradation cost G_{deg}	Effective profit without battery	Effective profit with battery	Net benefit of electricity storage	Avoided CO_2 emissions from clean generation ($kgCO_2$-e)
1	£542	£533	£185	£193	£399	£727	£327	−£400	1372
2	£542	£533	£185	£193	£107	£727	£619	−£108	1179
3	£542	£533	£185	£193	£77	£727	£649	−£78	996
4	£542	£533	£185	£193	£61	£727	£665	−£62	986
5	£542	£533	£185	£193	£44	£727	£682	−£45	813

current replacement cost (R_b) of a 2 kWh battery is circa: £1000 (according to the manufacturer) and the battery is defined, by the manufacturer, to be *not fit for purpose* when CF is 30%, the cost of degradation (G_{deg}) is defined as $R_b \times CF/0.3$. Although the trend of G_{deg} is monotonically falling, in line with CF trends, lithium-ion batteries can exhibit rapid CF in the latter portion of its operational life as was shown in an accelerated life study by Waldmann et al. [47]. The present study chose not to go past 20% CF, because this is beyond the range of model parametrisation. However, the likelihood of recovering the cost of installing an electricity storage system is, in the opinion of the authors, extremely unlikely given the expected trajectory of CF under $\Delta SoC = 80\%$ cycling conditions.

The evolution of annual CO_2 savings, even though the generation is assumed to be constant (3.33 MWh) over five years, reflects changes in electricity generation in the UK. For every kWh of electricity generated from on-site renewables in the UK in 2016, according to the Department of Energy and Climate Change (DECC), there is an equivalent saving of 0.412 kg of CO_2 [48]. This conversion factor fell by 11% from 2015 which is attributed to a significant decrease in coal generation, and an increase in gas and renewables generation in 2014. According to the DECC's projections, the equivalent CO_2 savings for years: 2017, 2018, 2019 and 2020 is 0.354, 0.299, 0.296 and 0.244 $kgCO_2$ per kWh of renewable electricity generated [49].

The annual CO_2 savings presented in Table 3 are related to installing a PV system. Assuming the energy mix of the electricity grid remains constant throughout the day, the integration of a lithium ion battery into a PV system only acts to reduce this CO_2 saving given that the efficiency of the battery system is less than 100%. In addition, if the environmental impact of the entire life cycle of the battery is considered, the CO_2 saving are further reduced. A study into the economic and environmental impact of using lead-acid batteries in domestic PV systems by McKenna et. al. [50] found the overall environmental impact of lead-acid batteries to be negative. A detailed life cycle assessment for lithium ion batteries found that the major contributor to the environmental burden is the supply of copper and aluminium required for the production of the current collectors for the anode and the cathode [51]. Since the integration of a lithium ion battery into a PV system only acts to reduce the CO_2 savings, the environmental benefit of battery storage systems is, in the authors view, presently unclear.

4.3. Sensitivity analysis of cost benefit analysis

The pricing tariffs used within the cost benefit analysis are specific to the property evaluated within the paper and as such, it is useful to understand how a change in pricing structure could affect the overall payback of the results. In addition, the size of the battery has an impact upon the payback period for the battery and therefore four key elements have a major impact upon the cost benefit of the system; battery price, FiT export tariff, electricity price and battery size.

The impact of the export income and electricity price are shown in Table 4, which indicates a very small change in the overall savings offered by the battery when degradation is not considered. The price of the battery has a linear relationship with the overall payback since $G_{deg} \equiv R_b \times CF/0.3$, such that a 20% decrease in battery cost decreases the estimated cost of battery degradation by 20%.

Table 4
Demonstrates the impact of changing export income and electricity price on the battery savings before the battery degradation costs are added.

Change in price	Savings		
	+20%	0%	−20%
Export income	£2.87	£1.00	−£0.87
Electricity price	−£0.67	£1.00	£2.67

Increasing the battery size by 20% to 2.4 kWh causes capacity fade to fall by 9.5% over 5-years (the year-on-year CF shown in Table 5). Following the manufacturers guide for battery cost, £500/kWh, the impact of a lower CF is reversed by an increased battery replacement cost (R_b) such that over 5-years the cost associated with battery degradation increases by a total of £59 (c.f., Tables 3 and 5). This demonstrates that the optimisation of battery size versus battery cost – considering battery degradation – requires more investigation.

5. Discussion

An assessment of the potential role of energy storage needs a robust analysis of costs verses benefits. The results presented show that battery degradation is a key factor and we present a validated model that can be used to calculate how these costs change over the lifetime of the battery. In this section, we further discuss the results and possible implications which will be explored in more detail in future research.

Our results show that for the commercially available battery system operated within a domestic property, the degradation costs are significant, reducing the gains from the PV generation by over a half in the first year. This large drop in storage capacity after the first year reduces the potential for the owner to make savings or earn revenue in subsequent years when it is likely that the value of storage will increase. The degradation is such that the battery would need to be replaced every five years in order to maintain the operational profile.

Even without including the cost of battery degradation, we find no economic benefit from integrating electrical energy storage with solar

Table 5
Impact of increasing battery size by 20% on Capacity Fade and therefore the cost of degradation.

Year	Fall in CF (change in CF) due to increase in battery size	Estimated battery degradation cost G_{deg}	Battery degradation cost saving due to increase in battery size
1	0.84% (−7%)	£445	−£46
2	1.11% (−7.3%)	£118	−£11
3	1.54% (−8.8%)	£75	£2
4	1.72% (−8.9%)	£66	−£5
5	1.96% (−9.5%)	£43	£1

PV. Technologically, the benefit of installing static battery storage has not been fully utilised within the commercial system installed due to: (i) the operation of the battery being relatively limited, i.e., the battery system cannot operate and respond to the building demand in real-time. Instead, a plan is set based on the previous days operation, meaning operation is not based on current demand of the building; (ii) the inverter rate in the battery unit is fixed at 400 W, meaning, when the building demand is less than 400 W and the battery is set to its discharge cycle, a portion of the energy is lost to the grid. As this is not paid by a Feed-In Tariff, this is lost income to the homeowner. Still, analysis of the data shows a relatively regular domestic electricity demand profile and trivial losses in revenue due to a fixed inverter rate.

Consumers should be aware of these 'hidden' costs, as it will have a material impact on how their batteries are most effectively used. Our results imply that providing ancillary services to the grid, with a lower depth of discharge, could lead to less battery degradation and extend the useful life of the device. To balance the full costs of battery ownership and operation will need more sophisticated control systems and a means of accumulating the split benefits of energy storage [53] that would accrue to the grid, distribution network and suppliers.

In many markets, small-scale generation from solar PV has increased rapidly, driven by cost reductions and subsidies [14,16]. Yet there has been little thought given to capturing the potential system benefits of such distributed generation. Rather, there is a risk that increased distributed generation introduces problems for electricity networks, with reverse flows out of the control of suppliers, or system operators. Because the peak times of solar generation and system demand tend not to coincide, there is a potential role for distributed electrical storage alongside PV to help manage the grid. Teng and Stbrac [52] have shown the value of storage (i) to reduce the peak load met by marginal thermal plant quite significantly; (ii) to increase the utilisation of existing distribution networks, avoiding costly upgrades that may be induced in order to meet peak supply or demand; and (iii) providing ancillary services.

In the case presented in this work, which would be typical of a consumer's behaviour when electricity prices and feed-in tariffs are non-time varying; the storage owner benefits from reduced import during the day when the PV panels are generating. This is only when the home system charges the battery rather than exports and the electricity is stored until the evening to meet domestic demand.

More appreciably, the lack of economic benefit from integrating electrical energy storage with solar PV is due to the potential value of battery storage not being recognised under the current market framework. Price signals that reflect network constraints and the system scarcity would incentivise export at peak times, reducing costs from both network infrastructure and central electricity generation fuel. With increasing capacity from variable renewables, greater variability in prices would also be expected if the market allowed, and so open the opportunities for storage. However, even if this value could be captured, it would need to outweigh the system costs, and it is often the capital costs that are most significant.

6. Conclusion

The techno-economic viability of integrated PV-battery storage systems has been studied. In this work, we first developed a comprehensive battery degradation model which enhances previous work. For this, we carried out over 50 long-term ageing experiments on commercially available $LiNiCoAlO_2/C_6$ 18650-type cells. The data accounted for all established modes of degradation including calendar ageing (> 500 days), capacity throughput (> 4000 A h), temperature ($10° C \leqslant T \leqslant 45°C$), state of charge ($5\% \leqslant SoC \leqslant 95\%$), depth of discharge ($DoD \leqslant 80\%$) and current ($I \leqslant I_{max}$) for battery charge and discharge. This model was then validated with six operationally diverse annual usage cycles. The maximum transient error between the modelled and experientially measured capacity fade and power fade, over a simulation time of 1 year, was less than 8%, significantly better than existing battery ageing models employed within the literature and often used within comparable studies.

To characterise electricity usage in a typical UK household, a commercially available PV and battery storage system was installed in a 3-bedroom property in Leicestershire. PV generation and household demand data was collected for more than a year. Based on this data and the battery degradation model, a cost benefit analysis for SHS was undertaken. The results show that even without including the cost of battery degradation, there is no economic benefit from integrating electrical energy storage with solar PV. When the cost of battery degradation is considered within the analysis, the annual loss to the home owner is significant.

This significant degradation is most likely to be caused by high frequency cycling with an SoC swing of 80%. This is reflective of the relatively small battery, 2 kWh, which is cycled at its operational limit. Thus, the use of a battery with a larger energy capacity rating, may significantly reduce the economic impact of battery degradation by lowering ΔSoC. However, this possible benefit must be balanced with the increased capital cost and negative impact within the home of using a more expensive and physically larger battery installation.

In addition to battery degradation, the battery system control strategy (intelligent control), the capacity of the battery storage system and the current market framework were identified as additional factors effecting the viability of SHS in the UK. As for the former, an adequate control strategy which operates in real-time could be developed to manage an optimum flow of energy. As such, these areas compel further research; analysis of the sensitivity of the CBA results to such parameters are also warranted. This forms a part of the authors' ongoing future work.

Acknowledgement

This research was supported by EPSRC grants (EP/M507143/1) and (EP/N001745/1); Innovate UK through the Ebbs and Flows of Energy Systems (EFES) project; the European Union, European Regional Development Fund (ERDF) and Interreg North Sea Region through the SEEV4-City project (project number 38-2-23-15); and the WMG centre High Value Manufacturing Catapult (funded by Innovate UK) in partnership with Jaguar Land Rover (JLR). The authors thank Dr. Dhammika Widanalage for his assistance in validating the ECM (i.e., Fig. 6) and partners of both EFES and the Consortium for Modelling and Analysis of Decentralised Energy Storage (C-MADEnS) projects.

References

[1] Bell M, Bellamy O, Gault A, Hemsley M, Smith S, Thompson M, et al. UK climate change action following the Paris agreement 2016.
[2] Defra. HC 534-I draft climate change bill fifth report of session 2006–07; 2007.
[3] Kannan R. Uncertainties in key low carbon power generation technologies – implication for UK decarbonisation targets. Appl Energy 2009;86(10):1873–86.
[4] Stewart M. Future energy scenarios GB gas and electricity transmission 2016.
[5] BEIS. National statistics. Electricity. Digest of United Kingdom Energy Statistics (DUKES). 2016 [chap. 5].
[6] Soytas U, Sari R. Energy consumption, economic growth, and carbon emissions: challenges faced by an EU candidate member. Ecol Econ 2009;68(6):1667–75.
[7] Strbac G, Aunedi M, Pudjianto D, Teng F, Djapic P, Druce R, et al. Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies. For the committee on climate change 2015.
[8] Hoppmann J, Volland J, Schmidt TS, Hoffmann VH. The economic viability of battery storage for residential solar photovoltaic systems – a review and a simulation model. Renew Sustain Energy Rev 2014;39:1101–18.
[9] Lund PD, Lindgren J, Mikkola J, Salpakari J. Review of energy system flexibility measures to enable high levels of variable renewable electricity. Renew Sustain Energy Rev 2015;45:785–807.
[10] Reichelstein S, Yorston M. The prospects for cost competitive solar PV power. Energy Policy 2013;55:117–27.
[11] Mundada AS, Prehoda EW, Pearce JM. U.S. market for solar photovoltaic plug-and-play systems. Renew Energy 2017;103:255–64.
[12] Ciez RE, Whitacre JF. The cost of lithium is unlikely to upend the price of Li-ion storage systems 2016.

[13] Nykvist B, Nilsson M. Rapidly falling costs of battery packs for electric vehicles. Nat Clim Change 2015;5(4):329–32.
[14] Quoilin S, Kavvadias K, Mercier A, Pappone I, Zucker A. Quantifying self-consumption linked to solar home battery systems: statistical analysis and economic assessment. Appl Energy 2016;182:58–67.
[15] Weniger J, Tjaden T, Quaschning V. Sizing of residential PV battery systems. Energy Proc 2014;46:78–87.
[16] Truong C, Naumann M, Karl R, Müller M, Jossen A, Hesse H. Economics of residential photovoltaic battery systems in Germany: the case of Tesla's Powerwall. Batteries 2016;2(2):14.
[17] De Boeck L, Van Asch S, De Bruecker P, Audenaert A. Comparison of support policies for residential photovoltaic systems in the major EU markets through investment profitability. Renew Energy 2016;87:42–53.
[18] Burgess M, Harris M, Walsh C, Carroll S, Mansbridge S, King N, et al. Assessing the viability of electric vehicles in daily life: a longitudinal assessment (2008–2013;2012). in 2013 world electric vehicle symposium and exhibition (EVS27) 2013:1–5.
[19] Vetter J, Novák P, Wagner MR, Veit C, Möller K-C, Besenhard JO, et al. Ageing mechanisms in lithium-ion batteries. J Power Sources 2005;147(1):269–81.
[20] Armand M, Tarascon J-M. Building better batteries. Nature Feb. 2008;451(7179):652–7.
[21] Uddin K, Perera S, Widanage W, Somerville L, Marco J. Characterising lithium-ion battery degradation through the identification and tracking of electrochemical battery model parameters. Batteries 2016; 2(2); 13. Multidisciplinary Digital Publishing Institute.26-Apr-2016.
[22] Richardson I, Thomson M, Infield D, Clifford C. Domestic electricity use: a high-resolution energy demand model. Energy Build 2010;42(10):1878–87.
[23] Yohanis YG, Mondol JD, Wright A, Norton B. Real-life energy use in the UK: how occupancy and dwelling characteristics affect domestic electricity use. Energy Build 2008;40(6):1053–9.
[24] Druckman A, Jackson T. Household energy consumption in the UK: a highly geographically and socio-economically disaggregated model. Energy Policy 2008;36(8):3177–92.
[25] Firth S, Lomas K, Wright A, Wall R. Identifying trends in the use of domestic appliances from household electricity consumption measurements. Energy Build 2008;40(5):926–36.
[26] Mansouri I, Newborough M, Probert D. Energy consumption in UK households: Impact of domestic electrical appliances. Appl Energy 1996;54(3):211–85.
[27] Live tables on Energy Performance of Buildings Certificates – GOV.UK. [Online]. Available: <https://www.gov.uk/government/statistical-data-sets/live-tables-on-energy-performance-of-buildings-certificates> [accessed: 04-Apr-2017].
[28] Allinson D, Irvine KN, Edmondson JL, Tiwary A, Hill G, Morris J, et al. Measurement and analysis of household carbon: the case of a UK city. Appl Energy 2016;164:871–81.
[29] Herrando M, Markides CN. Hybrid PV and solar-thermal systems for domestic heat and power provision in the UK: techno-economic considerations. Appl Energy 2016;161:512–32.
[30] McKenna E, Krawczynski M, Thomson M. Four-state domestic building occupancy model for energy demand simulations. Energy Build 2015;96:30–9.
[31] Abraham D, Liu J, Chen C, Hyung Y, Stoll M, Elsen N, et al. Diagnosis of power fade mechanisms in high-power lithium-ion cells. J Power Sources 2003;119:511–6.
[32] Shadow Huang H-Y, Wang Y-X. Dislocation based stress developments in lithium-ion batteries. J Electrochem Soc 2012;159(6):A815.
[33] Woodford WH, Chiang Y-M, Carter WC. 'Electrochemical shock' of intercalation electrodes: a fracture mechanics analysis. J Electrochem Soc 2010;157(10):A1052.
[34] Liaw BY, Roth EP, Jungst RG, Nagasubramanian G, Case HL, Doughty DH. Correlation of Arrhenius behaviors in power and capacity fades with cell impedance and heat generation in cylindrical lithium-ion cells. J Power Sources Jun. 2003;119–121:874–86.
[35] Stamps AT, Holland CE, White RE, Gatzke EP. Analysis of capacity fade in a lithium ion battery. J Power Sources 2005;150:229–39.
[36] Broussely M, Herreyre S, Biensan P, Kasztejna P, Nechev K, Staniewicz R. Aging mechanism in Li ion cells and calendar life predictions. J Power Sources 2001;97:13–21.
[37] Ramadass P, Haran B, White R, Popov BN. Capacity fade of Sony 18650 cells cycled at elevated temperatures: part I. Cycling performance. J Power Sources 2002;112(2):606–13.
[38] Smart MC, Ratnakumar BV, Whitcanack LD, Puglia FJ, Santee S, Gitzendanner R. Life verification of large capacity Yardney Li-ion cells and batteries in support of NASA missions. Int J Energy Res Feb. 2010;34(2):116–32.
[39] Waag W, Käbitz S, Sauer DU. Experimental investigation of the lithium-ion battery impedance characteristic at various conditions and aging states and its influence on the application. Appl Energy Feb. 2013;102:885–97.
[40] Ecker M, Gerschler JB, Vogel J, Käbitz S, Hust F, Dechent P, et al. Development of a lifetime prediction model for lithium-ion batteries based on extended accelerated aging test data. J Power Sources Oct. 2012;215:248–57.
[41] Ecker M, Nieto N, Käbitz S, Schmalstieg J, Blanke H, Warnecke A, et al. Calendar and cycle life study of Li(NiMnCo)O2-based 18650 lithium-ion batteries. J Power Sources 2014;248:839–51.
[42] Uddin K, Picarelli A, Lyness C, Taylor N, Marco J. An acausal Li-ion battery pack model for automotive applications. Energies 2014;7(9):5675–700.
[43] Widanage WD, Barai A, Chouchelamane GH, Uddin K, McGordon A, Marco J, et al. Design and use of multisine signals for Li-ion battery equivalent circuit modelling. Part 2: Model estimation. J Power Sources Aug. 2016;324:61–9.
[44] Hu X, Li S, Peng H. A comparative study of equivalent circuit models for Li-ion batteries. J Power Sources 2012;198:359–67.
[45] Fleischer C, Waag W, Heyn H-M, Sauer DU. On-line adaptive battery impedance parameter and state estimation considering physical principles in reduced order equivalent circuit battery models part 2. Parameter and state estimation. J Power Sources 2014;262:457–82.
[46] BEIS. Updated energy and emissions projections 2016; 2017.
[47] Waldmann T, Wilka M, Kasper M, Fleischhammer M, Wohlfahrt-Mehrens M. Temperature dependent ageing mechanisms in Lithium-ion batteries – a Post-Mortem study. J Power Sources 2014;262:129–35.
[48] Department of Energy and Climate Change. Greenhouse gas reporting – conversion factors 2016 – GOV.UK. [Online]. Available: <https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2016> [accessed 29-Mar-2017].
[49] Department of Energy and Climate Change. Updated energy and emissions projections 2015; 2015.
[50] McKenna E, McManus M, Cooper S, Thomson M. Economic and environmental impact of lead-acid batteries in grid-connected domestic PV systems. Appl Energy 2013;104:239–49.
[51] Notter DA, Gauch M, Widmer R, Wäger P, Stamp A, Zah R, et al. Contribution of Li-ion batteries to the environmental impact of electric vehicles. Environ Sci Technol Sep. 2010;44(17):6550–6.
[52] Teng F, Strbac G. Business cases for energy storage with multiple service provision. J Mod Power Syst Clean Energy 2016;4(4):615–25.
[53] Pudjianto D, Djapic P, Aunedi M, Gan CK, Strbac G, Huang S, et al. Smart control for minimizing distribution network reinforcement cost due to electrification. Energy Policy 2013;52:76–84.
[54] Uddin K, Jackson T, Widanage WD, Chouchelamane G, Jennings PA, Marco J. On the possibility of extending the lifetime of lithium-ion batteries through optimal V2G facilitated by an integrated vehicle and smart-grid system. Energy 2017.