buildings

MDPI

Article

Dispatch Strategies for the Utilisation of Battery Storage Systems in Smart Grid Optimised Buildings

Andreas D. Georgakarakos [1,2,*], Behrang Vand [3], Elizabeth Abigail Hathway [2] and Martin Mayfield [2]

1 CDT in Energy Storage & Its Applications, The University of Sheffield, Sheffield S1 3JD, UK
2 Department of Civil & Structural Engineering, The University of Sheffield, Sheffield S1 3JD, UK; a.hathway@sheffield.ac.uk (E.A.H.); martin.mayfield@sheffield.ac.uk (M.M.)
3 School of Engineering and the Built Environment, Edinburgh Napier University, Edinburgh EH10 5DT, UK; B.Vand@napier.ac.uk
* Correspondence: a.georgakarakos@sheffield.ac.uk

Abstract: This study investigates Smart Grid Optimised Buildings (SGOBs) which can respond to real-time electricity prices by utilising battery storage systems (BSS). Different building design characteristics are assessed to evaluate the impact on energy use, the interaction with the battery, and potential for peak load shifting. Two extreme cases based on minimum and maximum annual energy consumption were selected for further investigation to assess their capability of utilising BSS to perform arbitrage, under real-time pricing. Three operational dispatch strategies were modelled to allow buildings to provide such services. The most energy-efficient building was capable of shifting a higher percentage of its peak loads and export more electricity, when this is allowed. When using the biggest battery (220 kWh) to only meet the building loads, the energy-efficient building was able to shift 39.68% of its original peak loads in comparison to the 33.95% of the least efficient building. With exports allowed, the shifting percentages went down to 31.76% and 29.46%, respectively, while exports of 18.08 and 16.34 kWh/m^2 took place. The formation of a regulatory framework is vital in order to establish proper motives for buildings to undertake an active role in the smart grid.

Keywords: energy storage; battery storage; energy arbitrage; smart grid; smart buildings; smart grid optimised buildings; demand response

check for updates

Citation: Georgakarakos, A.D.; Vand, B.; Hathway, E.A.; Mayfield, M. Dispatch Strategies for the Utilisation of Battery Storage Systems in Smart Grid Optimised Buildings. *Buildings* **2021**, *11*, 433. https://doi.org/10.3390/buildings11100433

Academic Editor: Jan Kosny

Received: 6 July 2021
Accepted: 20 September 2021
Published: 25 September 2021

Publisher's Note: MDPI stays neutral with regard to jurisdictional claims in published maps and institutional affiliations.

Copyright: © 2021 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).

1. Introduction

The building sector is responsible for a significant percentage of energy consumption and greenhouse gas emissions, worldwide [1]. When it comes to the sector's electricity needs, the electricity demand is expected to increase in the future depending on many parameters, including the extent of electrification of space heating in buildings, utilisation of heat pumps and electric vehicles. Further adoption of these technologies will result in higher peak loads and put pressure on the grid infrastructure [1,2].

The ramifications of peak electrical loads are significant for the environment and the economy as expensive carbon intensive power generation is needed, often creating serious issues for the low voltage distribution networks and their capacity. Peak loads can lead to imbalances between supply and demand which consequently cause electricity price fluctuations in the wholesale markets. These imbalances will likely be present even in a decarbonised network due to the intermittency introduced by renewable energy sources (RES), seasonal weather conditions and the utilisation of the emerging technologies mentioned previously [3]. More specifically, because of the stochastic nature of RES and the uncertainty around their output characteristics, the grid operators are not able to control that energy output; therefore, scheduling and distributing their energy is not as flexible as with the traditional electric generators such as thermal power plants and hydropower. This effect has the potential to introduce frequency and voltage fluctuations which can affect the balance and the stability of the network [4]. Mechanisms that will provide temporal flexibility through peak demand management are urgently needed for the future operation of the electricity network.

At the building level, optimised peak demand reductions can take place through coordinated control of building loads, often called demand response (DR), local electricity generation (e.g., photovoltaics) and energy storage. By controlling their heating, ventilation and air conditioning (HVAC) loads over time, buildings can become demand-responsive following demand reduction signals from the electrical grid and result in significant savings [5–10]. DR can also be conducted in synergy with other energy technologies, such as combined heat and power (CHP), storage and RES [11–13]. Temporally, it can be classified as day-ahead (slow), intra-day or ancillary (fast) DR, indicating how much in advance its specifications are arranged. The DR framework can be applied in both existing and new buildings [14].

DR is usually delivered through incentive-based and price-based programs [15]. To implement DR, it is vital to know and understand the energy amount used by a building, on a daily and hourly basis. The ability of a building to modify its demand and how quickly this response can take place varies from building to building and depends on different parameters, including the HVAC configuration [16], domestic hot water (DHW) production method as well as the presence of battery storage and renewables [17]. It is essential to recognise and understand the peak demand reduction potential and the capabilities presented under different DR strategies for various building types, in different climates and occupancy profiles [18].

Building integrated energy storage, such as batteries, can allow buildings to manage their demand and reduce their peak loads, relieving pressure on the electrical network [2]. Additionally, they are able to store electricity when excess generation from RES takes place. Furthermore, energy storage can provide grid services such as reserve power, ancillary services for frequency response and regulation, facilitate the integration of RES into the system and offer more control to the final consumers [19]. The main balancing services are currently procured by the National Grid in Great Britain in order to achieve a balance between supply and demand. They are open to generators, big consumers or both. For each service, there are specifications regarding the response time needed, minimum duration and power provided. Rewards include availability (GBP/MW/h), utilisation (GBP/MWh) and nomination fee (GBP/hour) [20]. Therefore, it is important to understand the potential that can be unlocked by deploying an energy storage system (ESS) at the building level and providing services to the grid.

A summary of selected energy technologies for buildings along with their applications can be seen in Table 1. Energy storage is capable of providing a wide variety of services in various parts of the network and combining it with other technologies has been evaluated extensively in [21–23]. While many options are available for buildings, a techno-economic assessment is required on a case-to-case basis to evaluate the cost-effectiveness of any suggested scheme. There are many case studies investigating energy technologies in buildings; however, the literature is scarce on the utilisation of battery storage in buildings with different design characteristics.

It can be concluded that the building sector as the major energy consumer is expected to play a critical role in the development of future smart energy systems and the future smart grid through a variety of different mechanisms such as real-time trade of energy, DR, self-generation, decentralised renewable energy and energy storage [24,25]. These mechanisms will allow buildings to shift from passive elements to active players by cooperating in the network operation. However, this cooperation will require a closer relationship between the building and the energy sector [5,14,26] as well as the ability of the building to store energy, for instance with batteries [27]. A recent case study highlighted that establishing a proper regulatory framework and financial motives was deemed to be of the essence towards making battery storage attractive and cost-effective to potential investors [28]. Currently, there are many important barriers under the current regulatory and economic regimes that prevent ES from participating in the electricity markets and contributing towards technological innovations. These have been well summarised by [29–31].

Table 1. Studied energy technologies in buildings and their applications in selected publications.

Technologies	Application(s) in Buildings and/or the Grid	Comments/Conclusions
Batteries	Peak-shaving [32]	Residential Battery energy storage systems can reduce peak electricity loads by >40%.
	Time-of-Use (ToU) Energy management [33]	Medium-scale batteries can reduce the electricity bills of consumers through ToU energy management. They are economically beneficial for medium-scale buildings if there is an important difference between the max. and the min. electricity prices.
	Balancing Services, RES Integration, Customer Energy Management [34,35]	Batteries can provide several services, including balancing services, such as voltage support, black start and load following, as well as customer energy management (power quality/reliability). RES Integration can be achieved through time-shifting and capacity firming.
	Optimisation of energy dispatch schedule in a PV/storage system [36]	Batteries are important for providing peak-shaving and load shifting. The cost-effectiveness of the system depends on the electricity rates and battery technology used (lithium-ion, lead acid, etc.)
Hydrogen Storage	Self-sufficient energy buildings and cost minimisation [37]	There is an increasing interest in combined battery and hydrogen storage. Domestic hydrogen storage can render a building self-sufficient for an annual premium of 52% when compared to buying electricity from the grid by 2030. It can also lead to annualised cost reductions of 72–80% for the supply of heat and electricity when compared to Li-ion batteries.
	Integration of RES and balancing of the grid [38]	Electrochemical and mechanical storage are not sufficient to balance the grid; therefore, hydrogen is expected to play a major role in the energy transition. Evaluating hydrogen is very challenging while a detailed techno-economic assessment is required on a case-to-case basis.
Thermal mass	Energy flexible buildings [39]	Using the building's thermal mass as thermal storage through preheating, precooling and night ventilation can lead to a maximum of 3.2% savings for heating and 8.5% for cooling.
HVAC	Fast DR [40]	Turning off part of the HVAC is an efficient way for buildings to respond quickly to notifications issued by the Smart Grid, provide fast DR and achieve considerable power reduction (39%).
	Peak-shaving [41]	An HVAC energy management system can minimise cooling loads by altering thermostat settings, leading to a reduction in the daily peak loads by 25.5% in domestic buildings.
Hybrid System	Meeting loads, minimisation of costs and emissions [42]	Considering several energy systems (wind turbines, PVs, hydrogen storage, batteries), many optimal combinations include high levels of solar and wind power. As high costs are associated with hydrogen storage, priority is given to batteries.
CHP	Emissions reductions [43]	CHP can reduce emissions (CO_2, NO_x, CH_4) as well as the carbon equivalent in commercial buildings.
	Primary Energy Savings [44]	CHP can lead to the reduction in electricity and gas consumption by 56% and 43%, respectively. Results are considered to be dependent on climate conditions and building types.

The concept of SGOBs was first mentioned in [45], while [28] presented initial results for one building scenario, showing how battery arbitrage can change the building's electricity profile. The current paper recognises the potential of building integrated storage for the benefits of both the building and the electrical network. The combination of energy storage and renewables as well as optimisation algorithms for pumped-hydro energy storage (PHES) arbitrage are often encountered in the literature. However, the majority of PHES studies have focused on the financial aspect of storage operation by maximising the revenue streams, and therefore the profitability of such schemes. According to the literature review, utilising BSS in buildings in order to perform peak-shaving based on different technical (both building design and BSS sizes) and arbitrage scenarios has not been investigated before. Therefore, this study evaluates the utilisation of the battery as a standalone technology, without the concurrent use of renewables in buildings, to reduce peak loads. In this way, different buildings are taken into account in terms of glazing and insulation as building design affects daily and annual load profiles. To accomplish this, the developed arbitrage algorithms use the hourly electricity demand of different buildings, hourly electricity prices from the grid and the BSS technical specifications. Moreover, a cost-benefit analysis is studied for 10- and 20-year periods to quantify the financial motive required to make BSS economically attractive to building owners. The novelties of this study form the interaction between the building's dynamic requirements for power and the cost of electricity while using a battery to reduce peak load requirements.

Summing up, this research article examines a combination of unique parameters that include building design, operational dispatch strategies, BSS sizes and long-term economics to compare the SGOB potential of different buildings. This work takes the first vital step towards the establishment of a regulatory framework for battery arbitrage in the building sector to understand the suitability of buildings to become SGOBs.

2. Methodology

Three operational (dispatch) strategies are presented techno-economically, under which BSS are deployed at the building level to conduct energy arbitrage by responding to real-time electricity prices, shifting their daily electricity profile and providing in this way a service to the grid. The objective function of the arbitrage model is lowest operational costs; buying electricity when costs are low to use within the building or sell back to the grid at a later time. The results are finally evaluated in respect of total electricity consumption, peak hours shaved and net cost based on the relative impact of building design, battery and inverter sizing and dispatch strategies.

Building simulations are used to estimate hourly electricity loads across a full year. The output results of the building simulations include the building's electricity consumption on an hourly basis (kWh) while the output of the real-time electricity pricing includes retail hourly electricity prices (GBP/kWh); these data are used as the input of the BSS. The three main elements along with their examined characteristics are summarised below, in Figure 1, while Figure 2 demonstrates the modelling process and the software used along with the key inputs and outputs.

2.1. Building Specifications

In this section, the chosen building key parameters along with their characteristics and values are explained, regarding design, structure, HVAC configuration, building loads and simulations.

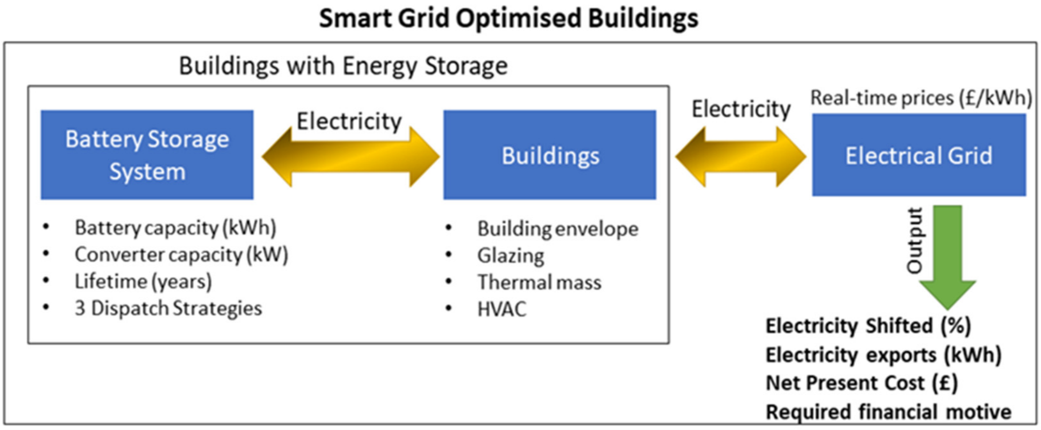

Figure 1. Main research elements and their characteristics.

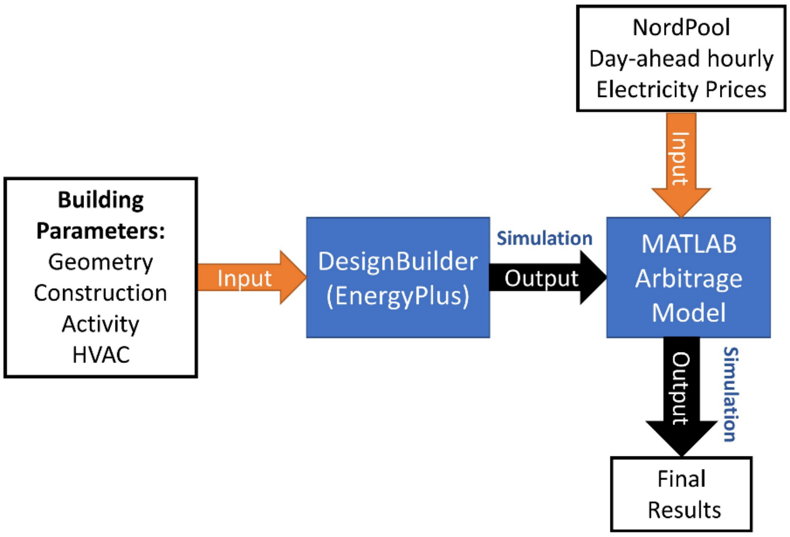

Figure 2. Modelling Methodology, inputs and outputs.

2.1.1. Design and Structure

One common commercial building geometry of four storeys, each one occupying 625 m^2 of total floor area. Each floor includes two zones: open-plan office (Zone 1) and a small generic reception/stairwell/lift area, located at the centre of the floor (Zone 2). Zone 2 is separated from the rest of the storey through an internal partition. The buildings vary in terms of three key design characteristics, as shown in Table 2:

Table 2. Properties of Building Scenarios.

Case	Thermal Mass	Insulation	Glazing
HwB30	Heavyweight	Best Practice	30%
HwL30	Heavyweight	Part L	30%
LwB30	Lightweight	Best Practice	30%
LwP30	Lightweight	Part L	30%
HwB80	Heavyweight	Best Practice	80%
HwL80	Heavyweight	Part L	80%
LwB80	Lightweight	Best Practice	80%
LwL80	Lightweight	Lightweight	80%

1. Building envelope. This characteristic refers to the thermal transmittance of the envelope elements and their airtightness. The first category meets the building regulations as described in Part L [46] while Best Practice is more energy-efficient

with lower envelope U-values, along with less external infiltration. Concerning the airtightness, crack templates are used to calculate the external infiltration that takes place due to surface cracks or by general fabric porosity, as explained in [47]. The envelope determines the interior climate conditions and consequently the additional heating and cooling demand required. The envelope parameters are presented in Table 3;

2. Thermal mass. Lightweight buildings are assumed to include metallic cladding with plastering while heavyweight buildings consist of brickwork, concrete and plastering at their respective external walls. Thermal mass is responsible for a time delay in the heat exchange (thermal lag) between the building interior and the outside environment, depending on the properties of the building materials used [48];
3. Window-to-Wall ratio. For this category, 30% and 80% glazed buildings are considered. Glazing is considered to be one of the weakest control points in the thermal performance of buildings as heating losses and solar gain take place through the windows [49].

Table 3. Building Envelope properties for the simulated buildings.

Parameter (Units)	Part L Compliant	Best Practice
Floor dimensions	25 m × 25 m (6 m × 6 m for Zone 2)	
Floor area (Zone 1)	2356 m^2	
Floor area (Zone 2)	144 m^2	
Volume	8750 m^3	
Flat roof U-value (W/m^{2}K)	0.25	0.18
External wall U-value (W/m^{2}K)	0.35	0.26
Ground floor U-value (W/m^{2}K)	0.25	0.22
Internal floor U-value (W/m^{2}K)	2.93	2.93
Internal partition (W/m^{2}K)	1.64	1.64
Windows glazing U-value (W/m^{2}K)	2.2 (30% glazed) 1.3 (80% glazed)	1.6 (30% glazed) 0.8 (80% glazed)
Windows g-value (%)	38	38
Windows lighting penetration (%)	53	53
Window shading	No shading	
Airtightness	Poor	Medium
Building's Orientation	South–North	
Shape	Rectangular	

Finally, concerning their occupancy, the buildings are occupied between 8 a.m. and 6 p.m., on weekdays only, while environmental control settings follow the CIBSE guidelines [50].

2.1.2. HVAC Configuration and Building Loads

The buildings are fully electric as ground source heat pumps (GSHPs) are used for both heating and cooling purposes. The heat pump's coefficient of performance (CoP) values (3.5 and 5, respectively) are considered to be constant and equal to the seasonal COPs. Mechanical ventilation is used to meet the minimum air requirements of the occupants (10 L/s·person) as well as deliver free cooling whenever the indoor temperature is higher than the cooling set-point. An economiser is used to provide free cooling during the occupied hours, at a maximum rate of two air changes per hour. Night cooling only takes place between 31 May and 30 September, for the heavyweight buildings. The auxiliary energy is assumed to be constant throughout the year. The set-point and set-back temperatures are 22 °C and 12 °C for heating, while the respective values used for cooling are 27 °C and 23 °C. Finally, equipment loads from desktop workstations are 9.06 W/m^2 while recessed LED with linear control is used for lighting purposes, with 10.6 W/m^2 and 7.4 W/m^2 for the office and the reception area, respectively, in order to meet the 500 and 200 lux illuminance targets.

2.1.3. Building Simulations

The building loads were calculated using DesignBuilder, which utilises the integrated EnergyPlus simulation engine which is a well-recognised and accepted building energy simulation software tool, capable of modelling HVAC as well as other energy flows in a building and therefore widely used to estimate building energy performance [51,52]. Figure 3 demonstrates the interoperation between DesignBuilder Graphical User Interface (GUI), and EnergyPlus Simulation engine. Regarding temperature control and the used indoor set-point and set-back temperatures, the operative temperature and therefore equal ambient and radiant fractions are considered for the simulations. The thermal comfort of the occupants is maintained, even in the highly glazed buildings. The discomfort hours, based on the ASHRAE 55 Simple Standard, were normalised per floor area and four time steps per hour were chosen for the Zone heat balance model calculations [53].

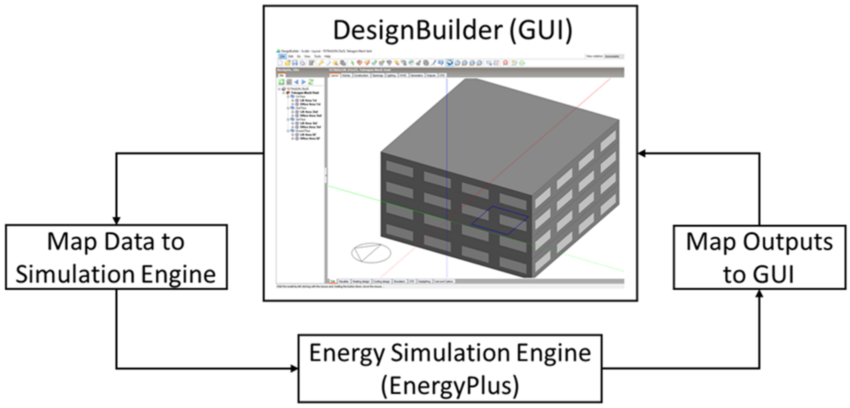

Figure 3. Interoperation between DesignBuilder Graphical User Interface and EnergyPlus (Adapted from [51]).

The location chosen is Birmingham Airport, United Kingdom (UK) with an ASHRAE Climate Zone 5C. The location weather data from IWEC were used. Daylight Saving Time is not observed to avoid any temporal changes on the electricity profile of the buildings.

2.2. Real-Time Electricity Pricing Data

Wholesale electricity prices were obtained from NordPool, for the day-ahead market [54,55]. The wholesale cost of domestic electricity constituted only 33.6% of the total domestic electricity bill, in 2017 [56]. Other parameters include operating costs, the supplier pre-tax margin, network costs, environmental and social obligation costs, as well as VAT. For non-domestic electricity prices, there are no readily available values provided from Ofgem and therefore, the wholesale percentage had to be calculated, based on the data reported by the Consolidated Segmental Statements of the six largest UK electricity suppliers.

In order to be able to convert wholesale costs to the retail level, it is assumed that the wholesale percentage remains constant throughout the year. The real contribution of the wholesale cost to the final electricity bill might vary hourly, depending on the circumstances. Therefore, Equation (1) is used for the wholesale-to-retail conversion.

$$\text{Retail Electricity Price (GBP/kWh)} = \frac{\text{Wholesale Electricity Price}\left(\frac{\text{GBP}}{\text{kWh}}\right)}{\text{Direct Fuel Cost Percentage (\%)}} \tag{1}$$

Finally, it must also be taken into account that while the reduced VAT rate of 5% applies for consumption of domestic electricity, non-domestic power is taxed at the standard rate of 20% [57]. The wholesale contribution to the non-domestic electricity price, reported by Ofgem as “direct fuel costs”, was calculated by the current study to be 36.6%, which is around 3% higher than its respective value for domestic electricity [58]. Figure 4 presents the maximum, minimum and average values per day for 2017 for the calculated retail electricity prices. It is shown that the daily difference between the lowest and the highest prices constitute the foundations of electricity arbitrage.

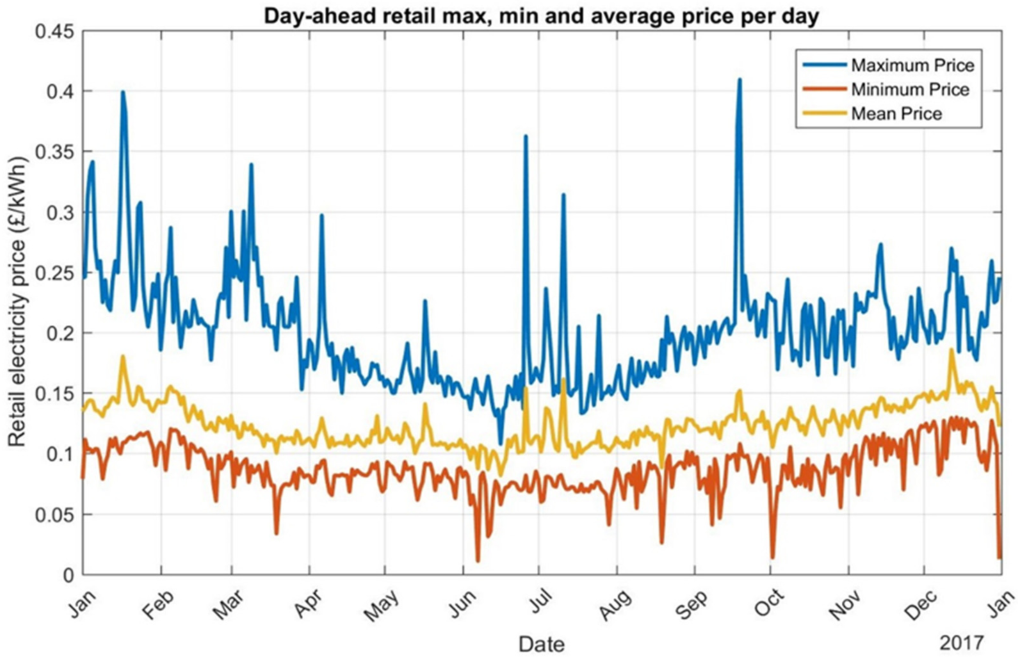

Figure 4. Real-time day-ahead hourly electricity retail prices for 2017.

2.3. Battery Storage Model

The BSS model consists of the battery bank, one inverter, one rectifier and the controller. The battery can be discharged to meet building loads or export electricity back to the grid. The rectifier and inverter are combined in a bidirectional inverter, also called a bi-directional converter [59]. The input of the model includes the values of the building which have been generated from the building simulations and the hourly electricity retail prices in order to configure the BSS operation, based on the applied control algorithm strategy. Regarding the sizing of the BSS components, it is assumed that the BSS is able to discharge the total usable battery capacity in a maximum of 2 h and charge it under 3 h. Ten battery sizes between 40 and 220 kWh were considered, with a 20 kWh step.

This study has adopted an arbitrage algorithm, originally designed for the utilisation of large scale PHES, as presented in detail and used in [60–62]. In this study, significant changes have been made in order for the algorithm to adapt to the unique characteristics of the building scale. Their common objective is to make the algorithm take into account the hourly building loads towards deciding whether to operate the battery or not. The model variables are listed in Table 4 along with their units.

2.3.1. Control Algorithm Strategies

The BSS model operates on an hourly basis and the algorithm takes into account day-ahead real-time electricity prices. It is assumed that the prices of the following day are announced at midnight and that it is possible to perfectly predict the building energy consumption for the following day, in advance. Using all the data mentioned above, the routine takes place 365 times, each covering one day of the year. The principle of the algorithm is to preschedule the charging and discharging operations of the battery; therefore, charging cannot take place without discharging and vice versa.

When discharging, the operation of the battery can have one of the following two forms: (a) meeting the local building loads or (b) exporting back to the grid. In this direction, a total of three operational strategies have been considered, each examining at least one form of the battery operation. Furthermore, it is important to examine the impact of the battery operation and the additional exports that take place, during non-working days, when no building loads are present; therefore, combinations of the above elements led to the formulation of three individual strategies: E7, E5 and E0. Under E7, both forms of the battery operation are allowed during the entire week, including exports to the grid when there is excess electricity stored in the battery. Additionally, E0 uses all stored electricity towards meeting building loads, during the working days of the week, with no exports allowed. Finally, as a middle-ground scenario, E5 allows both forms, but only during the working days of the week. An overview of the operational strategies is shown below, in Table 5.

Table 4. Battery Storage Model key variables and their units.

Model Variable	Unit
annual_energy_cost	Annual cost of electricity purchases (GBP/year)
annual_net_cost	Annual electricity net cost (GBP/year)
annual_OM_cost	Annual Operation and Maintenance cost for the BSS (GBP/year)
annual_revenues	Annual revenues from electricity exports (GBP/year)
battery_cost	Capital cost of the battery including cabling and other hardware (GBP)
bottleneck	Capacity to operate the battery based on conditions (kW)
converter_cost	Capital cost of the bi-directional converter (GBP)
energy_demand	The building's hourly electricity demand without storage (kWh)
energy_from_the_grid	Total amount of hourly electricity purchased by the grid (kWh)
energy_shifted	Hourly building loads shifted due to the utilisation of the battery (kWh)
exported_energy	Net annual amount of electricity exported back to the grid (kWh/year)
financial_reward	Financial reward required to provide the service (arbitrage) (GBP/kWh)
inflation_rate	Annual inflation rate
interest_rate	Annual interest rate
LCOE_with_storage	Levelised cost of electricity with storage for the study period (GBP/kWh)
LCOE_without_storage	Levelised cost of electricity without storage for the study period (GBP/kWh)
maxHourIndex	Period of maximum electricity price (index)
maxHourPowerLimit	Power limit below which discharging is not allowed (kW)
maxHourPrice	Electricity price for the maxHourIndex period (GBP/kWh)
maxRangeIndex	Latest period during which the battery can discharge (index)
minHourIndex	Period of minimum electricity price (index)
minHourPowerLimit	Power limit above which charging is not allowed (kW)
minHourPrice	Electricity price for the minHourIndex period (GBP/kWh)
minRangeIndex	Earliest period during which the battery can charge (index)
n_{battch}	Charging efficiency
n_{battd}	Discharging efficiency
$n_{inverter}$	Inverter efficiency
$n_{rectifier}$	Rectifier efficiency
NPC_with_storage	Net Present Cost using storage for the study period (GBP)
NPC_without_storage	Net Present Cost without using storage for the study period (GBP)
OM_cost	Total Operation and Maintenance BSS costs for the study period (GBP)
$\text{replacement\_cost}_j$	Cost of the replacement of BSS component j of the system (GBP)
RTP_retail	Calculated hourly retail electricity price (GBP/kWh)

Table 5. Overview of the Operational Strategies.

Activity	Operational Strategy		
	E7	E5	E0
Battery is allowed to discharge to meet building loads on working days	✓	✓	✓
Exports can take place on working days	✓	✓	×
Exports can take place on non-working days	✓	×	×
Charging takes place when electricity prices are cheap and building loads insignificant	✓	✓	✓
Discharging takes place when electricity prices are expensive and building loads significant	✓	✓	✓

2.3.2. Operational Strategy E7: Exports Allowed with Retail Revenues

The first operational strategy identifies the cheapest and most expensive hours of the day and schedules the BSS to take advantage of the price difference. The process refers to a day and is repeated until the end of one calendar year and until all periods (8760 h) have been examined for their suitability for battery operation. No distinction is made between working and non-working days (NWDs) and therefore the algorithm operates the battery as many times as technically possible. The combined flow chart for both operational strategies E7 and E5 is presented in Figure 5.

Discharging hours (maxHourIndex) and their respective prices (maxHourPrice) are identified and given priority. However, if the corresponding building loads exceed a specific value (maxHourPowerLimit), the hours in question are removed from the time series and the algorithm moves on to the next iteration to identify the next suitable maxHourIndex. This is necessary in order to avoid discharging the battery during hours when the building loads are insignificant. This threshold is calculated as the average value of the building loads of the first day, which is always a non-working day, plus an optional margin of 5 kW to allow for error.

Afterwards, a range around maxHourIndex where charging might occur is established. The earliest hour the battery can charge is after the most recent period to maxHourIndex when the battery was full (minRangeIndex). Likewise, the latest hour when charging can happen after maxHourIndex is the hour before the battery has reached its minimum state of charge (maxRangeIndex). Then, the minimum electricity price in this range is identified (minHourIndex) along with its respective price (minHourPrice). If the building loads that take place during minHourIndex exceed a specified limit (minHourPowerLimit), which is set equal to maxHourPowerLimit, then the period is removed from the price series and the next iteration starts again to identify a new period for charging. This ensures that charging does not take place during the building's operation, as it would result in higher peak loads.

The total cost of operating the BSS is based on the buying electricity price and the roundtrip efficiency in order to ensure that the energy discharged by the battery to meet the building loads is less expensive than directly buying electricity from the grid. The marginal operational costs of charging and discharging the ESS, often used in PHES arbitrage, are assumed to be zero and therefore the marginal cost of production is equal to maxHourPrice. The battery only operates if the condition of Equation (2) is met, which takes into account the roundtrip efficiency that consists of four different efficiencies that are present in charging and discharging:

$$\text{maxHourPrice} \leq \frac{\text{minHourPrice}}{\text{n}_{\text{battch}} \cdot \text{n}_{\text{battd}} \cdot \text{n}_{\text{inverter}} \cdot \text{n}_{\text{rectifier}}} \quad (2)$$

Finally, operational bottlenecks are in place and will instruct the BSS with the exact amount of power to charge and discharge, depending on the amount of the energy stored in the battery. More specifically, constraints for the charging and discharging capacities of the battery will also apply to avoid charging above a state of charge of 100% and discharging below the minimum percentage required (10%). The storage content is then updated, and the process is complete when all the time periods have been evaluated.

2.3.3. Operational Strategy E5: Exports Allowed Only on Working Days

This version of the algorithm excludes the non-working days (NWDs) from the battery operation; therefore, 52 weekends and four public holidays, a total of 108 days and the equivalent of 2592 h during which the battery is not allowed to charge or discharge. This number of hours constitute approximately 30% of a calendar year and when combined with the technical capability of the BSS to cycle more than once daily can have an enormous impact on the energy exports and consequent revenues, which are massively reduced. It should be noted that a significantly less frequent battery usage leads to a higher battery life.

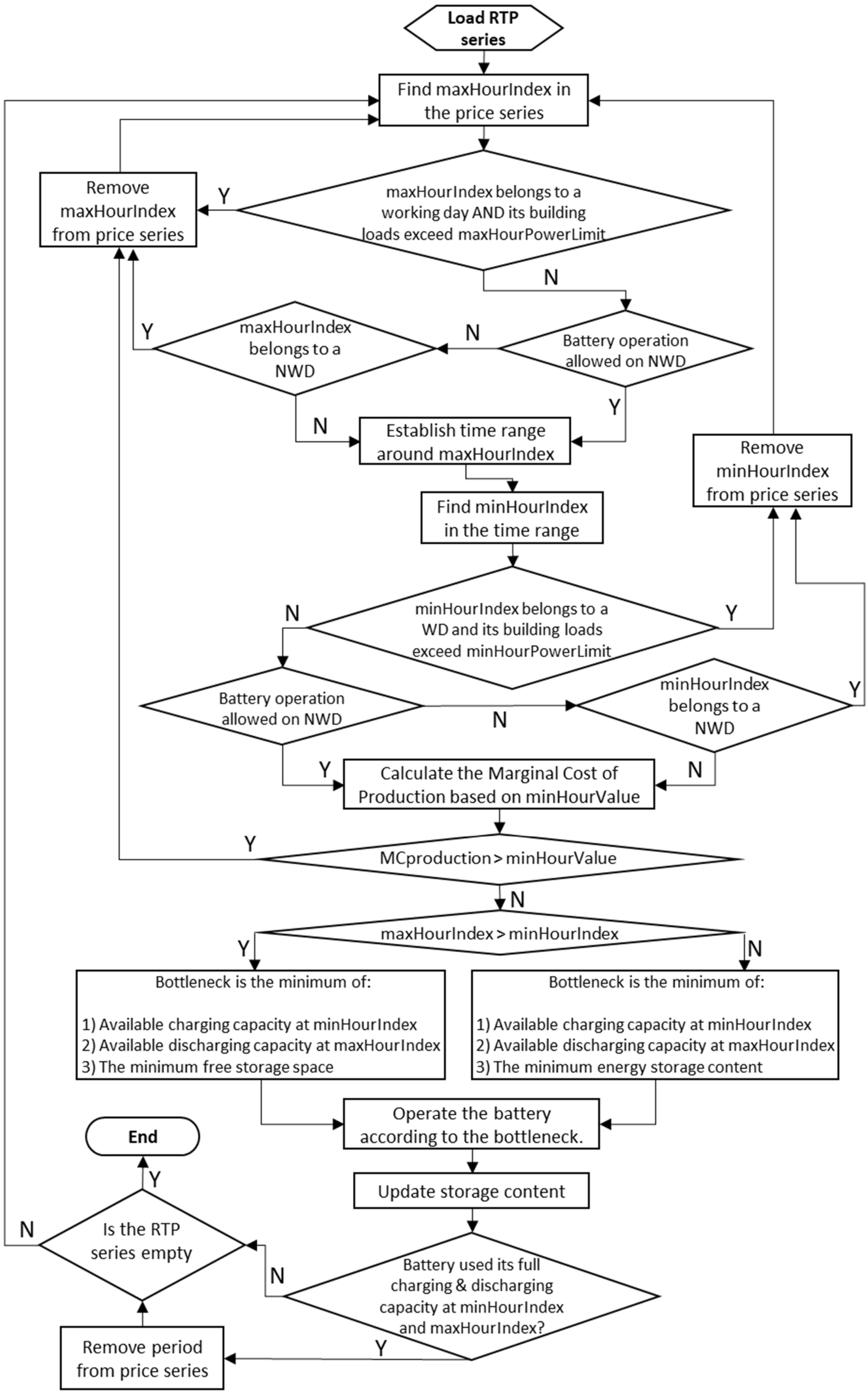

Figure 5. Flow chart for Arbitrage with Exports for Strategies E7 and E5. If the battery operation is not allowed on NWDs, minHourIndex is removed from the price series (E5); otherwise, the algorithm proceeds directly with the calculation of the marginal cost of production (E7) based on the respective minHourValue.

Operational Strategies E7 and E5 make use of all the available battery and inverter capacities, trying to discharge as much as possible during the most expensive hour(s), with any excess electricity being exported back to the electrical grid.

2.3.4. Operational Strategy E0: No Exports Allowed

The third version of the algorithm introduces one additional constraint to ensure that all the discharged energy from the battery is only used locally to cover the local building loads. Therefore, the maximum power discharged in any given hour is never greater than the building's electricity demand. The roundtrip efficiency is also considered in order to avoid any additional grid purchases for remaining loads (Figure 6).

2.4. Economics and Cost–Benefit Analysis (CBA)

The battery used was based on a nominal lithium-ion lifecycle of 5000 cycles with a depth of discharge (DOD) of 90%, the equivalent of 4500 full cycles [63]. For the operation strategies that allow exports to the grid, the annual revenues are calculated by multiplying the hourly retail prices with the amount of the respective exported electricity. The total annual net costs of the electricity are considered to be equal to the electricity grid purchases, minus any export revenues. The calculated (annual) electricity cost is given in Equation (3), with its revenues and net cost given in Equations (4) and (5), respectively. Operation and maintenance (O&M) costs for the BSS are calculated through Equation (6) with the lifetime referring to the duration of the study period (life of the system in years). The replacement costs are calculated in Equation (7) with $\mathrm{Nrep_j}$ representing the number of the replacements needed for a component j, such as the battery and the converter, and $\mathrm{life_j}$ referring to the estimated lifetime of a component j. The last part of the equation is used to consider the revenues due to the remaining lifespan of the components.

Regarding the CBA conducted, the BSS prices used are calculated per kWh and kW, based on a high-end commercial power pack [64]. The exact capital costs have been calculated to be around GBP 371/kWh and GBP 162/kW [65,66]; slightly higher values of GBP 390/kWh and GBP 170/kW are considered to adjust for error and inflation. The costs of cabling and other hardware are included in the total battery cost and are estimated to be approximately GBP 28/kWh.

In order to calculate the net present costs (NPCs) for each scenario, an annual inflation rate of 2% and an interest rate of 5% were taken into account, for 10-year and 20-year periods (Equations (8) and (9)). The levelised costs of electricity (LCOE) were calculated by dividing each NPC by the respective amounts of energy involved, as shown in Equations (10) and (11), excluding any battery losses for charging and discharging. Finally, the financial reward needed is introduced in Equation (12) to represent the economic benefit that a building must receive per kWh shifted in order to make the two NPCs equal and consequently render the scheme cost-effective, for the entire lifetime of the project. It should be noted that Equation (2) is based on [60,61] and Equations (3)–(11) on [59,67], adjusted for the needs of the current research.

$$\mathrm{annual\_energy\_cost} = \sum_{t=1}^{8760} \left(\mathrm{RTP_{retail}} \cdot \mathrm{energy\_from\_the\_grid}\right) \tag{3}$$

$$\mathrm{annual\_revenues} = \sum_{t=1}^{8760} \left(\mathrm{RTP_{retail}} \cdot \mathrm{exported\_energy}\right) \tag{4}$$

$$\mathrm{annual\_net\_cost} = \mathrm{annual\_energy\_cost} - \mathrm{annual\_revenues} \tag{5}$$

$$\mathrm{OM\_cost} = \sum_{k=1}^{lifetime} \left[\mathrm{annual\_OM\_cost} \cdot \left(\frac{1+\ \mathrm{inflation\_rate}}{1+\ \mathrm{interest\_rate}}\right)^{k}\right] \tag{6}$$

$$\begin{aligned} \mathrm{replacement\_cost_j} = {} & \sum_{k=1}^{Nrep_j} \left[\mathrm{component\_cost_j} \cdot \left(\frac{1+\mathrm{inflation\_rate}}{1+\mathrm{interest\_rate}}\right)^{k \cdot life_j}\right] \\ & - \mathrm{component\_cost_j} \cdot \frac{\left[\frac{(\mathrm{Nrep_j}+1) \cdot \mathrm{life_j} - \mathrm{lifetime}}{\mathrm{life_j}}\right] \cdot (1+\mathrm{inflation\_rate})^{\mathrm{lifetime}}}{(1+\mathrm{interest_{rate}})^{\mathrm{lifetime}}} \end{aligned} \tag{7}$$

$$\text{NPC\_without\_storage} = \sum_{k=1}^{\text{lifetime}} \left[\text{annual\_energy\_cos t} \cdot \left(\frac{1 + \text{inflation\_rate}}{1 + \text{interest\_rate}} \right)^{k} \right] \quad (8)$$

$$\text{NPC\_with\_storage} = \text{battery\_cost} + \text{converter\_cost} + \text{replacement\_cost} + \text{OM\_cost} + \sum_{k=1}^{lifetime} \left[\text{annual\_net\_cos t} \cdot \left(\frac{1+\text{ inflation\_rate}}{1+\text{ interest\_rate}} \right)^{k} \right] \quad (9)$$

$$\text{LCOE\_without\_storage} = \frac{\text{NPC\_without\_storage}}{\sum_{t=1}^{8760} \text{energy\_demand}} \quad (10)$$

$$\text{LCOE\_with\_storage} = \frac{\text{NPC\_with\_storage}}{\sum_{t=1}^{8760} (\text{energy\_demand} + \text{exported\_energy})} \quad (11)$$

$$\text{financial\_reward} = \frac{\text{NPC\_with\_storage–NPC\_without\_storage}}{\text{lifetime} \cdot \sum_{t=1}^{8760} (\text{energy\_shifted})} \quad (12)$$

The lifetime of the battery will differ depending on the operational strategy, as shown in Table 6 along with key technical and economic parameters considered in the modelling process. For strategy E7, the estimated battery lifetime is approximately 10 years, whereas for E5 and E0 the lifetime is higher, around 20 years. Moreover, the converter lifetime is assumed to be 10 years for all strategies. The economic analysis for this study is considered over 10- and 20-year periods; therefore, while there are no replacements required for the former period, an additional battery and converter is needed under strategy E7 while E5 and E0 require only the addition of a replacement converter, for the 20-year period.

Table 6. Technical and economic parameters used for modelling purposes.

Parameter	Value	Comments
Battery cost	GBP 390/kWh	Based on [65,66]
Bidirectional converter cost	GBP 170/kW	Based on [65,66]
O&M cost	GBP 100 per annum	Based on [67,68]
Battery lifecycle	5000 cycles at DOD 90% (4500 full equivalent cycles)	Based on [63]
Estimated battery lifetime	10.5 years (E7) 19.5 years (E5, E0)	E7: 1 cycle per day for working days 2 cycles per day for NWDs. E5 and E0: 1 cycle per day for working days only.
Estimated converter lifetime	10 years (E7, E5, E0)	Based on [42]
Inflation rate	2%	Based on [42,59,67] Efficiencies are assumed to be constant
Interest rate	5%	
Charging efficiency	97%	
Discharging efficiency	97%	
Inverter efficiency	96%	
Rectifier efficiency	96%	
Roundtrip efficiency	86.7%	

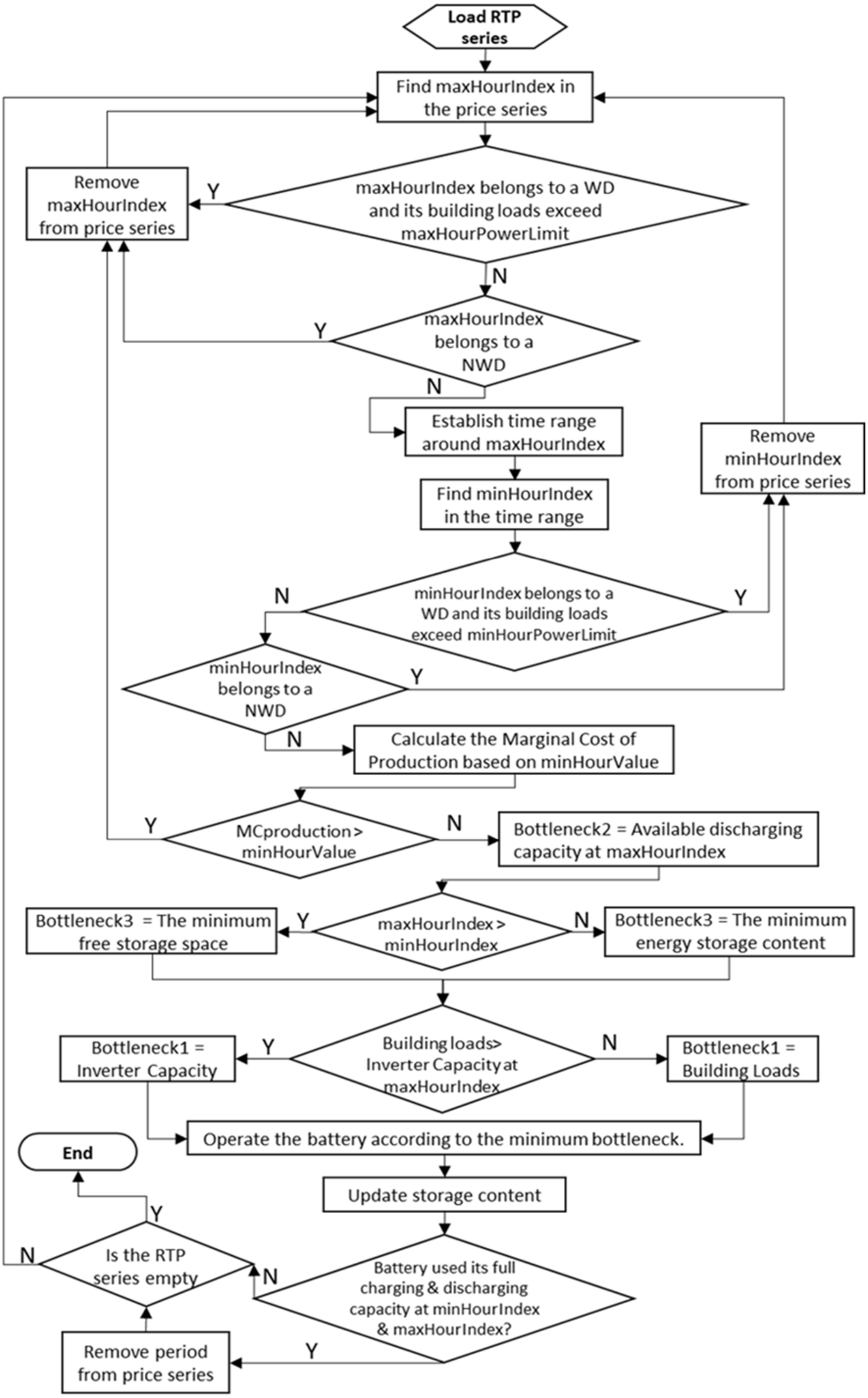

Figure 6. Flowchart for Arbitrage without exports (Strategy E0). The algorithm presents structural differences compared to Figure 5 as building loads are now taken into account in the calculation of the bottlenecks. Bottleneck1 is set equal to either the building loads or the inverter capacity in kW based on the comparison of their values.

3. Results

3.1. Breakdown Electricity Consumption

The electricity consumption results per sector for all the simulated buildings are presented in Figure 7. All buildings have demonstrated satisfactory thermal comfort for the occupants, based on the ASHRAE 55 Standard. Electricity loads for room equipment, auxiliary energy and DHW are equal for all building scenarios as they are based on the same assumptions and occupant needs. Heating loads are significantly higher for the Part L Compliant buildings compared to best practice due to the higher U-Values and infiltration. Higher levels of glazing reduced both electricity for heating and lighting, but increased cooling requirements due to higher solar gain. Higher levels of thermal mass reduced electricity required for cooling as they took advantage of passive night cooling; however, this value is small in comparison to the total building energy consumption.

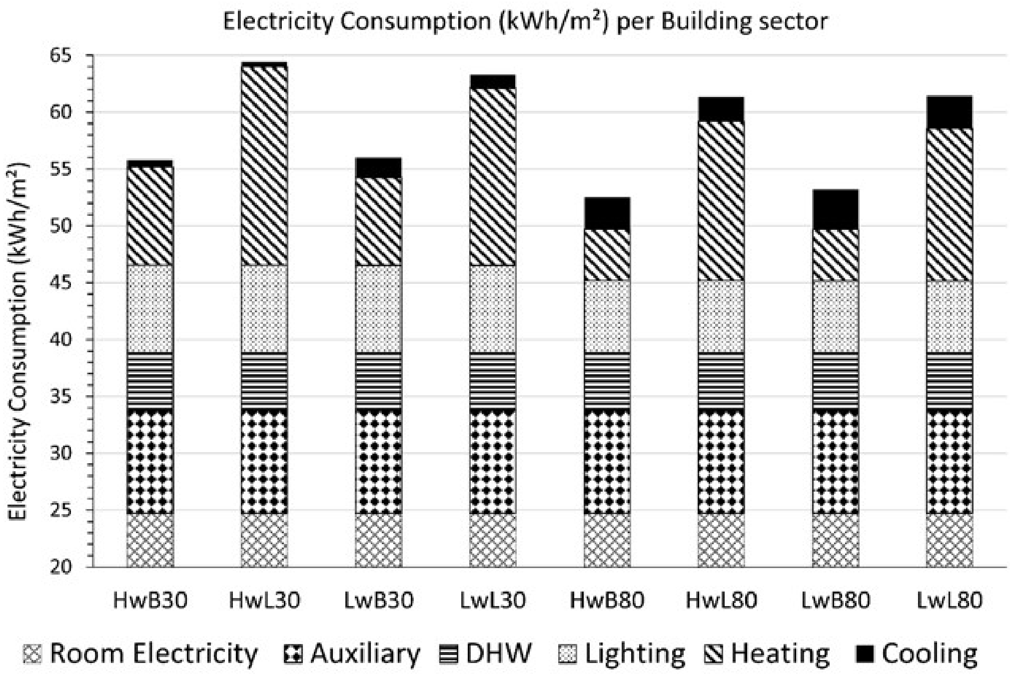

Figure 7. Annual Electricity Consumption per sector for the simulated buildings.

In conclusion, Buildings HwL30 and HwB80 have the highest and lowest electricity consumption values, respectively, and at the same time they provide very good thermal comfort for their occupants. Therefore, as the two extreme cases, they are selected to be further analysed and compared, using several BSS and operational strategies E7, E5 and E0.

3.2. Battery Storage

The sizing of BSS is based on the "three hours to charge" and "two hours to discharge" rules. However, for the biggest systems, the first results indicated that the inverters rated power were oversized when compared with the average or even the maximum hourly building loads. Therefore, instead of using the stored electricity towards shifting building loads, all the excess electricity would be exported back to the grid (for the E7 and E5 scenarios). More specifically, when batteries larger than 160 kWh are used, the differences in the shifted peak loads would be insignificant. Consequently, the BSS components were revised and presented in Table 7.

Table 7. BSS Components Sizing.

Battery Size (kWh)	Initial Rectifier and Inverter Rated Power (kW/−kW)	Final Rectifier and Inverter Rated Power (kW/−kW)
40	15/−20	15/−20
60	20/−30	20/−30
80	25/−35	25/−35
100	35/−45	35/−45
120	40/−55	40/−55
140	45/−65	45/−65
160 *	55/−75	45/−65
180 *	60/−80	45/−65
200 *	65/−90	45/−65
220 *	70/−100	45/−65

* Revision needed for the respective inverter and rectifier sizes.

3.2.1. Exports Allowed with Retail Revenues (E7)

The results from the Battery Storage model are presented in Table 8, for the Operational Strategy E7, which allows exports to take place every day. The peak loads shifted refer to the loads directly met by the battery instead of buying electricity from the grid, between the building's opening hours (8 a.m.–6 p.m.) while the electricity net cost includes the revenues from selling back to the grid. The operation of the BSS and its impact on the building's electricity profile can be seen in Figure 8, for a Sunday and two working days.

Table 8. Annual BSS Results for Operational Strategy E7.

BSS Specs	Electricity Consumption (kWh/m^2)		Electricity Net Cost (GBP/m^2)		Electricity Shifted (% of Peak Loads)		Exports (kWh/m^2)	
	HwL30	HwB80	HwL30	HwB80	HwL30	HwB80	HwL30	HwB80
No BSS	64.45	52.57	8.68	7.01	N/A	N/A	N/A	N/A
40 kWh	67.65	55.77	8.30	6.63	7.68	9.34	2.23	2.23
60 kWh	69.52	57.64	8.12	6.44	10.86	13.22	3.62	3.63
80 kWh	71.27	59.46	7.95	6.28	14.11	17.00	4.91	4.99
100 kWh	73.94	62.47	7.75	6.08	16.16	18.74	7.08	7.50
120 kWh	76.55	65.39	7.57	5.90	17.97	20.24	9.21	9.93
140 kWh	79.35	68.53	7.38	5.71	19.40	21.22	11.54	12.60
160 kWh	80.75	70.02	7.29	5.62	22.54	24.81	12.53	13.68
180 kWh	82.11	71.38	7.21	5.54	25.67	28.59	13.48	14.64
200 kWh	83.83	73.34	7.13	5.47	27.82	30.59	14.82	16.23
220 kWh	85.71	75.56	7.06	5.40	29.46	31.76	16.34	18.08

It is clear that the utilisation of battery storage which is adaptable to dynamic electricity prices leads to different results every day of the year. These results are always a function of the daily variation in both the electricity prices (GBP/kWh) and the building loads (kW). Potential applications of BSS include load-shifting and peak-shaving which can take place either in terms of reducing the highest load of the day or by reducing the number of hours during peak loads. Additionally, it can also be seen that during non-working days, the battery has the capacity to cycle more than once in order to export back to the grid as much as possible, during the most expensive prices, and take advantage of the price difference.

Regarding the comparison of the two buildings investigated, it is clear that Building HwB80 can shift more loads when using the same BSS. The difference is also dependent on the BSS size and specifications, varying between 1.66% and 2.92%. For the smallest BSS sizes (40–80 kWh), both buildings are able to shift their peak loads by a considerable percentage that varies between 7.68 and 17%. Concerning the electricity exports, the comparison between the two buildings is negligible for the smaller battery sizes as the entire stored electricity is used to meet building loads and there is no excess energy left to be sent back to the grid. However, as the BSS size increases and excess electricity is generated, it is evident that Building HwB80 is able to export higher amounts of electricity. For the BSS of 220 kWh, Building HwB80 exports 18.08 kWh/m^2, which is 1.74 kWh/m^2 more than Building HwL30.

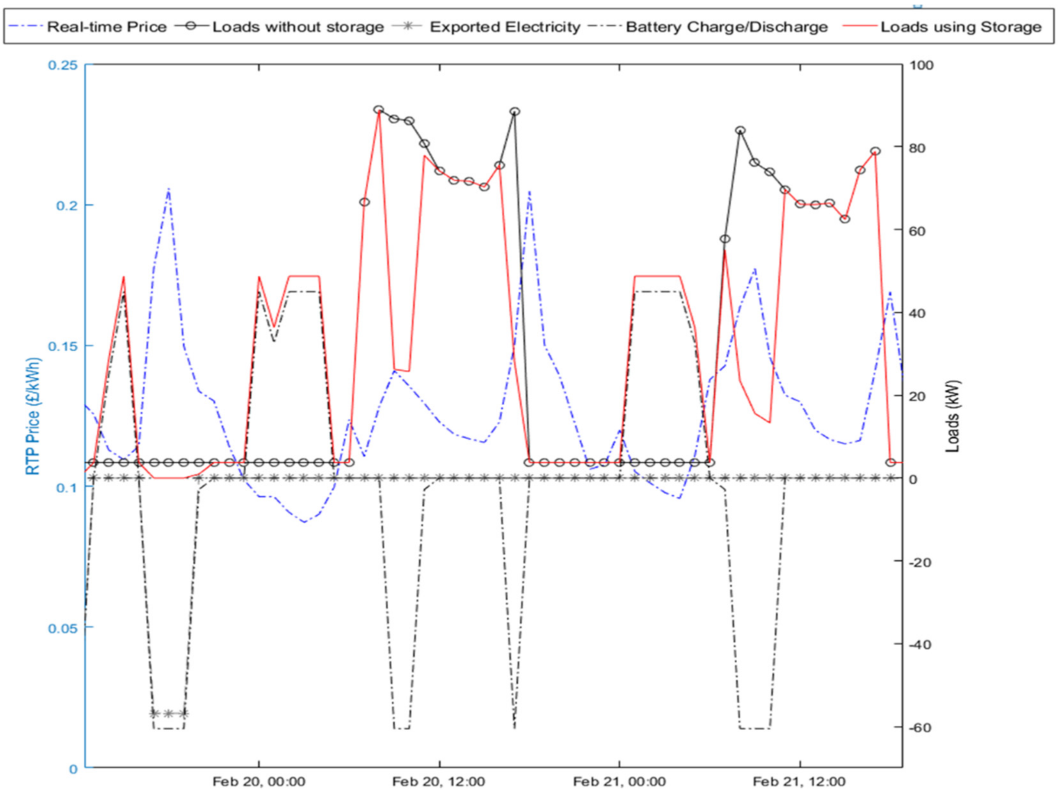

Figure 8. Arbitrage E7 Results for Building HwL30 using Battery Storage (220 kWh, 45/−65 kW).

Finally, regarding the electricity economics and the annual net costs (GBP/m^2), as Building HwL30 is less energy-efficient, it consumes more electricity to meet its loads and therefore its total electricity purchases from the grid increase even more when utilising battery storage. For all scenarios and BSS sizes, Building HwB80 costs 1.67 GBP/m^2 less, which translates into GBP 4175 of annual savings. Additionally, as the BSS size increases, the excess electricity also grows, resulting in higher electricity exports, increasing amount of revenues and a consequent lower net cost. The differences between the no storage scenario and the biggest BSS size are shown to identify the maximum benefits introduced by the battery. The net cost of electricity can be reduced from 8.68 to 7.06 and from 7.01 to 5.40 GBP/m^2 for Buildings HwL30 and HwB80, respectively.

3.2.2. Exports Allowed on Working Days with Retail Revenues (E5)

The impact of the BSS regarding the Operational Strategy E5 which allows exports to take place on working days can be seen in Figure 9, for a Sunday and two working days. The BSS results are identical to E7 when it comes to working days and the shifting of peak loads; however, the battery does not run on weekends.

Building HwB80 can shift a higher percentage of its peak loads, in comparison with Building HwL30. Once using the same BSS, Building HwB80 shifts 2% more than HwL30 on average, which is not significant. It should be pointed out that all peak load shifts have been decreased when compared with Table 8 and Operational Strategy E7. The battery operation for both E7 and E5 strategies is the same for working days; however, E7 allows load-shifting during weekends as well. While the buildings' activity is minimal at weekends, there is a small constant electricity load (~4 kW), representing the auxiliary (parasitic) energy consumption. Therefore, E7 leads to higher load-shifting around 2% more when compared to the E5 respective results.

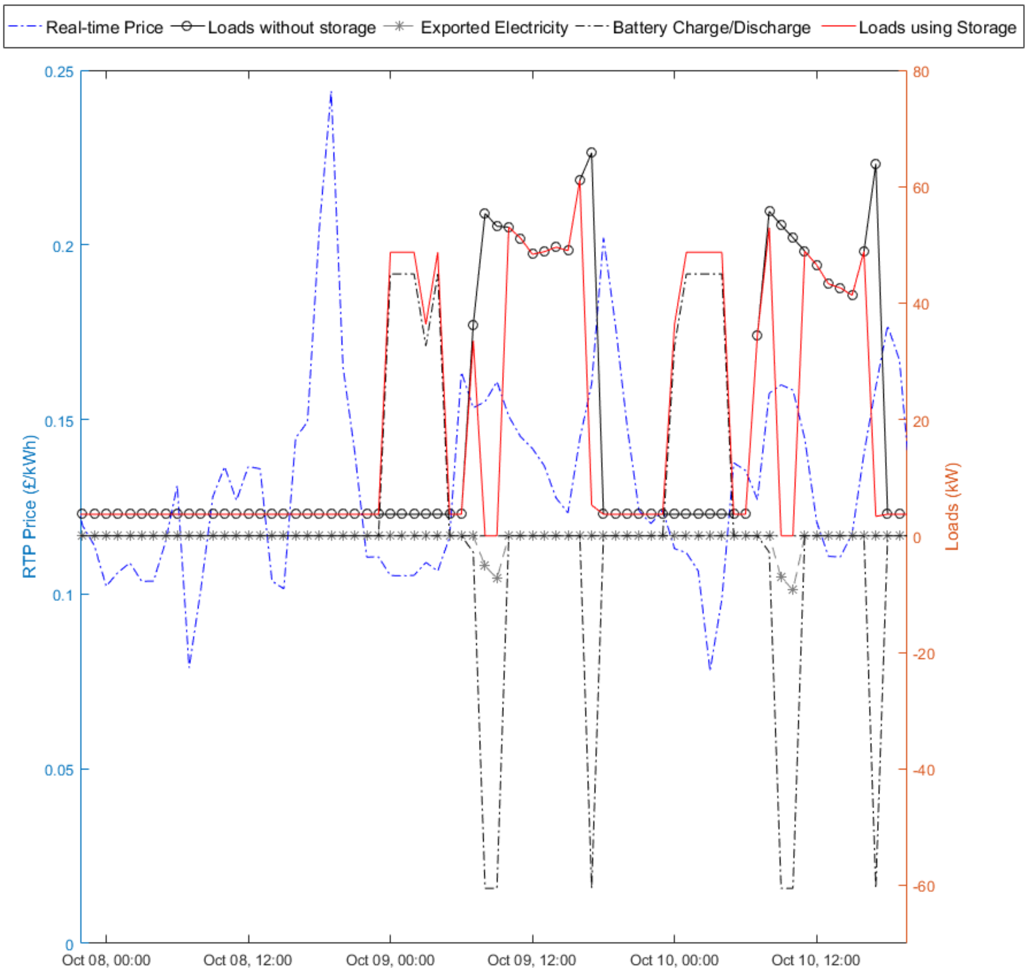

Figure 9. Arbitrage E5 Results for Building HwL30 using Battery Storage (220 kWh, 45/−65 kW).

Revenue-wise, the most important parameter when comparing E5 and E7 is the electricity exported back to the grid. Under E5, the battery is idle on non-working days and exports can only take place in cases of excess electricity, on weekdays. For the different battery sizes, export ranges of 0–3.79 and 0–5.53 kWh/m^2 can be achieved for Buildings HwL30 and HwB80, respectively. For comparison purposes, the respective export ranges under the E7 strategy were 2.23–16.34 and 2.23–18.08 kWh/m^2. In addition, as the E5 export values are smaller, they also lead to consequent lower revenue streams and therefore higher net costs. Under E5, the electricity net costs are in the range 7.74–8.46 for HwL30 and 6.07–6.79 kWh/m^2 for HwB80. The respective values for the E7 strategy were previously shown to be 7.06–8.30 and 5.40–6.63 kWh/m^2.

3.2.3. No Exports (E0)

The absence of exports and the excess stored electricity under E0 have led to higher amounts of energy being available and used towards meeting the local building loads. Consequently, from an electricity footprint perspective, buildings implementing E0 have been able to change their daily profile significantly (Figure 10). For the first time, the peak loads-shifting has now established a linear relationship with the battery capacity of the system; this was not the case for E7 and E5 strategies.

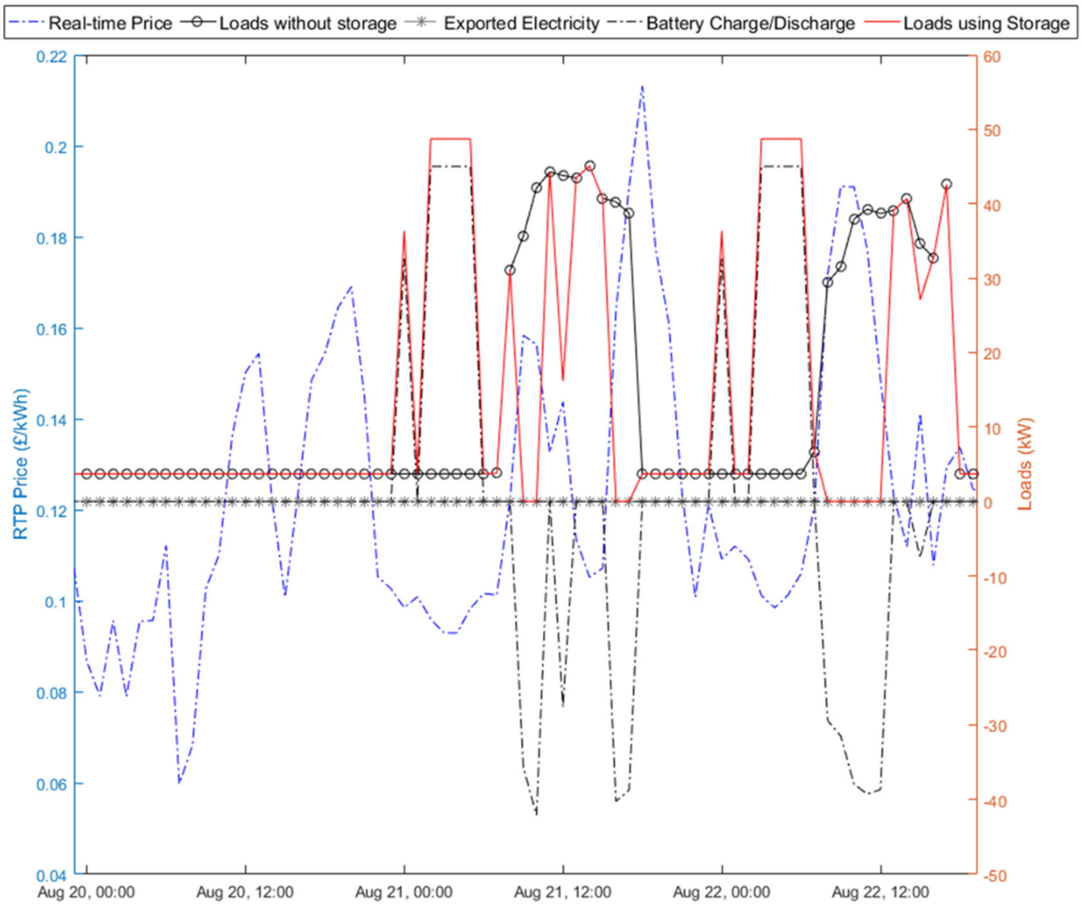

Figure 10. Arbitrage E0 Results for Building HwL30 using Battery Storage (220 kWh, 45/−65 kW).

Quantitively, the potential for load-shifting has been significantly increased when compared with the E7 and E5 strategies, as the battery operation now focuses exclusively on this objective. More specifically, the peak load-shifting percentage ranges are now 6.38–33.95% and 7.79–39.68% for Buildings HwL30 and HwB80, respectively. The peak load-shifting of the two buildings for the larger 220 kWh battery, under the E7 strategy, was respectively 4.5 and 8% lower than with No Exports.

Finally, the total absence of exports and the relevant revenue streams also result in higher annual net costs, when compared with E7; however, net cost differences between E5 and E0 are insignificant, reflecting the low amount of E5 exports. In terms of cost-effectiveness, Building HwB80 still appears to be more attractive, as for every BSS size, it is always GBP 1.6/m^2 cheaper than HwL30.

3.3. Cost–Benefit Analysis

A CBA for a 10- and 20-year period was conducted for the two final buildings in order to evaluate the long-term economics, taking into account parameters that have the potential to affect the cost-effectiveness of the suggested SGOB scheme, including the inflation and interest rates that are assumed to be constant. Two batteries (120 and 240 kWh) were used along with a common inverter size (60 kW). The rectifier capacity was chosen in order to be able to fully charge the battery within 3 h (40 and 80 kW). The CBA focusses on the BSS and does not consider costs for the building construction, as they are deemed to be outside the scope of this article and the suggested scheme can also be applied to existing buildings.

3.3.1. CBA for a 10-Year Period

The NPCs for all operational strategies can be seen per building, in Figure 11. The difference between the no storage case and the rest of the scenarios is due to the introduced

BSS capital cost which is dependent on the battery and converter sizes. When not using storage, Building HwL30 has an NPC over 10 years of GBP 185,661 which is approximately GBP 35,000 more expensive than Building HwB80. This GBP 35,000 NPC difference between the two buildings appears to be consistent throughout all operational strategies and BSS sizes, indicating that HwB80 is more economical for all the scenarios presented. This is in accordance with the results presented in Section 3.1, where the buildings' total electricity consumption was 64.45 kWh/m^2 for HwL30 and 52.57 kWh/m^2 for HwB80.

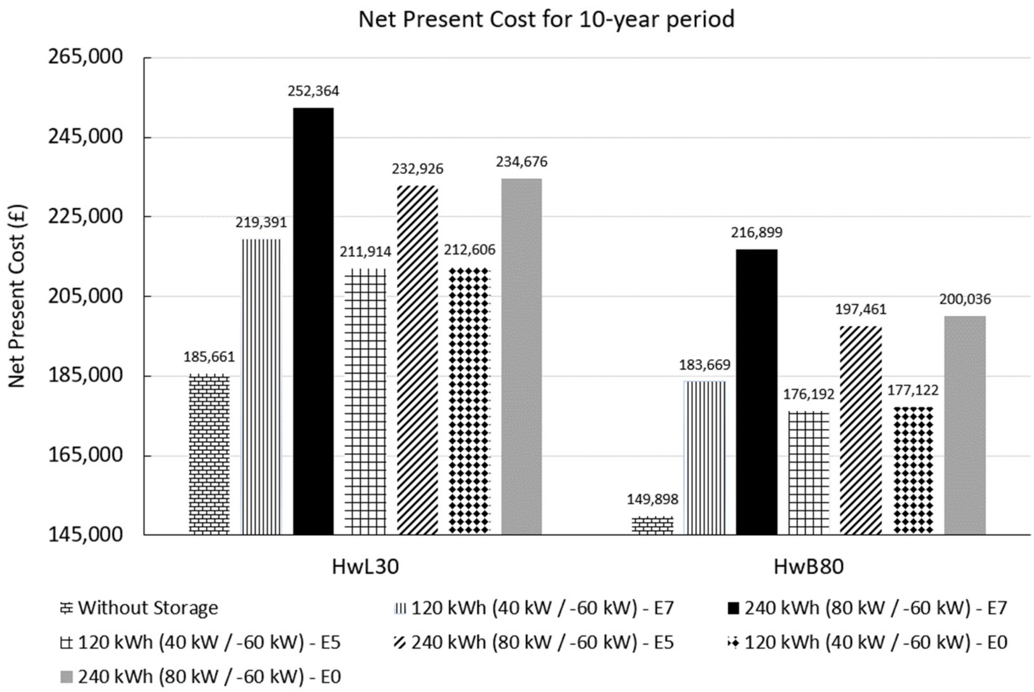

Figure 11. Net Present Cost for 10-year period (all operational strategies).

From the three suggested operational strategies, E7 appears to incur the highest NPCs, despite the additional revenue stream of exports that is introduced during weekends. It should be highlighted that at the end of the 10-year period, E7 is the only operational strategy under which the lifetime of the battery reaches its end. In contrast, under E5 and E0, the battery has a remaining lifespan of 10 additional years and therefore has 50% of its lifetime intact, as previously shown in Table 6, leading to the reduction in the battery's NPCs. Furthermore, the second highest NPC values are observed under E0 where no exports take place, followed by E5 that allows exports only on working days. For both buildings, the results for E5 and E0 strategies appear to be very similar for both scenarios, forming a separate group from E7 and demonstrating that the impact of the minimal number of exports under E5 is insignificant, resulting in a marginal difference between E0 and E5 of just GBP 1000–3000, depending on the battery size.

Under E7, the NPC is around GBP 8000 or GBP 20,000 higher than the respective values under E5 for the 120 kWh and 240 kWh battery, respectively. It is important to point out that while the primary objective of the three operational strategies is to shift electricity demand from peak to off-peak periods of the day and occasionally perform peak-shaving, exports are of vital economic importance for the viability and the cost-effectiveness of the SGOB scheme. Reviewing the results per building and beginning with HwB80, E7 adds a GBP 34,000 cost when using the 120 kWh battery, compared to the no storage case, while the 240 kWh battery brings the total extra cost to GBP 67,000. The exact same trends are observed for HwL30.

It is vital to highlight that under the E7 and E5 scenarios, it is assumed that building-exported energy is rewarded with the retail electricity price. As explained, there is no current mechanism or financial motive for buildings to provide such a service to the electrical grid. This is also one of the reasons that made the distinction between E7 and E5 necessary.

In this direction, a financial reward is necessary in order to encourage commercial buildings to participate in this suggested enterprise and become SGOBs. This reward may at least cover the difference between the (business as usual) NPC without storage and the NPC when using a BSS. Essentially, this will create an additional revenue stream that will render the two NPCs equal. Concerning the structure of this SGOB reward, the authors of this paper support that it should be based on the amount of electricity shifted and/or exported by the BSS. For the needs of the current article, emphasis will be given only on the electricity shifted as this is present in all three operational strategies.

If financial motives are to be calculated based on the amount of electricity shifted during the building's working hours, as presented in Chapter 2.4, the reward range is GBP 0.0966–0.1432 for HwL30 and GBP 0.1031–0.1575 for HwB80, as shown in Figure 12. Shifting electricity is of benefit to the grid; however, for an individual building more energy shifted is usually due to the building having a higher energy consumption due to poor energy efficiency. It is therefore necessary that any incentive does not incentivise lower energy efficiency in the building stock. In this case, this is tackled by using energy shifted in the denominator of the calculation for incentives. This can also be achieved with incentives only applied to buildings when they reach a certain level of energy efficiency.

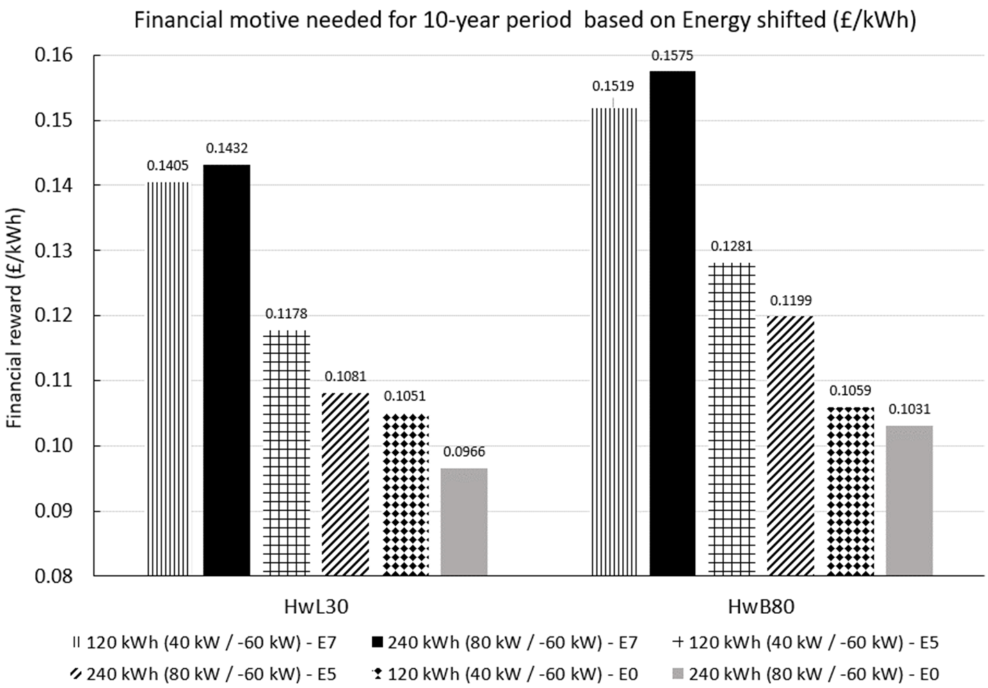

Figure 12. Required financial motive for a 10-year period (all operational strategies).

Operational strategy E7 requires the highest financial rewards, followed by E5 and E0. In descending order, the financial motive establishes a range between GBP 0.1405–0.1575 for E7, GBP 0.1081–0.1281 for E5 and finally GBP 0.0966–0.1059 for E0. The highest numbers observed under E7 can be explained due to the reduced lifetime of the battery, which leads to comparatively higher NPCs and therefore to a greater NPC difference which needs to be covered by the financial motive (Equation (12)). The reward needed under E0 appears to be slightly lower than the respective values under E5 due to the entirety of the E0 battery operation being dedicated to load shifting while there is a combination of load shifting and minor electricity exports, under E5.

Finally, the levelised cost of electricity (LCOE) is presented below, in Table 9. The cost is almost the same for buildings without storage, around GBP 0.1146/kWh. For the smaller BSS size (120 kWh), it can be seen for both buildings that, under operational strategy E7, the cost of purchasing electricity is similar to the no storage scenario, while the value increases to approximately GBP 0.1289 for E5 and reaches its maximum price for E0, with a mean value of GBP 0.1334. When utilising the bigger BSS (240 kWh), the LCOE has a mean value of GBP 0.1225 under E7, marginally higher than the respective value of the smaller battery. The electricity costs for E5 and E0 strategies are higher, with respective mean values of GBP 0.1382 and GBP 0.1489.

Table 9. Levelised Cost of Electricity (LCOE) for 10-year period.

Building	Operational Strategy	Levelised Cost of Electricity (GBP/kWh) with Storage		Levelised Cost of Electricity (GBP/kWh) without Storage
		120 kWh (40 kW/−60 kW)	240 kWh (80 kW/−60 kW)	No BSS
HwL30	E7	0.1190	0.1235	0.1152
	E5	0.1288	0.1381	
	E0	0.1320	0.1456	
HwB80	E7	0.1174	0.1215	0.1141
	E5	0.1290	0.1382	
	E0	0.1348	0.1522	

In conclusion, despite some minor differences, the LCOE results are similar for both buildings. The parameters that affect the electricity costs are the operational strategy and the size of the BSS while the LCOE under E7 appears to be similar to the no storage scenario value. It should be reminded that this is also related to the LCOE calculation methodology followed as the NPCs are divided by sum of the electricity demand and any present exports. It can be argued that the inclusion of exports can potentially lead to an underestimation of the LCOE, for the E7 and E5 strategies. However, the additional electricity is purchased from the grid to only be later exported back, resulting in a subsequent profit and at the same time providing an important service to the electrical grid.

3.3.2. CBA for a 20-Year Period

The 20-year CBA results are shown, in detail, in Table 10, along with the number of replacements needed, for the bidirectional converter and the battery. It should be noted that, as a result of increasing the study period from 10 to 20 years, all the NPC values, including the no-storage scenario, have increased due to the higher amounts of electricity purchased by the grid to cover the local building loads. More specifically, when not using storage, Building HwL30 has an NPC over 20 years of GBP 324,602, which is around GBP 62,000 more expensive than Building HwB80. Similarly to the 10-year period results, this GBP 62,000 NPC difference between the two buildings is present throughout all strategies and BSS sizes, confirming that HwB80 is indeed more economical. Furthermore, the additional costs introduced by the capital expenditure of the replacements has led to an increase of the NPCs for all storage scenarios. At the same time, as all the BSS components do not have any remaining lifespan at the end of the study period, there are no deductions from their respective NPC values. Nevertheless, the 20-year results and their trends are consistent with the 10-year period results, as presented in Section 3.3.1.

At this point, it is important to present a brief comparison between the 10- and 20-year results in order to evaluate how the NPC values affect the financial motives needed to render the SGOB scheme cost-effective (Figure 13). For both buildings and study periods, it can be seen that, with the exception of some minor variations, the financial motive values are largely the same for both BSS sizes used; this is expected due to their normalisation (GBP/kWh shifted). In terms of the financial motive values per operational strategy, the same trends are observed, as in Section 3.3.1, with E7 requiring the highest financial reward, followed by E5 and finally E0. In addition, it is clear that for the 20-year period, the financial motive needed is reduced by GBP 0.02/kWh, for both buildings and all operational strategies, when compared to the respective values of the 10-year period.

Consequently, the BSS operation is not just able to compensate the additional capital costs needed for the replacement components of the 20-year period, but it also results in a reduction in the financial reward needed when increasing the study period from 10 to 20 years. In more detail, for the smaller 120 kWh BSS and both buildings, the reduction reaches 13% for E7 and 21% for E5 and E0, while the respective values for the 240 kWh BSS (13%, 22%, 21%) remain largely consistent.

Table 10. LCOE, NPC and financial motive needed for 20-year period.

Operational Strategy	Replacements Needed	Parameter *	Building and BSS Combination			
			HwL30		HwB80	
			BSS 120 kWh	BSS 240 kWh	BSS 120 kWh	BSS 240 kWh
E7	1 converter 1 battery	NPC	383,573	441,222	321,118	379,217
		LCOE	0.1040	0.1080	0.1026	0.1062
		Fin. motive	0.1228	0.1251	0.1328	0.1377
E5	1 converter	NPC	366,094	398,424	303,639	336,419
		LCOE	0.1112	0.1181	0.1111	0.1177
		Fin. motive	0.0931	0.0844	0.1013	0.0937
E0	1 converter	NPC	367,304	401,484	305,265	340,920
		LCOE	0.1140	0.1246	0.1161	0.1297
		Fin. motive	0.0832	0.0758	0.0840	0.0811
No storage	N/A	NPC	324,602		262,076	
		LCOE	0.1007		0.0997	

* Parameter (value): NPC (GBP), LCOE (GBP/kWh), Financial motive (GBP/kWh).

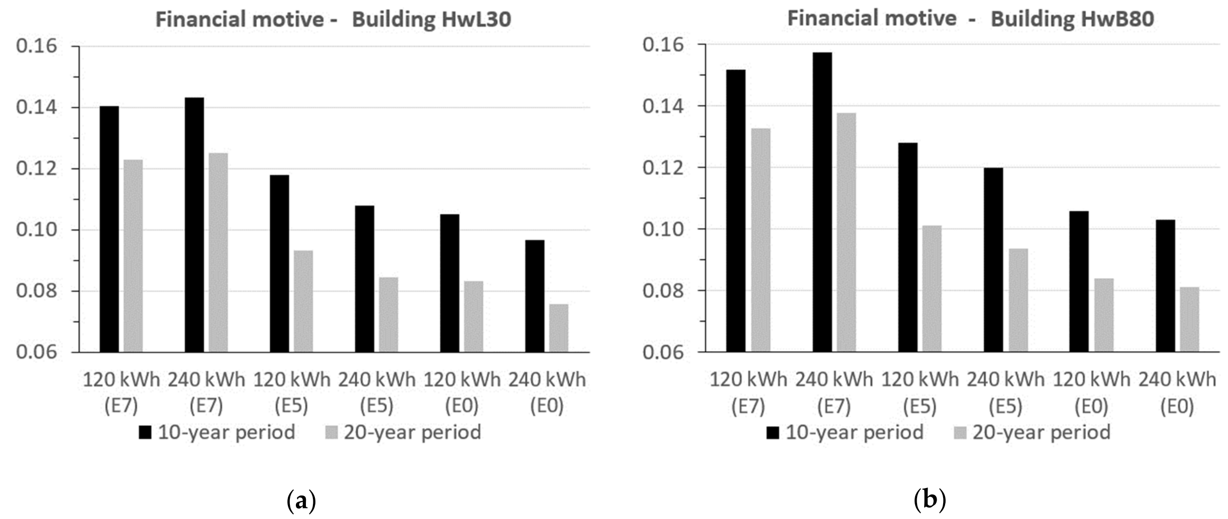

Figure 13. Financial reward needed for a 10-year and 20-year period, based on the electricity shifted (GBP/kWh), for buildings (**a**) HwL30 and (**b**) HwB80.

4. Conclusions

From a total of eight simulated buildings with different design characteristics, the two extreme cases, energy-wise, were selected for further investigation in order to assess their capability to utilise BSS to perform arbitrage under real-time electricity prices. When assuming the biggest battery size of 220 kWh, the most energy-efficient building (HwB80), in terms of the envelope U-values, has proven to be capable of shifting a higher percentage of its peak loads (31.76% for E7, 29.51% for E5 and 39.68% for E0) and at the same time export more electricity (18.08 kWh/m^2 for E7 and 5.53 kWh/m^2 for E5) when this is available as an option. In addition, HwB80 has been proven to have the lowest annual net costs (5.40 GBP/m^2 for E7, 6.07 GBP/m^2 for E5 and 6.20 GBP/m^2 for E0) which are significantly lower when compared with the no-storage scenario cost of 7.01 GBP/m^2, for the same building. It is clear that the building design affects the energy as well as the arbitrage performance.

Regarding the long-term economics and the CBA conducted for a 10-year period, Building HwB80 proved to be the most economical, incurring GBP 35,000 less costs under all scenarios, including no storage. The lowest NPCs were observed under the E5 strategy due to the remaining lifetime of the battery (50%) at the end of the 10-year period, and the small amount of revenues. The E0 results are very similar to E5′s, indicating that the E5 operational strategy leads to an insignificant revenue stream from exports. Finally, strategy E7 has the highest NPC values for all scenarios as the export revenues are not sufficient to compensate for the fact that the remaining battery lifespan is non-existent, leading to zero NPC deductions at the end of the study period. When a 20-year period is considered, HwB80 is still the most economical building, incurring GBP 62,000 less in costs under all scenarios, including no storage. Increasing the study period from 10 to 20 years leads to a reduction in the financial motive by GBP 0.02 per kWh shifted, despite the introduction of the additional capital costs needed for the system replacements.

The results regarding the financial rewards needed to make the building-arbitrage scheme cost-effective were remarkably interesting, as the energy-efficient building (HwB80) proved to require a higher amount of extra revenues (GBP/kWh shifted). The problematic nature of the financial reward definition was explained; therefore, the authors of this article believe that the monetisation of building-provided services to the grid by BSS utilisation should be based on the percentage of the building loads shifted (%) rather than the total amount of electricity shifted. The latter constitutes a much fairer criterion that is able to reflect the energy efficiency of the buildings and indirectly their design and HVAC configuration.

Regarding limitations of this study, it should be noted that the majority of the end-users do not have access to real-time electricity prices and there is no current mechanism enabling battery arbitrage at the building scale. However, this paper makes the case for methods to enable this to happen towards wider building-level storage utilisation.

It is clear that the formation of a proper regulatory framework is of fundamental importance in order to establish motives for buildings to undertake an active role in the future smart grid by utilising battery storage and evolving gradually into SGOBs. This will be possible only if all the associated market players and stakeholders recognise the peak demand reduction potential and the capabilities presented under different DR strategies for various building types, in different climates and occupancy profiles. They have to come together to discuss and create such a framework, including the electricity utilities, the government, the public and building owners.

The current article made the first vital step by examining how building design and BSS characteristics affect the performance of commercial buildings conducting arbitrage by introducing three operational strategies and examining the techno-economic implications in the long term. Further work should be carried out towards defining and examining potential financial motives and subsidy mechanisms, not only for arbitrage but for other balancing services as well. These motives could be structured similarly to the services procured by the National Grid, mentioned previously, and could include availability fee (GBP/hour), utilisation (GBP/MWh) and nomination fee (GBP/hour).

Regarding future work, it is important to examine additional building design and HVAC configurations, especially naturally ventilated buildings which could demonstrate a different behaviour in terms of their daily electricity profile, especially in the summer period. Further development to incorporate building scale renewables should also follow.

Author Contributions: Conceptualization, A.D.G., B.V., E.A.H. and M.M.; formal analysis, A.D.G., B.V., E.A.H. and M.M.; investigation, A.D.G., B.V., E.A.H. and M.M.; methodology, A.D.G., B.V., E.A.H. and M.M.; software, A.D.G.; supervision, B.V., E.A.H. and M.M.; Writing—original draft, A.D.G.; Writing—review and editing, A.D.G. All authors have read and agreed to the published version of the manuscript.

Funding: The authors gratefully acknowledge support from the EPSRC via grant EP/L016818/1 which funds the Centre for Doctoral Training in Energy Storage and its Applications.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: The data presented in this study are available on request from the corresponding author.

Conflicts of Interest: The authors declare no conflict of interest.

References

1. D'Agostino, D.; Cuniberti, B.; Bertoldi, P. Energy consumption and efficiency technology measures in European non-residential buildings. *Energy Build.* **2017**, *153*, 72–86. [CrossRef]
2. Warwicker, B.; Cash, D. The building services relationship to the national grid. In Proceedings of the CIBSE ASHRAE Technical Symposium, London, UK, 18–19 April 2012.
3. Anderson, B.; Torriti, J. Explaining shifts in UK electricity demand using time use data from 1974 to 2014. *Energy Policy* **2018**, *123*, 544–557. [CrossRef]
4. Das, P.; Mathur, J.; Bhakar, R.; Kanudia, A. Implications of short-term renewable energy resource intermittency in long-term power system planning. *Energy Strat. Rev.* **2018**, *22*, 1–15. [CrossRef]
5. Sehar, F.; Pipattanasomporn, M.; Rahman, S. An energy management model to study energy and peak power savings from PV and storage in demand responsive buildings. *Appl. Energy* **2016**, *173*, 406–417. [CrossRef]
6. Palensky, P.; Dietrich, D. Demand side management: Demand response, intelligent energy systems, and smart loads. *IEEE Trans. Ind. Inform.* **2011**, *7*, 381–388. [CrossRef]
7. Brandt, T.; Feuerriegel, S.; Neumann, D. Modeling interferences in information systems design for cyberphysical systems: Insights from a smart grid application. *Eur. J. Inf. Syst.* **2018**, *27*, 207–220. [CrossRef]
8. Valogianni, K.; Ketter, W. Effective demand response for smart grids: Evidence from a real-world pilot. *Decis. Support Syst.* **2016**, *91*, 48–66. [CrossRef]
9. Alimohammadisagvand, B. Influence of Demand Response Actions on Thermal Comfort and Electricity Cost for Residential House. Ph.D. Thesis, Aalto University, Espoo, Finland, 2018.
10. Alimohammadisagvand, B.; Jokisalo, J.; Siren, K. The potential of predictive control in minimizing the electricity cost in a heat-pump heat residential house. In Proceedings of the 3rd IBPSA-England Conference BSO 2016, Great North Museum, Newcastle, UK, 12–14 September 2016.
11. Hemmati, M.; Mirzaei, M.A.; Abapour, M.; Zare, K.; Mohammadi-Ivatloo, B.; Mehrjerdi, H.; Marzband, M. Economic-environmental analysis of combined heat and power-based reconfigurable microgrid integrated with multiple energy storage and demand response program. *Sustain. Cities Soc.* **2021**, *69*, 102790. [CrossRef]
12. Korkas, C.D.; Baldi, S.; Michailidis, I.; Kosmatopoulos, E.B. Occupancy-based demand response and thermal comfort optimization in microgrids with renewable energy sources and energy storage. *Appl. Energy* **2016**, *163*, 93–104. [CrossRef]
13. Gholinejad, H.R.; Loni, A.; Adabi, J.; Marzband, M. A hierarchical energy management system for multiple home energy hubs in neighborhood grids. *J. Build. Eng.* **2020**, *28*, 101028. [CrossRef]
14. Kiliccote, S.; Piette, M.A.; Ghatikar, G.; Hafemeister, D.; Kammen, D.; Levi, B.G.; Schwartz, P. Smart buildings and demand response. *AIP Conf. Proc.* **2011**, *1401*, 328–338. [CrossRef]
15. Derakhshan, G.; Shayanfar, H.A.; Kazemi, A. The optimization of demand response programs in smart grids. *Energy Policy* **2016**, *94*, 295–306. [CrossRef]
16. Lee, Y.M.; Horesh, R.; Liberti, L. Optimal HVAC control as demand response with on-site energy storage and generation system. *Energy Procedia* **2015**, *78*, 2106–2111. [CrossRef]
17. Lorenzi, G.; Silva, C.A.S. Comparing demand response and battery storage to optimize self-consumption in PV systems. *Appl. Energy* **2016**, *180*, 524–535. [CrossRef]
18. Lawrence Berkeley National Laboratory. Introduction to Commercial Building Control Strategies and Techniques for Demand Response. 2007. Available online: https://buildings.lbl.gov/publications/introduction-commercial-building (accessed on 18 March 2021).
19. Winfield, M.; Shokrzadeh, S.; Jones, A. Energy policy regime change and advanced energy storage: A comparative analysis. *Energy Policy* **2018**, *115*, 572–583. [CrossRef]
20. National Grid ESO. Balancing Services. 2021. Available online: https://www.nationalgrideso.com/balancing-services/list-all-balancing-services (accessed on 10 March 2021).
21. Heris, M.-N.; Mirzaei, M.A.; Asadi, S.; Mohammadi-Ivatloo, B.; Zare, K.; Jebelli, H.; Marzband, M. Evaluation of hydrogen storage technology in risk-constrained stochastic scheduling of multi-carrier energy systems considering power, gas and heating network constraints. *Int. J. Hydrogen Energy* **2020**, *45*, 30129–30141. [CrossRef]
22. Nazari-Heris, M.; Mohammadi-Ivatloo, B.; Asadi, S. Optimal operation of multi-carrier energy networks with gas, power, heating, and water energy sources considering different energy storage technologies. *J. Energy Storage* **2020**, *31*, 101574. [CrossRef]

23. Mirzaei, M.A.; Nazari-Heris, M.; Zare, K.; Mohammadi-Ivatloo, B.; Marzband, M.; Asadi, S.; Anvari-Moghaddam, A. Evaluating the impact of multi-carrier energy storage systems in optimal operation of integrated electricity, gas and district heating networks. *Appl. Therm. Eng.* **2020**, *176*, 115413. [CrossRef]
24. Bulut, M.B.; Odlare, M.; Stigson, P.; Wallin, F.; Vassileva, I. Buildings in the future energy system—Perspectives of the Swedish energy and buildings sectors on current energy challenges. *Energy Build.* **2015**, *107*, 254–263. [CrossRef]
25. Bulut, M.B.; Wallin, F. Buildings as components of smart grids—Perspectives of different stakeholders. *Energy Procedia* **2014**, *61*, 1630–1633. [CrossRef]
26. Agarwal, Y.; Weng, T.; Gupta, R.K. Understanding the role of buildings in a smart microgrid. In Proceedings of the 2011 Design, Automation & Test in Europe, Grenoble, France, 14–18 March 2011.
27. Niu, J.; Tian, Z.; Lu, Y.; Zhao, H. Flexible dispatch of a building energy system using building thermal storage and battery energy storage. *Appl. Energy* **2019**, *243*, 274–287. [CrossRef]
28. Georgakarakos, A.D.; Mayfield, M.; Hathway, E.A. Battery storage systems in smart grid optimised buildings. *Energy Procedia* **2018**, *151*, 23–30. [CrossRef]
29. Gissey, G.C.; Dodds, P.; Radcliffe, J. Market and regulatory barriers to electrical energy storage innovation. *Renew. Sustain. Energy Rev.* **2018**, *82*, 781–790. [CrossRef]
30. Forrester, S.P.; Zaman, A.; Mathieu, J.; Johnson, J. Policy and market barriers to energy storage providing multiple services. *Electr. J.* **2017**, *30*, 50–56. [CrossRef]
31. Zame, K.K.; Brehm, C.A.; Nitica, A.T.; Richard, C.L.; Schweitzer III, G.D. Smart grid and energy storage: Policy recommendations. *Renew. Sustain. Energy Rev.* **2018**, *82*, 1646–1654. [CrossRef]
32. Leadbetter, J.; Swan, L. Battery storage system for residential electricity peak demand shaving. *Energy Build.* **2012**, *55*, 685–692. [CrossRef]
33. Graditi, G.; Ippolito, M.; Telaretti, E.; Zizzo, G. Technical and economical assessment of distributed electrochemical storages for load shifting applications: An Italian case study. *Renew. Sustain. Energy Rev.* **2016**, *57*, 515–523. [CrossRef]
34. Palizban, O.; Kauhaniemi, K. Energy storage systems in modern grids—Matrix of technologies and applications. *J. Energy Storage* **2016**, *6*, 248–259. [CrossRef]
35. Gür, T.M. Review of electrical energy storage technologies, materials and systems: Challenges and prospects for large-scale grid storage. *Energy Environ. Sci.* **2018**, *11*, 2696–2767. [CrossRef]
36. Parra, D.; Gillott, M.; Norman, S.A.; Walker, G.S. Optimum community energy storage system for PV energy time-shift. *Appl. Energy* **2015**, *137*, 576–587. [CrossRef]
37. Knosala, K.; Kotzur, L.; Röben, F.T.; Stenzel, P.; Blum, L.; Robinius, M.; Stolten, D. Hybrid hydrogen home storage for decentralized energy autonomy. *Int. J. Hydrogen Energy* **2021**, *46*, 21748–21763. [CrossRef]
38. Elberry, A.M.; Thakur, J.; Santasalo-Aarnio, A.; Larmi, M. Large-scale compressed hydrogen storage as part of renewable electricity storage systems. *Int. J. Hydrogen Energy* **2021**, *46*, 15671–15690. [CrossRef]
39. Ramos, J.S.; Moreno, M.P.; Delgado, M.G.; Domínguez, S.Á.; Cabeza, L.F. Potential of energy flexible buildings: Evaluation of DSM strategies using building thermal mass. *Energy Build.* **2019**, *203*, 109442. [CrossRef]
40. Wang, S.; Gao, D.-C.; Tang, R.; Xiao, F. Cooling supply-based HVAC system control for fast demand response of buildings to urgent requests of smart grids. *Energy Procedia* **2016**, *103*, 34–39. [CrossRef]
41. Perez, K.X.; Baldea, M.; Edgar, T.F. Integrated HVAC management and optimal scheduling of smart appliances for community peak load reduction. *Energy Build.* **2016**, *123*, 34–40. [CrossRef]
42. Dufo-López, R.; Agustín, J.L.B. Multi-objective design of PV–wind–diesel–hydrogen–battery systems. *Renew. Energy* **2008**, *33*, 2559–2572. [CrossRef]
43. Mago, P.J.; Smith, A.D. Evaluation of the potential emissions reductions from the use of CHP systems in different commercial buildings. *Build. Environ.* **2012**, *53*, 74–82. [CrossRef]
44. Jung, Y.; Kim, J.; Lee, H. Multi-criteria evaluation of medium-sized residential building with micro-CHP system in South Korea. *Energy Build.* **2019**, *193*, 201–215. [CrossRef]
45. Georgakarakos, A.D.; Mayfield, M.; Buckman, A.H.; Jubb, S.A.; Wootton, C. What are smart grid optimised buildings? In Proceedings of the Living and Sustainability: An Environmental Critique of Design and Building Practices, Locally and Globally, London, UK, 9–10 February 2017.
46. HM Government. The Building Regulations 2010: Conservation of Fuel and Power (L1A). 2016. Available online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/540326/BR_PDF_AD__L1A__2013_with_2016_amendments.pdf (accessed on 5 March 2021).
47. International Energy Agency. Numerical Data for Air Infiltration & Natural Ventilation Calculations. 1998. Available online: https://www.aivc.org/sites/default/files/members_area/medias/pdf/Technotes/TN44%20NUMERICAL%20DATA%20FOR%20AIR%20INFILTRATION.PDF (accessed on 10 February 2021).
48. Florides, G.; Tassou, S.; Kalogirou, S.; Wrobel, L. Measures used to lower building energy consumption and their cost effectiveness. *Appl. Energy* **2002**, *73*, 299–328. [CrossRef]
49. Pacheco-Torres, R.; Ordóñez, J.; Martínez, G. Energy efficient design of building: A review. *Renew. Sustain. Energy Rev.* **2012**, *16*, 3559–3573. [CrossRef]
50. CIBSE. *Environmental Design: CIBSE Guide A*, 8th ed.; The Lavenham Press: Suffolk, UK, 2015.

51. Kamel, E.; Memari, A.M. Review of BIM's application in energy simulation: Tools, issues, and solutions. *Autom. Constr.* **2018**, *97*, 164–180. [CrossRef]
52. Boyano, A.; Hernandez, P.; Wolf, O. Energy demands and potential savings in European office buildings: Case studies based on EnergyPlus simulations. *Energy Build.* **2013**, *65*, 19–28. [CrossRef]
53. DesignBuilder. Calculation Options. 2019. Available online: https://designbuilder.co.uk//helpv5.4/#Calculation_Options.htm%3FTocPath%3DBuilding%2520Models%7CModel%2520Options%7CSimulation%2520Calculation%2520Options%7C_____2 (accessed on 5 January 2021).
54. Nord Pool. Nord Pool Spot Annual Report 2018. 2018. Available online: http://www.nordpoolspot.com/globalassets/download-center/annual-report/annual-report_nord-pool-spot_2013.pdf (accessed on 15 December 2020).
55. Nord Pool. Historical Market Data. 2019. Available online: https://www.nordpoolgroup.com/historical-market-data/ (accessed on 20 November 2020).
56. Ofgem. Breakdown of an Electricity Bill. 2018. Available online: https://www.ofgem.gov.uk/data-portal/breakdown-electricity-bill (accessed on 12 December 2020).
57. HM Government. Fuel and Power (VAT Notice 701/19). 2016. Available online: https://www.gov.uk/guidance/vat-on-fuel-and-power-notice-70119 (accessed on 11 November 2020).
58. Ofgem. Energy Companies' Consolidated Segmental Statements. 2018. Available online: https://www.ofgem.gov.uk/system/files/docs/2018/08/css_-_energy_companies_consolidated_segmental_statements_css_-_2018.pdf (accessed on 25 November 2020).
59. Dufo-López, R.; Bernal-Agustín, J.L. Techno-economic analysis of grid-connected battery storage. *Energy Convers. Manag.* **2015**, *91*, 394–404. [CrossRef]
60. Connolly, D.; Lund, H.; Finn, P.; Mathiesen, B.; Leahy, M. Practical operation strategies for pumped hydroelectric energy storage (PHES) utilising electricity price arbitrage. *Energy Policy* **2011**, *39*, 4189–4196. [CrossRef]
61. Staffell, I.; Rustomji, M. Maximising the value of electricity storage. *J. Energy Storage* **2016**, *8*, 212–225. [CrossRef]
62. Barbour, E.; Wilson, G.; Hall, P.; Radcliffe, J.; Wilson, I. Can negative electricity prices encourage inefficient electrical energy storage devices? *Int. J. Environ. Stud.* **2014**, *71*, 1–15. [CrossRef]
63. TESVOLT. The Lithium Storage System for Business and Industry. 2016. Available online: http://www.solfex.co.uk/uploads/downloads/TESVOLT_ENG_Li_Datasheet_Version_2016_06.pdf (accessed on 3 November 2020).
64. Tesla. Tesla Powerpack. 2020. Available online: https://www.tesla.com/en_GB/powerpack (accessed on 8 October 2020).
65. Pimm, A.J.; Cockerill, T.T.; Taylor, P.G.; Bastiaans, J. The value of electricity storage to large enterprises: A case study on Lancaster University. *Energy* **2017**, *128*, 378–393. [CrossRef]
66. Yang, L.; Ribberink, H. Investigation of the potential to improve DC fast charging station economics by integrating photovoltaic power generation and/or local battery energy storage system. *Energy* **2019**, *167*, 246–259. [CrossRef]
67. Dufo-López, R. Optimisation of size and control of grid-connected storage under real time electricity pricing conditions. *Appl. Energy* **2015**, *140*, 395–408. [CrossRef]
68. Dehghani-Sanij, A.; Tharumalingam, E.; Dusseault, M.; Fraser, R. Study of energy storage systems and environmental challenges of batteries. *Renew. Sustain. Energy Rev.* **2019**, *104*, 192–208. [CrossRef]