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Policy options for enhancing economic profitability of residential solar photovoltaic with battery energy storage

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HIGHLIGHTS

- Pairing solar PV with battery can reduce electricity imports from the grid by up to 84%.
- Home battery doubles PV self-consumption in the building.
- Rewarding self-consumption of PV is the most effective policy for mobilizing onsite flexibility solutions like batteries.
- Solar PV paired with battery can be profitable for residential consumers even in high-latitude countries.
- Value of arbitrage for residential electricity storage can be three times higher than utility-scale storage.

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ABSTRACT

Share of solar photovoltaic (PV) is rapidly growing worldwide as technology costs decline and national energy policies promote distributed renewable energy systems. Solar PV can be paired with energy storage systems to increase the self-consumption of PV onsite, and possibly provide grid-level services, such as peak shaving and load levelling. However, the investment on energy storage may not return under current market conditions. We propose three types of policies to incentivise residential electricity consumers to pair solar PV with battery energy storage, namely, a PV self-consumption feed-in tariff bonus; "energy storage policies" for rewarding discharge of electricity from home batteries at times the grid needs most; and dynamic retail pricing mechanisms for enhancing the arbitrage value of residential electricity storage. We soft-link a consumer cost optimization model with a national power system model to analyse the impact of the proposed policies on the economic viability of PV-storage for residential end-users in the UK. The results show that replacing PV generation incentives with a corresponding PV self-consumption bonus offers return on investment in a home battery, equal to a 70% capital subsidy for the battery, but with one-third of regulatory costs. The proposed energy storage policies offer positive return on investment of 40% when pairing a battery with solar PV, without the need for central coordination of decentralized energy storage nor providing ancillary services by electricity storage in buildings. We find that the choice of optimal storage size and dynamic electricity tariffs are key to maximize the profitability of PV-battery energy storage systems.

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1. Introduction

1.1. Background

Energy transitions worldwide seek to increase the share of low-carbon energy solutions mainly based on renewable energy. Variable renewable energy (VRE), namely solar photovoltaic (PV) and wind, have been the pillars of renewable energy transitions [1]. To cope with the temporal and spatial variability of VRE, a set of flexibility options have been proposed to match energy supply and demand reliably [2]. Electrical energy storage (EES)[1] systems are one of the flexibility options that can contribute to, *inter alia*, the integration of high shares of VRE [3], minimizing the need for fossil fuel-based peak generation and backup power capacity [4], decreasing carbon emissions [5], and reducing electricity prices and price volatility [6].

With ever declining capital cost of solar PV, many governments promote distributed solar PV generation as one of the key energy technologies in energy transitions. Residential solar PV has grown significantly globally, with an annual average growth rate of about 50% between 2010 and 2020 [7]. In this respect, government subsidies have encouraged many households to install roof-top solar PV in different countries [1]. PV generation in high-latitude countries does not completely coincide with the household electricity demand [8], calling for options such as the export of excess PV generation to the grid or onsite storage. To increase the self-consumption of PV and reduce possible grid contingencies in peak PV generation, EES can be effectively employed to shift generation from PV from off-peak to peak demand times, reducing system-wide generation costs and potentially avoiding the need for network reinforcement [9]. The value of EES for the system will grow as solar PV deployment rate increases [10] and the cost of EES declines [11]. However, the cost of distributed EES is typically higher than the benefits that it can offer to prosumers[2] under current market conditions [12], leaving the deployment rate of distributed EES combined with PV very low [13].

1.2. Policies for promoting PV and storage: economic considerations

Different policy options have been employed to improve the economic feasibility of distributed solar PV, with feed-in tariffs (FiTs) being the main incentive adopted in many countries in the last decade [14]. However, until recently, there has been little or no policy support for distributed EES, such as small-scale batteries, which is shown to be a key barrier in deploying storage [15] under current policy regimes [16]. Supporting distributed renewable generation without adequate incentives for onsite flexibility and distributed EES might not fully realize the private and system-level benefits of distributed energy generation systems [17,18]. Introducing such policy supports can contribute to a significant adoption of distributed EES; such as the subsidy mechanism for PV paired with EES by the California Public Utilities Commission (CPUC) making homeowners eligible for a capital subsidy when installing a home battery [19].

The economic feasibility of distributed EES has been subject to a wide number of studies with different modelling approaches. Uddin et al. [20] examines the feasibility of residential EES by applying a battery degradation model, showing no financial benefits and even possible economic losses. Zakeri and Syri [21] apply a holistic life cycle cost analysis of different EES systems, concluding that the levelized cost of storage (LCOS) for most batteries is way too high to be competitive in the current electricity markets. Murrant et al. proposes multi-attribute value theory to investigate the economic viability of different distributed EES systems [22]. The economic benefits of battery energy storage under different ownership structures are also studied in [23]. The reviewed literature commonly conclude that EES systems are not generally profitable without policy intervention and removing market barriers, e.g., for community-level storage solutions [24], aggregator-led coordination of residential EES [12], and qualifying EES for providing multiple grid services (revenue stacking) [4,25]. To respond to this gap, a number of studies focus on policies that could improve the financial case of EES systems. For example, Winfield et al. [17] investigate the role of EES policies in Canada, EU, and the US; Zakeri and Syri [26,27] show the benefits of EES from day-ahead, intra-day, and balancing markets in different Nordic countries; and Zakeri et al. [28] compare potential benefits of EES from energy arbitrage and the reserve markets in Germany. These studies highlight the role of the aggregation of benefits as a key policy support for promoting EES, but without using a model-based quantification of the impact of such policies.

There are few studies that investigate policies that could improve the value of distributed PV-EES systems to residential end-users by quantification of the impact of such policies. Zhang et al. [29] explore the payback period of investing in integrated PV-EES systems for different building types and locations in the US under different financial incentives and carbon prices. The study suggests a payback period of 11–29 years depending on the location and policy. In [30], the value of EES to a private owner in the UK is calculated based on the possibility of multiple-service provision, also known as “aggregation of benefits” or “revenue stacking”. The study shows that advanced pricing schemes, such as time-of-use (ToU) tariffs and aggregation of benefits can enhance the value of EES in PV-EES systems. In a more recent study, Gardiner et al. [31] compare different policies and quantifies the impact of each policy on financial profitability of a PV-EES system in the UK. The study shows the importance of aggregation of benefits, and those policies that remove the barriers for EES owners to provide multiple storage services to the grid. Weniger et al. [32] calculates the optimal size of a PV-battery system with detailed representation of the system at the end user side and considering a high temporal resolution using one-minute timeseries data. The study suggests the policy intervention is needed to guide the consumer in optimal sizing of their asset. Last but not least, Stephan et al. [33] explore policy options that can promote the aggregation of the benefits of EES in Germany, concluding that if the policy focus should be guided towards the removal of barriers for such revenue aggregation. In Section 1.3, we explain our modelling approach for the quantification of energy storage policies, compared to the reviewed literature.

1.2.1. Solar PV self-consumption policies

Initial incentives for residential solar PV were mainly rewarding solar PV generation, or the export of excess solar PV generation to the grid, or a combination of both. A review of such policies by International Energy Agency (IEA) [34] shows that the self-consumption of solar PV has been poorly rewarded in many countries, leading to an indirect incentive for householders to export their PV overproduction to the grid. In some cases, this has led to inefficient public expenditure, e.g., by rewiring of the PV system to the distribution grid instead of onsite usage in Spain. In a few countries, like China, the self-consumption is directly incentivized, which can encourage consumers to reduce their dependency on the grid. As the share of decentralized solar PV increases in the grid and PV subsidies phasing out in many countries, it is a crucial policy concern to encourage prosumers to increase their self-consumption rather exporting to the grid. The EU Renewable Energy Directive (2018/2001) has explicitly asked Member States to look for policies to increase “renewable energy self-consumption” in buildings through storage and other options [35]. In Germany, the solar PV FiT system may discontinue soon after reaching the goal of 52 GW total installed capacity. As consumer electricity prices are high in Germany and the cost of battery is declining, a significant uptake of solar PV with

[1] In this paper, the term EES, electricity storage, and storage have been used alternatively for technologies like batteries that can store electrical energy and discharge it at any desirable time when needed.

[2] The term “prosumer” in this paper reflects those residential electricity consumers who own electricity generation, either with or without storage technologies.

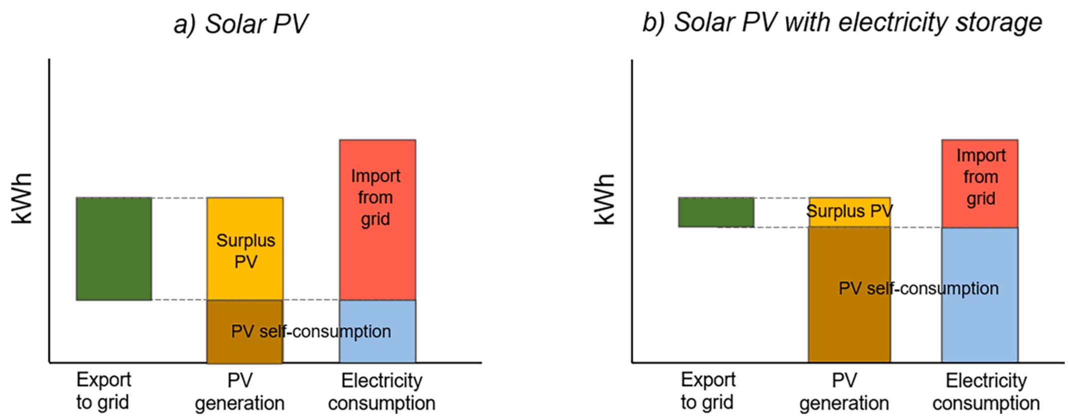

Fig. 1. Solar PV generation, self-consumption onsite, overproduction (surplus PV), and export to the grid for (a) a typical PV installation compared to (b) a PV-storage system.

battery systems has happened in recent years, e.g., 65,000 home PV-batteries installed only in 2019 [36].

A few studies have analysed the impact of PV self-consumption incentives on the distribution grid [37] and the integration of PV-storage systems [38]. Dehler et al. [39] shows that self-consumption policies cannot be successful without prosumers being able to adopt energy storage or other demand side flexibility. Pairing PV with battery significantly increases the self-consumption of PV but reduces the imports from and exports to the grid (see Fig. 1). Hence, effective policies are needed to promote solar PV self-consumption with batteries. We explore the impact of such policies in this paper.

1.3. Contribution of this study

In the reviewed literature in Section 1.2, distributed PV-EES systems are commonly modelled stand alone, i.e., without modelling PV-EES integrated or linked with the rest of the power system. This lack of representation of distributed PV-EES within the overarching power system leads to two major shortcomings in such studies: (i) assuming exogenous, commonly fixed, electricity prices throughout the lifetime of distributed PV-EES systems, and (ii) considering PV-EES systems as price taker technologies. Assuming fixed electricity prices for the lifetime of a distributed PV-EES system – a period spanning between 20 and 30 years – may overlook the impact of the transition in the power system on electricity prices and price volatility [40]. As the share of VRE grows in the power generation mix, the gap between peak and off-peak electricity prices in different days of the year will change, and as such, the potential revenues of a PV-EES system. Missing this transition in the modelling of a PV-EES system can lead to underestimation of the contribution of EES in high VRE systems.

On the other hand, assuming a distributed PV-EES system as price taker, neglects the impact of storage on the market, including the smoothening effect of EES on peak prices in the power system, which is observed in different studies [41]. This may lead to the overestimation of the benefits of PV-EES systems as penetration of EES in the system has a self-competing effect – the higher installed capacity of EES in a given system, the lower price gap between peak and off-peak hours. To address this gap, we model a distributed PV-EES system linked with a national electricity dispatch model. Hence, we estimate future electricity prices during the lifetime of PV-EES internally consistent with the rate of deployment of residential PV-EES in the overarching power system.

This paper aims to answer the following questions:

(i) Is investing in residential PV-EES profitable under current market conditions, i.e., without incentives for EES?
(ii) What support policies can enhance the profitability of stand-alone EES or PV-EES systems for residential electricity consumers?
(iii) What is the system (or regulatory) cost of each PV-EES policy compared to the benefit of that policy for residential consumers who invest in these technologies?

We propose a few new storage policies, which aim to reward the operation of residential storage for increasing solar PV self-consumption, peak shaving, and load levelling. The policies proposed in this study are based on designing new retail electricity tariffs combined with new policies that reward the discharge of electricity from home batteries at times the system needs that most. We compare the proposed policies with traditional policies such as capital subsidies or export-to-grid FiTs. We show that the joint profitability of PV-EES improves significantly under proposed storage policies, compared to common financial incentives for distributed energy technologies. We analyse this using the historical data of the UK power system as a case study. The UK power system is chosen as it has a high share of solar PV installations with feed-in and export tariffs, while no similar incentives for EES. Since this situation prevails in many countries worldwide, the findings of this study can potentially inform energy policy in other countries with large-scale deployment of distributed PV and the need for EES for balancing the demand and supply.

The remainder of this paper is structured as follows. Section 2 introduces the methods and data. Results are presented in Section 3. Policy implications are presented in Section 4, with discussing one alternative policy for using electric vehicles (EVs) with vehicle to grid (V2G) capabilities for residential energy storage combined with PV. Concluding remarks are summarized in Section 5.

2. Methods

2.1. Modelling framework

We estimate the private value of an investment in PV-EES for a typical residential consumer, considering a period of 26 year[3] for the analysis based on the lifetimes of EES and PV systems. We consider the consumer's annual cost of electricity and demonstrate the profitability

[3] The lifetime of 26 years, covering 2015–2040, is chosen because the lifetime of solar PV panels is estimated between 25–30 years. Also, the future energy scenarios used as the basis for this analysis are developed by National Grid through to 2040. The solar PV panels may be still useable after 25–26 years with a lower capacity [55], but there is no FiT after 26 years. We assume no recycling revenues for the owner at the end of the useful lifetime of solar PV and battery.

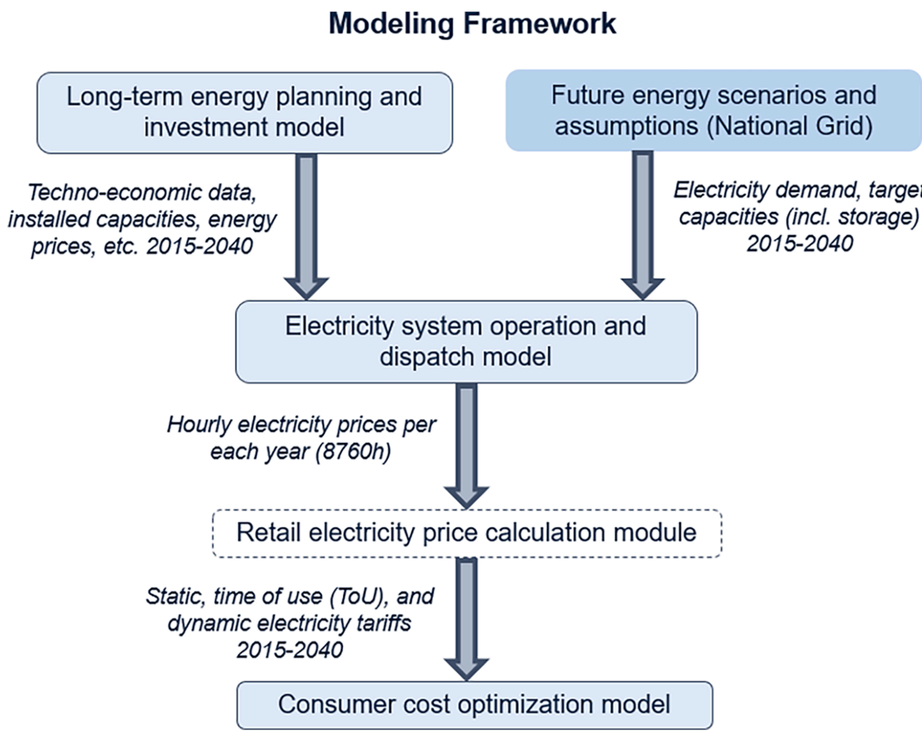

Fig. 2. Modelling framework applied in this paper with the flow of data between different models and calculation modules.

of a capital investment in PV-EES by the aid of the linkage of a national-level electricity system dispatch model with a consumer PV-EES investment model. The modelling method in this study is based on the following main steps:

I. Future national-level energy scenarios, including capacities of renewables and thermal power plants through to 2040, are based on four pathways developed by the UK National Grid [42]. These pathways are derived in a multi-stakeholder process, showing different futures for the UK energy system based on different socio-economic assumptions, such as level of sustainability, consumer engagement and economic growth. We derive electricity generation installed capacities, fuel prices and electricity demand in each year of the modelling horizon, i.e., 2015–2040, from these scenarios.
II. A national electricity dispatch model is employed to model the hourly operation of the power system using capacities and demand from (I). The dispatch model calculates hourly wholesale electricity prices for different years under different scenarios.
III. The wholesale electricity prices are fed into a retail electricity model to calculate consumer prices based on static, time of use (ToU), and dynamic tariffs. This is conducted for each year in 2015–2040.
IV. A distributed PV-EES optimization model is developed to yield the most profitable operational strategy for a consumer with the objective of reducing consumer electricity costs.

Fig. 2 shows the modelling framework applied for our analysis and the flow of data between the models. In the following Section, we describe each part of this integrated modelling approach in more details.

2.2. Input data and assumptions

2.2.1. National-level electricity system model

We derive wholesale electricity prices from the Electricity System Management Model (*ESMA*), an hourly model consisting of explicitly modelled domestic, commercial, and industrial electricity consumers. The model has been applied previously to model the operation and dispatch of the UK power system, linked with consumer investments in distributed energy technologies in different studies [12,43]. The system operator optimizes flexible demand and other flexibility options at the supply side with the objective of minimizing the total system costs. Based on National Grid [42], storage needs are procured partly by central EES and another by consumers who own small-scale EES.

National Grid has developed four future scenarios for the UK, namely No Progression (with no significant transition to renewables), Slow Progression (resembling business as usual), Green Ambition (sustainability scenario), and Consumer Power (representing the active role of consumers in adopting new technologies). In our analysis, we take the mean installed capacity of different electricity generation modes and EES, between No Progression and Consumer Power scenarios to represent a plausible evolution of the system in terms of future green ambition and economic prosperity (see more details on these scenarios in [42]).

2.2.2. Electricity tariffs

Based on calculated wholesale electricity prices from the electricity dispatch model, we derive retail prices by considering a real-time markup over marginal costs (see Appendix A for more details on calculation of retail prices). These prices are then calibrated using historical data form three electricity tariffs. UK National Statistics [44] provide national averages, including static tariffs of 0.15 £/kWh, and ToU tariffs based on the UK program Economy7 with an off-peak (24–7 h) tariff of 0.07 £/kWh and an on-peak (7–24 h) of 0.16 £/kWh. Assuming consumers use smart meters, we also consider real-time tariffs to understand whether they could better reflect the value of EES in energy time shifting. To provide a direct comparison of electricity costs under ToU and real-time tariffs, we assume that both have the same daily mean. Static and ToU tariffs are assumed to vary quarterly, and real-time tariffs vary continuously on an hourly basis with the wholesale price.

2.2.3. Residential solar PV with energy storage

We model the hourly operation of solar PV and a battery energy storage technology for a residential consumer with a medium-sized, three-bedroom dwelling with an annual electricity consumption of

Table 1
Main modelling assumptions and input parameters of consumer technologies and tariffs.

	Parameter	Value	Note	Source of data
Consumer	Annual load	3750 kWh/a	fixed throughout the analysis except in Section 3.6.1 for sensitivity analysis	[45]
	Building type	3 bedrooms	Terrace or private house	[45]
	Location	London area	fixed throughout the analysis except in Section 3.6.2 for sensitivity analysis	
	Load profile	Domestic class 1 (unrestricted)	seasonal and time-of-day residential electricity load profiles from Elexon [46] are populated for the entire year (8760 h), then scaled relative to the country-wide average load in each season and day obtained from ENTSOE for each examined year (2016–2019) [47]	[46] and [47]
Electricity tariffs	Static	0.15 £/kWh	varying year to year based on yearly average of wholesale electricity prices	[44]
	Time of use (ToU)	off-peak: 0.07 £/kWh peak: 0.16 £/kWh	- off-peak hours between 0 and 7 and peak hours 7–24 - varying yearly based on average wholesale electricity prices	[44]
	Real-time	3.22 times hourly prices	- a 3.22 premium for taxes and levies applied to wholesale electricity prices	[44]
Solar PV	Investment cost	1813–1866[a] £/kW	cost data for small modules (0–4 kW), including installation costs.	UK official statistics [49]
	Capacity	4 kW	the size qualified for tariffs [48]	modelling assumption
	Inverter replacement cost	1000 £	an average value between 500-1500 £.	[50]
	Inverter replacement period	10 year		[50]
	O&M cost	20 £/kW/a	including full-scope O&M cost and a small premium for home insurance	[51,52]
	Lifetime	26 year	based on estimation of 80% degradation rate after 25–26 year	[53]
	FiT generation	0.0491 £/kWh	- declining on an annual basis and lasting until 2040	[48]
	FiT export to grid	0.043 £/kWh	- guaranteed for 20 years starting 2016, adjusted with the consumer price index.	[48]
	Hourly generation		based on simulated data from website: renewables.ninja	[54]
Battery energy storage	Investment cost of battery	712 £/kWh	- average value of the market price of Tesla Powerwall. - Including 20% VAT and installation cost.	[55]
	Power rating	3.3[b] kW	both for charge and discharge (based on Tesla Powerwall I)	[55]
	Storage size	6.4[b] kWh	both for charge and discharge (based on Tesla Powerwall I)	[55]
	Round-trip efficiency	92.5%	at nominal depth of discharge and excluding battery self-discharge	[22]
	Self-discharge	0.5% per hour	considering losing 80% of full charge after one week if unused	
	Lifetime	13 year	based on warranty time for 80% capacity (or 5000 discharge cycles)	[55]
	Replacement cost	213 £/kWh	estimation of replacement cost in 2030 (30% of capital cost today)	[11]
Economic assumptions	Discount rate	5.1%	based on a hurdle rate of 5.1–5.6 for small-scale solar PV projects	[56]
	Lifetime of analysis	26 year	based on lifetime of technologies and available FiTs	modelling horizon
	Retail price index (RPI)	+3.2% per year	used for changing tariffs over time	[48]

[a] Based on UK official statistics "solar PV cost data". The higher cost is for 2016 and the lower cost for 2019.
[b] Fixed throughout the analysis except for the optimal sizing in Section 3.6.3.

3750 kWh (the average of 3084–4399 kWh/a), as a potential adopter of solar PV and EES, which is considered a standard consumer based on UK Electricity Survey Data [45] and National Statistics [44]. Later, in Section 3.6.1, we analyse the results for different buildings with different load data to cover a wider range of buildings. The hourly time-of-day load data of the residential consumers for each season and day are obtained from Elexon [46]. Then, the data are populated for the entire year (8760 h) and scaled relative to the country-wide average load in each season and day (365 d) based on the hourly data from ENTSOE [47]. As a result, we generate hourly load profiles for a residential consumer for each year (8760 h). The solar PV generation in cases where the consumer operates a solar PV system is dependent on the latitude (geographical location). In our main analysis, we use the hourly solar PV generation for a location in London, based on simulated data from Renewables.ninja.[4] The yearly capacity factor for solar PV in the selected location is between 12 and 13% in 2016–2019. In Section 3.6.2, we reproduce the results for five different locations across the country with different solar PV generation data to understand the impact of the geographical location on the results.

We analyse the consumer technology options based on four different cases. First, we consider a consumer who owns neither EES nor a solar PV system, i.e., "-no-technology" case. We simulate the consumer's hourly load profile based on national data of annual load and hourly load pattern [48]. Then, we consider a case called "storage-only", in which the consumer installs a battery energy storage, but without solar PV onsite. The storage-only case is to explore the benefits of storage for price arbitrage (load management) without having PV installed. Next, we analyse the case of a consumer with solar PV but without storage, called "PV-only". This consumer benefits from additional revenues from solar PV generation and export to grid (hereafter called export) feed-in tariffs (FiTs). Finally, we consider the case of "PV-storage", in which the consumer operates both solar PV and storage onsite. Here, storage can be used to increase the solar PV self-consumption as well as price arbitrage (shifting load from peak to off-peak), with the objective of minimizing the consumer's electricity bill.

We model consumer financial case between 2015 and 2040. This way we account for year-to-year changes in some of input parameters such as tariffs. The solar PV FiT starts with 0.049 £/kWh of electricity generated and declines on an annual basis based on [48]. The export tariff of 0.043 £/kWh is guaranteed for 20 years – increasing by the retail price index (RPI) of 3.4% per year. For scenarios with solar PV, the consumer operates a 4-kW system, while for storage a battery of 6.4 kWh–3.3 kW is taken into account. This is equivalent to the size of Tesla Powerwall I

[4] Renewables.ninja converts solar irradiance from satellite reanalysis data into power output using the Global Solar Energy Estimator model presented in [56]. For more information: https://www.renewables.ninja/

batteries in the market. The consumer solar PV generation and load vary hourly, monthly, and seasonally. Hence, the PV-EES optimization model helps consumer capture energy time-shifting value of EES, resulting in most optimal hourly figures for grid purchases, battery charge level, solar consumption, and delayed self-consumption. The main input data and assumptions for the consumer PV-EES model is summarized in Table 1.

We propose a simple PV-EES model for minimizing the households' hourly electricity bill. The optimization model ensures the consumer can gain the highest performance from the integrated EES-alone, PV-alone, or PV-EES system. The electricity prices are known to the consumer before optimizing their onsite technologies. This is a valid assumption for static and ToU electricity tariffs. For real-time electricity tariffs where electricity prices are a function of the supply and demand in the power market, this perfect foresight is not a realistic assumption. However, since the battery has a self-discharge rate of 0.5% per hour, the modelling approach does not lead to long-term storage. Further details on the modelling and optimization strategy of the distributed PV-EES system is presented in Appendix B.

Fig. 3 shows the optimal hourly operation of the consumer's onsite technologies, including the impact of such technologies on electricity import from and export to the grid for the four technology options and under the time of use (ToU) tariff in three sample days. In this example, we show how the operation of storage can be different based on the possibility of solar PV generation. In Fig. 3 (b), the battery is mainly used for price arbitrage, i.e., charging during the night-time for reducing the import from the grid in peak hours. However, in Fig. 3 (d), the battery is mainly increasing the solar PV self-consumption, resulting in no imports from the grid in the examined period. The operation of solar PV with storage will reduce the export to the grid significantly, compared to PV-alone (Fig. 3 (c)). As the results show, different technology options results in a different mode of the operation of EES and interaction between the consumer and the grid. Consumers with solar PV alone will export the negative residual load to the grid at the FiT export tariff.

2.3. Investment analysis

For assessing the financial case of a private consumer adopting distributed technologies, we employ different indicators, including annualized cost of electricity and technologies, Net Present Value (NPV) and Return on Investment (ROI), presented relative to four scenarios with the consumer operating: (1) no technology; (2) a battery energy storage device; (3) a solar PV system; or (4) both a battery and a solar PV system. For each technology adoption scenario, we consider the impact of electricity tariffs, namely: (A) static, (B) time-of-use (ToU), and (C) real-time[5] tariffs. Operational savings are relative to the base case, scenario 1A. We use a discount rate of 5.1%, in line with the recommendations of Committee on Climate Change (CCC) [57]. The consumer cost optimization model described in Section 2.3.3 derives annual electricity costs in each scenario based on available onsite technologies. The consumer cost includes the electricity bill as well as the investment and management costs of PV and EES technologies. We employ an annual resolution and assume no debt financing, with investment costs arising in 2016. The consumer accumulates revenues by generating electricity from solar PV and/or exporting electricity, a process which can be optimized when using a battery to store electricity and release when it is economically most feasible to do so (i.e., price arbitrage).

Based on Table 1, considering installation and equipment costs of technologies, the capital cost of EES (~4.6 k£) is 63% that of PV (7.25 k£), which is without considering possible replacements of EES during the lifetime of analysis. If a consumer decided to use both PV and EES, an upfront investment of ~12 k£ would be required.

2.4. Financial incentives for energy storage

In this Section, we define the policy scenarios for our modelling and analysis. In addition to the Reference scenario, in which a fixed solar PV generation and export-to-grid FiT is in place for the analysis period (2015–2040), we compare different incentive options. Some of these incentive policies are based on already-known mechanisms such as capacity subsidy and generation FiTs. Moreover, we introduce new dedicated energy storage policies, and test them with other incentives. The following discusses these policies, summarized in at the end of Section.

2.4.1. Eliminating PV generation tariff in favour of self-consumption

We propose a policy measure that could improve the profitability of EES technologies when combined with PV. Because excess solar electricity will be exported to the grid during low electricity demand periods, the self-consumption of solar PV is typically low in high-latitude countries. The PV generation FiT combined with an export to grid FiT has been the main incentive for residential PV in the UK. This resulted in a large deployment of small-scale solar PV in the UK until 2019, when the regulator discontinued generation FiT for new installations. This decision resulted in rapid decline of new PV installations. Rewarding solar PV generation alone is not an efficient policy for increasing solar PV self-consumption, especially if this payment will be double subsidized with an export tariff. Policy design should incentivize consumers to increase their own PV self-consumption when it is useful for the system and for the distribution grid, as shown in [37]. More importantly, an effective self-consumption policy can incentivize consumers to deploy storage options to increase the use of solar energy onsite rather than exporting to the grid. As shown in Fig. 1, there are differences between self-consumption and export for a typical PV installation for PV-only compared with PV-battery. Deploying a battery onsite reduces the export to the grid significantly, which results in less income from export FiT for the consumer.

We propose to eliminate the solar PV generation tariff, while simultaneously recompensing the PV owners for the subsequent loss of FiT payments with an enhanced PV self-consumption tariff. For this policy not to negatively impact holders of solar PV alone, who are not able to increase their self-consumption without storage, the amount of tariff can be designed to maintain the original combined generation and export FiT revenues to users with PV alone over the technology's lifetime (see Appendix E for more details on calculation of self-generation tariff.

2.4.2. Introducing a new storage policy

We propose a new incentive, called "Storage tariff", to renumerate the operation of EES systems, if this operation contributes to the systemwide load management. This policy is quantified in the form of a FiT, payable to storage owners only if their storage device discharges electricity during certain hours a day, e.g., at peak time. Moreover, any charge of electricity to the storage device in the peak time will be negatively penalized with the same or different tariff rate. This policy should encourage EES owners to optimize their device so that they maximize the discharge of electricity during the hours rewarded most by the system, e.g., peak time or the time grid contingencies occur, and shift charging of storage to off-peak hours or hours with excess solar PV generation. This hourly storage tariff, which varies depending on the needs of the power system, can be linked to wholesale day-ahead or intraday prices (see Appendix D, Eq. D3).

2.4.3. Capital subsidies

Capital subsidies are one of the well-established incentive mechanisms for promoting new technologies. For example, the subsidy mechanism for PV-EES by California Public Utilities Commission (CPUC) rewards storage buyers by a lucrative subsidy of 1000 US$/kWh,

[5] In this paper, the terms "real-time" and "dynamic" tariffs have been used interchangeably denoting a retail electricity tariff changing on an hourly basis following the wholesale electricity prices in the power market.

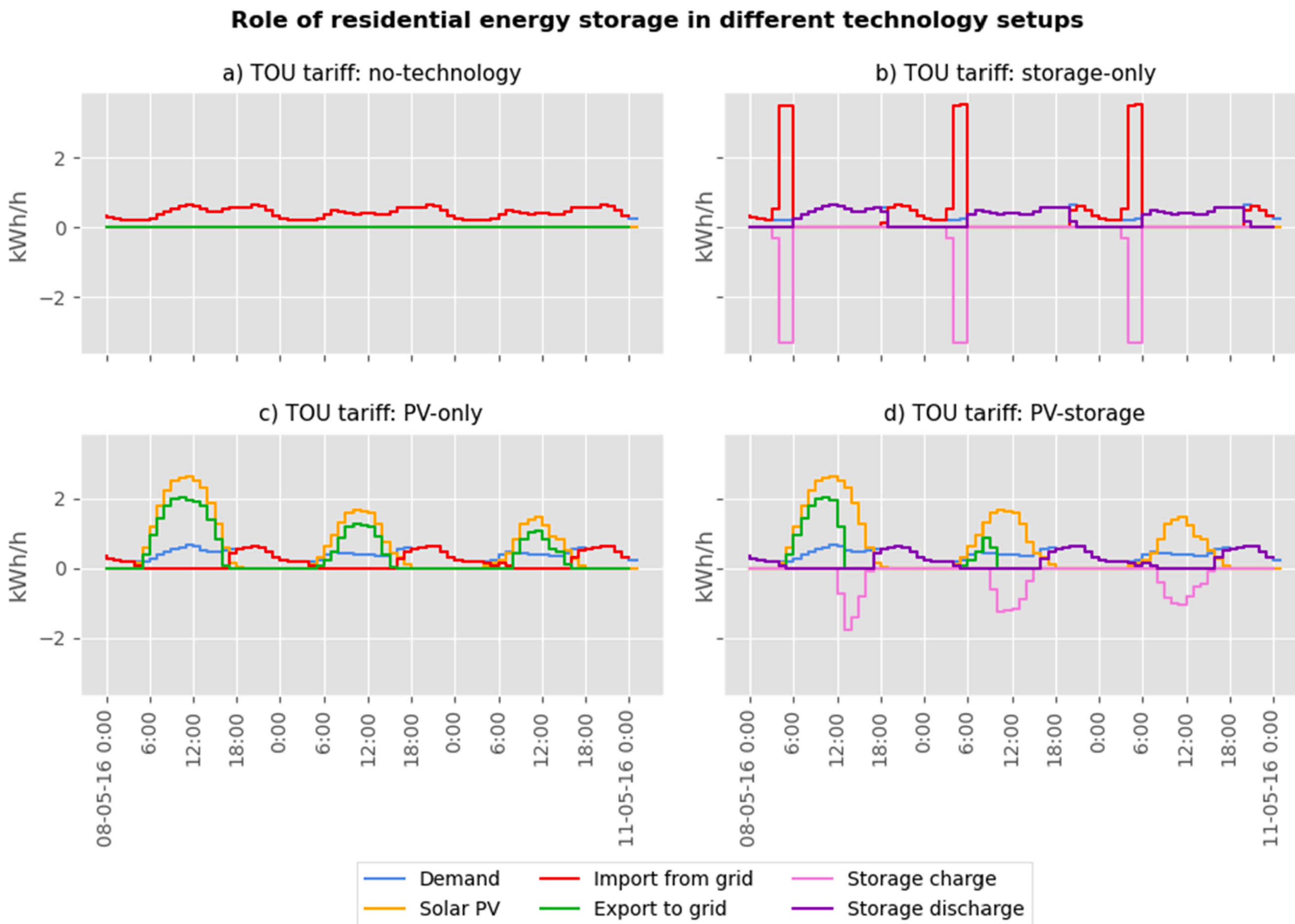

Fig. 3. Optimized operation of battery energy storage under time of use (ToU) electricity tariff and for different technology combinations. In three sample days. a) Import from the grid when no onsite technology, b) value of storage in arbitrating load from peak to off-peak hours, c) excess solar PV is exported to the grid when exceeding the load, and d) storage increases the self-consumption of solar PV and minimizes import from the grid in peak hours. The results are based on three sample days in May with different solar PV profiles.

which could almost cover the investment cost of the battery in 2020 [58]. We consider how decreasing the cost of batteries through capital subsidies affects the financial case for EES. The subsidies are assumed to decrease the nominal cost of both purchased batteries by 30%, 60%, and 90%, with the second battery already costing 70% less than current costs.

2.4.4. *Price-gap widening policy*

Lastly, we introduce a new electricity pricing policy called “Price-gap widening” tariff. In this policy, the system operator purposely increases retail electricity prices at peak hours while decreasing off-peak prices for consumers. This tariff resembles “critical peak pricing” policies in Japan [59], the US [60], or similar tariffs in France, where the system operators is interested in load levelling due to abundant, low-cost, nuclear baseload generation. This tariff not only encourages consumers to shift their peak consumption to off-peak hours, but also widens the gap between off-peak and peak prices, which contributes to the profitability of EES from price arbitrage. The optimal operation of residential EES for price arbitrage is not dependent on the absolute price of electricity but rather on the gap between prices at charging and discharging times. However, the increase in peak prices should be done smartly to not negatively affect the yearly electricity bills of consumers without EES.

2.4.4.1. Dynamic storage tariffs. As a variant of our proposed “storage tariff”, we analyse a “dynamic storage tariff”, in which the discharge tariff for storage is indexed with real-time hourly electricity prices. Therefore, as opposed to “storage tariff”, where the payment for discharge at peak hours were fixed tariffs, the dynamic storage policy rewards storage with higher payments if peak-time prices are high in some days and less if peak-time prices plummet. Also, in this policy, the retail electricity prices are changed based on the “price-gap widening”.

Table 2 summarizes the main features and assumptions of the policies examined in this paper.

3. Results

3.1. *Impact of storage on annual electricity bills*

Our analysis of consumers’ operating electricity costs shows how a consumer’s choice of technology and electricity tariff affects annual electricity bills. We find that battery storage can substantially reduce the cost of electricity to consumers, and that ToU are the most appropriate tariffs to realize the value of EES to consumers in reducing their import from the grid.

3.1.1. *Consumer’s choice of technology*

Most UK electricity consumers do not own any energy technology and pay static tariffs [61]. Annual bill savings for a user under static tariff when adopting different technologies can be seen in Fig. 4. These values are without considering the cost of the PV-EES technology, to provide a picture on the level of potential savings irrespective of the cost of technology. If the household does not operate EES or PV, electricity

Table 2
Main characteristics of financial incentives and storage policies analysed in this study.

Policy	Main feature	Solar PV FiT	Export to grid FiT	Capital subsidy	Storage discharge FiT	Retail electricity tariffs
Reference	Fixed FiT for PV generation and export to grid in each year	0.0438 £/kWh[a]	0.0491 £/kWh	–	–	As usual
Dynamic export tariff	Varying export to grid FiT based on hourly or time-of-day prices of electricity	0.0438 £/kWh[a]	static: 0.0438 £/kWh[a] ToU and dynamic tariffs: scaled by 0.3273[c]	–	–	As usual
Self-consumption bonus	Enhanced PV self-consumption FiT with no generation FiT	Self-consumption 0.1 £/kWh[a,b]	0.0491 £/kWh	–	–	As usual
Storage policy	Payment for storage discharge and penalty for charging in peak hours	0.0438 £/kWh[a]	–	–	Peak time discharge: 0.0491 £/kWh peak time charge: −0.0491 £/kWh off-peak: 0	As usual
Capital subsidy	Compensating a part of initial investment of storage device	0.0438 £/kWh[a]	0.0491 £/kWh	Three variants: 30, 60, and 90%	–	As usual
Price gap-widening policy (critical pricing)	Smart increase of retail prices at peak hours and lowering them in off-peak time	0.0438 £/kWh[a]	–	–	–	Increased peak prices and lowered off-peak prices in ToU and dynamic tariffs
Enhanced storage policy	Same as "storage policy" but with a time-of-day varying payment/penalty scheme	0.0438 £/kWh[a]	–	–	Applying a price multiplier of 0.3273[c] (positive for peak-time charge, negative for peak-time charge, and zero for off-peak)	Increased peak prices and lowered off-peak prices in ToU and dynamic tariffs

[a] The value is given for the first year of analysis, declining over years and ceased in 2040.
[b] This is derived from the sum of revenues from original solar PV FiT (0.0438 £/kWh) and export FiT (0.0491 £/kWh) divided by the reduced annual electricity import due to self-consumption. For a prosumer with PV-only (without battery), this PV self-consumption tariff yields the same revenues as original PV generation and export FiTs.
[c] This multiplier is estimated by dividing buying electricity price (i.e., 0.15 £/kWh under the static tariff) by fixed export-to-grid FiT (i.e., 0.0491 £/kWh).

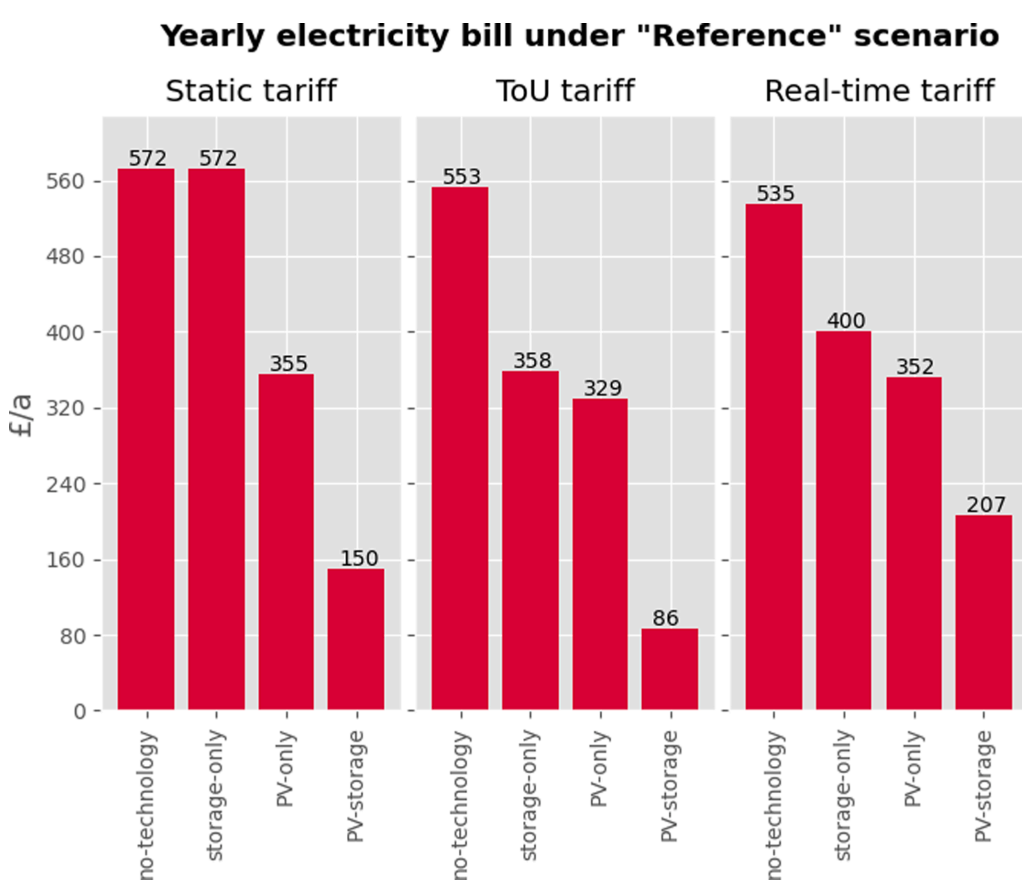

Fig. 4. Annual cost of purchasing electricity from the grid for the household in the base year (2016). The values are for Reference scenario (i.e., fixed PV and export to grid FiTs).

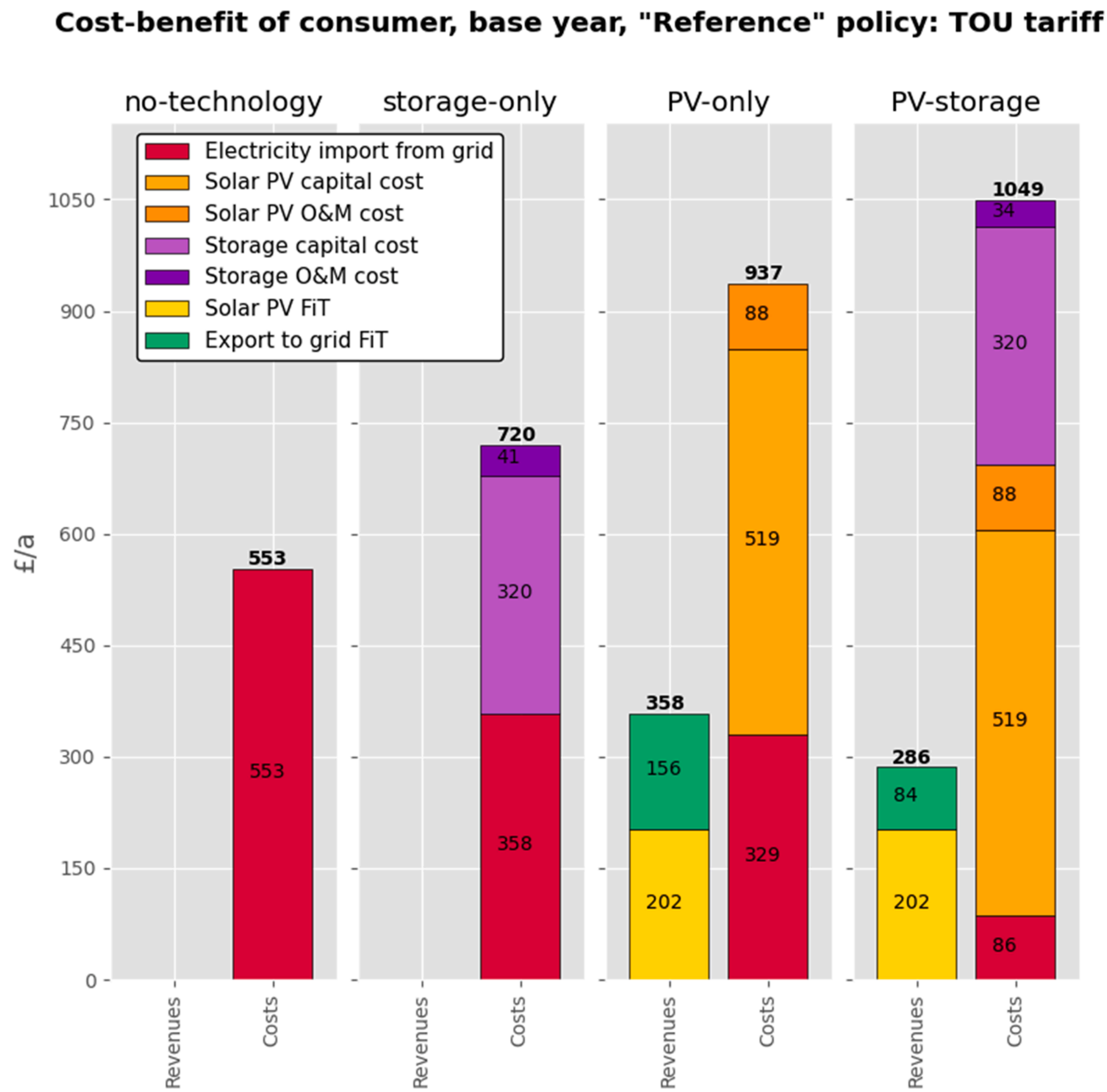

Fig. 5. Annualized costs and revenues for each technology choice (no-technology, storage-only, PV-only and PV-storage), under time of use (ToU) tariff, Reference scenario in 2016 (the base year for the analysis). The values on the bars show the respective costs or revenues, and the values in bold on top of each bar shows the total.

costs are 572 £/a. If it operates EES alone, costs are identical to "no-technology" because static tariffs do not make energy time-shifting a lucrative activity. Annual costs fall by 38% to 355 £/a if the consumer only operates a PV system, and by 74% to 150 £/a if it operates both a battery and a PV system. Hence, pairing EES with PV implies a reduction in electricity bills of 205 £/a, or 63% lower annual costs compared to running PV alone.

3.1.2. *Choice of electricity pricing scheme*

Fig. 4 compares the annual cost of buying electricity from the grid for three retail tariffs, i.e., static, ToU and real-time (dynamic). The values are for the base year under the "Reference" scenario, i.e., assuming fixed FiTs for export to grid and PV generation[6]. Deploying a battery without solar PV, i.e., the "storage-only" case, offers significant savings in electricity bills in ToU and dynamic tariffs, 35% and 25% compared to "no-technology", respectively. In the "PV-only" case, the consumer can reduce dependency on the grid by 34–41% depending on the tariff. With the installed capacity of PV (4 kW) and the hourly generation pattern of PV in 2019 in the examined location (London), the consumer benefit from a solar PV generation of 4620 kWh per year. However, without storage, the self-consumption of PV for this consumer remains at 31%, independent of the tariff.

Pairing PV with storage offers the highest savings in electricity bills compared to "no-technology", with ToU being the best (84%) and dynamic tariff (61%) the lowest. It should be noted the reduction in electricity bill is not necessarily showing the best cost optimal scenario, as there are other cost components such as technology investment and O&M costs, and revenue streams such as export FiT. For example, the consumer will be able to exert more price arbitrage under dynamic tariffs, resulting in greater electricity imports from and exports to the grid (see Appendix D, Fig. H2). Therefore, the import from the grid for real-time tariff is higher than static in the PV-storage cases.

Fig. 5 presents the components of cost and revenue in the household's balance sheet, calculated for the ToU tariff and for different technology combinations for the base year. The capital cost and future replacement and maintenance costs are annualized using a discount factor of 5%. As shown by the results, the technology costs comprise a

[6] The FiT for solar PV generation was discontinued for PV installations after March 2019. However, the previously installed PVs are still entitled for the promised FiTs. which is the basis of our analysis for the period of 2015–2040.

Table 3
Annual bill savings by technology and electricity tariff relative to the respective technology choice under static pricing. The results are for the Reference scenario.

Tariff	Technology option	Annual bill (2016) (£/a)	Compared to Static tariff		Compared to no-technology		Impact of storage	
			Savings (£/a)	Savings (%/a)	Savings (£/a)	Savings (%/a)	Savings (£/a)	Savings (%/a)
Static	No technology	572	–	–	–	–	–	–
	Storage-only	572	–	–	0	0%	0	0%
	Solar PV-only	355	–	–	217	38%	–	–
	PV-storage	150	–	–	422	74%	205	58%
ToU	No technology	553	19	3%	–	–	–	–
	Storage-only	358	214	37%	195	35%	195	35%
	Solar PV-only	329	26	7%	224	41%	–	–
	PV-storage	86	64	43%	467	84%	243	74%
Real-time	No technology	535	37	6%	–	–	–	–
	Storage-only	400	172	30%	135	25%	135	25%
	Solar PV-only	352	3	1%	183	34%	–	–
	PV-storage	207	−57	−38%	328	61%	145	41%

large portion of the total annual cost of the consumer, being 51% in "storage-only", 65% in "PV-only", and 92% in "PV-storage". PV scenarios benefit from revenues of generation and export FiTs. However, these values are relatively lower than the costs, making the technology combination cases neither net profitable nor being more profitable compared to "no-technology". PV-only under ToU offers a near break-even situation. For comparing these results with those of static and dynamic tariffs, the reader may refer to Appendix D.

The choice of pricing scheme can greatly reduce electricity bills. Annual costs associated with ToU, real-time, and static pricing are reported in Table 3 relative to the consumer's choice of technology under static pricing.

The examined UK consumer if without onsite technology would be better-off with ToU rather than static tariffs, saving 19 £/a, experiencing 3% lower annual bills. ToU pricing implies marginally greater savings relative to real-time tariffs, when the consumer operates a technology. Where the consumer owns a battery, but not solar PV, annual bills fall by 37% if ToU pricing is chosen over static pricing, and by 30% if the consumer switches from static to real-time tariffs.

When the consumer operates PV-EES, electricity bills with ToU tariffs are 43% lower relative to the same case with static tariffs. If consumers with PV alone who are on ToU decided to also purchase EES, they would cut annual bills by roughly one forth (see Fig. 4). However, savings from PV-EES under real-time tariff is lower than that of static pricing. As mentioned earlier, this is due to a higher electricity exchange with the grid in real-time pricing, i.e., much greater arbitrage, importing electricity at low price and exporting back to the grid at higher prices later.

3.1.3. Impact of future electricity prices on consumer's profitability

The private value of residential PV and EES depends on the development of electricity prices throughout the lifetime of such technologies. Future electricity prices will directly impact the electricity bill, and hence, the economic benefit of the prosumer. Since future prices are uncertain, depending on many parameters, including the energy transition in the country; many studies adopt exogenous assumptions for prices to run the cost-benefit analysis, e.g., as done in [62] and [63]. In our analysis, we derive future wholesale electricity prices from a power system model, explained in Section 2.2.1 and calculate retail prices for each tariff. This methodology and the estimated prices are described in [43].

Fig. 6 compares the annual bill of the consumer in different years. The results are calculated for the Reference scenario based on historical electricity hourly prices in 2016–2019. The results suggest that the annual electricity bill, if adjusted based on the wholesale electricity price, varies from one year to another. Fr static and ToU use tariffs, where the tariff is calculated based on average prices, the year-to-year variations are uniformly observed across different technology choice. However, for real-time tariffs with storage, the electricity bill is the function of both magnitude of the wholesale price and the price volatility: the higher price volatility between min and max values will result in higher arbitrage benefits (see Fig. 6, PV-storage technology in 2018).

3.2. The financial case for consumers

We apply a system-based Net Present Value (NPV) for the calculation of the financial case of the consumer when investing in different technologies. Electricity prices in the lifetime of the investment, i.e., 2015–2040 comprises an important part of the consumer cost. The system-based NPV accounts for the development of future electricity prices internally, i.e., by deriving these prices using a power system model and based on future energy scenarios, as opposed to exogenous assumptions (see more details in [43]).

Fig. 7 reports the NPV of consumer investments by technology and electricity tariff. None of the combinations of technology and electricity tariffs yield positive values for NPV under current tariffs and technology costs. However, comparing with the "no-technology" case, we can analyse the economic attractiveness of investment in each technology option. Distributed technologies reduce the import from the grid significantly, however, EES and PV investments, and the combination thereof, are barely reducing the total costs given the high capital costs of both technologies relative to the savings they generate. The PV-only scenario, however, offers an NPV relatively close to that of "no-technology" under static and ToU tariffs. Solar PV owners would receive a total FiT of 2050 £ in 2016-£ values for the lifetime of investment, covering less than 25% of their initial investment of 7800 £ and total O&M cost of 1340 £. Investing in EES require 4850 £ (based on Powerwall II market price scaled for lower capacities). The O&M cost of EES depends on possible battery degradation and replacement costs in the lifetime, varying between 520 and 630 £ if one replacement happens after 13 years from the installation. Solar PV is most profitable when used in combination with ToU tariffs, namely 4% more profitable compared to real-time and static tariffs.

When investing in EES alone, the consumer will face no Return on Investment (ROI) in any tariffs, −100% in static tariffs, −22% in ToU and −45% real-time. If the consumer invests in PV-EES, capital costs will be the highest across all scenarios. However, storage can help to increase self-consumption of PV and reducing the imports. As such, PV-storage shows a better NPV compared to storage-alone in static and ToU tariffs.

Given the high cost of batteries, pairing EES with PV will not make a better investment compared to solar PV alone. This would reduce the NPV obtained with solar PV alone by between -1100 £ and -2200 £ depending on the electricity tariff.

3.3. Impact of policy incentives on investment

In this section, we explore how different policy options can improve the private value of investing in distributed technologies. We evaluate

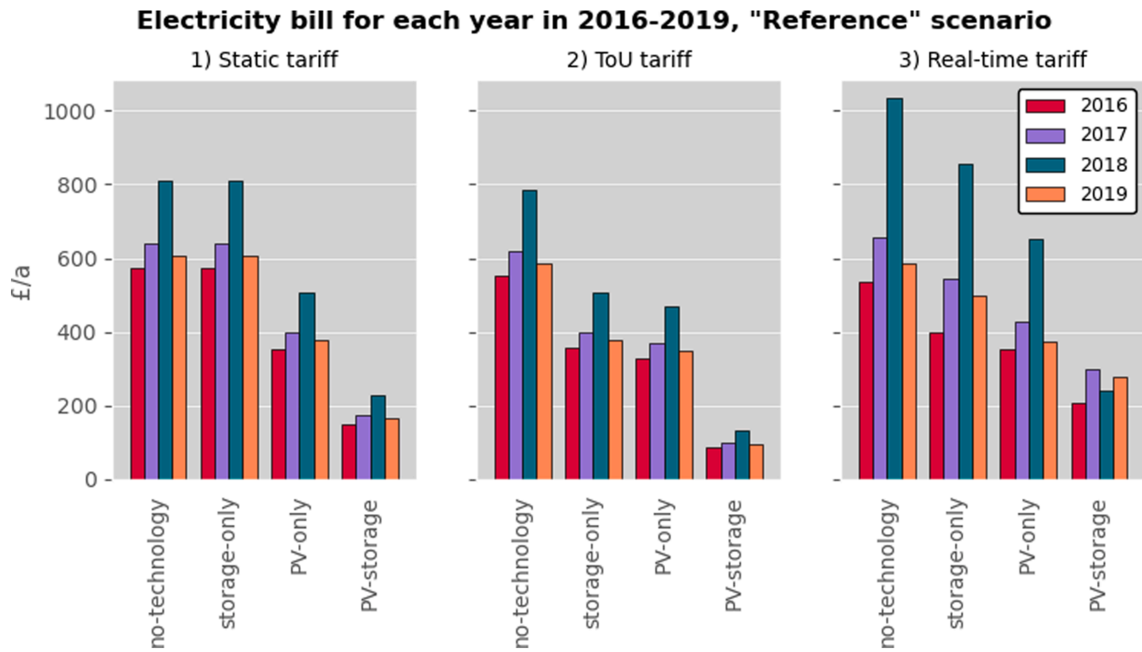

Fig. 6. Annual electricity bills for different technology options and under different tariffs in 2016–2019 for the "Reference" scenario.

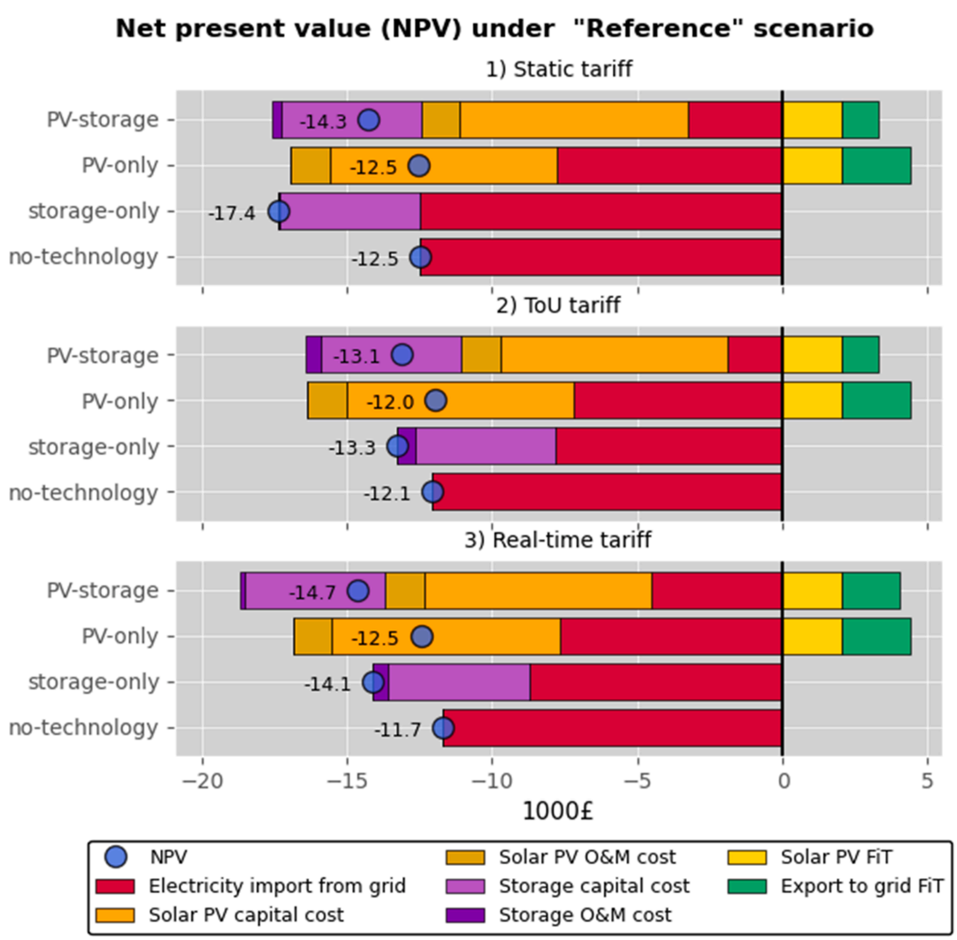

Fig. 7. Cost-benefit of the consumer investment in onsite technologies under Reference scenario for the standard residential building (middle-sized terrace house, with electricity load of 3750 kWh/a). The costs are shown with negative values and revenues with positive. The blue marker and number on each bar show the NPV of the investment (NPV = present value of revenues – present value of costs). The NPVs shown on the bars are in 1000-£ and rounded up by one decimal.

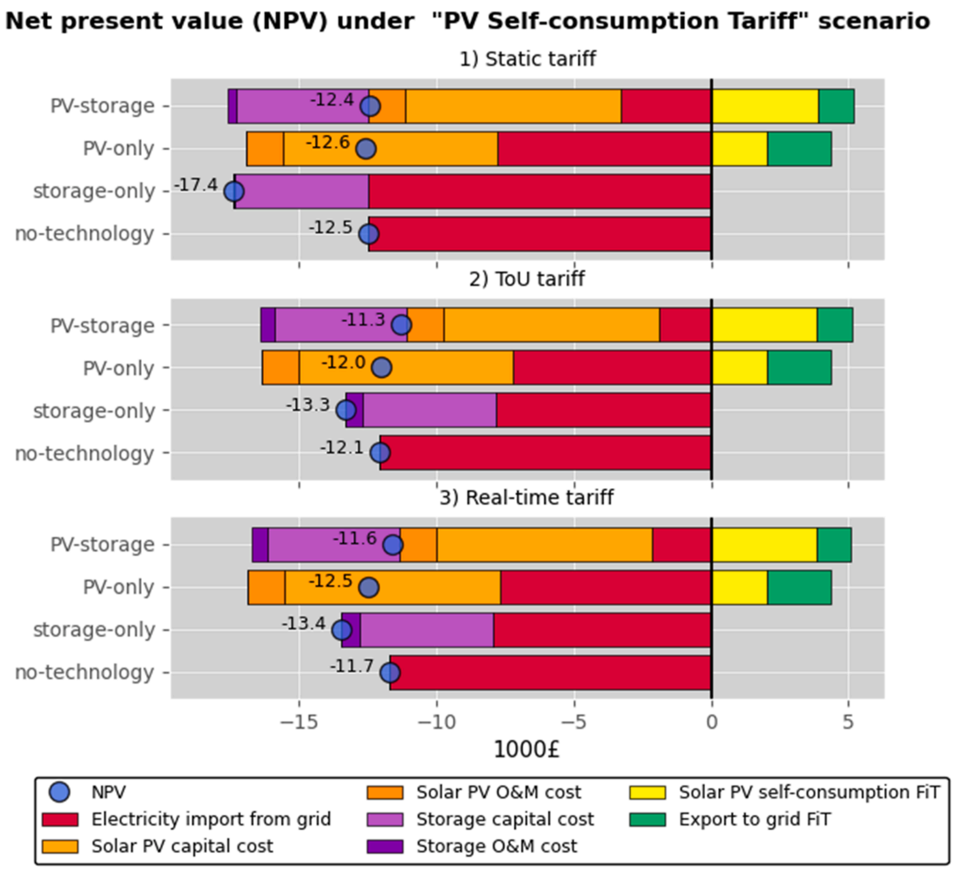

Fig. 8. Cost-benefit of the consumer investment in onsite technologies under the PV Self-consumption Tariff scenario for the standard residential building (middle-sized terrace house with electricity load of 3750 kWh/a). The costs are shown with negative values and revenues with positive. The blue marker and number on each bar show the NPV of the investment (NPV = present value of revenues – present value of costs). The NPVs shown on the bars are in 1000-£ and rounded up by one decimal.

the policies introduced in Table 2.

3.3.1. Dynamic export tariffs

Current tariffs for exporting electricity to the grid are fixed throughout the year. We analyse a tariff design, in which the export tariffs are dynamic changing based on the wholesale price of electricity announced 24 h ahead. The purpose of this policy is to encourage EES owners to optimize their device and export in higher prices, which is a signal for scarcity in the market. The results show no significant difference for ToU and static tariffs, as these are not impact by dynamic prices in the market. However, consumers under with real-time will improve their financial case under this policy for both storage technology options by 9% compared to Reference. However, this policy is not capable of making any technology option with storage net profitable (for more details see Appendix D).

3.3.2. Self-consumption tariff policy

The current export FiT provides a financial incentive to export electricity to the grid, but these exports typically occur during periods of low electricity demand. Also, PV-EES owners do not benefit from this tariff as they can reduce their export of PV by increasing self-consumption onsite. We therefore propose to eliminate generation-based incentives and enhance the FiT self-consumption tariff in a way that would maintain a constant stream of income to consumers with solar PV alone. We show how this policy would indirectly improve the financial case for EES by increasing rewards to solar PV self-use.

Fig. 8 shows how this policy could positively affect the NPV for consumers investing in PV-EES. While consumers with solar PV alone would not be affected by this policy, setting a well-designed PV self-consumption tariff would offer net positive value obtained by PV-EES 1800 £ for ToU tariff and up to 3080 £ for users under real-time tariffs compared to the Reference scenario. This is equivalent to 36–57% ROI for a residential PV-EES system, depending on the tariff. This increased ROI makes PV-EES more profitable than PV-alone in different tariffs, which translates into an increase in the value of self-consumption for prosumers, or up to 481 £/kWh installed capacity of EES, which is effectively equivalent to a subsidy of 68% of incurred battery capital costs.

3.3.3. Price gap widening policy

Price-gap widening policy, or also known as critical pricing, aims to increase the gap between off-peak and peak hours to offer higher potentials for arbitrage to private owners and encourage them to discharge at the times prices are high. The results show that this policy can effectively make storage a net profitable investment for a consumer operating storage for price arbitrage (see Fig. 9, storage-only). This policy, without having any capital burden on the regulator, would offer a value of 2230 £ to the storage owner in ToU and 3830 £ under real-time tariffs. This policy is very favourable for storage-only operators, who can capture the highest benefits for price arbitrage, making a ROI of 41% for users under ToU and 70% for those under real-time tariffs. The policy offers a slightly more moderate, yet significant, savings to consumers with PV-storage. The PV-storage operators need to allocate a portion of storage capacity for storing solar energy, which makes it less available for price arbitrage. Yet, this policy can make storage paired with PV near breakeven under the real-time tariff.

3.3.4. Introducing storage tariffs

The introduction of a storage tariff for rewarding owners of EES for each kWh of electricity discharged at the peak time could improve the financial case for EES. The storage tariff is calculated in a way that reflects the value created by the EES device relative to an investment in solar PV alone, which makes this tariff a function of the type of electricity tariff.

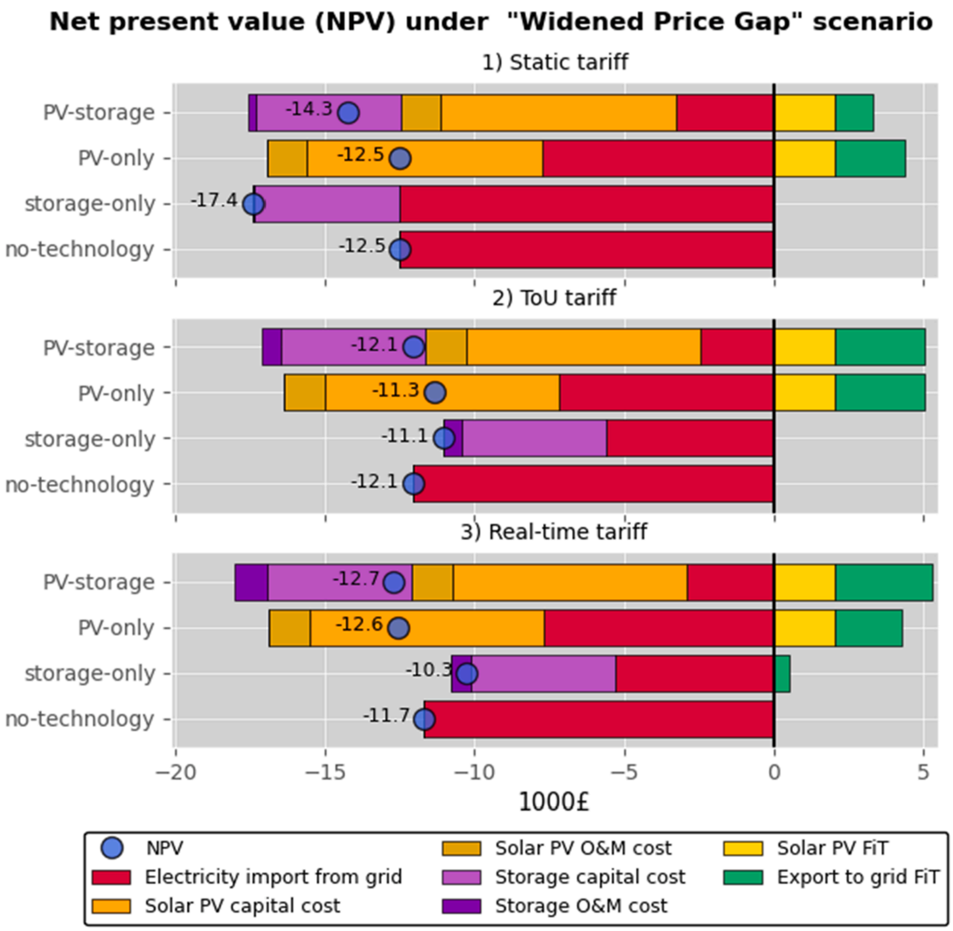

Fig. 9. Cost-benefit of the consumer investment in onsite technologies under Price-gap widening Tariff scenario for the standard residential building (middle-sized terrace house with electricity load of 3750 kWh/a). The costs are shown with negative values and revenues with positive. The blue marker and number on each bar show the NPV of the investment (NPV = present value of revenues – present value of costs). The NPVs shown on the bars are in 1000-£ and rounded up by one decimal.

With a moderate storage tariff of 0.049 £/kWh, this policy is effective in making storage-only net profitable compared to not having any onsite technology, under ToU tariffs. The proposed storage policy can save 1720 £ for ToU and 2380 £ under real-time tariffs, which makes up to 40% ROI. This policy therefore indirectly provides further incentives to switch to the tariffs which provide the highest savings, i.e., dynamic tariffs (see Appendix D for further details).

3.3.4.1. Enhanced storage policy. We analyse a combination of price-gap widening policy and storage tariff introduced in this study, in a new policy called Enhanced storage policy. The results show that this policy can make storage-only investment net profitable under both ToU and real-time tariffs. The consumer can enjoy a discounted revenue of 4050 £ under ToU and 5780 £ under real-time tariffs if switching to this policy. This means the consumer can cover the entire capital cost of battery under real-time tariffs. As Fig. 10 shows, the cost of this policy for the regulator is typically lower than the payments for export FiTs. Moreover, for PV-storage cases, this policy is the only policy so far that can make investment in storage profitable for PV-battery owners (under real-time tariffs).

3.3.5. *Capital subsidies*

Given the high capital cost of EES, lowering the upfront cost through capital subsidies has a large impact on profitability. The results show that while a 30% capital subsidy is barely enough to make storage owners reaching breakeven in their investments and only in ToU, a capital subsidy of 50–60% can make investment in batteries profitable almost for all storage-only and PV-storage tariff combinations (see Fig. 11). The capital subsidy is not combined with any preferential tariff for energy storage.

3.4. *Comparing different policy options*

The examined policy options have diverse impacts on the profitability of consumers depending on the chosen electricity tariff by consumers and the technology option. Also, each policy has a cost for the regulator, or the system operator, to be paid either through incentives generally referred to as policy cost. Fig. 12 compares the benefits of different policies for consumers investing in storage under real-time tariffs with the cost of that policy for the system. The values are based on the NPV of benefits and payments during 2015–2040 for each unit of storage capacity invested, relative to the Reference scenario (current policies). The results show that most of the proposed policies have higher benefits for consumers than the cost for the regulator, which overall increases the welfare[7] in the system. Interestingly, the policies have a different performance for storage-only and PV-storage, as the owners tend to use storage for two different purposes: price arbitrage for the former and increasing PV self-consumption plus price arbitrage for the latter technology option. For storage-only investments, the enhanced storage policy tariff introduced in this paper offers the highest benefits to the consumer, followed by price gap widening strategies. Considering the cost of these policies for the system, the net welfare that they generate is significant, i.e., 520–540 £/kWh of storage capacity. However, for consumers pairing storage with their PV, the PV self-consumption tariff followed by capital subsidies and storage policies

[7] By "system welfare", we refer to direct costs and benefits of a policy to relevant stakeholders, i.e., the consumer and the system operator. We do not account for indirect costs and benefits of each policy, e.g., in terms of the changes in the welfare of central power producers.

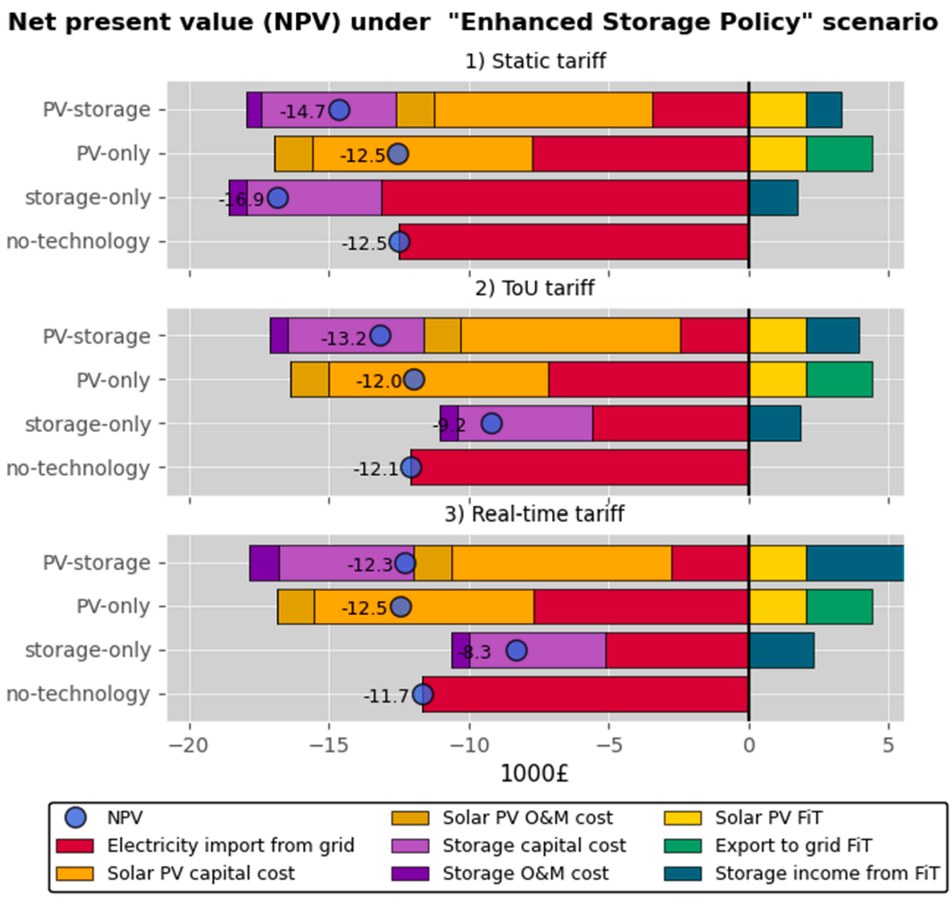

Fig. 10. Cost-benefit of the consumer investment in onsite technologies under Enhanced Storage Tariff scenario for the standard residential building (middle-sized terrace house with electricity load of 3750 kWh/a). The costs are shown with negative values and revenues with positive. The blue marker and number on each bar show the NPV of the investment (NPV = present value of revenues – present value of costs). The NPVs shown on the bars are in 1000-£ and rounded up by one decimal.

are more economical choices.

Considering the cost and benefits of the policies, the self-consumption tariff and storage policy generate the highest welfare for the system. Capital subsidy of 60% has the highest cost for the system, making such capacity-based incentives net-zero in terms of welfare generation. The results for consumes under ToU tariff show that dynamic, price-based storage policies offer the highest value if the user adopts storage without pairing with PV (storage-only case) (see Fig. 13). However, when paired with PV, the proposed storage policies based on price gap offer no significant benefits, and for both "price gap widening" and "enhanced storage policy", the cost for the system is higher than the benefit for consumers. Because in ToU tariffs with only two timespans (peak and off-peak), retail electricity prices remain unchanged for most of the hours, i.e., from 7 AM until midnight. Therefore, storage will be mainly used for increasing PV self-consumption with limited opportunity for price arbitrage. This conflict of benefit from night-to-day price arbitrage and keeping storage capacity for shifting solar generation from daylight to evening peaks, makes the storage policies less attractive for PV-storage owners, compared to adopting storage alone.

The results show little potential for consumers under static tariff to benefit from storage policy options proposed based on time-of-the-day prices, making capital subsidies best policy for this type of tariffs. Table 4 shows the impact of the considered policies on the financial case for the consumer when investing on a EES system for all three tariffs and storage technology options. The results show the return on investment (ROI) on storage, change in the NPV compared to the Reference scenario, and change in the cost of the policy compared to the Reference scenario. The cost of policy is calculated based on additional tariffs and subsidies that the regulator must pay to the consumer investing in EES.

As the results show, the system cost of policy is in most cases, like subsidies, equal to the private gain of the storage owner. However, there are some cases that a policy creates higher benefits for the consumer compared to the cost for the system operator. For example, in the price-gap widening scenario and for real-time tariffs, the gain of consumer is between 60% to more than 7-fold higher than the tariffs that the regulator needs to pay. In some cases, like the storage policy, both consumer and the regulator gain positively from the proposed policy, under real-time tariffs and PV-storage. Subsidies of 60% show the highest cost in the examined policies in this comparison. The enhanced storage tariff offers almost double savings to consumers (5780 £ cf. 2870 £), with 19% lower cost for the system compared to 60% capital subsidy.

PV self-consumption tariffs and the implementation of a storage tariff show to be the most effective policies in terms of added benefits for consumers for each unit of cost carried over by the regulator. Finally, switching from static to ToU and further to real-time tariffs can improve the system's profitability considerably for the policies that are targeting to optimize the performance of residential PV-storage with respect to electricity price signals in the wider power system. A 50–60% capital subsidy (~2500–2700 £) is enough to enable PV-EES to reach profitability compared to current-day policies.

The proposed enhanced storage tariff is shown to be among the most effective policies to improve the profitability of EES for consumers with only storage at their site, offering a ROI of 74–105% depending on the tariff.

3.5. Sensitivity analyses

To verify the robustness of our results, we calculate the sensitivity of NPV of PV-storage subject to changes in nominal discount rate; capital cost of solar PV; O&M cost of solar PV; and capital cost of the battery. The sensitivity analyses indicate that the financial case for PV-EES is mostly sensitive to the capital cost of technologies, and the least by the

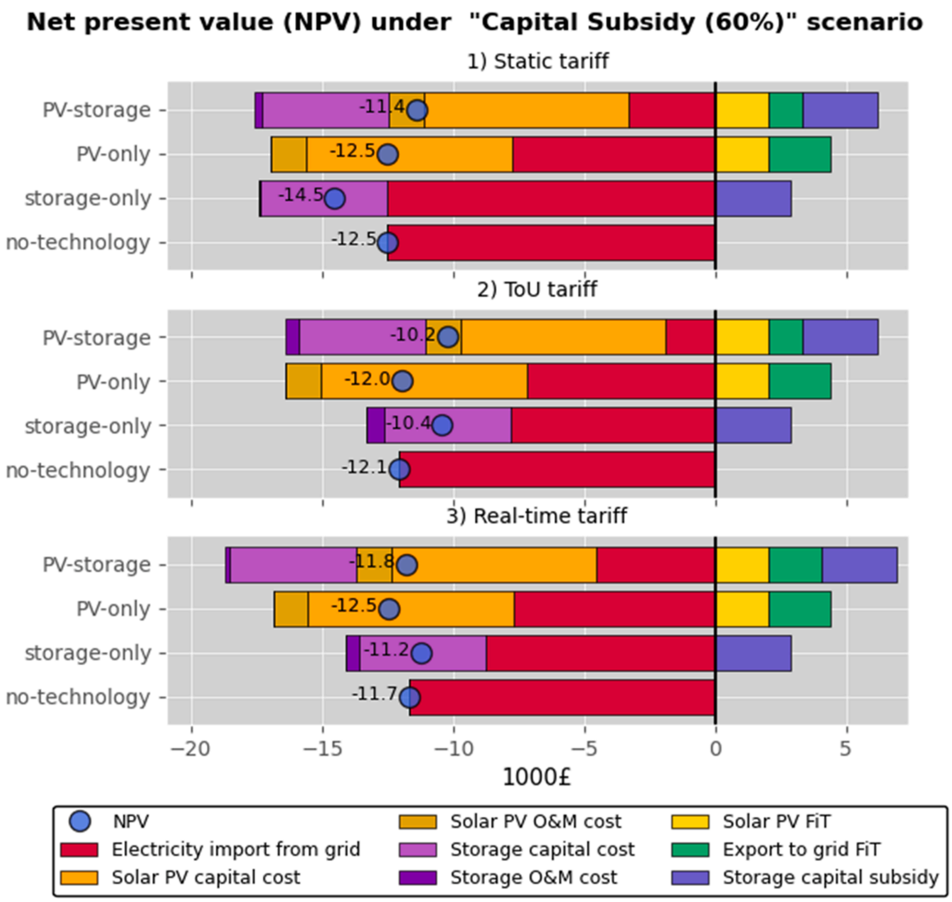

Fig. 11. Cost-benefit of the consumer investment in onsite technologies under 60% Capital Subsidy for the battery, for the standard residential building (middle-sized terrace house with electricity load of 3750 kWh/a). The costs are shown with negative values and revenues with positive. The blue marker and number on each bar show the NPV of the investment (NPV = present value of revenues – present value of costs). The NPVs shown on the bars are in 1000-£ and rounded up by one decimal.

O&M costs. Generally, our sensitivity analysis, summarized in Table 5, indicates that 33% reduction in the capital cost of battery will make PV-EES systems net profitable under current market conditions (Reference scenario). More importantly, assuming zero capital cost for the battery shows a NPV of 677 £ for each kWh installed battery. This can be an indication of the cost of the battery that can result in breakeven between costs and benefits. This includes the battery unit cost, installation, and 20% VAT.

3.5.1. *Different building sizes with different electricity demand*

The results so far presented the financial case for a standard building, medium sized, three bedrooms with 3750 kWh load per year. We run simulations for a range of different residential buildings with different load values to examine the profitability of the examined technology options with respect to the size of the building. The UK Electricity Survey Data [45] has classified UK households with their annual electricity demand ranging from 3080 kWh for small terrace house to 4400 kWh for large private houses. We analyse consumer loads for a range between 2750 and 6000 kWh to cover all possible cases. We apply the same hourly load pattern but scaled based on the annual load of the household. We do not explicitly model the future changes in the load pattern, e.g., due to electric vehicle charging, which is one of the limitations of this study.

Fig. D6 in Appendix D compares the NPV of investing in battery for seven different building types, based on the annual load of the building and the electricity tariff of the consumer. The results show that the battery size (6.4 kWh) examined in this study shows better NPV in buildings bigger than the standard type examined here (3750 kWh). For ToU tariff, if the residential building would have an annual load of greater than 5250 kWh, the battery will be already net profitable when pairing with PV. The result indicates that the size of batteries in the market (6.4 kWh and 12.3 kWh for Tesla Powerwall variants) are relatively large for the size of most buildings in the UK, considering a solar PV capacity of 4 kW (more details in Appendix D)

3.5.1.1. Solar PV Self-consumption. Increasing solar PV self-consumption is one of the objectives of prosumers to reduce their import from the grid. Also, the system operator benefits from self-consumption as this will ensure a smooth operation of the distribution grid at peak sunny hours, eliminating the grid management cost for coping with excessive export of electricity from homes to the grid in short periods, as noted in different studies [64,65]. Increasing self-consumption improves the economic value of the PV system for the prosumer as export tariffs are usually much smaller compared to buying electricity from the grid. Mckenna et al. [66] analyses a large dataset of solar PV data from different countries, concluding that self-consumption depends mostly on the amount of solar electricity generated and the amount of electricity consumed during the day. Fig. 14 shows the PV self-consumption for different building sizes and the role of storage in increasing self-consumption. These values are for a 4-kW PV installation, and if storage is used, the battery size is 6.4 kWh. For the standard building analysed in this study (load = 3750 kWh), pairing PV with battery almost doubles the self-consumption from 31% to 59–60% for consumers under ToU and static tariffs. However, those consumers running PV-storage with real-time tariffs would experience a lower self-consumption rate (see Fig. 14 (1)). This is due to the use of storage for price arbitrage in some hours when the price gap is so large that outcompetes the use of storage capacity for self-use of solar PV generation, resulting in exporting solar PV to the grid.

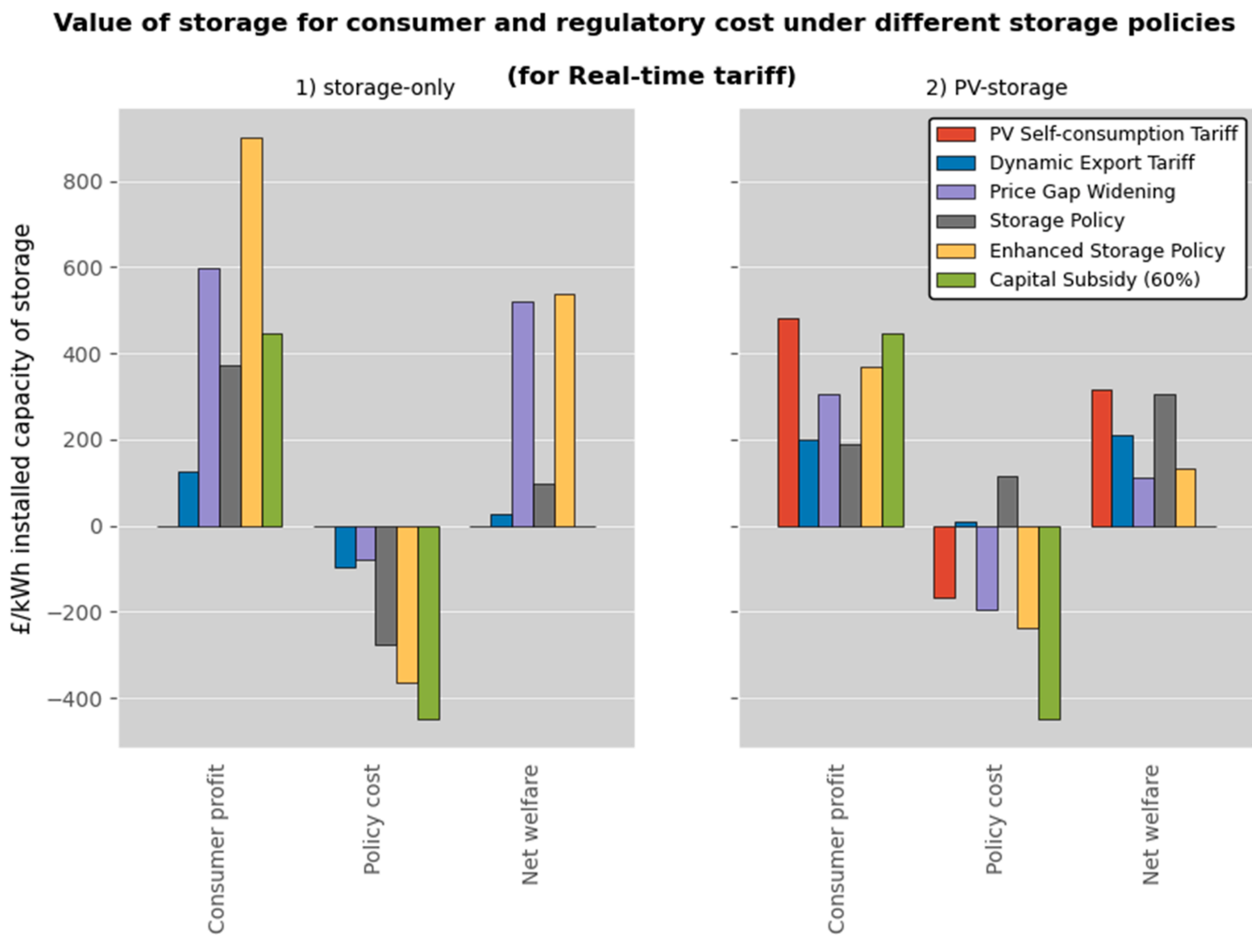

Fig. 12. Net present value (NPV) per unit of installed storage capacity under different policy options. The profit for consumers is compared to the cost of that policy for the regulator (under real-time retail electricity tariffs). Consumer benefit is the difference in the NPV of investment in storage compared to the Reference scenario. Policy costs show the relative difference in the discounted FiTs and subsidies paid by the regulator compared to Reference. Net welfare = consumer benefit – policy cost. Calculations are based on solar PV size of 4 kW, storage size of 6.4 kWh, and building annual load of 3750 kWh.

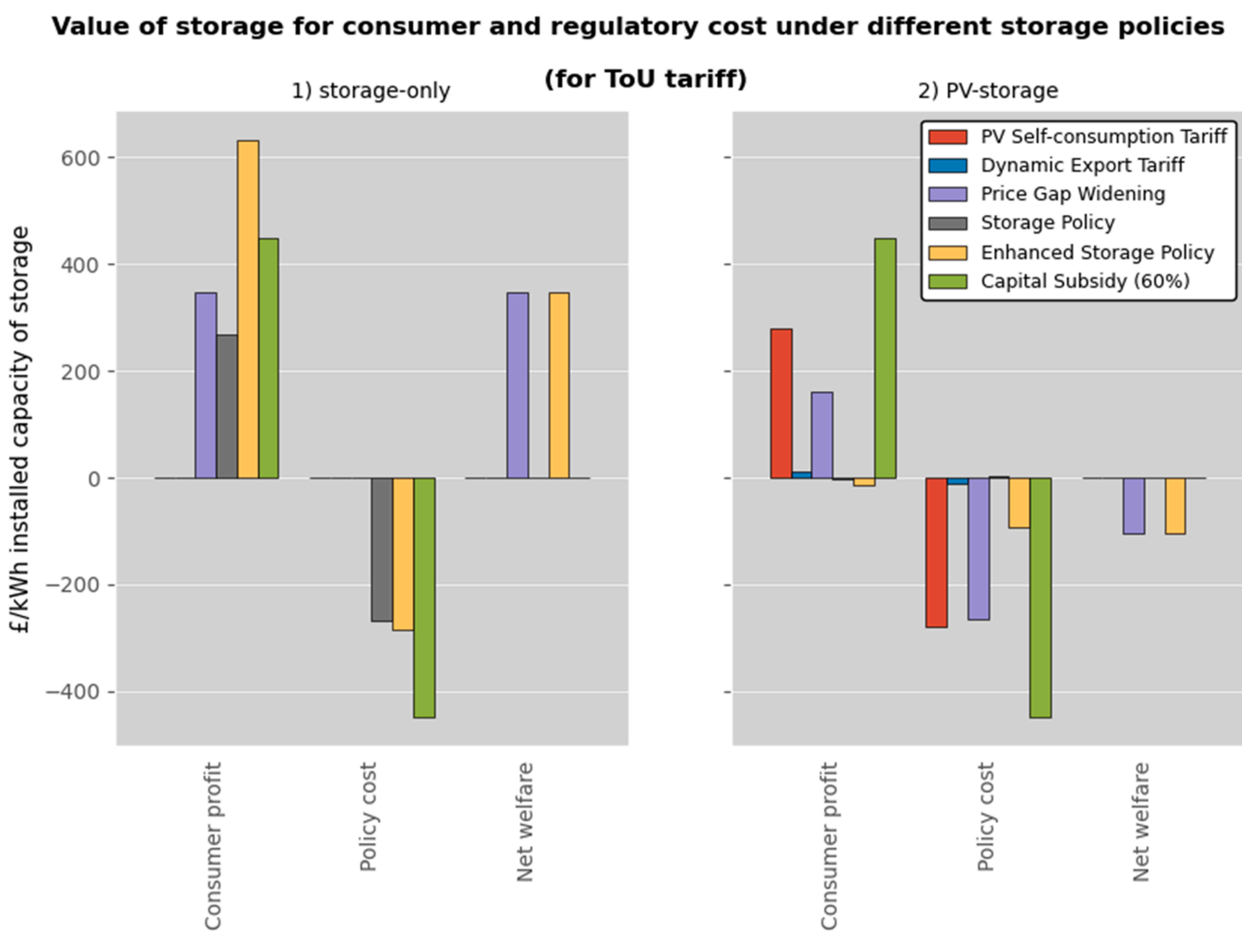

Fig. 13. Net present value (NPV) per unit of installed storage capacity under different policy options. The profit for consumers is compared to the cost of that policy for the regulator (under time-of-use (ToU) retail electricity tariffs). Consumer benefit is the difference in the NPV of investment in storage compared to the Reference scenario. Policy costs show the relative difference in the discounted FiTs and subsidies paid by the regulator compared to Reference. Net welfare = consumer benefit – policy cost. Calculations are based on solar PV size of 4 kW, storage size of 6.4 kWh, and building annual load of 3750 kWh.

Table 4
Comparing investment profitability of energy storage with and without solar PV under different policies. The values are relative to the Reference scenario for each technology and tariff combination.

Tariff type	Technology	Reference[a]	Self-consumption tariff			Dynamic export tariff			Price gap growth			Storage tariff			Enhanced storage tariff			Capital subsidy 60%		
		ΔNPV_{Ref}(£)	ROI[b] (–)	ΔNPV[c] (£)	ΔCost[d] (£)	ROI (–)	ΔNPV (£)	Δcost (£)	ROI (–)	ΔNPV (£)	Δcost (£)	ROI (–)	ΔNPV (£)	Δcost (£)	ROI (–)	ΔNPV (£)	Δcost (£)	ROI (–)	ΔNPV (£)	Δcost (£)
Static	storage-only	−4906	0%	0	0	0%	0	0	0%	0	0	10%	529	−1721	10%	529	−1721	58%	2868	−2868
	PV-storage	−1764	36%	1850	−1865	0%	0	0	0%	0	0	−8%	−409	15	−8%	−409	15	56%	2868	−2868
ToU	storage-only	−1207	0%	0	0	0%	0	0	41%	2227	0	31%	1721	−1721	74%	4053	−1826	52%	2868	−2868
	PV-storage	−1024	34%	1795	−1795	1%	75	−75	19%	1032	−1706	0%	−15	15	−2%	−85	−589	54%	2868	−2868
Real-time	storage-only	−2411	0%	0	0	14%	795	−619	70%	3834	−513	44%	2381	−1766	105%	5776	−2324	54%	2868	−2868
	PV-storage	−2972	57%	3079	−1061	23%	1282	60	33%	1948	−1238	23%	1213	740	40%	2366	−1509	57%	2868	−2868

[a] The difference in net present value of consumer after investment in each technology compared to having no technology onsite: $\Delta NPV_{Reference,technology} = NPV_{Reference,technology} - NPV_{Reference,no-technology}$.
[b] ROI, Return on investment = profitability of storage / storage investment. Storage investment includes the possible replacement of battery due to reaching end of life cycles. Thus, storage investment is slightly different under different policies, e.g., being higher in enhanced storage and price-gap widening policies because storage charge-discharge cycles are more frequent than other policies.
[c] ΔNPV, difference in net present value of consumer after investment in energy storage compared to the Reference policy: $\Delta NPV = NPV_{policy,technology} - NPV_{Reference,technology}$.
[d] ΔCost, difference in the cost of implementing the policy compared to the Reference policy: $\Delta Cost = -(Cost_{policy,technology} - Cost_{Reference,technology})$.

3.5.2. *Location of the building and solar PV irradiance*

The analysis of the storage policy options so far was focused on a location in London. To understand the impact of latitude and solar irradiance on the revenues of prosumers from their PV and PV-storage technologies, we examine five different locations in the country, namely Brighton, Birmingham, London, Manchester, and Edinburgh, with annual solar PV capacity factors ranging between 11 and 14% (2019) from south to north (hourly data from [67]).

The results show that the latitude has direct impact on the profitability of investment in solar PV, either alone or combined with storage. Among the examined cities, Brighton is the most southern one, in which the NPV of investing in solar PV under ToU and static tariffs will be already net positive in the Reference scenario. On the other end, Edinburgh shows the lowest NPV of investment in PV and PV-storage compared to the other cities. If a consumer in this high-latitude city invests in solar-PV, the NPV of the investment will be -4200 £ compared to no technology onsite. This is almost 50% lower compared to London, the location for the case study of the paper, where the NPV of investment in PV-storage is -2200 £ compared to having no technology under the Reference scenario. These results can be seen in Appendix D.

However, if we compare the value of storage paired with PV under the proposed enhanced storage policy, the cities in higher latitudes show greater savings compared to the Reference scenario for the same city (see Fig. 15). This happens because storage capacity can be more favorably used for price arbitrage, hence, making up for some part of lower PV generation in higher latitudes. In summary, the NPV of investment in PV-storage in Edinburgh is still lower than London, for example, in all examined scenarios. But switching from PV-only to PV-storage in Edinburgh has 18% savings for the consumer compared to that of 16% in London under dynamic FiT-based storage policies.

3.5.3. *Optimal sizing of storage and benefits from policies*

For the examined consumer type (load 3750 kWh/a), the Powerwall1 battery (6.3 kWh) is too large. The results show that due to a mix between low insolation and magnitude of electricity consumption, the operating cost of electricity will not fall should the consumer purchase an additional battery or a battery with higher capacity, such as Tesla's larger Powerwall2.

The optimal maximum battery size for the average UK consumer is 3.1 kWh, almost half of the 6.4 kWh usable battery capacity examined in this paper (=Tesla Powerwall1). Therefore, a battery with half the original capacity (3.2 kW) and, assuming a linear relationship between capacity and capital costs, costing half the original price, would offer breakeven in costs and revenues even under the Reference scenario (see Fig. 16 (a)). We also show the optimal size of the battery for one of the proposed policies, i.e., enhanced storage policy in Fig. 16 (b), which indicates that a smaller-sized battery with 3–4 kWh capacity would have offered more profits compared to the examined case study. Other studies have confirmed this finding that the optimal size of residential batteries in high-latitude countries is smaller than commercial products in the market for most households (for example see [68]). Tesla Powerwall II battery with a size of 12.3 kWh is not profitable for any building size listed in the UK Consumer Electricity Survey under the Reference scenario but shows positive NPV for buildings with an annual load of greater than 5250 kWh under the proposed enhanced storage policy (see Fig. 16 (b)). Therefore, it is important for residential distributed technologies to be sized correctly to optimize the financial case for the private user.

Fig. 17 shows the NPV of storage as a function of size of the PV and battery for two scenarios. In the Reference scenario (Fig. 17 (a)), the value of PV-storage is maximized when the size of storage (kWh) is half of the annual load (here 3.75 MWh), and half of the PV capacity (kW). For the standard building examined in this study, the size of storage (6.4 kWh) seems to be large, and a storage size of 2–3 kWh seems to be most optimal. Under the enhanced storage policy (Fig. 17 (b)), the householder can pair larger storage sizes with their PV and remain in the net

Table 5
Sensitivity analysis: change in net present value (NPV) of investing in a PV-storage system. The values are under ToU tariff, for PV-storage technology option (4 kW PV and 6.4 kWh battery), and under the Reference scenario.

Input variable	Initial value	Net present value (NPV) per unit of installed storage capacity (£/kWh)					
		Decreasing input variable by			Increasing input variable by		
		−100%	−66%	−33%	+33%	+66%	+100%
Nominal discount rate	5%	696	444	62	−497	−858	−1249
Capital cost of storage	712 (£/kWh)	677	401	34	−436	−712	−997
Capital cost of solar PV	1866 (£/kW)	1064	661	121	−563	−969	−1384
O&M cost solar PV (including inverter)	~90 (£/kW/a)	50	−21	−113	−228	−299	−370

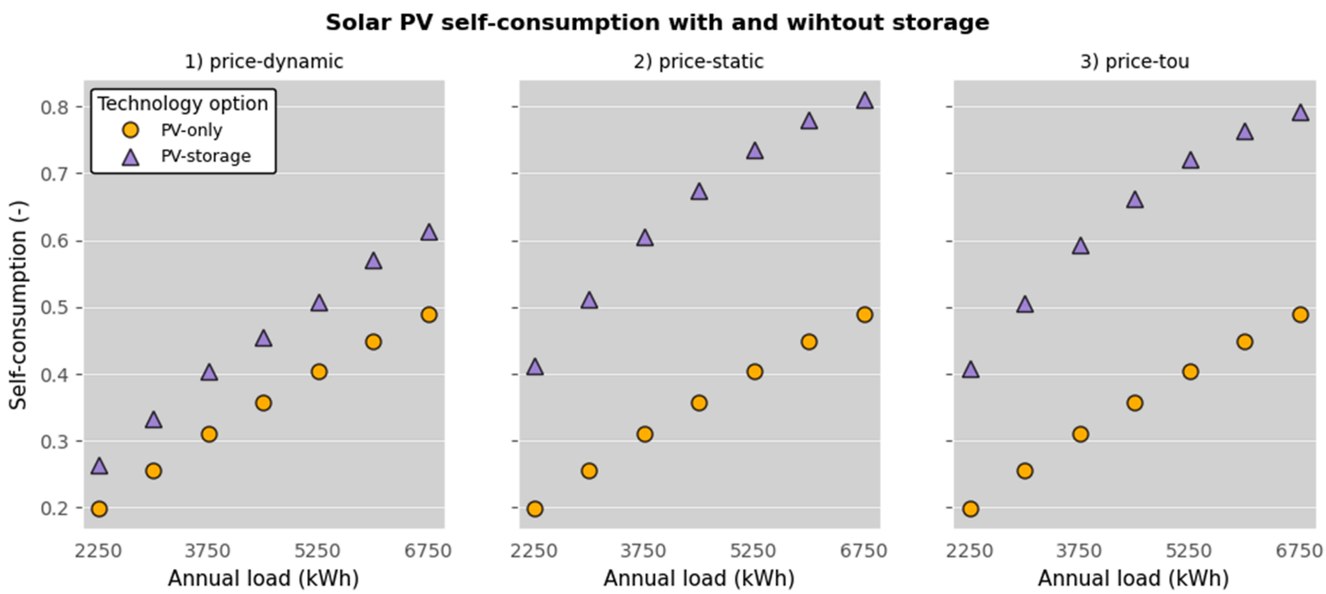

Fig. 14. Solar PV self-consumption with and without storage for different building sizes and consumer electricity tariffs under Reference scenario. The installed capacity of solar PV is 4 kW, battery is 6.4 kWh, and the location is the London area.

positive value region. For example, for a PV size of 3 kW, a battery size of 6.4 kWh can be paired with net positive return (however, the optimal battery size is approximately 4 kWh). Because in this policy, the unused capacity of battery after PV self-consumption can be employed in price arbitrage and increasing the profits of the owner.

4. Discussions and policy implications

4.1. Storage and consumer electricity bills

4.1.1. Storage decreases annual electricity costs

Self-consumption of PV electricity increases considerably with EES for a typical UK consumer. EES substantially decreases the cost of electricity imports from the grid, except for those under a static tariff regime. By pairing a battery to a solar PV system, consumers can reduce annual electricity bills by up to 84% (467 £/a) if combined with ToU tariffs.

While EES decreases annual electricity bills, the high capital costs make it an unprofitable investment under current market and tariff conditions. Considering the system benefits that EES can provide, policies aiming to improve the attractiveness of such investments will be increasingly valuable as the share of domestic PV capacity increases in the power system and self-consumption is becoming more important. The efficacy of these policies is discussed hereafter.

Results obtained for lower-latitude countries may be different from those reported in this study. The amount of solar PV generation will determine the utility of the battery to the consumer, hence the battery's profitability. Solar generation, on the other hand, depends on insolation, which can be approximated by the country's latitude. We show that in higher latitudes the profitability of PV stand-alone system decreases. However, pairing solar PV with EES, and employing the unused capacity of EES for arbitrage will compensate for the loss of expected gain from solar self-consumption in higher latitudes.

Bhandari *et al.* [69] finds that insolation generally has the larger impact on the profitability of solar PV . The results of policy analysis can therefore vary significantly across from different latitudes. However, if consumer electricity prices would be high, like that of Germany, the PV-EES investment will be net positive value for the prosumer due to significantly less dependency on the grid. By analysing a range of policies, we show that the regulator can design retail tariffs more flexibly to reflect hourly dynamics of wholesale prices in them, encouraging consumers to deploy their storage capacity to offer load levelling and peak shaving.

4.1.2. Dynamic electricity tariffs for domestic users

Dynamic tariffs, including ToU and real-time tariffs, provide the highest cost savings to consumers deploying EES, under tariff-based policies analysed in this paper. More consumers on time-of-use tariffs would make the retail price more reflective of the wholesale cost, which would in turn make consumers (especially those more reliant on the grid) more dependent on wholesale cost fluctuations. In early 2016,

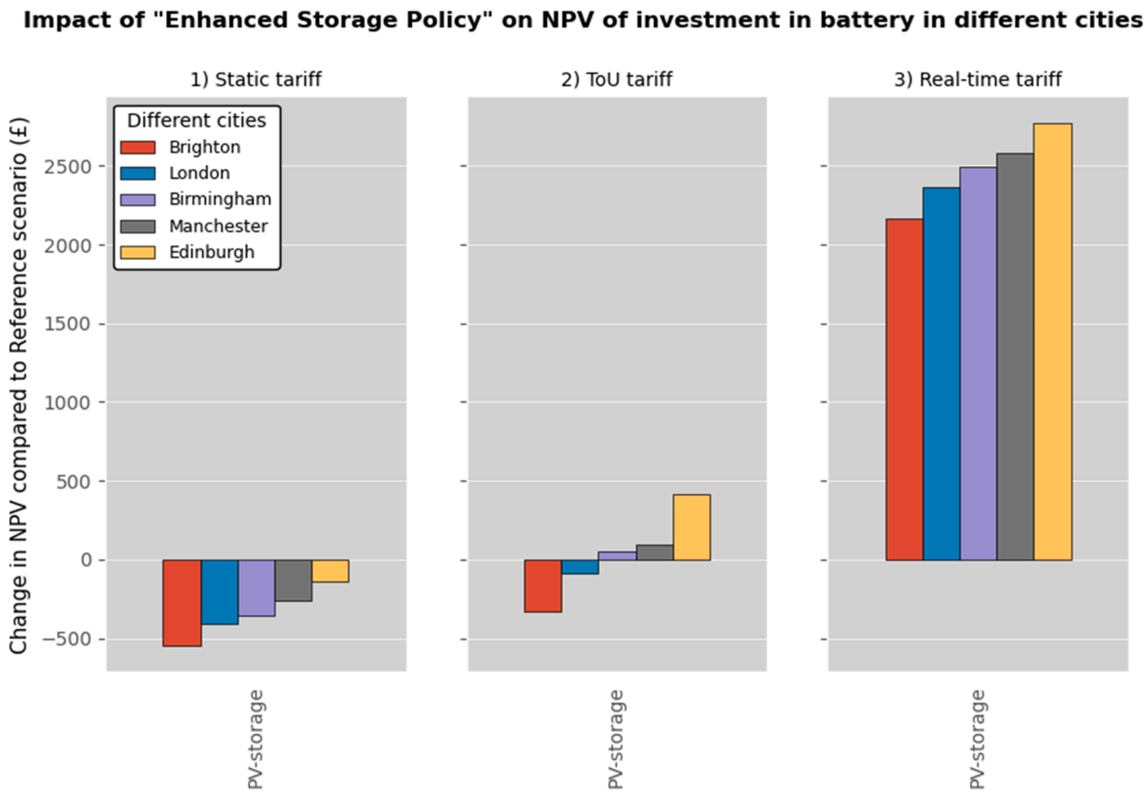

Fig. 15. Impact of the proposed storage policy on the profitability of prosumers with PV-storage systems in different cities with different solar irradiance. The results show the change in the net present value (NPV) of investment in storage device of 6.4 kWh, compared to the Reference scenario.

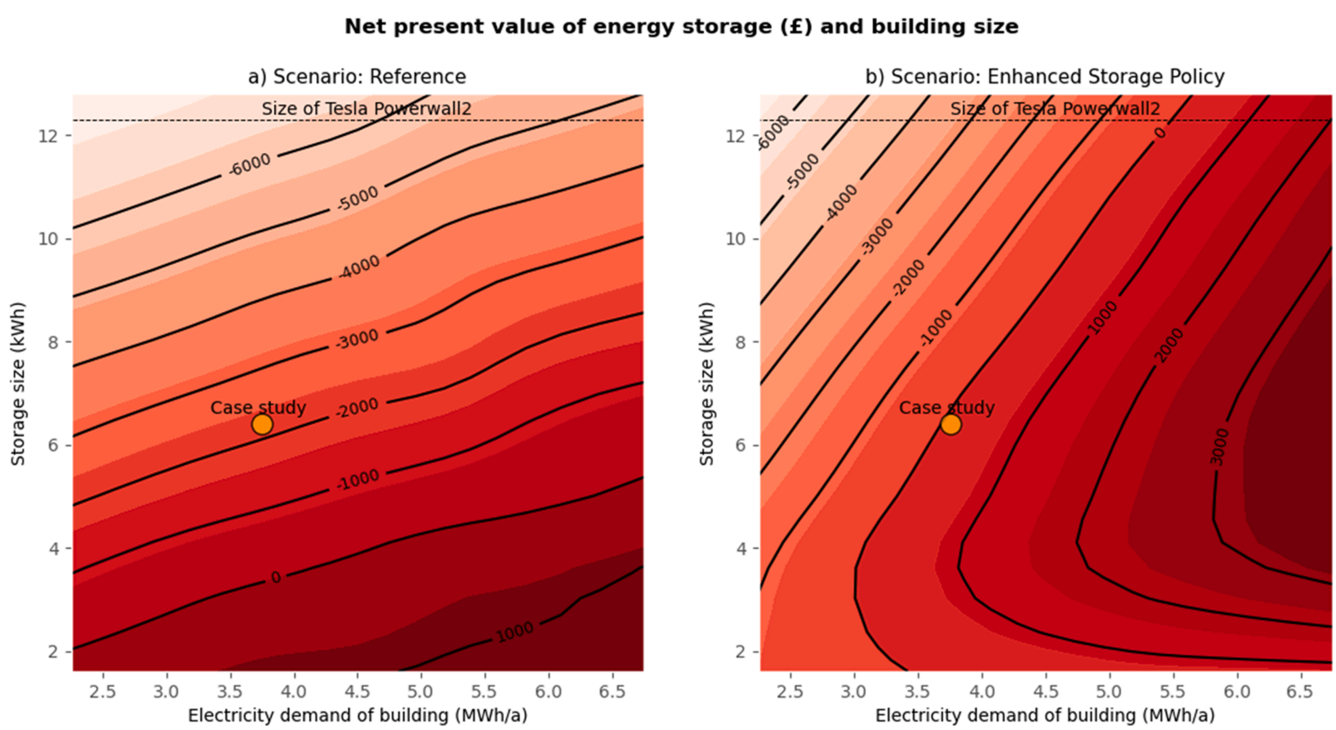

Fig. 16. The combined impact of building size (electricity demand of the building) and storage size on the net present value (NPV) of investment in storage when paired with Solar PV (size of solar PV of 4 kW). The standard building size examined as the case study in this paper is shown with the circle, orange marker. The NPV is the difference between NPV of PV-storage and that of PV-only for consumers under real-time electricity tariffs.

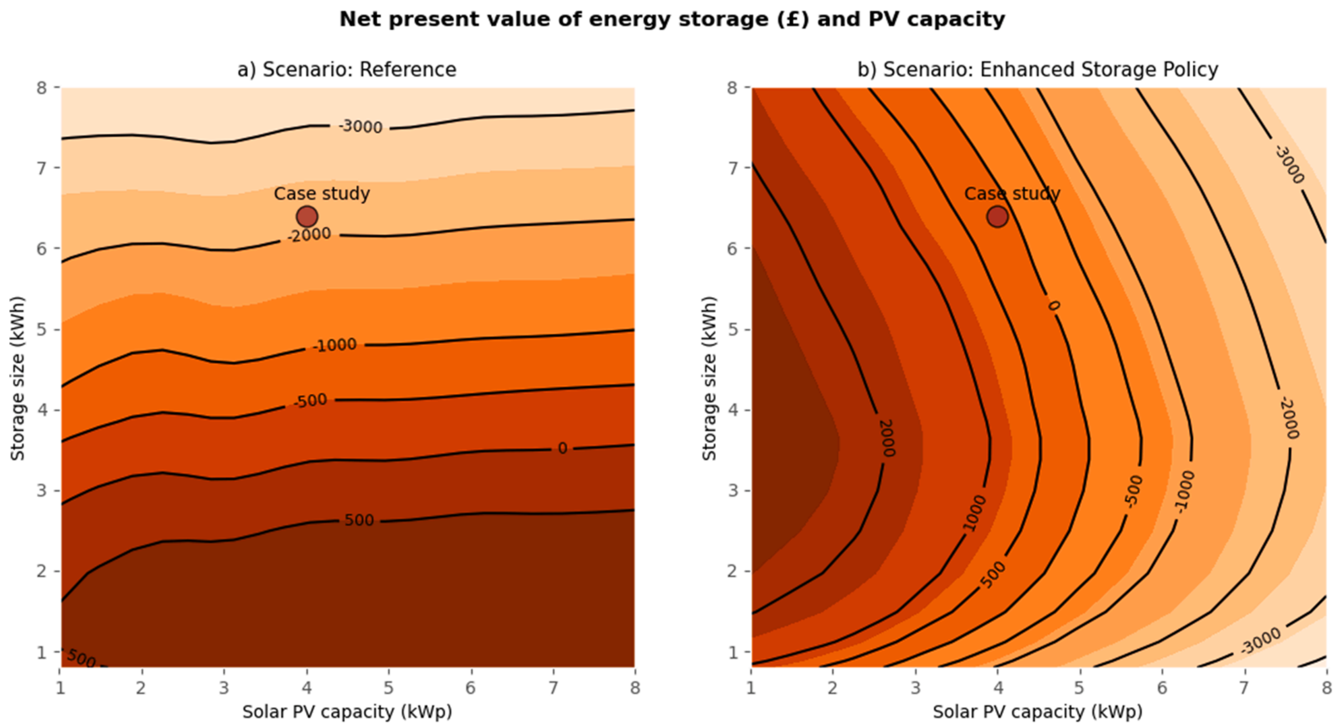

Fig. 17. The net present value (NPV) of the investment in storage when paired with Solar PV as a function of solar PV capacity and storage size. The standard building size examined as the "case study" in this paper (building annual load = 3750 kWh) is shown with the circle, brown marker. The NPV is the difference between NPV of PV-storage and that of PV-only for consumers under real-time electricity tariffs.

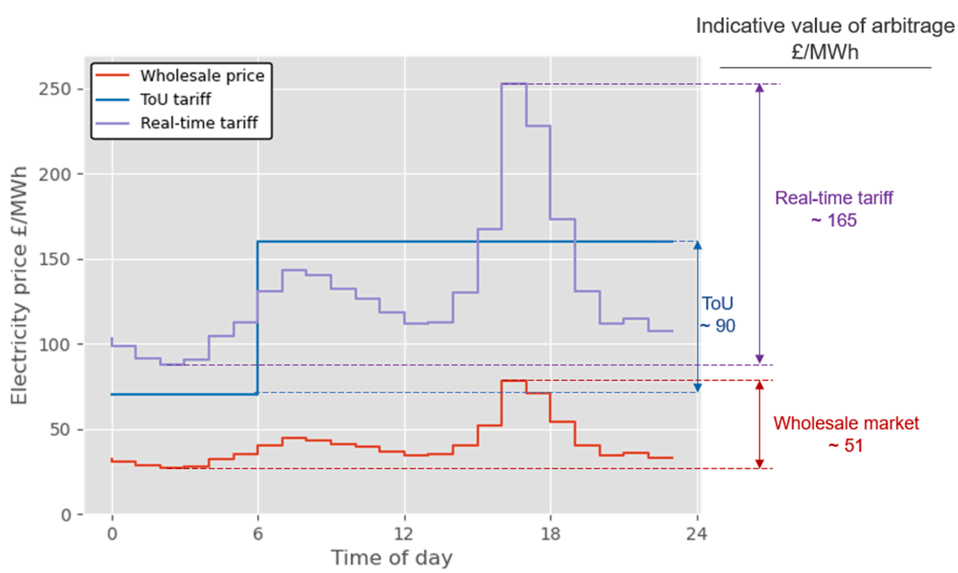

Fig. 18. Comparing the gap between peak and off-peak electricity prices averaged for each hour of the day for one year. This gap is an indication for the potential value of price arbitrage by electricity storage. Wholesale electricity prices are relevant for utility-scale storage while time-of-use (ToU) and real-time prices for residential storage (home battery).

California approved Net Metering 2.0, a policy which will require new solar homeowners to switch to ToU rates[8] [70], which could be beneficial even for consumers who do not operate EES or PV. Our results confirm this, showing that installing storage (without PV) under ToU tariffs will reduce the electricity bills of consumers by 35%. If storage paired with PV, the electricity bills can decline by 74% compared to PV-alone, and by 84% compared to having no technology onsite.

4.1.2.1. Designing ToU and real-time tariffs. Retail electricity prices consists of wholesale electricity prices plus network fees and system taxes and levies. Whether savings from EES are higher with ToU or real-time tariffs depends on the tariff levels at times of positive residual load, i.e., overproduction of solar electricity. EES-led annual bill savings can be higher for consumers on ToU and real-time tariffs, compared to existing tariffs, if the ratio between the peak and off-peak tariff will be wide enough to make price arbitrage by EES profitable. This price gap can be designed by the regulator by distributing network fees and taxes unevenly between different hours of the day, for example, charging

[8] http://www.cpuc.ca.gov/General.aspx?id=3800

Table 6
Comparing different policies analysed in this study with respect to their main characteristics, advantages, and complexities.

Policy option	Main feature	Ease of policy implementation	Public Expenditure considerations	Consumer perspective/ ease of uptake	Economic value for consumer[a] (£/kWh battery installed)	Policy cost[b] (£/kWh battery installed)
PV self-consumption tariff	Direct incentive for self-consumption	Straightforward: - net metering of annual load, PV generation, and imports from the grid.	FiT over many year	Moderate (optimizing battery for self-use of solar PV)	481	−166
Dynamic export tariff	Hourly export FiT based on market prices of electricity	Moderate: - hourly metering of import/export, - communicating hourly tariff levels to consumers	FiT over many year, adjustable	Complex[c]	200	Positive gain = 9
Price gap widening policy	Critical pricing of peak and off-peak prices in consumer tariffs	Easy: - hourly metering of import–export	Retail tariffs over many year, adjustable	Complex[c]	304	−193
Storage policy	Rewarding storage discharge at peak hours	Moderate: - hourly metering of storage charge and discharge - communicating hourly tariff levels to consumers	Retail tariffs over many year, adjustable	Complex[c]	190	Positive gain = 116
Enhanced storage policy	Combination of critical pricing and storage policy	Moderate: - hourly metering of storage charge and discharge, import and export - communicating hourly tariff levels to consumers	Retail tariffs over many year, adjustable	Complex[c]	369	−235
Capital subsidy (60%)	Subsidizing 60% of the investment cost of battery	Straightforward	One-off capital cost	Easy (no uncertainty related to future prices, and no need for optimal operation of the battery)	448	−448

[a] Difference in the net present value (NPV) of investment in PV-EES compared to the Reference scenario.
[b] Difference in the cost of implementing the policy compared to the Reference policy (negative sign shows payments, and positive sign shows gains).
[c] The consumer needs a battery management and optimization system to maximize the benefits from price arbitrage and PV self-consumption. The operation of battery will depend on hourly electricity prices and the generation of solar PV electricity each day. Also, there is uncertainty in estimating the benefits, if future electricity prices are unknown and the regulator does not guarantee the tariffs for long term.

higher taxes and fees at peak hours compared to off-peak. Implementing real-time tariffs that can increase the arbitrage value of EES implies monitoring the wholesale electricity prices during periods of high demand and setting the hourly real-time tariff level during these periods higher relative to the wholesale prices. The retail prices can be updated on a rolling basis when wholesale electricity prices are cleared in the day-ahead market. Fig. 18 shows the potential value of arbitrage for residential consumers under current ToU tariffs, which is already 80% higher than that value based on the wholesale prices. The real-time tariff shown in this figure generates the same average electricity bill as ToU, however, with a much higher arbitrage value for EES. The regulator can intensify the gap between peak and off-peak retail prices (so called, critical pricing), to reflect the need for storage at the distribution grid level, which is not typically accounted for in wholesale prices. This widened price gap offers an enhanced arbitrage value to residential EES, three times that of in the wholesale market, for load levelling and peak shaving in the system.

4.1.3. *Size of battery and consumer savings*

The Tesla Powerwall1 battery capacity is substantially larger than the optimal size for the needs of a standard UK electricity consumer (annual load 3750 kWh/a). Consumers in the UK and high-latitude countries could benefit from lower battery sizes since this may maintain a higher utilization level of EES . Our analysis for different building sizes shows that a ratio of 80% between battery capacity in kWh and annual load of the building in MWh is the maximum threshold for EES being net profitable under current market conditions. This means, for a terrace house with the annual load of 5 MWh, the suitable size of battery is approximately 4 kWh, which is much smaller than current commercial batteries like Tesla Powerwall 2, with 12.3 kWh storage size.

Given the low charge levels ordinarily achieved by the studied consumer-operated battery, policies aimed at supporting higher battery capacities or improving battery efficiency are irrelevant toward improving the battery's use, or its profitability to consumers. Additional battery capacity or enhanced efficiency may typically not improve the value of EES in high-latitude countries due to high electricity consumption and low insolation. However, we show that if policies enhancing the arbitrage values of EES will be in place, such as critical pricing of retail tariffs or enhanced storage tariff discussed in this paper, higher sizes of the battery can be profitable too. Under such policies, the storage owner can capture synergies between PV self-consumption and peak shaving, or load levelling, with their battery creating private and system-level benefits.

4.2. *Consumer's financial case for solar PV and EES*

EES can reach profitability in the current market conditions if it will be able to provide more energy market services aside from arbitrage alone. There can be a trade-off or synergy between the EES used for private and system-wide utility. Encouraging consumers to adopt EES-only technology onsite could provide self-sufficiency, as well as flexibility services to the system. The financial case for EES will depend on the ability of the system operator to nudge consumers into foregoing the discharge of their electricity at those times that the system needs most, which could help the system operator to minimize system costs, making decentralized EES useful in the provision of balancing, load levelling, and peak shaving services. Under current FiTs, pairing EES with PV increases the overall cost of the system for the consumer relative to PV alone leading to a net loss. With higher price volatility, the provision of storage services for the grid, and battery innovation-driven declining costs, it could be possible for the integrated PV-EES system to become profitable, and even more profitable than PV alone.

Based on the examined system, battery cost reduction or value enhancement events (such as those described above) could lead to the

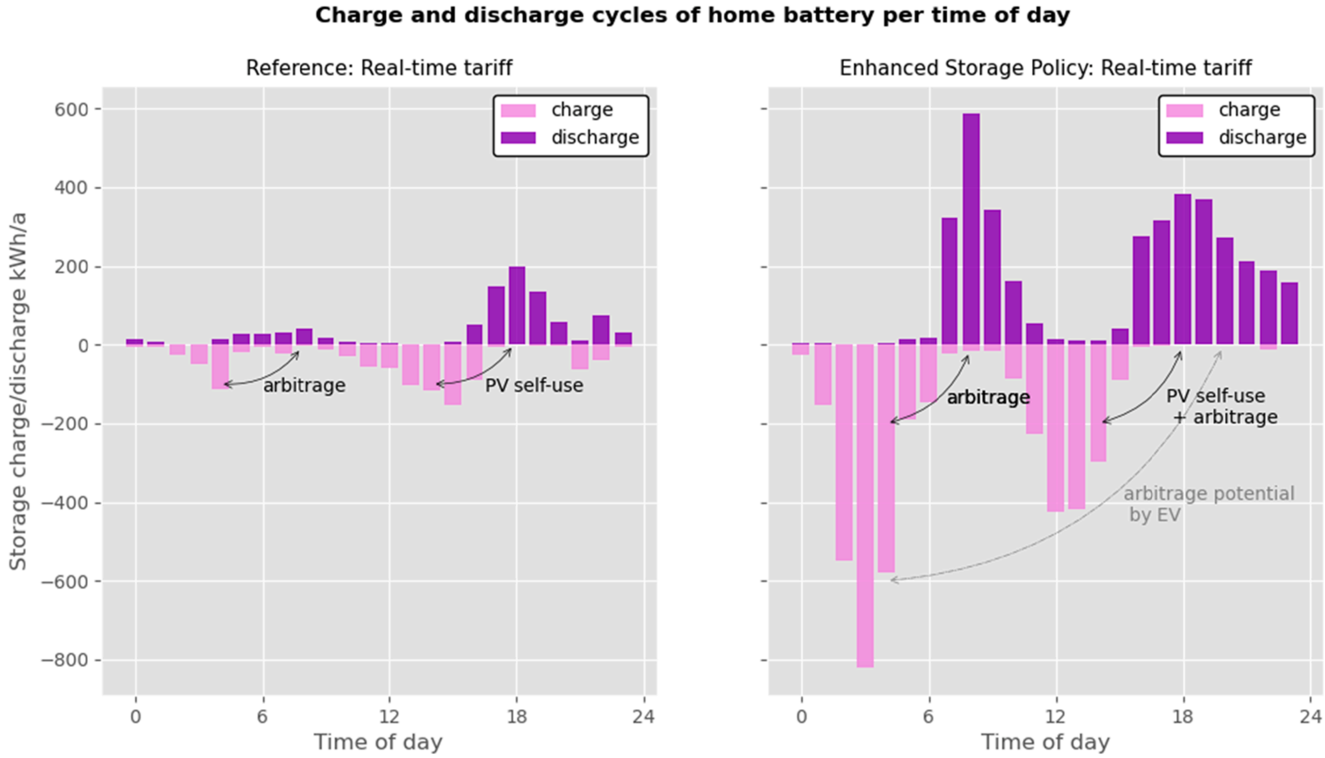

Fig. 19. Yearly charge and discharge of home battery in different hours of the day. The values are the sum of hourly operation of storage in a year for a PV-battery system (PV = 4 kW and battery = 6.4 kWh) for two different policies but for the same building.

NPV of solar PV and that of the integrated PV-EES system to equalize. For example, should the capital cost of batteries including installation fall to 369–541 £/kWh (depending on the consumer electricity tariff), the NPV of solar PV alone and that of solar plus EES would converge. This is 25–48% lower than the cost of battery today (assuming 712 £/kWh).

An investment in solar PV, EES, or both, is unprofitable for the average UK consumer under current policy and market arrangements. Whether, or how quickly, PV-EES will become more profitable than PV alone will depend on how policy accommodates EES, both directly and indirectly through supporting PV.

4.3. Storage policy and investment incentives

We analyse a range of policies that can enhance the profitability of EES for residential applications, both stand-alone and paired with solar PV. The proposed policies include, an enhanced PV self-consumption tariff, retail price gap widening scenarios, and energy storage policies.

The issue for residential EES in high-latitude countries is the low daytime electricity demand, rather than low solar generation. In hot climate countries, peak demand is during the day for air conditioning, while it occurs during the evening in colder countries such as the UK. Consumers in these countries tend to export electricity to the grid at times of low demand, so their value to the system is lower than if their PV systems were paired with EES, which can make PV-generated electricity available to the system when it is more valuable. We propose that the regulator would eliminate PV generation FiT in favour of a PV self-consumption bonus. For a typical consumer, eliminating generation and export-to-grid incentives can not only reduce electricity to be injected to the grid when it has a low value, but can also improve the self-consumption of PV electricity by consumers, reduce the burden of consumers' PV on distribution networks, and, as we have shown, improve the economic attractiveness of EES. This policy could be reserved to consumers who pair solar PV with EES and could be positively viewed by consumers because it has a net positive present value equal to 481 £/kWh for consumers under real-time tariffs. This return on investment is almost 70% of the capital cost of the battery. We have proposed a methodology for converting an existing generation FiT to a new PV self-consumption FiT, which would maintain the same benefits as generation FiT if consumers operating PV-alone (without EES).

We propose dynamic export FiT based on indexing the FiT on wholesale prices. This tariff is easy to implement as it does not require any behind the meter technology for metering or complex calculation. The user can employ their storage to export at times of high export prices, which can be announced a priory. This simple policy can save up to 200 £/kWh installed capacity of EES, which is equivalent to a 30% capital subsidy. More importantly, our results show that this policy has no additional cost for the regulator, compared to a fixed export tariff; hence, offering net positive value for both consumers and the system. Furthermore, we investigate some policies for regulating retail prices to widen the gap between peak and off-peak prices. These pricing mechanisms show to be among those with a high net present value for PV-EES owners, equivalent to 304 £/kWh installed battery. The system operator can benefit from this simple policy for example for load levelling and peak shaving.

A tariff paying EES providers for their ability to shift electricity in time could result in a more extensive deployment. We propose a storage tariff that could reward the value of EES to the system, by paying incentives for the discharge of storage at peak times. This policy was shown to offer net positive value to consumers from their investment. The policy prioritizes the discharge of electricity from residential batteries for grid services (e.g., reducing peak or contingencies and/or load levelling) over solar PV self-consumption alone. This means at some hours the consumer will be encouraged to export solar PV generation to the grid instead of storing that for their later use, while at some other hours this export to the grid will not be rewarded at all.

4.3.1. Policy implementation and consumer perception

The dynamic policies introduced here, which depend on hourly wholesale electricity prices, could be positively seen by domestic users as they offer positive net revenues from investment in storage paired with PV. However, there can be uncertainties in the level of price-based FiTs in the future, i.e., in years and decades to come. The system operator needs to design storage tariffs based on wholesale electricity prices or considerations related to the grid contingency management to be able to optimally reward consumers. This entails uncertainties as to future prices are not known and estimating benefits can be difficult and complicated both for the regulator and consumers. Model-based analyses and cost-benefit application can help consumers to understand these uncertainties and dependencies. Moreover, some storage policies should consider the trade-offs between higher current electricity prices to encourage the uptake of EES and lower future peak prices as the share of EES grows in the system. The net effect will depend on the ability of the system operator to jointly maximize private and system benefits, hence its ability to employ consumers' EES resources.

To overcome this challenge, i.e., sending right signals to residential consumers to invest in EES and operate their storage at times most valuable for the system; many studies have proposed the central coordination of EES by an aggregator or the system operator itself [12]. However, this represents a privacy issue as consumers may be reluctant to give away the control of their devices and perceive security risks for their home apparatus [71]. The storage FiTs proposed in this study have two advantages over central coordination. First, these policies do not need aggregation or virtual control of home batteries, hence, alleviating the risk of privacy-related reluctancy of consumers. Second, these storage tariffs empower consumers to benefit from retail price gaps and arbitrage value designed for end users, which is way greater than utility-scale value of arbitrage for central EES (see Fig. 18). More importantly, the regulator can accommodate any distribution grid related considerations in the tariffs, which are not typically possible to be reflected in wholesale prices derived at large price areas or at the national level.

The storage tariff can be designed in two ways: in a first embodiment, a fixed amount can be paid to storage providers based on the amount of electricity discharged at certain times of the day. This price can be chosen ex-ante based on an optimal price that would meaningfully stimulate deployment of the technology. A second possibility is for each consumer to be paid a different price based on the system value of flexibility, or the system cost of providing alternative marginal flexibility at a given hour of the day at a specified location. This case would be complex to solve and would require the use of often big distribution-level data. More significantly, tariff differentiation based on the location of consumers in the ditribution grid may be illegal in some power system jurisdictions. One solution is to offer different storage tariffs for different locations, reflecting the distribution grid needs, so that consumers can choose the tariff optionally based on their choice of distributed technology. Otherwise, it is recommended that a storage tariff would be designed in a similar way to PV generation and export tariffs, which are based on simple criteria such as unit size, presence of energy efficiency certification, time-of-day metering, etc.

Finally, we note that policies aiming to nudge consumers into switching tariffs have the least impact on the profitability of EES at present but may become relevant as capital costs fall over time. Yet, capital costs will only fall if there is widespread deployment, and an initial push could be decisive in providing confidence to those consumers considering an investment in EES. Table 6 summarizes the main features, advantages and complexities of the storage policies examined in this study.

4.4. Residential PV and electric vehicles

In this analysis, we did not explicitly model the role of electric vehicles on the residential PV-EES system. The possibility of using an EV with V2G capability as an alternative to a separate household EES to combine with PV is another option for increasing self-consumption [72]. The functionality would be very similar to a standard household EES when the EV is connected bidirectionally to the residential power circuit; charging when the PV panel is producing and discharging at night and in periods of low solar insolation. Clearly there would be some restrictions based on the presence of the vehicle at the building site and the householder's need for the EV to have a certain required charge level according to their mobility needs. However, the typical size of EV batteries –averaging around 50 kWh (as equipped in the cheapest version of Tesla Model 3[9]) is considerably more than the EES options studied here, i.e., 6.4 kWh. This indicates that a significant margin of the EV battery capacity would be available at most times, while a smaller household EES may still be needed as a buffer and also to cover daily needs if the EV is not present.[10]

Fig. 19 shows the charge and discharge of electricity in one year for each hour of the day for the modelled standard building. The results are shown for two scenarios: The Reference scenario including the existing policies (left) compared to a storage policy proposed in this study. The results show that there are typically two cycles of charge–discharge, one from nights to morning peaks and the second operating cycle from PV generation time to evening peaks. The enhanced storage policy (Fig. 19 (right)) shows the same pattern, however, with much higher frequency and amount of charge and discharge per year due to larger price gaps compared to Reference. The EV has a potential here to link the first storage cycle to the second, i.e., by charging the EV at night, using the vehicle during the day, and plugging back the remaining charging to the grid in evenings; when the owner returns home, there is no sun, and the electricity demand and prices are still high.

On the policy options for promoting V2G-based EES with PV, an interesting possibility for study could be adaption of existing subsidies for EVs (currently a maximum of 3000 £ in the UK). If these capital subsidies were redirected or banded according the V2G capabilities of the vehicles, with a further premium for combination with residential PV, the net government expenditure on subsidies could be minimized compared to implementing separate support policies for EVs and household PV-EES systems. The capital subsides for EVs could even be directly re-orientated towards the costs of the necessary electrical installations necessary for bi-directional connection between the EV and household power system. However, this synergistic option towards the promoting dual objectives of both increasing electromobility and residential PV self-consumption could be worth investigating. One technical barrier at present is that only one V2G-compatible EV is available on the consumer market, the second generation Nissan Leaf [73], and even in this case, the V2G-capability is available only with the installation of extra equipment, currently only used in test operation in Japan [72]. However, this is likely to change into the future and incentives for V2G-equipped vehicles would likely increase vehicle manufacturer offering to the private car market.

[9] https://www.tesla.com/en_eu/model3

[10] A number of optimization measures would be required – e.g., reduced charging of the car in advance of expected PV power being available and adapting the charging speed of the vehicles in line with the PV production – e.g., the current Tesla Model 3 has a minimum charging current of 6A, equating to 1540 W in the UK residential setting (converting power to 110 V could reduce the minimum compatible charging power to closer 700 W).

4.5. Drawbacks and future work

We only evaluated economic incentives for the consumers in their investments in solar PV with EES. Yet wider consumer preferences can be an important determinant of the adoption of distributed technologies. Consumers may wish to adopt EES for security reasons, environmental friendliness or simply because they are enthusiastic early adopters, and their decisions are not always based on measurable costs and benefits. Moreover, consumers are assumed to have rational expectations about the future [74], neglecting consumer psychology other than their ability to choose between technology performance and costs.

The same EES device could be used for arbitrage at certain times and for security at other times, especially for the consumers in off-grid areas or locations with a vulnerable grid. The value of the security option is not considered in this study and would constitute a valuable extension of this work. In-house EES could provide ancillary services in the future, but these potential revenue streams have not been considered in this paper. Aggregated EES has recently competed successfully in Capacity Market auctions and has provided Enhanced Frequency Response services [75]. However, optimal planning of EES for making aggregated revenues from different services in combination with arbitrage services is a complex issue and not considered here. We did not model EV charging and V2G possibilities as a potential EES device to be paired with PV. The future work can examine this, including the impact of EV charging on the hourly load pattern of the building, which we did not cover in this paper.

5. Conclusions

By applying a soft-linking modelling approach, we analyse the impact of different incentive mechanisms on the profitability of investing in solar PV and electricity storage technologies for a residential electricity consumer in the UK. Substantial savings on annual electricity bills could be achieved by prosumers if they were to pair their solar PV systems with batteries. These savings would be maximized with time-of-use (ToU) and real-time tariffs, rather than static, depending on the prevailing incentives for solar PV generation, export-to-grid, and self-consumption.

This paper shows that electricity storage would provide 25–35% annual electricity bill savings when adopted stand-alone. More significantly, storage offers 41–74% savings when paired with PV, compared to PV-alone. These ranges depend on the type of the retail electricity tariff. Combining solar PV and storage without policy intervention, however, is not economically profitable under current market conditions and incentives for solar PV.

We analyse the provision of financial incentives targeting electricity storage based on the system-level benefits of the technology, contribution of storage in self-consumption of PV onsite, and the cost of each policy for the regulator. We propose three types of policies, including, solar PV self-consumption bonus, dynamic retail pricing mechanisms, and a ‘storage policy’. The storage policy is to reward consumers for each kWh of electricity discharged from their storage device at times needed by the system. This policy shows to be among the most effective for improving investments in distributed PV-battery systems, especially if combined with enhanced pricing mechanisms. In a enhanced pricing mechanism, the regulator can design tax and network fees – which are usually added as a fixed premium on top of hourly wholesale electricity prices – on a dynamic basis, or so called a “critical pricing” mechanism. This will generate an hourly retail price that reflects the system needs, including the contingencies in the distribution grid, which are not typically reflected in the wholesale prices. This redesigned, dynamic retail price can guide home batteries for a charge and discharge regime that is beneficial for the system.

In addition, we propose replacing PV generation tariffs by a PV self-consumption incentive. We demonstrate that the economic case for a solar PV-battery system can be greatly improved under this altered tariff, as battery increases self-consumption of renewable energy onsite. We demonstrate a calculation method for deriving the PV self-consumption bonus without deteriorating the benefits of prosumers with solar PV alone (without storage onsite). The proposed self-consumption tariff offers a net present value to consumers equal to 70% capital subsidy for battery. This policy can be applied in other high-latitude countries, where prosumers with solar PV alone tend to export electricity back to the grid during hours of low electricity demand. We find that typical prosumers in high-latitude countries operating both PV and storage may benefit from smaller-sized batteries than those currently in the market. Self-consumption policies, however, incentivise prosumers with a PV-battery system to reduce their dependency on the grid, with significantly less electricity imported from or exported to the grid. Therefore, the incumbent utility companies or retail firms may not benefit from the energy transition towards a decentralized energy system, where their "trade" based revenues will decline as self-sufficiency of prosumers improves.

Capital subsidies are among the easiest policies to implement, while being the costliest. More importantly, with capital subsidies the system operator is not necessarily able to employ the residential energy storage resources optimally for the system needs. The most effective policy measures to improve the economic profitability of storage for prosumers are those combining dynamic retail tariffs with a pricing mechanism for rewarding storage discharge at times system prices are high, as a proxy for the more urgent needs in the system. We show that such storage-oriented policies are economically net positive investments for consumers and have much less costs for the system compared to capital subsidies. However, the sucess of these storage policies depends on reducing complexity of the battery management and optimization at the consumer side, and minimizing the uncertainty in expected revenues of electricity storage in future years by offering flexible, long-term and transparent retail electricity tariffs to prosumers.

CRediT authorship contribution statement

Behnam Zakeri: Conceptualization, Methodology, Software, Data curation, Formal analysis, Writing - original draft, Writing - review & editing, Visualization. **Samuel Cross:** Conceptualization, Writing - review & editing. **Paul.E. Dodds:** Conceptualization, Supervision, Funding acquisition. **Giorgio Castagneto Gissey:** Conceptualization, Methodology, Software, Data curation, Formal analysis, Writing - original draft, Funding acquisition.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix

Appendix A presents sources of data and assumptions used for the electricity dispatch model, including electrical energy storage (EES) operation and constraints, as well as heat pump (HP) and thermal energy storage (TES) constraints. Appendix B represents the operational constraints of a central EES in the system, e.g., pumped hydro storage (PHS). The methodology for calculating wholesale and retail electricity prices is reported in Appendix C. Appendix D provides the methodology for the consumer's electricity cost minimization problem. Appendix E reports the methodology to calculate the PV self-consumption tariff, whereas Appendix F shows some of the results.

Appendix A. Calculating retail electricity prices

The wholesale prices are calculated in the electricity dispatch model based on the system demand and a merit ordered supply curve based on short run marginal costs of available generators. The market knows the residual system demand, i.e., $L_{net}(t,d)$ for $t = 1,\cdots,T$ and the available capacities of electricity generation technologies, K^w, and their costs, p^w_{SRMC}.

$$Gen(t) = \begin{pmatrix} type^1 & K^1 & p^1_{SRMC} \\ \vdots & \vdots & \vdots \\ type^M & K^M & p^M_{SRMC} \end{pmatrix}, \tag{A1}$$

where:

$w = 1,\cdots,M$ – generator index;
$type^w$ – generation technology type w;
K^w – available capacity of technology w;
p^w_{SRMC} – short run marginal cost of technology w.
Output: Wholesale prices, given by: $p(t) = (p_1(t),\cdots p_H(t))$ for $i = 1,\cdots,H$.

The matrix M is ordered in an ascending order of price p^w_{SMRC}. Then, for $t = 1,\cdots,T$, we perform the following sequential operations:

a. Set $j \leftarrow 0$, $\varrho = L_{net}(t)$
While ($\varrho > 0$)
Do {
$\xi^+ = \min(e, Gen[j,2])$ – power bought
$cost(t) += \xi^+ \cdot Gen[j,3]$ – cost of purchase
$\varrho -= \xi^+$ – remaining demand to fulfil
$j \leftarrow j+1$ – reset iteraction counter j
}
b. $p(t) = \dfrac{cost(t)}{L_{net}(t)}$ }

Retail electricity prices

Wholesale prices are then transformed into retail electricity prices, $\pi^a(t,d)$, by assuming a real-time mark-up on short-run marginal costs that is consistent with the following equation:

$$\pi^a(t,d) = p(t,d)\cdot l^a_{net}(t,d)\cdot k^a \tag{A2}$$

Retail prices are calculated as:

$$p_{retail}(year) = \sum\nolimits_{i=1}^{d}\sum\nolimits_{t=1}^{T}\left(p_i(t) + k^a_t\right)\cdot L_i(t) \tag{A3}$$

Solving the following equation allows to calibrate the mark-up against historical prices:

$$\pi^a_{his} = \frac{\sum_{d=1}^{\Gamma}\sum_{t=1}^{T}\pi^a\cdot l^{net,a}(t,d)}{\sum_{d=1}^{\Gamma}\sum_{t=1}^{T} l^{net,a}(t,d)} \tag{A4}$$

where π^{his} is the average historical retail price for electricity [£/MWh]; π^a is the retail price for consumer a; t, T is the time step counter and maximum number of time slices in a day, d and Γ are the day counter and maximum number of days in a year. Referring to Eq. (A2) allows us to calibrate the real-time mark-up, k_t^a.

Appendix B. Consumer's cost optimization problem

A linear programming model has been developed to minimize the operating cost of the consumer for running onsite technologies and paying electricity bills. This problem is dependent on the consumer's choice of technology and electricity tariff.

In the "no-technology" case, with neither a battery nor a solar PV system, the consumer simply pays the relevant electricity tariff. When only owning a battery, in the TOU tariff, the battery will be charged during off-peak hours (24–7 h) at the lower night-time tariff (0.07 £/kWh), and then the maximum available electricity from the battery is consumed during peak hours (7–24 h), when prices are higher (0.16 £/kWh), until the battery is fully discharged. When consumer has only solar PV installed, the consumer simply utilizes electricity from solar when this is available, at a zero-marginal cost, and exports the extra electricity to the grid for saving on its daily operating cost. Lastly, when customer owns both a battery and a solar PV system, at times when PV generation exceeds the load, any excess electricity is utilized to charge the EES device. Once the battery is fully charged, the remaining electricity is then exported back to the grid. In simple terms, electricity that is stored during the day is used during the evening when solar generation falls below the load level, thereby providing the consumer with additional savings by avoiding relatively expensive imports from the grid, which can be shown to maximize self-consumption from the PV system.

Using an hourly resolution, where $t = 1, \cdots, T$, the EES device is modelled with a nominal power rating P (in kW), the max storage content of S (in kWh). The overall efficiency (η_{tot}) represents the losses during charging and discharging. Eq. (B1) shows the dynamic relationship between the electricity loaded to EES at the charging mode ($E_{cha}(t)$) and discharged electricity at a time step ($E_{dis}(t)$) in kW, relative to the state of charge of the EES device ($SoC(t)$), and $l(t)$ storage self-discharge in time t:

$$SoC(t) = E_{cha}(t) - \frac{E_{dis}(t)}{\eta_{tot}} + SoC(t-1)^{*}l(t) \tag{B1}$$

This modelling approach is based on price arbitrage, which is applied when the electricity prices are known to a price taking EES. Hence, decision variables are the amount of charge and discharge of the EES device at each time step, which are elated to the state of charge (SoC) of EES. Other parameters affecting the profit of the owner of the PV-EES, such as solar PV generation, grid electricity prices, and grid time-of-use tariffs are not controlled or affected by decisions of a price-taking EES. The objective function is shown in Eq. (B2). The calculations can be done at each half-hour or hourly time steps for each day through a whole year period.

$$min_{Edis} \sum_{d=1}^{\Gamma} \sum_{t=1}^{\varsigma} L_{net}(t)C_{el}(t) + E_{dis}(t)C_{stor}(t) - E_{grid}(t)F_{grid}(t) \tag{B2}$$

where d shows days in the optimization horizon (e.g., a whole year $\Gamma = 365$); t is each modeling time slice in a day, e.g, for an hourly analysis $\varsigma = 24$; L_{net} is the net electricity bought from the grid (kWh) and C_{el} is the price of electricity (£/kWh); C_{stor} is the operational cost of discharging one unit of electric energy from EES (£/kWh) and E_{grid} is the exported electricity to the grid (kWh); and F_{grid} is the price of electricity sold to the grid or so called export FiT (£/kWh).

Storage policies

For storage policies modelled in this paper, when storage discharge receives a payment from the regulator, the objective function will slightly change as shown in Eq. (B3), where F_{stor} is the storage discharge FiT as function of time steps and K_{stor} is the penalty for charging storage at a certain time. These two values can be equal or can be designed differently for each time step t.

$$min_{E_{dis},E_{cha}} \sum_{t=1}^{\Gamma} \sum_{t=1}^{\varsigma} L_{net}(t)C_{el}(t) + E_{dis}(t)(C_{stor}(t) - F_{stor}(t)) + E_{cha}(t)K_{stor}(t) - E_{grid}(t)F_{grid}(t) \tag{B3}$$

The objective function is subject to the following constraints. The net load is calculated through an energy balance presented in Eq. (B4), where L_{act} denotes the actual load of the household, and $E_{pv}(t)$ is the net solar PV electricity (in kWh) at time step t.

$$\forall t \quad L_{net}(t) = L_{act}(t) + E_{cha}(t) - \left[E_{dis}(t) + E_{pv}(t)\right] + E_{grid}(t) \tag{B4}$$

Eq. (B4) ensures that if solar PV production exceeds load and EES charging capacity, the surplus would be sold to the grid. Moreover, since the price of export to the grid is always lower than the cost of purchasing electricity from the grid, it is not possible for the household to bypass electricity, meaning that eitherL_{net} or E_{grid} would be zero at each time step. Eq. (B5) and Eq. (B6) control the energy content and power capacity at charge/discharge of the EES system and ensure they are less than the maximum values of the selected technology:

$$\forall t \quad SoC(t) \le SoC_{max} = S \tag{B5}$$

$$\forall t \quad E_{dis}(t) \le P, E_{cha}(t) \le P \tag{B6}$$

where S is the maximum size, or capacity, of the EES device (kWh), and P is the maximum power rating of EES[11] device (kW). All variables are positive in this formulation, as shown with Eq. (B7):

$$\forall t \quad 0 \le E_{pv}(t), E_{dis}(t), E_{cha}(t), SoC(t), L_{act}(t), L_{net}(t), E_{grid}(t) \tag{B7}$$

[11] If the maximum power rating in charging and discharging mode would be different, the formulation should be written separately for each operating mode to accommodate that.

The model is run for different technology combinations and types of electricity tariffs, from year 1 to year 26, or from 2016 to 2040. The EES device is assumed to be a price taker in this model, so price arbitrage decisions have no impact on grid electricity prices. This assumption holds true as we use the storage capacity required in the system determined by the power system model.

Appendix C. Calculating PV self-consumption tariff

We propose a policy measure for promoting solar PV self-consumption through PV-EES, which is based on an enhanced self-consumption tariff (s). In this Appendix, we show how an existing solar PV generation and/or export tariff (hereafter called original tariffs) can be converted to a self-consumption tariff. For this policy not to negatively impact holders of stand-alone solar PV technology, this policy must be designed in a way that the level of revenues to these consumers can be kept equivalent to original tariffs over the lifetime of the solar panels as expected by consumers. For achieving this goal, we derive the total level of income from solar PV alone over the lifetime of the device, k, as the sum of original generation and export tariffs, which both can be changed independently from year to year (e.g., a digressing PV generation tariff). Therefore, the original revenues of consumer with PV-alone can be derived by discounting future revenues to present value through Eq. (C1):

$$\mathrm{k} = \mathrm{k}_g + \mathrm{k}_e = \sum_{y=1}^{Y} \frac{\boldsymbol{G}(\boldsymbol{y})^*\boldsymbol{g}(\boldsymbol{y})^*(1+\boldsymbol{i})}{(1+\boldsymbol{r})^y} + \sum_{y=1}^{Y} \frac{\boldsymbol{E}(\boldsymbol{y})^*\boldsymbol{e}(\boldsymbol{y})^*(1+\boldsymbol{i})^{q(y)}}{(1+\boldsymbol{r})^y} \tag{C1}$$

where $\mathrm{k}, \mathrm{k}_g, and \mathrm{k}_e$ are the present values of total FiTs, PV generation FiT, and export FiT, respectively.$G(y)$ is the annual generation of electricity from solar PV in year y; $E(y)$ is the annual electricity export to the grid in each year; $y = 1, \cdots, Y = 26$ years; r is the discount rate; $g(y)$ is the PV digressing generation tariff, which is digressing and falls to zero from year $y = 20$ onwards; $g(y)$ in each year is linked to the RPI, i, and $q(y)$ is the compound rate for digressing indexation. If the government were to change the length of the tariff, this would be reflected by simply using the new generation tariff in $g(y)$, or the export tariff in $e(y)$, and updating those values for Y. $e(y)$ is the export tariff, which falls to $e(20)p.a.2$ from $y > 20$ years; $e(y)^*(1+i)^{q(y)}$ is the digressing FiT tariff changing with retail price index (RPI), where $q(y)$ is the compound inflation rate; and in $y = 21$, there is no RPI indexation, meaning that $q(21) = 0$ in this case. Considering $S(y)$ is the yearly self-consumption of solar PV, the total expected revenues from this tariff (k_s) can be calculated by Eq. *(C2)*:

$$\mathrm{k}_s = \sum_{y=1}^{Y} \frac{S(y)^*s(y)^*(1+i)}{(1+r)^y} \tag{C2}$$

The original generation tariff $g(y)$ can be related to the proposed self-consumption tariff $s(y)$ with a multiplier ($\omega(y)$:

$$s(y) = g(y)^*\omega(y) \tag{C3}$$

If the regulator aims at deriving ω such that total revenues under both tariffs would be maintained equal ($\mathrm{k}_g = \mathrm{k}_s$), this leads to:

$$\sum_{y=1}^{Y} \frac{G(y)^*g(y)^*(1+i)}{(1+r)^y} = \sum_{y=1}^{Y_g+1} \frac{S(y)^*(\omega(y)^*g(y))^*(1+i)}{(1+r)^y} \tag{C4}$$

and:

$$\sum_{y=1}^{Y_g+1} \frac{S(y)^*\omega(y)^*(1+i)}{(1+r)^y} = \frac{1}{1+i} \frac{\sum_{y=1}^{Y} \frac{G(y)^*(1+i)}{(1+r)^y}}{\sum_{y=1}^{y(g)+1} \frac{S(y)}{(1+r)^y}} \quad for \ \ y = 1, \cdots, y_g + 1 \tag{C5}$$

Hence, the new self-consumption tariff in each year (y) which enables solar PV consumers to achieve original income, in the absence of incentives to PV generation, can be achieved by combining Eqs. (C3) and (C5):

$$s(y) = g(y)^* \frac{1}{1+i} \frac{\sum_{y=1}^{Y} \frac{G(y)^*(1+i)}{(1+r)^y}}{\sum_{y=1}^{y(g)+1} \frac{S(y)^2}{(1+r)^y}} \quad for \quad y = 1, \cdots, y_g + 1 \tag{C6}$$

And

$$s(y) = g(y) = 0 \quad for \quad t = y_g + 2, \cdots, Y \tag{C7}$$

We remark that both the static and ToU electricity tariff cases do not present any differences, since the only condition for these to differ is that they present dissimilarities in the term $g(y)$, since an identical $g(y)$ is required to obtain the same level of income k.

Appendix D. Additional modelling results

In this Section, we present some of the modelling results that were not shown in the main article. Fig. D1 shows the consumer cost-benefit results for adopting different technologies under static tariff and current FiT policies for export to grid and solar PV generation. Fig. D2 shows the same results for dynamic tariffs.

Fig. D3 shows the results of NPV analysis for the "Dynamic Export Tariff" policy (see Fig. D4).

Fig. D5 shows the NPV of investing in solar PV and solar PV-storage in different cities in the UK. The values are for the Reference scenario and are the difference in NPV after investing in onsite technologies compared to the case of no-technology in each respective city.

Fig. D6 shows the NPV based on the size of building under different tariffs and the Reference scenario.

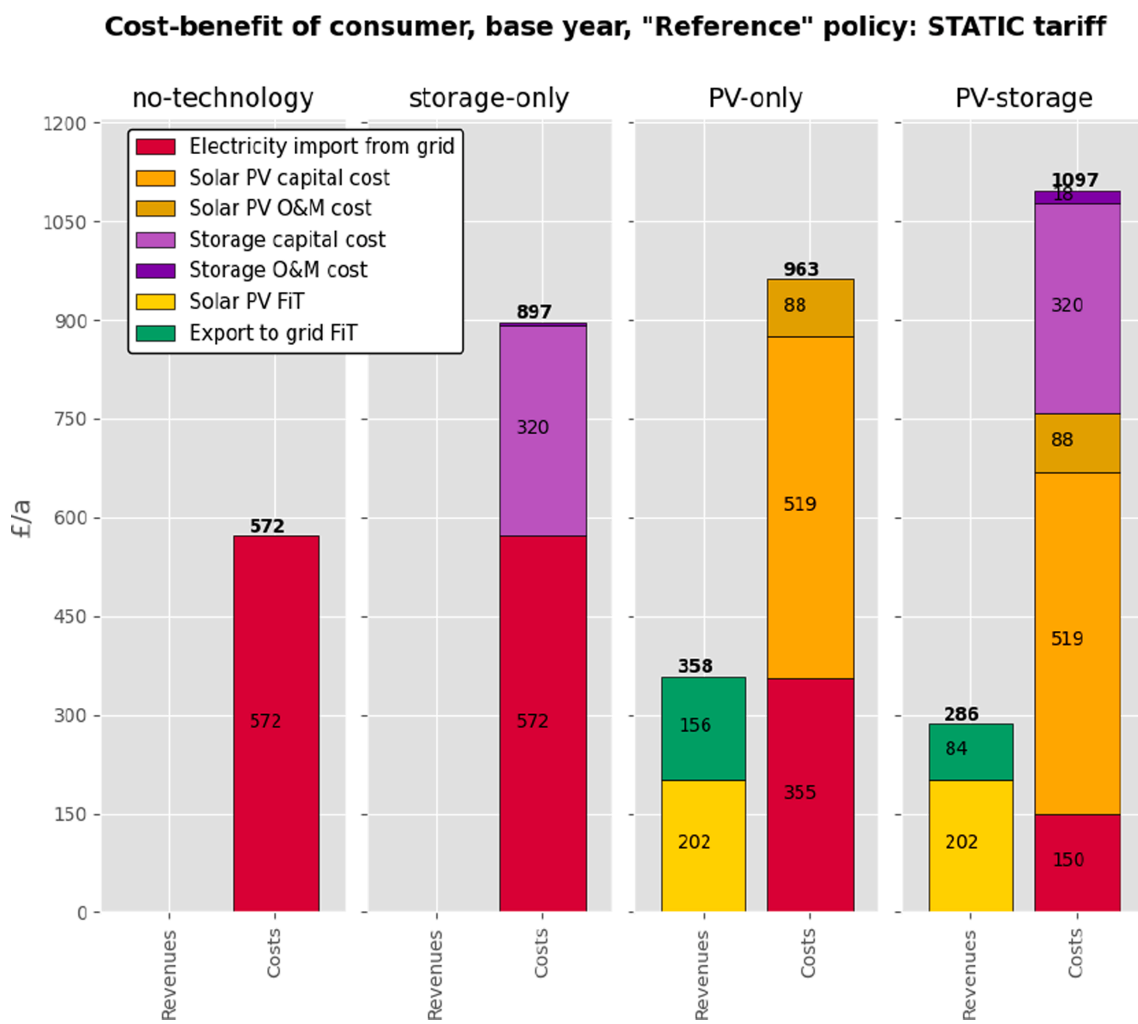

Fig. D1. Total annualized costs and revenues for each technology choice (no-technology, storage-only, PV-only and PV-storage), under static tariffs, and assuming the current policy scenario for the base year (2016). Feed-in tariff (FiT) payments are for electricity generation and export. The values on the bars show the respective costs or revenues, and the values on top of each bar shows the total cost or revenue.

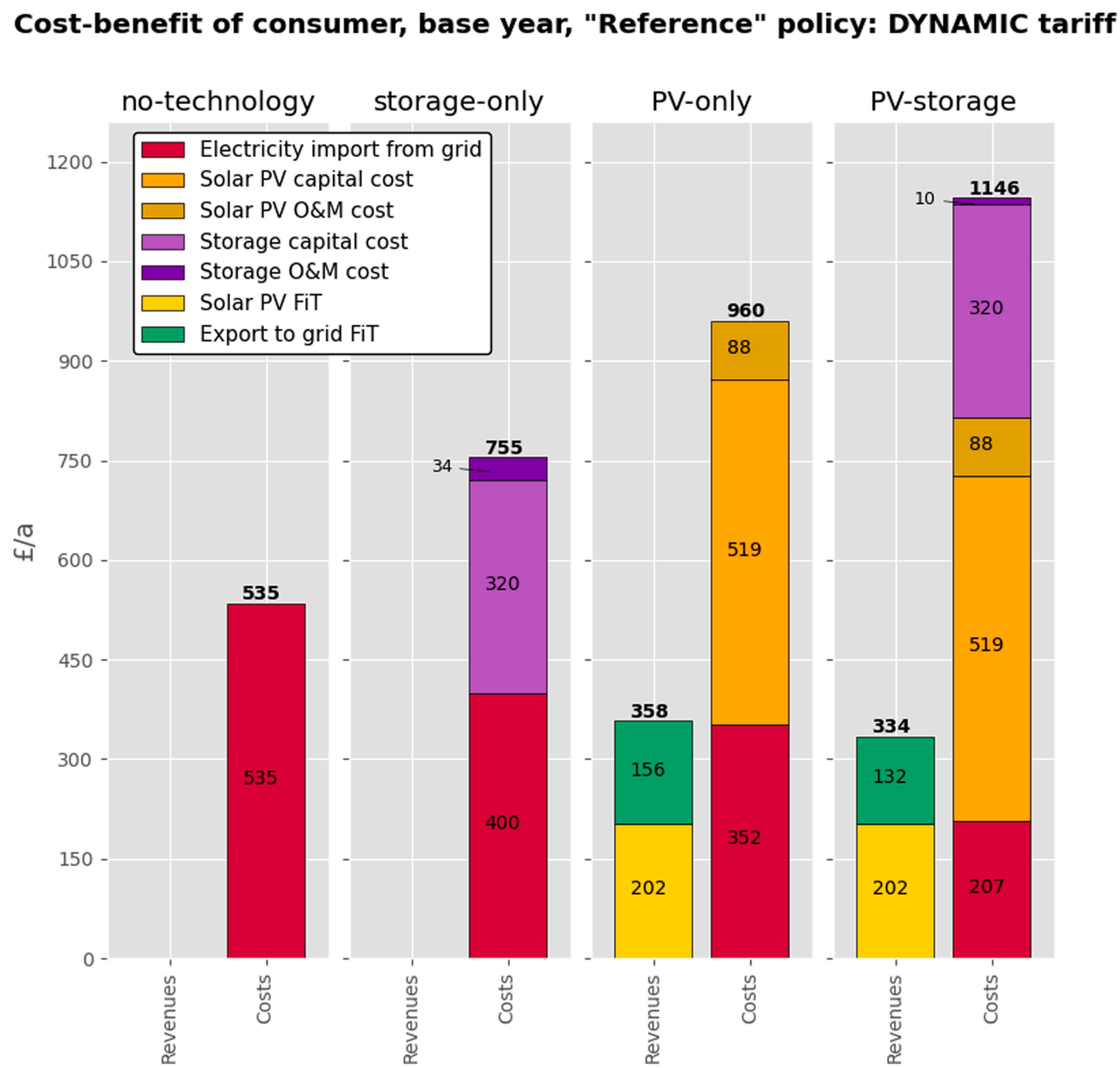

Fig. D2. Total annualized costs and revenues for each technology choice (no-technology, storage-only, PV-only and PV-storage), under dynamic tariffs, and assuming the current policy scenario for the best year (2016). Feed-in tariff (FiT) payments are for electricity generation and export. The values on the bars show the respective costs or revenues, and the values on top of each bar shows the total cost or revenue.

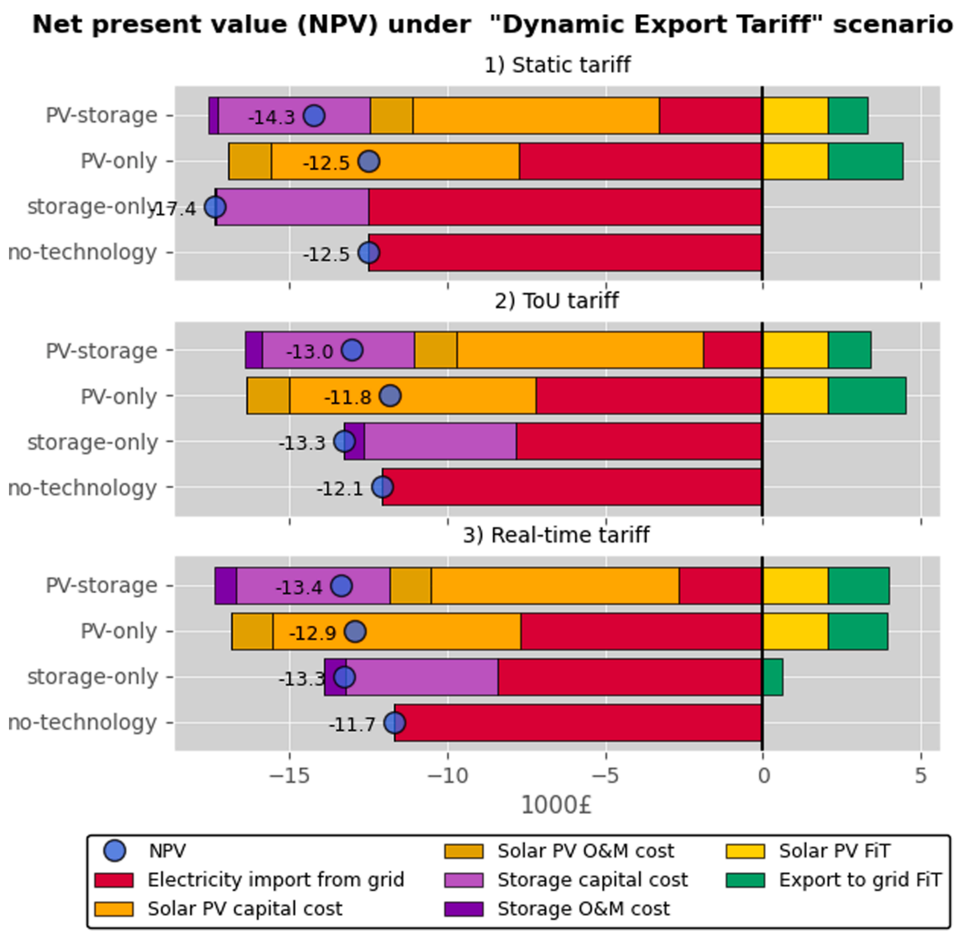

Fig. D3. Net present value (NPV) of the consumer investment in onsite technologies under *Dynamic Export Tariffs* for the standard residential building (middle-sized, 3 bedrooms, with electricity load of 3750 kWh/a). The costs are shown with negative values and revenues with positive. The blue marker and number on each bar show the NPV of the investment (NPV = present value of revenues – present value of costs). The NPVs shown on the bars are in 1000-£ and rounded up by one decimal.

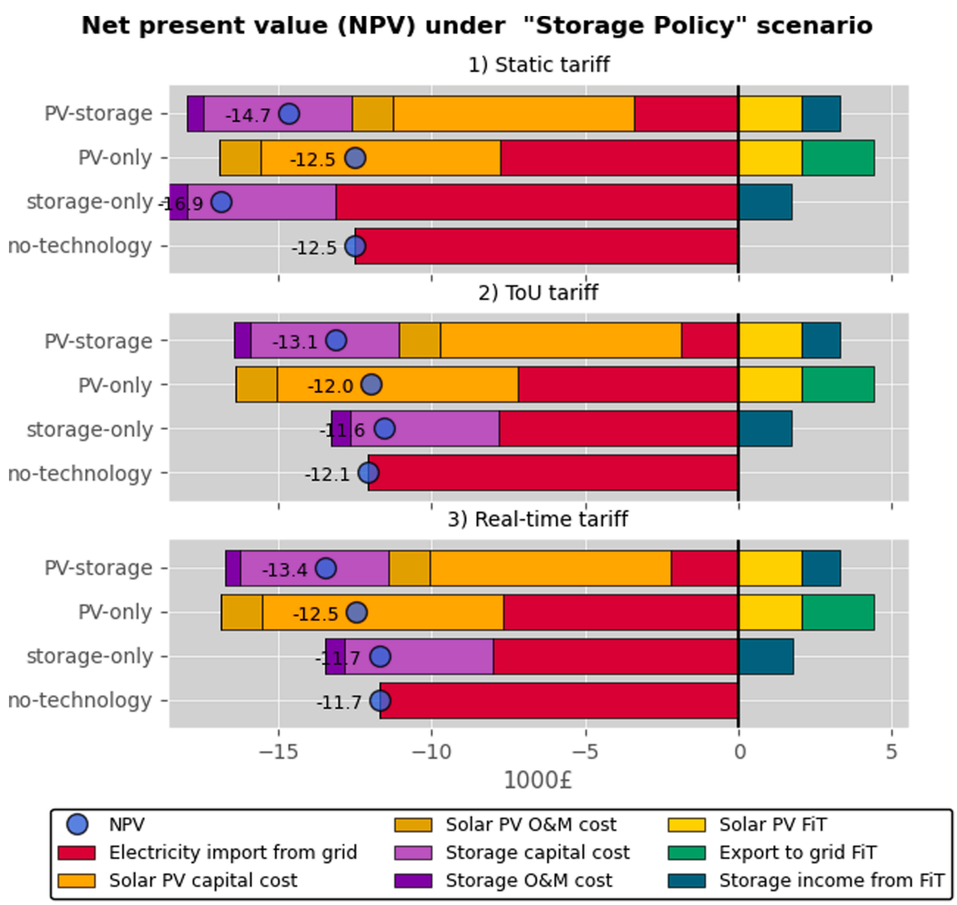

Fig. D4. Net present value (NPV) of the consumer investment in onsite technologies under *Storage Policy Tariffs* for the standard residential building (middle-sized, 3 bedrooms, with electricity load of 3750 kWh/a). The costs are shown with negative values and revenues with positive. The blue marker and number on each bar show the NPV of the investment (NPV = present value of revenues – present value of costs). The NPVs shown on the bars are in 1000-£ and rounded up by one decimal.

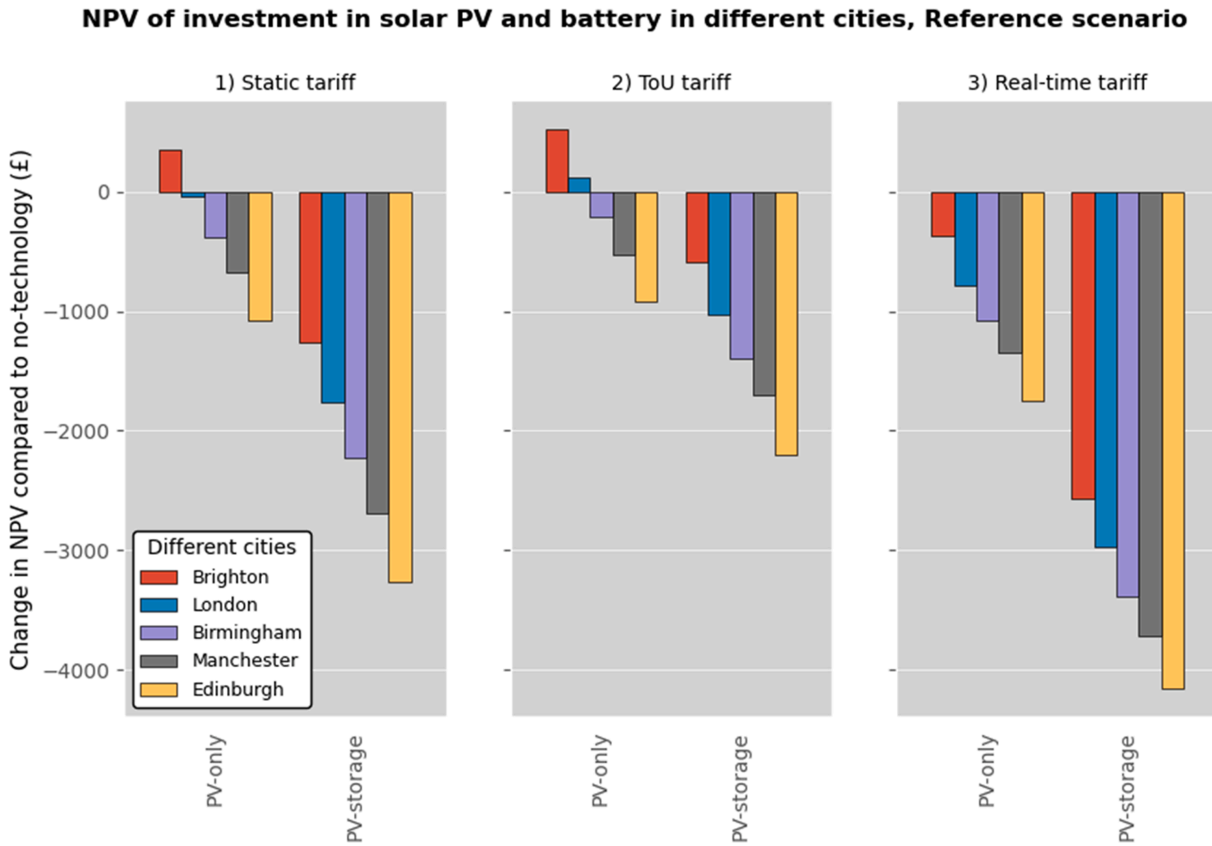

Fig. D5. Net present value (NPV) of investment in PV and PV-storage in different cities under the Reference scenario, compared to the case of consumer with "no-technology" in the same location.

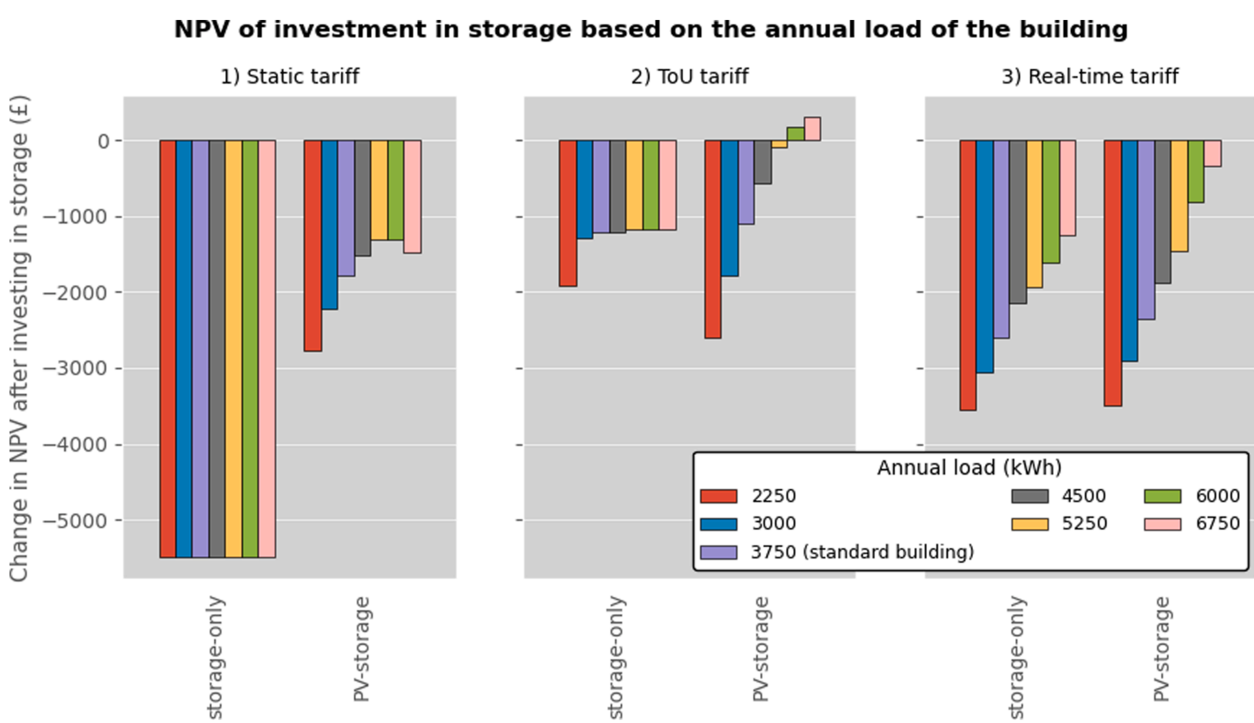

Fig. D6. Net present value (NPV) of investment in energy storage relative to the case of no storage, for different building sizes and three electricity tariffs. (NPV of storage-only is compared with no-technology; NPV of PV-storage is compared with PV-only).

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