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Optimum community energy storage system for demand load shifting

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HIGHLIGHTS

- PbA-acid and lithium-ion batteries are optimised up to a 100-home community.
- A 4-period real-time pricing and Economy 7 (2-period time-of-use) are compared.
- Li-ion batteries perform worse with Economy 7 for small communities and vice versa.
- The community approach reduced the levelised cost by 56% compared to a single home.
- Heat pumps reduced the levelised cost and increased the profitability of batteries.

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ABSTRACT

Community energy storage (CES) is becoming an attractive technological option to facilitate the use of distributed renewable energy generation, manage demand loads and decarbonise the residential sector. There is strong interest in understanding the techno-economic benefits of using CES systems, which energy storage technology is more suitable and the optimum CES size. In this study, the performance including equivalent full cycles and round trip efficiency of lead-acid (PbA) and lithium-ion (Li-ion) batteries performing demand load shifting are quantified as a function of the size of the community using simulation-based optimisation. Two different retail tariffs are compared: a time-of-use tariff (Economy 7) and a real-time-pricing tariff including four periods based on the electricity prices on the wholesale market. Additionally, the economic benefits are quantified when projected to two different years: 2020 and a hypothetical zero carbon year.

The findings indicate that the optimum PbA capacity was approximately twice the optimum Li-ion capacity in the case of the real-time-pricing tariff and around 1.6 times for Economy 7 for any community size except a single home. The levelised cost followed a negative logarithmic trend while the internal rate of return followed a positive logarithmic trend as a function of the size of the community. PbA technology reduced the levelised cost down to 0.14 £/kW h when projected to the year 2020 for the retail tariff Economy 7. CES systems were sized according to the demand load and this approximated the performance of PbA and Li-ion batteries, the capital cost per unit energy storage (kW h) of the latter assumed to be the double.

1. Introduction

Demand side management (DSM) and the use of deferrable loads could be utilised to make demand play a stronger role in the matching of variable generation and demand, voltage stabilization and frequency control [1]. At the moment, balancing demand and generation is mainly achieved by controlling the supply and short-term demand has been assumed inelastic. In fact, there was no incentive or available technology for changing customer demand profiles in the short-term. In addition to regulated incentives, tariffs are one of the main economic drivers to stimulate the participation of industrial, commercial and domestic customers in DSM [2]. Battery electric vehicles, plug-in hybrid vehicles and heat pumps (HPs) can also play a role as flexible loads in the coming years and research is looking at the best ways of integrating the transport and heat sectors into the smart grid. Car charging and electric heat can provide large quantities of short-term flexibility ranging from a few minutes to several hours [3]. Among DSM advantages, it has been argued that it has the potential of providing flexibility at lower cost than energy storage (ES) [4]. However, its impact is limited by the amount and type of loads which can be

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Nomenclature

BoP	balance of plant
CES	community energy storage
DOD	depth of discharge
EFC	equivalent full cycles
ES	energy storage
HP	heat pump
Li-ion	lithium ion
PbA	lead acid
SOC	state of charge
η	round trip efficiency
C	battery capacity, kW h
CF	cash flow, £
$cost$	relative cost, £/kW h
$Cost$	absolute cost, £
D_{ES}	proportion of the total demand of a community met by a CES system
E_{char}	seasonal CES charge, kW h
E_d	seasonal demand of a community, kW h
E_{dis}	seasonal CES discharge, kW h
IRR	internal rate of return, %
$LCOES$	levelised cost of energy storage, £/kW h
$LVOES$	levelised value of energy storage, £/kW h
n	number of years the battery lasts
P	price of the electricity, £/kW h
Rev	revenue, £
$TLCC$	total levelised cost, £
Z	linear durability coefficient of a battery technology, %/EFC

Subscripts

ex	export
i	import
l	limit
nom	nominal
sm	storage medium
p	peak
o-p	off-peak

deferred (up to 30% of the demand at the moment [3]). Drysdale et al. estimated that the 55% of the total domestic demand projected to the year 2030 (68.2 TW h) will be flexible in Great Britain including electric space and water heating, cold and wet appliances [5], but this percentage will be lower if customers prefer not to have their appliances used as flexible loads.

ES can also be used to level-out the demand (grid import specifically) by charging at off-peak periods and discharging at peak periods to meet the demand load. At the very large scales, matching of bulk supply and demand is achieved by using large scale technologies such as pumped hydroelectricity and compressed air ES. At the distribution level, battery storage could be utilised, typically at the sub-station level or even closer to the consumption points as studied in this work. ES can also be used to meet the maximum peaks in the demand. The most expensive power plants in the "merit order" run the least just to meet the peak demand. An alternative solution would be to use cheaper or more efficient power plants, store the energy generated by them and use it for the peak periods. There are several ES technologies available for this application depending on the magnitude of the peak and its duration. Likewise, electricity bills are broken down into a part which is proportional to the subscribed power and another related to the consumed energy from a customer perspective in some countries, e.g., Sweden and Germany. The subscribed power becomes economically more important to energy intensive industrial customers which use high intensive electrical demand loads. However, they usually pay for a maximum subscribed power which is not often used. ES can be used to smooth the grid import and even reduce the subscribed power, especially when the value of the maximum demand load can be forecast [6]. In the domestic sector, ES can reduce the typical peak during the afternoons and/or evenings by performing load shifting.

In the UK, most of the battery systems are either distribution-grid connected (and installed for the benefit of the distribution system operator (DSO) rather than the local community) or installed in single homes (with several manufacturers and installers available in the market) at the moment. Community energy storage (CES) is emerging as an alternative to both grid-scale and single-home ES solution which is able to provide services to both end users and distribution system operators. There are a few companies offering CES products but CES is mainly at the research and development phases in the UK. There are several relevant projects involving manufacturers, DSOs, utility companies, research institutions, technology companies and energy service companies driven by funding from the British Government and European commission [7–9]. At the moment, conditions for CES are more developed in other countries such as Australia, Germany and USA [10–12].

By increasing the efficiency and improving the performance of current electricity assets, ES has the potential of balancing the electricity system and postponing the construction of new generation units and transmission lines, so-called investment deferral. The generation, transport and distribution systems were designed to meet the maximum peak demand load using the traditional network approach. There are several factors which suggest that this approach is not the most efficient. For instance, daily demand is very variable and the maximum value is only required during several hours per year. Besides, the maximum power demand load increases more rapidly than the maximum daily energy demand [13]. ES acting as a variable demand can modify the profile seen by the generator, optimise the transmission and distribution systems and defer upgrades. This paper focuses on ES, CES in particular, as flexible demand load used with variable retail tariffs and answers the following research questions still not answered in the previous literature: (i) how the performance and economic benefits of CES system performing demand load shifting vary as a function of the size of the community depending on the electricity retail tariff and (ii) what is the optimum battery capacity for different community sizes and how it is affected by the HP penetration.

2. Community energy storage for demand load shifting

CES refers to ES located at the consumption level which can perform several applications with a positive impact for both end users and the network. Different to single home ES systems, a CES system is connected to several customers and this potentially could offer several benefits in terms of balancing capability and economy of scale. Different to distributed ES located in distribution substations, CES systems are located closer to end users and this enhances reliability, security of supply and flexibility [14]. A CES system can perform different applications to increase its value including PV energy time-shift, demand load shifting, demand load support during outages and the possibility to aggregate multiple units together

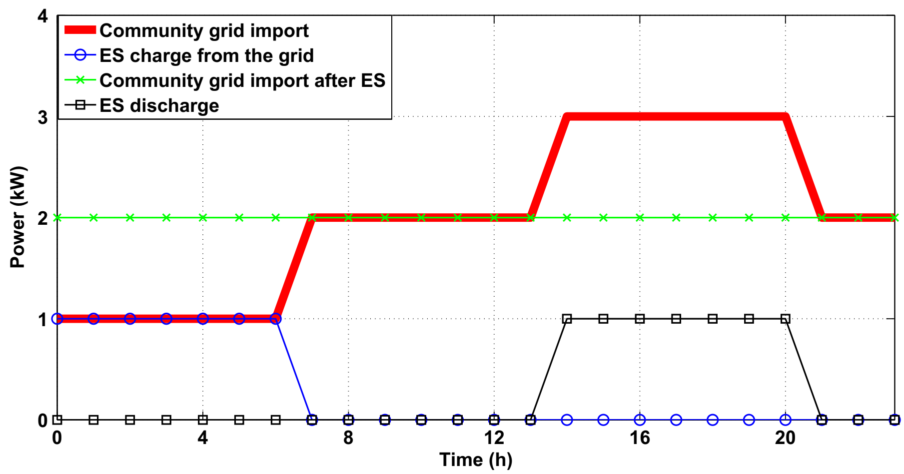

Fig. 1. Representation of load shifting performed by CES and its impact on the electricity imported by a community.

so that "upstream services" can be provided to the grid, such as provision of reserve and frequency response services [15,14]. A CES system can shift the electricity imported by a community (this application being the focus of this study) as represented in Fig. 1. This is done without affecting the customer habits and this is a key advantage over DSM tools. Demand load shifting with CES is related to tariffs which make a difference in the electricity price depending on time of day. There are different types of tariffs, time-of-use tariffs or real-time pricing tariffs being the most common options [2]. In terms of the CES management, it consists of charging the CES system whenever the price of electricity is low at the off-peak period, P_{o-p} (£/kW h), and using the energy stored when the import price of electricity, P_p (£/kW h), is higher (peak period). The revenue obtained from load shifting, Rev_{LS} (£), is calculated using Eq. (2) derived from Eq. (1) for battery technologies in which E_{char} (kW h), E_{dis} (kW h) and η refers to the battery charge, discharge and round trip efficiency respectively (the latter resulted from the division between E_{dis} by E_{char}). Demand load shifting is only economically sensible when the round trip efficiency is higher than the ratio between the off-peak and the peak prices. In this work, two different tariffs are investigated: a time-of-use tariff and a real-time pricing tariff. The two tariffs selected in this work are Economy 7 and a 4-period tariff derived from the prices of the imbalance market in the UK, described in more detail below.

$$Rev_{LS} = E_{dis} \times P_p - E_{char} \times P_{o-p} \quad (1)$$

$$Rev_{LS} = E_{char} \times P_p \times \left(\eta - \frac{P_{o-p}}{P_p}\right) \quad (2)$$

2.1. Economy 7

Economy 7 is a 2-period time-of-use tariff which should be considered as a reference because it has been used in UK homes with electrical space storage heating for the last 40 years to promote the smoothing of the daily demand peak by using more cost-effective base load generation. The two prices are constant through the year and the consumer knows in advance what these prices are and the periods to which they apply. This tariff defines two different periods: day (peak) and night (off-peak). Although there are several versions of Economy 7 depending on the electricity supplier, the Economy 7 tariff assumed in this work is supplied for a total of 7 h between midnight and 7 am (local time). The day and night electricity prices were taken from a real electricity retail tariff in the UK: 0.1347 £/kW h and 0.0632 £/kW h (including VAT) respectively.

2.2. Four period real-time pricing tariff based on the prices from the imbalance market

As an example of a future consumer tariff, a real-time pricing tariff based on the electricity prices of the New Electricity Trading Arrangements (NETA) in the UK in 2011 is suggested. This is the latest data set that the authors had access to. NETA is a daily market in which generators and suppliers sell and buy electricity respectively by notifying their position for each half-hour (48 prices per day) according to the generation and demand for the day ahead. This tariff is referred to as "NETA-based" tariff in the rest of this study. The price is obtained from the equilibrium between generators and suppliers in the market. Fig. 2 shows the half hourly prices from the market for every day of 2011. The minimum and maximum half hourly prices in 2011 were equal to −11.6 £/MW h and 179.7 £/MW h respectively, the average being equal to 46.6 £/MW h. According to the pattern followed by the prices shown in Fig. 2, four fixed periods were selected for every day of the year and the four prices of the tariff per day, $\bar{p}$, were calculated using the half hourly prices from the NETA market, p_i, using a weighted arithmetic mean with respect to the amount of electricity which was traded per period, E_i, as represented in Eq. (3). The four periods were defined as shown in Table 1.

$$\bar{p} = \frac{E_1 \times p_1 + E_2 \times p_2 + \cdots + E_n \times p_n}{E_1 + E_2 + \cdots + E_n} \quad (3)$$

In order to create the NETA-based retail tariff, other charges applied to electricity retail tariffs including transport cost, renewable energy incentives and taxes were added to the prices calculated using Eq. (3). The CES management system forecasts the community demand load which will be shifted when it receives the price signals from the market the day before. Then, it schedules the off-peak charging i.e. day-ahead real-time pricing. Perfect forecast was utilised in this study in order to quantify the performance and economic benefits regardless of any specific forecast methodology. This tariff is referred to as the NETA-based tariff.

3. Methodology

A comprehensive presentation of the methodology utilised for this paper is detailed in two previous publications [16,15] therefore only the key details to understand the rationale behind it are introduced below.

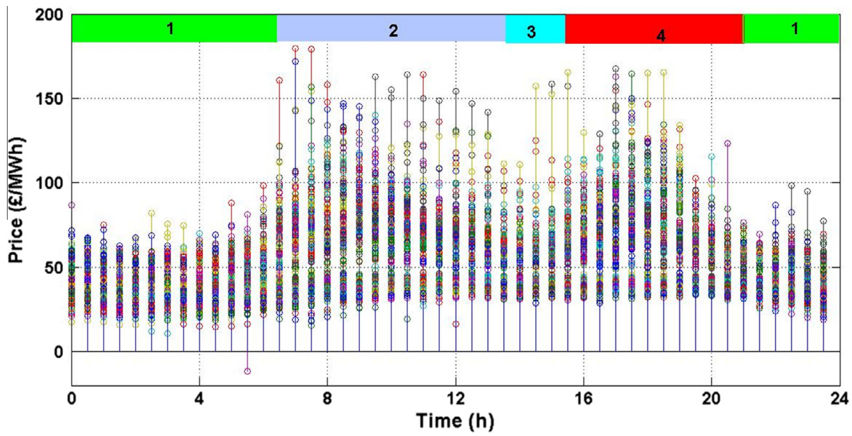

Fig. 2. NETA prices from the imbalance market for every day of 2011. The daily market has been split into 48 half hour time periods. Four different periods have been distinguished for creating a real time tariff.

Table 1
Four periods of the NETA-based tariff according to the profile shown in Fig. 2.

Period	Interval
Period 1	Between 21:30 and midnight–midnight and 06:30
Period 2	Between 06:30 and 13:30
Period 3	Between 13:30 and 15:30
Period 4	Between 15:30 and 21:00

3.1. Demand data

Demand data monitored in a low carbon community located in the north of London (UK) was used for this study [17]. Specifically, a data set 102 dwellings was available with annual average electricity and heat demands equal to 3.2 MW h and 12.5 MW h respectively. As a consequence, the largest community included in this study comprises 100 dwellings. The demand dataset has a temporal resolution of one minute. In all future scenarios considered by the UK Government, electric heating becomes more important due to the penetration of HPs [3]. This study also analyses the impact of meeting the space heating and domestic hot water demands (DHW) by using air source HPs on the CES performance, durability and economic benefits.

3.2. Energy storage modelling

This study focuses on batteries for CES due to discharge period ranging from several minutes to several hours, modular capacity (kW h) and maturity compared with other ES technologies available on the market [18]. Since lead-acid (PbA) batteries are the most mature battery technology on the market and lithium-ion (Li-ion) is the most promising technology at the moment, both technologies are compared in the analysis and this adds value regarding previous studies which focused on a specific technology [14,19] or followed a technology agnostic approach [20,21]. The CES model utilised in this work comprises performance, durability and economic submodels in order to perform a comprehensive techno-economic evaluation. Different to previous studies which investigated the economic benefits of battery systems managing PV generation or demand load assuming most performance parameters as constant values [14,20,22], this study firstly quantifies the (i) round trip efficiency (η); (ii) the annual discharge to meet the community demand load (D_{ES}), defined in Eq. (4) as the ratio between the annual battery discharge, E_{dis} (kW h), and the annual community demand load, E_d (kW h); and (iii) the equivalent full cycles (EFC) throughout the battery lifetime using both dynamic performance and durability submodels. These key performance indicators are used to quantify the economic benefits brought by CES systems with PbA and Li-ion technologies.

$$D_{ES} = \frac{E_{dis}}{E_d} \tag{4}$$

The round trip efficiency is defined as the ratio between the annual electricity discharged by the battery system and the annual electricity charged into the battery system, E_{char} (kW h), taking into account the efficiency of the bidirectional converter. Both the battery charge and discharge are calculated on a minute basis but the seasonal value of the round trip efficiency during the first operational year is represented in this study. This calculation therefore accounts for dynamic aspects such as variable discharge rates and battery wear.

3.3. Performance submodel

The PbA and Li-ion battery performance submodels are based on the equivalent circuit of a battery comprising a voltage source and resistance, the state-of-charge (SOC) being the main parameter which affects their variations [23,24]. A bidirectional converter is necessary to charge and discharge the battery system during the off-peak and peak period respectively. A converter rating equal to half the maximum community peak load was selected after running some simulations in order to investigate the size which minimise the levelised cost [16]. The efficiency of the bidirectional converter as a function of the load factor was also included in the analysis [25]. Table 2 summarises the main input data utilised with the performance submodel including the maximum charge rating, discharge rating and the depth of discharge depending on the battery technology and current state of art. Companies like Hitachi, Saft and Solom were consulted for these data. The minimum discharge time would be 12 min and 1.25 h for Li-ion and PbA batteries respectively according to the technical characteristics shown in Table 2.

Table 2
Value of the different control parameters implemented for PbA and Li-ion batteries.

Parameter (Unit)	PbA	Li-ion
Maximum charge current (A)	0.2 C	3 C
Maximum discharge current (A)	0.4 C	3 C
ΔSOC	0.5	0.6
Maximum SOC	0.9	0.8
Minimum SOC	0.4	0.2

3.4. Durability submodel

The durability submodel is based on the reduction of battery capacity from cycle losses (during charge/discharge) and calendar losses (a time-dependent loss in capacity independent of operation) [26]. The battery lifetime was related to the capacity drop to a certain level which was assumed to be 70% of the initial. The cycle losses were assumed to be linear with the depth of discharge for a given cycle and with the nominal battery capacity, C_{nom} (kW h), for the SOC ranges indicated in Table 2 using a linear life coefficient characteristic for any battery technology Z according to Eq. (5) [25]. However, the final cycle life is smaller than the maximum cycle life presented in Table 2 due to the calendar losses. Calendar losses were based on an Arrhenius formula for Li-ion technology [27] and on a linear relationship between the capacity loss and the maximum battery life (years) for PbA technology due to the lack of related data. The key input data for the durability submodels depending on the battery technology are given in Table 3 for the two scenarios included in this study.

$$\Delta C = Z \times C_{nom} \times \Delta SOC \tag{5}$$

3.5. Economic submodel

Finally, the economic submodel quantifies the levelised cost of ES, *LCOES* (£/kW h), levelised value of ES, *LVOES* (£/kW h), and internal rate of return, *IRR* (%). The levelised cost and levelised value include the different costs and revenues respectively throughout the battery life by calculating their present value (for the year in which the investment is performed) as seen in Eqs. (6) and (7) respectively. In the first equation, *TLC* refers to the total levelised cost of the battery system including capital and operation expenditures. A discount rate equal to 10% was utilised, this value also being used in other previous techno-economic ES evaluations made from an utility company perspective [28,29]. Finally, the *IRR* is a measure or the profitability of the CES investment including related positive and negative cash flows, CF_k (£), during n years of operation.

$$LCOES = \frac{TLC}{\sum_{k=0}^{n} \frac{E_{dis}}{(1+r)^k}} \tag{6}$$

$$LVOES = \frac{\sum_{k=1}^{n} \frac{Rev_{LS}}{(1+r)^k}}{\sum_{k=0}^{n} \frac{E_{dis}}{(1+r)^k}} \tag{7}$$

$$0 = \sum_{k=0}^{n} \frac{CF_k}{(1+IRR)^k} \tag{8}$$

As shown in Table 3, the total cost of a CES system is comprised of the cost of the storage medium (£/kW h), converter cost (£/kW), balance of plant (BoP) (£/kW) and maintenance (£/kW). For any battery capacity larger than C_l (kW h), the storage medium cost, $Cost_{sm}$ (£), was obtained from Eq. (9) in which 0.7 is the power factor selected to demonstrate the manufacturing economy of scale [30]. C_l was assumed to be 100 kW h for both battery technologies [31]; $cost_{sm}$ refers to the relative storage medium cost (£/kW h) given in Table 3.

$$Cost_{sm} = \left(\left(\frac{C_{nom}}{C_l} \right)^{0.7} \right) \times C_l \times cost_{sm} \tag{9}$$

3.6. Optimisation method

A method was designed to obtain the optimum CES system for end user applications as a function of the size of the community ranging from a single home up to a 100-home community. From a simulation point of view, deterministic models based on time-series data in which uncertainty was tackled by a sensitivity analysis were utilised [15,16]. However, randomness was introduced by the use of 100 different monitored demand data profiles. The method firstly obtains the largest CES system when determining the maximum ES demand throughout the year depending on the community demand load, the tariff structure and the CES system round trip efficiency. The algorithm used to obtain the maximum and optimum CES size depends on the tariff, specifically on the number of periods. As a consequence, two different algorithms were developed for Economy 7 and the NETA-based tariff using the same rationale. Specifically, the maximum CES requirements were given by the day of the year in which the community demand load was greatest during the peak period. Then, 10 different CES systems were tested, the performance and ageing of battery systems being quantified for all of them.

Fig. 3 shows the algorithm which was used to determine the performance of battery systems when performing Economy 7 (the peak period occurs between 7 am and midnight on a daily basis). The main input data of the algorithm were the demand load of the community with a temporal resolution of 1 min and the estimated round trip efficiency of the battery (based on previous simulations). The rationale behind the decision of performing demand load shifting relies on the comparison between the round trip efficiency of the CES system and the ratio between the electricity price at the off-peak and peak periods as indicated by Eq. (2). As Fig. 3 shows, forecasting the demand load which occurred at the peak time was necessary on a daily basis. The result of this forecast was divided by the battery round trip efficiency to obtain the required charge of the CES system during the off-peak period for every day. Demand load forecasting was performed with a time resolution of 1 h. The management system controlled the performance of the battery system according to the technical values presented in Table 2. In addition to the number of periods, the basic

Table 3
Summary of the input data selected for the scenarios, including the electricity price, PV generation, demand and battery properties.

Parameter		2020	Zero carbon
Electricity price (p/kW h)[a]		16.3	31.0
HP percentage (%)[b]		14	100
Electricity demand (MW h/year)[b]		up to 2.9	up to 2.4
Space heating demand (MW h/year)[b]		up to 10.3	up to 6.1
DHW demand (MW h/year)[b]		Current	Current
converter cost reduction (%)[c]		−25	−30
BoP cost (£/kW)[d]		50	45
Maintenance cost (£/kW)[d]		6.5	6.5
PbA	Maximum cycle life (EFC)[e]	1250	1500
	Z (%/EFC)[f]	0.024	0.02
	Calendar losses (%/month)[f]	0.15	0.12
	Storage medium cost (£/kW h)[g]	150	65
Li-ion	Maximum cycle life (EFC)[e]	3000	3600
	Z (%/EFC)[f]	0.01	0.0083
	Calendar losses (%/month)[f]	0.09	0.08
	Storage medium cost (£/kW h)[g]	310	160

[a] The price of the utilities was estimated using an average trend of those followed in the last 25 years and last seven years [32].
[b] These various data are based on estimations from the UK Government [3]. The annual space heating and DHW demand of the average household was 16.8 MW h in 2006 and the annual electricity consumption was 3.0 MW h [33]. The HP percentage refers to the fraction of homes in the community with a HP system and it was calculated based on the HP penetration in the UK.
[c] Cost reduction according to the one in the last 15 years [34] over current cost based on data from SMA Solar Technology AG, e.g., £1100 for a 3 kW single phase inverter.
[d] Based on published data from the Department of Energy (DOE) [35].
[e] From available literature [36,13,37,38] and confirmed with manufacturers including Solom and Hitachi.
[f] Monthly battery capacity percentage reduction.
[g] From available literature [39,40,37,41].

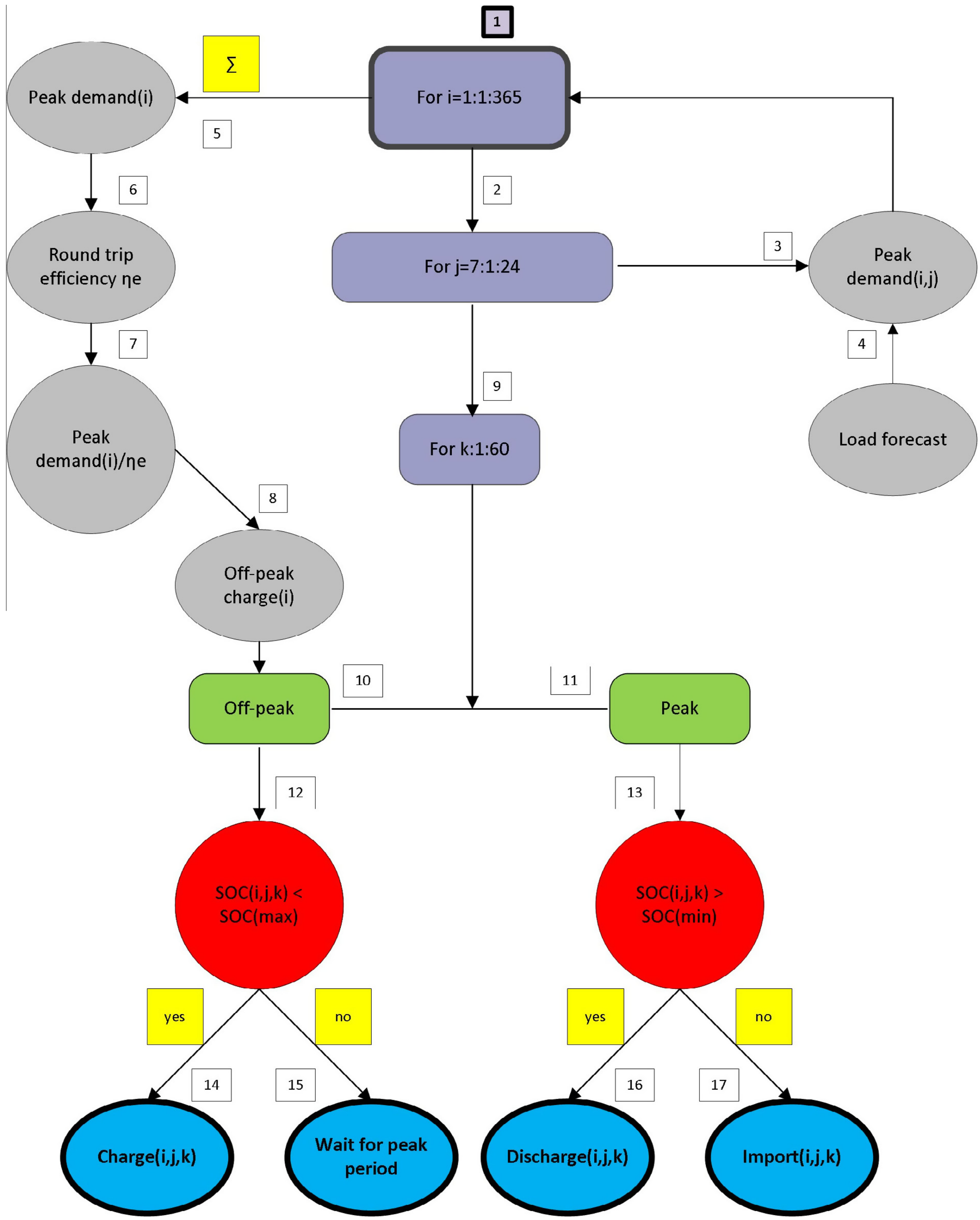

Fig. 3. Flow chart representing the algorithm which was utilised to obtain the schedule of a battery system as CES system performing demand load shifting with Economy 7 using 1 min (loop variable *k*) data for every day (loop variable *i*) of the year as well as the community electricity import. The flowchart sequence follows the number sequence in the boxes. The sum symbol represents the aggregation of results to obtain the daily values from hourly data. All the parameters which depended on the demand load forecast are represented in grey.

difference between Economy 7 and the NETA-based tariff is the fact that Economy 7 is a time-of-use tariff in which the prices are known prior to use and they are the same for every day of the year while the NETA-based tariff is a real-time pricing tariff in which prices vary each day. These two aspects were considered by the algorithm for the NETA-based tariff. Moreover, it was assumed that the four prices per day of the NETA-based tariff were known one day ahead and the algorithm searched for the minimum price which defined the off-peak period for every day. Subsequently, the algorithm obtained the ratio between the minimum price and the subsequent prices every day. Then, it compared these ratios with the round trip efficiency of the battery. All the different models presented in this work and simulations have been implemented in the Matlab–Simulink environment.

3.7. Reference years

The cost, value and profitability of CES systems is affected by several parameters including the capital cost of ES technologies, durability and community demand. In this study, two different scenarios are studied including different values for these input data. The first scenario focuses on low carbon communities in which demand load requirements are reduced according to the objectives of the UK Government by 2020 [3] and battery technology develops according to expectations of manufacturers supported by government programs on ES. The second scenario is based on more ambitious objectives and assumed a zero carbon scenario in which battery technologies reach a high level of maturity while communities become carbon neutral. According to these assumptions, the first and second scenarios are referred as "2020" and "zero carbon" scenarios respectively. In order to model these scenarios, projections from the UK Government were used for demand assumptions [3] while technological objectives established by manufacturers were considered for cost and durability of batteries [42,43].

When a HP is installed in a dwelling, it was considered that they supplied both space heating and DHW. In particular, both demand loads were transformed into an electrical demand load when considering the coefficient of performance (COP) of an air-source HP system using water to distribute the heat. Water was assumed to be generated at 40 °C since it is instantaneously supplied without being stored it in a hot water tank. A dynamic HP model was utilised for this study and a comprehensive explanation can be found in a previous publication [16]. It obtains the enthalpy of the refrigerant (assumed to be R-134A) at the inlet and outlet of the main components of the HP cycle using the equations which governs the thermodynamic performance of each component. Performance parameters such as temperature differences between fluids in heat exchangers and efficiencies are based on previous experimental research [44,45]. In order to determine the HP percentage of a community (fraction of homes in the community with a HP system), a total electrification of the heat sector in the zero carbon scenario was assumed, i.e. each house has a HP (100%). The penetration of HPs by 2020 was assumed to be equal to 14% based on a linear trend between 2012 and the total electrification of the heat sector by 2050. In this scenario, HPs were randomly introduced as the size of the community increased based on this HP penetration.

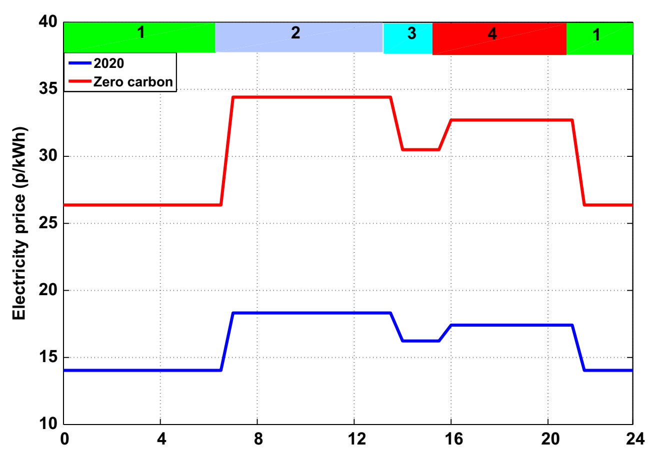

Fig. 4. Average value of the four electricity prices of the NETA-based tariff in 2020 and the zero carbon scenario.

Finally, in order to study different scenarios for retail prices in the 2020 and zero carbon scenarios, the retail prices were increased using the average trend of the last 7 and 25 years, specifically to an average price equal to 0.165 £/kW h and 0.31 £/kW h in 2020 and the zero carbon scenario respectively. Fig. 4 shows the average value of the four electricity prices of the NETA-based tariff in 2020 and the zero carbon scenario after increasing the prices regarding the weighted average values in 2011 while keeping the ratio between the prices constant. Table 3 summarises all the input data selected for the 2020 and zero carbon scenarios..

4. Performance results

In this section, performance results are presented as a function of the size of the community (ranging from a single home up to a 100-home community) and the battery capacity. The latter is given as a percentage of the maximum CES demand for load shifting through the year. Hence, 100% battery capacity will increase with the number of homes in the community, for example this corresponded to a 55 kW h and 1194 kW h Li-ion battery system for the single home and the 100-home community respectively in 2020.

4.1. 2020 scenario for PbA battery systems

Figs. 5 and 6 show the EFC, round trip efficiency and D_{ES} for PbA technology when performing load shifting with the NETA-based tariff and Economy 7 respectively. The EFC were affected by both the battery capacity and the size of the community. For any community size, there was an intermediate battery capacity (between 40% and 60% of the maximum) which maximised the EFC and the EFC gently grew with the size of the community and there was only a sharp increase in the transition from a single home to the 10-home community. The maximum EFC of the 10-home and 100-home communities were, over the life of the battery, 630 EFC and 657 EFC respectively with the NETA-based tariff. Fig. 6 demonstrated that PbA batteries performing load shifting with Economy 7 achieved the greatest EFC. This was a consequence of the ratio between the off-peak and the peak prices for Economy 7 (0.47) which was always lower than the round trip efficiency compared to the price differential for the NETA tariff. Additionally, the peak period of Economy 7 lasts for 17 h and therefore a high fraction of the demand can be shifted. The maximum number of EFC equal to 914 cycles were achieved by a 99 kW h battery in the 10-home community. This was related to the higher weight of the peak demand load for small communities as explained with the D_{ES} below.

The round trip efficiency increased with the capacity steadily and with the size of the community for the two tariffs. Again, the transition was more abrupt for the smaller communities. For any community, the depth of discharge and the relative discharge rating reduced with the battery capacity and this had a positive impact on the round trip efficiency. Regarding the community size, the positive effect of the aggregations of demands reduced the discharge rates in relation to the battery capacity [15]. The maximum round trip efficiency increased from 76% (57 kW h) and 83% (73 kW h) for the single home to 88% (1340 kW h) and 88% (1073 kW h) for the 100-home community (1340 kW h) in the case of the NETA-based tariff and Economy 7 respectively.

Finally, the D_{ES} increased with the battery capacity but it slightly decreased with the size of the community. The main reason for this relied on the fact that the aggregation of demands reduced the relative weight of the peak demand load in the daily demand since the community profile became smoother and flatter [16]. Specifically, the fraction of the daily peak demand was up to

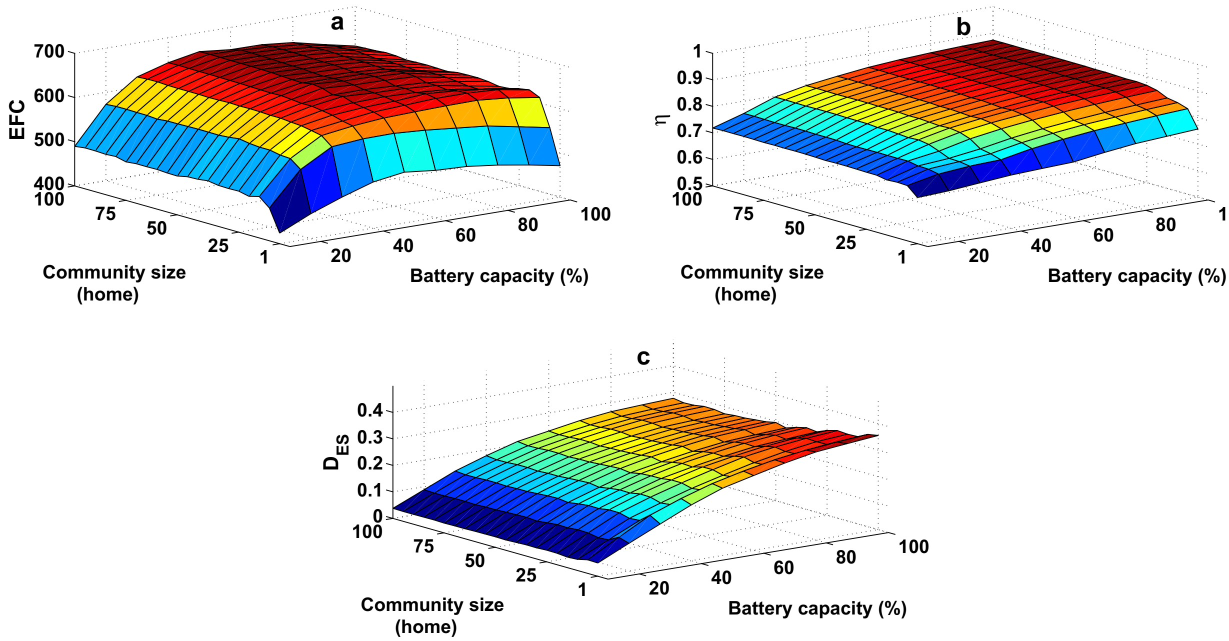

Fig. 5. Performance results of PbA batteries performing demand load shifting with the NETA-based tariff in 2020 as a function of the size of the community and the battery capacity: (a) equivalent full cycles, (b) round trip efficiency and (c) D_{ES} (the proportion of annual community demand put through the battery). The battery capacity is given as a percentage of the maximum ES demand.

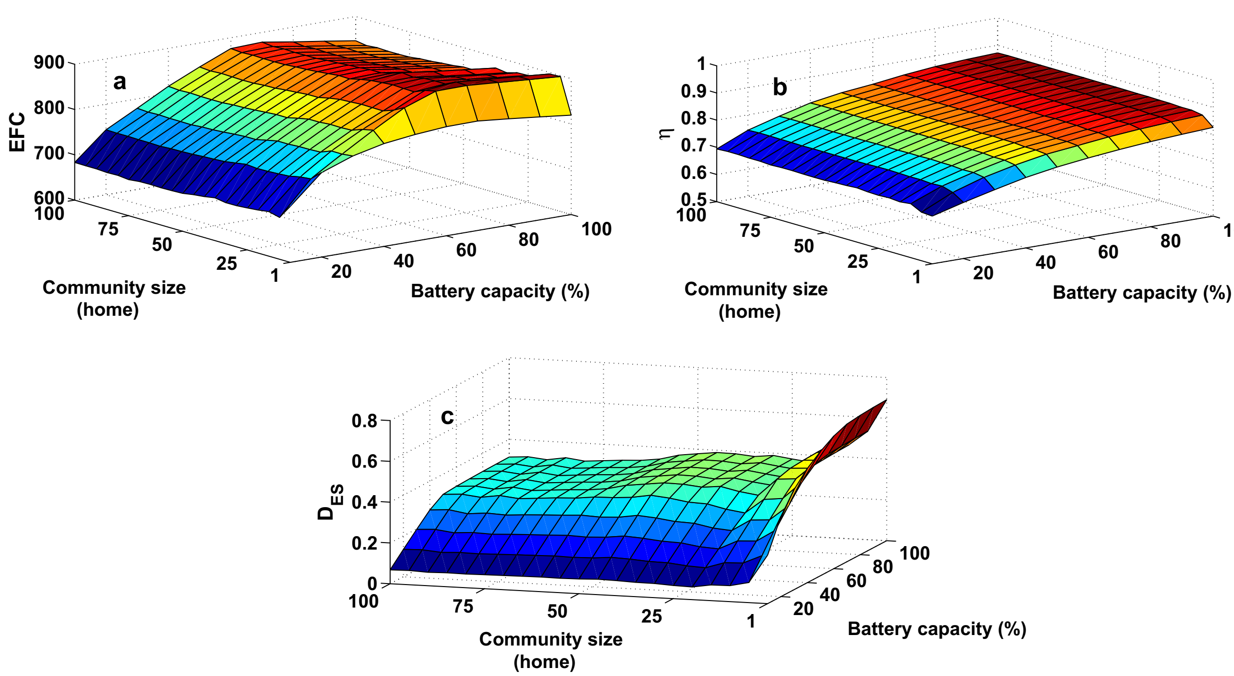

Fig. 6. Performance results of PbA batteries performing demand load shifting with Economy 7 in 2020 as a function of the size of the community and the battery capacity: (a) equivalent full cycles, (b) round trip efficiency and (c) D_{ES} (the proportion of annual community demand put through the battery). The battery capacity is given as a percentage of the maximum ES demand.

97% for the single home and up to 85% for the 100-home community with Economy 7. The battery was charged to supply the peak demand and this was reflected in the results. The maximum D_{ES} for the single home was 0.32 while it reduced to 0.27 for the 100-home community. This effect was strengthened in the case of Economy 7 due to the longer duration of the peak period and the higher battery activity, the maximum D_{ES} being equal to 0.69 for the single home. This result emphasises that Economy 7 is an attractive tariff for demand load shifting since the revenue is proportional to the fraction of demand at peak time. The EFC is a measurement of how well the battery system is utilised for the given demand load therefore battery capacities which achieved maximum values should be consider in order to design CES systems from a techno-economic perspective.

4.2. 2020 scenario for Li-ion battery systems

Figs. 7 and 8 show the EFC, round trip efficiency and D_{ES} of Li-ion technology when performing demand load shifting with the NETA-based tariff and Economy 7 respectively. In addition to

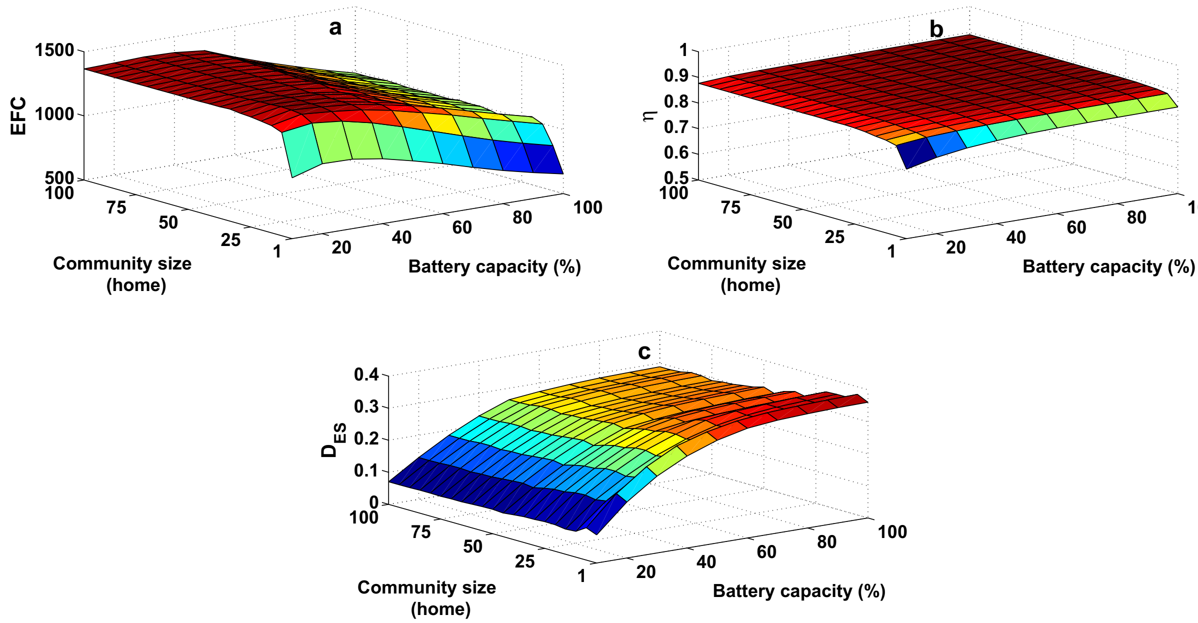

Fig. 7. Performance results of Li-ion batteries performing demand load shifting with the NETA-based tariff in 2020 as a function of the size of the community and the battery capacity: (a) equivalent full cycles, (b) round trip efficiency and (c) D_{ES} (the proportion of annual community demand put through the battery). The battery capacity is given as a percentage of the maximum ES demand.

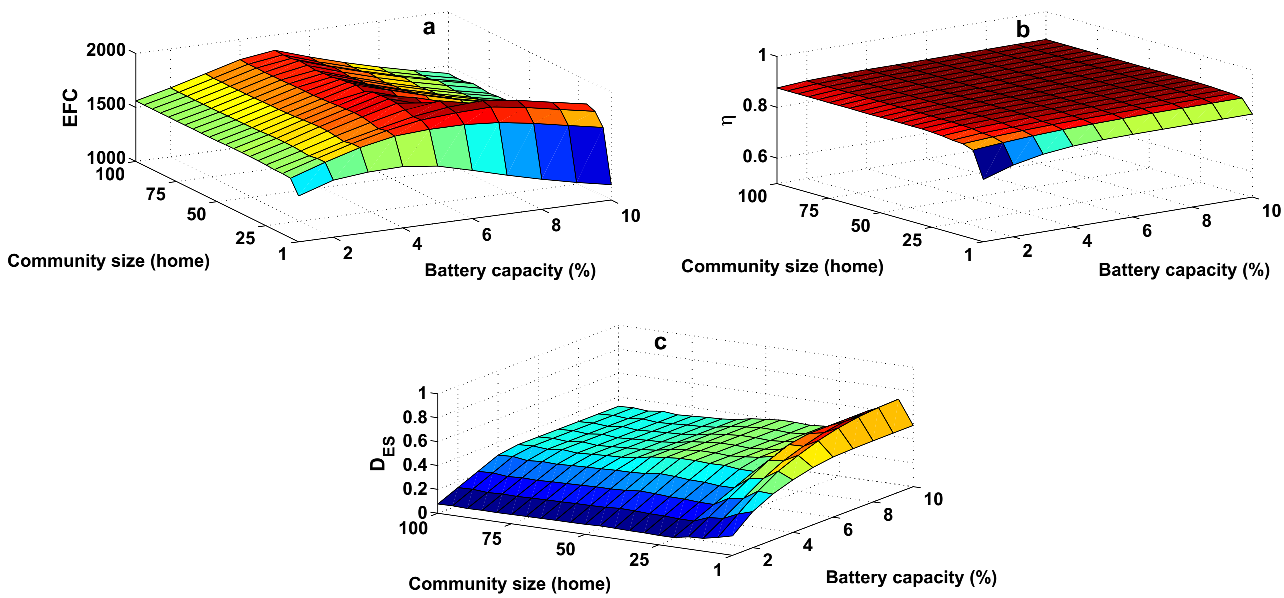

Fig. 8. Performance results of Li-ion batteries performing demand load shifting with the Economy 7 in 2020 as a function of the size of the community and the battery capacity: (a) equivalent full cycles, (b) round trip efficiency and (c) D_{ES} (the proportion of annual community demand put through the battery). The battery capacity is given as a percentage of the maximum ES demand.

obtaining higher performance values than PbA batteries, the most important difference was Li-ion batteries required smaller capacities to obtain the maximum number of EFC for any community with the two tariffs. In the case of the NETA-based tariff, a 64.8 kW h, a 192 kW h and a 637 kW h Li-ion batteries achieved 1368 cycles, 1381 cycles and 998 cycles respectively in the 50-home community, the maximum being equal to 1400 for a 59 kW h in the 20-home community. Another difference was the different EFC pattern followed by Li-ion batteries performing load shifting with Economy 7 for small communities. The relatively higher peak demand load (in comparison with the flatter profile of bigger communities, as shown above) meant that the EFC did not reduce with the percentage battery capacity as shown in Fig. 8 for small communities. In fact, a 174.6 kW h Li-ion battery achieved 1942 cycles in the 20-home community, the maximum result. This result highlights the fact that Li-ion technology offer higher cycle life than PbA technology.

In terms of the round trip efficiency, results did not vary significantly with the battery capacity and the community size as seen in Figs. 7 and 8 except for the transition between the single home and the 5-home community. For example, the minimum round trip efficiency of Li-ion batteries performing with the NETA-based tariff was 0.77 (for a 6.1 kW h battery), 0.85 (for a 11 kW h battery) and 0.85 (for a 121 kW h battery) for the single home, 5-home and

100-home communities respectively. Finally, the D_{ES} values were similar to those obtained by PbA technology. PbA batteries counterbalanced the lower round trip efficiency with the use of larger capacities as quantified in Fig. 9 (battery systems were sized according the demand load requirements).

5. Economic results for PbA and Li-ion battery systems in 2020 and zero carbon scenarios

Fig. 9 shows the battery capacities which minimised the *LCOES* of performing demand load shifting for PbA and Li-ion technologies depending on the tariff. PbA batteries required larger capacities than Li-ion batteries to reduce the *LCOES* with the two tariffs. The PbA battery capacity which minimised the cost of performing load shifting with Economy 7 in the 50-home community was 513 kW h, while it reduced to 305 kW h for Li-ion technology in 2020. According to the results represented in Fig. 9, the optimum PbA capacity was approximately twice the optimum Li-ion capacity in the case of the NETA-based tariff and around 1.6 times for Economy 7 for any community except for the single home in the case of Economy 7. The reason why the ratio was slightly higher with the NETA-based tariff was larger battery capacities were necessary to increase the round trip efficiency and meet the load shifting condition given by Eq. (2). The optimum PbA and Li-ion battery capacities were similar with Economy 7 in the single home because PbA technology was not able to meet the relatively high peaks which randomly occurred in the demand. This reduced the optimum capacity for PbA technology to 30.5 kW h, the optimum capacity of Li-ion battery being 27 kW h. Increasing the PbA battery capacity beyond this value resulted in higher LCOES values.

Fig. 9 also shows that, for both battery technologies, the optimum battery capacity was very similar with the two tariffs for any community. Specifically, Li-ion capacity was slightly larger for Economy 7 due to the longer duration of the peak period while slightly larger capacities were necessary for PbA batteries with the NETA-based tariff as discussed above. The optimum capacity profile was less uniform for the NETA-based tariff since the prices of the NETA market and the round trip efficiency determined if load shifting was performed or not on a daily basis. This modified the annual results and the optimum size varied more steeply as a result. The optimum battery capacities required in the zero carbon year were around 50–60% and 75–85% larger than in 2020 for the NETA-based tariff and Economy 7 respectively. In order to illustrate the impact of the HP percentage, the optimum Li-ion battery capacities performing Economy 7 for the 100-home community were 568 kW h (HP percentage equal to 14%) and 1020 kW h (HP percentage equal to 100%) in 2020 and the zero carbon year respectively.

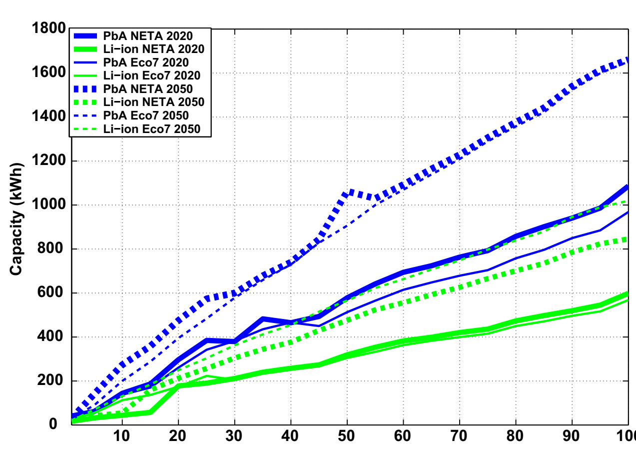

Fig. 9. Optimum battery capacity which minimised the levelised cost, *LCOES*, associated with demand load shifting with Economy 7 and the NETA-based tariff as a function of the community size for PbA and Li-ion technologies in 2020 and the zero carbon year.

Figs. 10 and 11 show the *LCOES*, *IRR* and *LVOES* optimised PbA and Li-ion cases performing demand load shifting as a function of the size of the community in 2020 and the zero carbon target respectively. The pattern followed by the *LCOES* and the *IRR* was similar for the two battery technologies and for the two tariffs considered. The pattern demonstrates the positive effect of the community size. The *LCOES* followed a negative logarithmic trend while the *IRR* followed a positive logarithmic trend as a function of the size of the community. The positive effect of the aggregation of the demands impacted on the *IRR* and *LCOES* but the effect became less pronounced as the community size increased. The best economic results were obtained in the 100-home community while the maximum *LCOES* and the minimum *IRR* were achieved in the single home. The two battery technologies achieved better economic results with Economy 7. The *LCOES* and the *IRR* of a 342 kW h PbA battery in the 25-home community were 0.20 £/kW h and −8% for Economy 7, the cost increasing to 0.29 £/kW h and −16% for a 384 kW h PbA battery with the NETA-based tariff when projected to the year 2020. Additionally, the profitability of the two battery technologies was affected by the type of tariff. With Economy 7, Li-ion battery systems are less viable than PbA battery systems for small communities up to 50 homes, this effect being reversed with the NETA-based tariff.

With the input data selected in Table 3, PbA was the technology which obtained the lowest *LCOES* and the highest *IRR* equal to 0.14 £/kW h and −2.5% respectively in the 100-home community, yet Li-ion values were very similar. Li-ion technology obtained slightly lower *LCOES* values with the NETA-based tariff just for the single home and the 5-home community. The main reason for this was the round trip efficiency of PbA battery system was a bit lower for these communities and this reduced the EFC. Specifically, the round trip efficiency of the optimum PbA systems was 0.72 (35 kW h) and 0.77 (61 kW h), while the round trip efficiency of Li-ion technology was 0.81 (17 kW h) and 0.87 (31 kW h) for the single home and the 5-home community respectively.

The improvement of the ES properties assumed for the reference scenarios in the zero carbon year together with the increase of the energy prices made the business case more widespread ($IRR > 0$) for any technology, tariff and size of the community as shown in Fig. 11. PbA and Li-ion batteries performing load shifting with Economy 7 achieved positive *IRR* for any community, the maximum values 36.5% and 33.2% respectively achieved in the 100-home community. However, communities with less than 15 homes did not achieve positive *IRR* with the NETA-based tariff. Additionally, the *LCOES* went down markedly by the zero carbon year and reached the minimum value for the two battery technologies, 0.08 £/kW h, at the 100-home community. In the case of the NETA-based tariff, the *LCOES* was always higher than the *LVOES* i.e. the *IRR* was lower than the discount rate assumed (10%).The *LVOES* related to Economy 7 and the NETA-based tariff was 0.17 £/kW h and 0.11 £/kW h respectively for both battery technologies regardless of the community size.

6. Sensitivity analysis: impact of heat pump penetration

The impact of the heat demand load on the optimum battery capacity and the economic benefits with demand load shifting is quantified in this section. Load shifting is an CES application for managing the domestic demand load and therefore demand is a key factor to understand the performance and economic benefits.

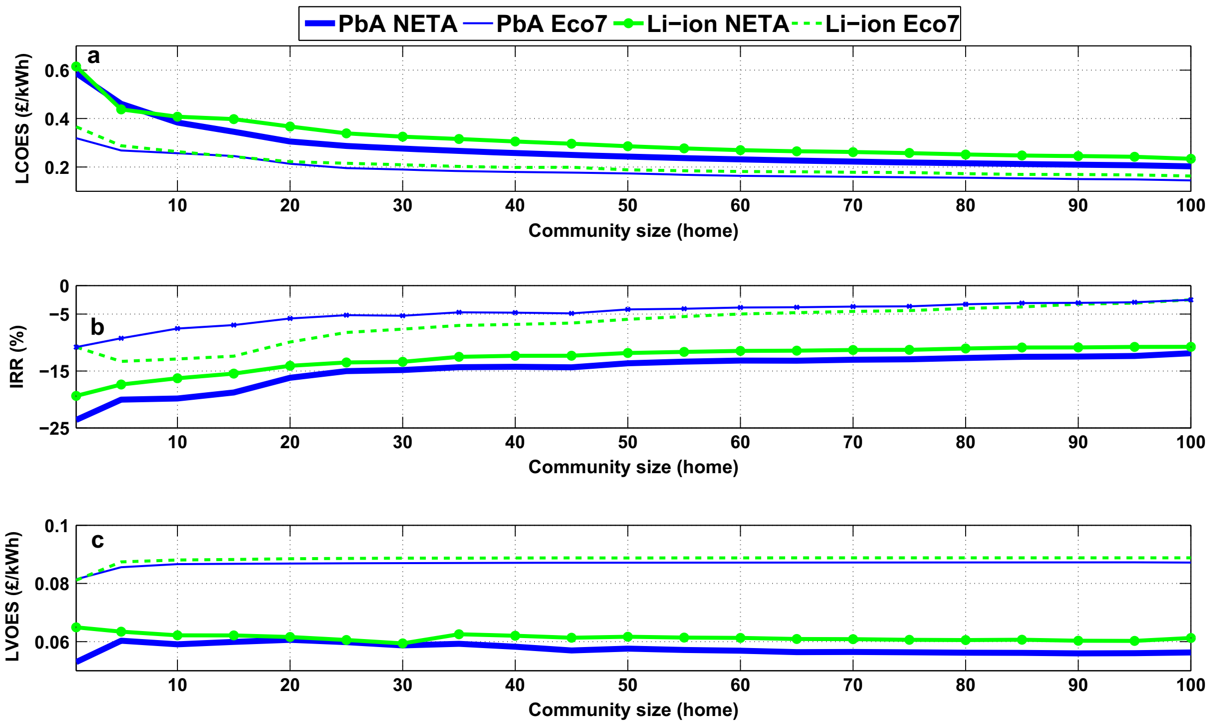

Fig. 10. (a) *LCOES*, (b) *IRR* and (c) *LVOES* optimised for PbA, and Li-ion technologies performing load shifting in 2020 depending on the tariff.

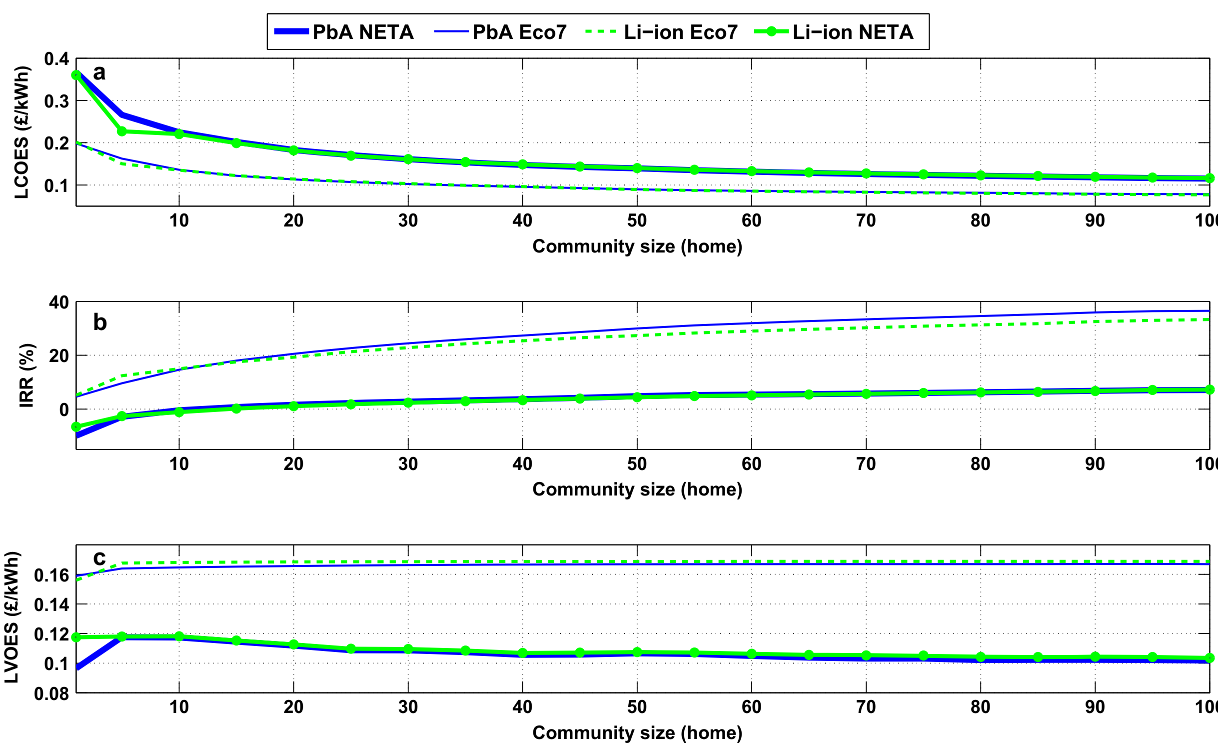

Fig. 11. (a) *LCOES*, (b) *IRR* and (c) *LVOES* optimised for PbA and Li-ion and technologies performing load shifting in the zero carbon year depending on the tariff.

Fig. 12 shows the optimum battery capacity which reduced the cost of performing load shifting for PbA and Li-ion batteries depending whether the heat demand load was considered (HP percentage equal to 14%) or not (HP percentage equal to 0%). The optimum capacities were similar for small communities and then the trend became more steady and slightly more positive for a HP percentage of 14% for both battery technologies. The battery capacity reduced by 21% and 20% for PbA and Li-ion technologies respectively which is consistent with the two different chemistries considering that the absolute capacity was larger for PbA technology. This can be illustrated with the 90-home community in which the optimum battery capacities were 941 kW h and 744 kW h for PbA technology and 519 kW h and 414 kW h for Li-ion technology when considering or not the heat demand load.

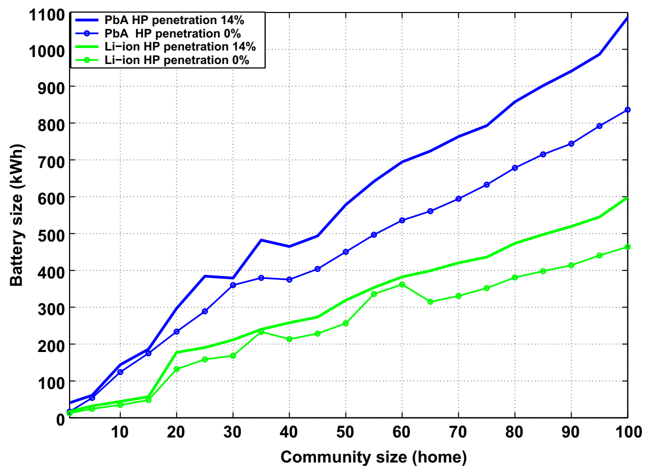

Fig. 12. Optimum CES system which minimised the levelised cost, *LCOES*, when performing demand load shifting as a function of the size of the community for PbA and Li-ion batteries depending on the HP percentage in 2020.

Fig. 13 shows that the *LCOES* and the *IRR* slightly reduced and increased respectively if HPs were connected to the battery system. In fact, just the single home was considerably affected by the use of a HP. The presence of HPs was partially minimised in the optimum results because the optimisation method selected a battery capacity which is not markedly affected by the seasonal pattern of heat demand load. The case of PbA technology in the single home can be used to illustrate the impact of the heat demand load. While the optimum capacity reduced significantly from 35.4 kW h to 16.5 kW h when a HP was not considered, the EFC also went down from 471 cycles to 417 cycles respectively. When the heat demand load was included, battery systems were able to manage more energy on an annual basis per kW h of capacity. In the case of the single home, the *LCOES* increased to 0.89 £/kW h (+37%) and 0.98 £/kW h (+58%) for PbA and Li-ion batteries, while the *IRR* reduced to −28.1% and −21.3% respectively without a HP.

7. Discussion

Demand load shifting allows community energy battery systems to achieve very attractive *LCOES* values as demonstrated with Economy 7 but the maximum *LVOES* associated with load shifting was very limited, specifically up to 0.06 £/kW h and 0.09 £/kW h for load shifting with Economy 7 and the NETA-based tariff respectively when projected to the year 2020. The maximum *LVOES* was not markedly affected by the community size since the round trip efficiency was similar for the batteries with largest capacities for any community as discussed above. Despite the prices in the NETA market are much more variable, those variations were averaged and smoothed when the NETA-based tariff was created. In the case of the *LCOES*, the minimum values were 0.14 £/kW h, 0.2 £/kW h for load shifting with Economy 7 and with the NETA-based tariff respectively. To put these results into context, the minimum *LCOES* and maximum *LVOES* achieved by CES systems (a Li-ion battery system) performing PV energy time-shift was equal to 0.30 £/kW h and 0.15 £/kW h respectively [15]. For load-shifting, the *IRR* was negative for any community by 2020 and only for an average electricity price equal to 0.194 £/kW h (instead of 0.165 £/kW h as assumed in 2020), the *IRR* becomes positive for load shifting with Economy 7 in 2020 [16]. Alternatively, CES became a profitable energy option when projected to a hypothetical zero carbon target even when the technology cost is kept constant, i.e. the same as the 2020 levels.

The ratio of peak demand to total demand is a random variable for which the level of randomness decreases with the community

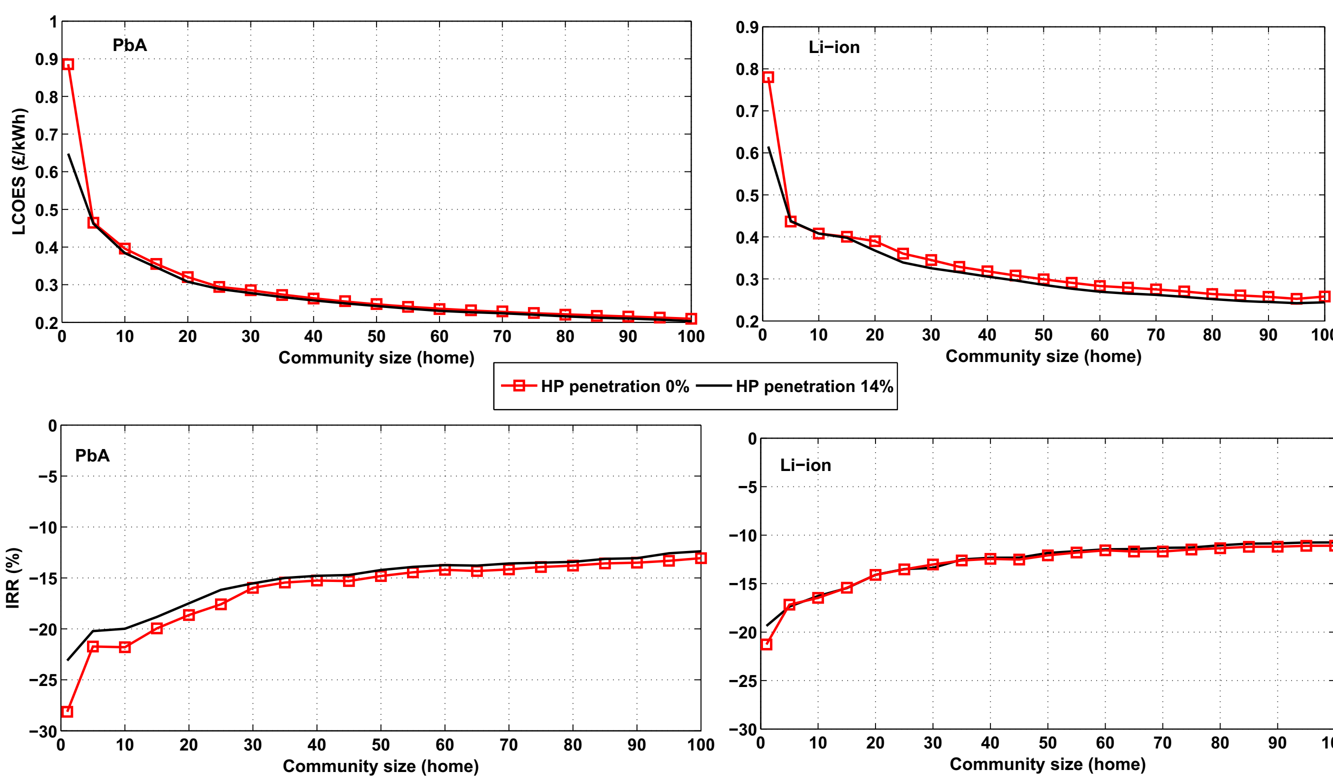

Fig. 13. *LCOES* and *IRR* optimised for PbA and Li-ion technologies as a function of the size of the community when performing load shifting with the NETA-based tariff depending on the HP percentage in 2020.

size due to the aggregation of demands and small communities consume relatively more electricity at peak time [16]. As a consequence, CES requirements per home reduced with the community size due to the less importance of the peak demand period for larger communities. The community effect made some performance parameters such as the EFC and D_{ES} higher for small communities up to 20 homes. However, the community approach helped to increase the range of CES sizes which achieved high performance values as the community size increased. This helped to reduce the *LCOES* associated with load shifting when considering that the optimum CES system is a trade-off decision between the EFC and the round trip efficiency for battery technology. The larger the community, the higher the *IRR* and the lower the *LCOES* although the benefits introduced by the community approach were more marked for communities up to 25 homes. This was a consequence of the randomness associated with the demand loads for the small communities. PbA technology demonstrated good performance and better economic behaviour than Li-ion technology for load shifting because CES systems are sized according to the demand load for this application. Besides, new deep cycle PbA batteries can potentially operate with larger ΔSOC than assumed in this study (see Table 2) without reducing the battery lifetime significantly. In comparison with the results presented in this study, the number of EFC would be higher (in proportion to ΔSOC) due to the larger effective PbA battery capacity. This would significantly reduce the levelised cost (by increasing the total battery discharge considering the capital expenditure keeps constant) and increase the internal rate of return as a result.

In contrast to this, a previous study concluded that Li-ion technology should be selected as technology for CES systems performing PV energy time-shift [15]. However, the required ratio of power rating to energy capacity of battery systems performing demand load shifting is lower than for PV energy time-shift and the lower capital cost of PbA batteries was the over-riding factor. For example, the PbA battery capacity which minimised the *LCOES* associated with PV energy time-shift and load shifting in a 10-home community was equal to 73 kW h and 132 kW h respectively (HP percentage equal to 14%). For the projected scenario in 2020, there is not a business case for CES performing demand load shifting since *IRR* values are still negative. However, (slightly) positive *IRR* values for CES performing PV energy time-shift were projected with a storage medium price of 310 £/kW h (Li-ion cell) and an electricity price of 19 p/kW h by 2020 [15]. CES systems could perform various applications simultaneously but also some incentives may occur in some countries (e.g., Germany).

8. Conclusions

From an end user perspective, there are two reasons why Economy 7 is a very attractive tariff for demand load shifting combined with battery ES technologies. Firstly, in Economy 7, the ratio between the off-peak price and the peak price (0.47) is always lower than the round trip efficiency of any battery system and therefore load shifting can be performed on a daily basis (even with PbA batteries). Secondly, the peak period lasts for 17 h and therefore a high fraction of the daily demand can be shifted. Specifically, the fraction of the daily peak demand was up to 97% for a single home and up to 85% for a 100-home community. Additionally, end users know the electricity prices before hand and the logic and control necessary to implement this tariff is simple. In the case of the four-period tariff, the ratio between the off-peak and peak prices was not always attractive on a daily basis but also the peak period was shorter.

Utility companies, house-builders, and DSOs considering to invest on CES systems performing demand load shifting (and potentially other ES applications) should know that the *LCOES* followed a negative logarithmic trend while the *IRR* followed a positive logarithmic trend as a function of the size of the community. The positive effect of the aggregation of the demands became smoother as the community size increased. In fact, battery systems performing load shifting needed communities with more than 75 homes to maximise the economic benefits. The minimum *LCOES* (0.14 £/kW h) and the maximum *IRR* (−2.5%) were obtained by the 100-home community while the maximum *LCOES* (0.32 £/kW h in 2020) and the minimum *IRR* (−10.8% in 2020) were achieved in a single home.

From a battery technology perspective, the optimum PbA capacity was approximately twice the optimum Li-ion capacity in the case of the NETA-based tariff and around 1.6 times for Economy 7 for any community size except the single home in the case of Economy 7. Regarding the type of tariff, the optimum battery capacity (including PbA and Li-ion batteries) was very similar for demand load shifting with Economy 7 and the NETA-based tariff. Specifically, Li-ion capacity was slightly larger for Economy 7 (up to 20%) due to the higher duration of the peak period while PbA technology needed slightly larger capacities (up to 19%) with the NETA-based tariff in order to increase the round trip efficiency and meet the load shifting condition in terms of round trip efficiency. The type of tariff and battery technology affect the economic case depending on the size of the community. For communities with 5–50 homes, Li-ion battery systems achieve higher IRR than PbA battery systems with the NETA-based tariff while PbA battery systems are more economically viable than Li-ion battery systems with Economy 7. For larger communities than 50 homes, the battery technology and tariff effects remains but differences become less significant.

Interesting outputs for different stakeholders including battery manufacturers, utility companies and policy makers also came from the heat pump analysis with CES systems performing demand load shifting. The integration of HPs affects the economic benefits of CES but especially the required battery capacity. Heat pumps increase the required optimum battery capacity since CES systems are sized according to the demand load requirements for load shifting. The size of the optimum battery system which performs load shifting increased by 20% when the heat pump penetration increased from 0% to 14% in 2020. Likewise, the size of the optimum battery system which performs load shifting increased around 75% when the heat pump penetration varied from 14% in 2020 to 100% in the zero carbon year. Heat pumps reduce the *LCOES* and increase the *IRR* of battery systems which perform load shifting. The *LCOES* reduced by 5–8% for load shifting depending on the size of the community when the heat pump penetration varied from 0% to 14%.

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