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Time-of-use and time-of-export tariffs for home batteries: Effects on low voltage distribution networks

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ABSTRACT

Time-of-use electricity tariffs are gradually being introduced around the world to expose consumers to the time-dependency of demand, however their effects on peak flows in distribution networks, particularly in areas with domestic energy storage, are little understood. This paper presents investigations into the impact of time-of-use and time-of-export tariffs in residential areas with various penetrations of battery storage, rooftop solar PV, and heat pumps. By simulating battery operation in response to high resolution household-level electrical and thermal demand data, it is found that home batteries operating to maximise cost savings in houses signed up to time-dependent tariffs cause little reduction in import and export peaks at the low voltage level, largely because domestic import and export peaks are spread out over time. When operating to maximise savings from the first three-tier time-of-use tariff introduced in the UK, batteries could even cause increases in peak demand at low voltage substations, if many batteries in the area commence charging at the start of the overnight off-peak price band. Home batteries operating according to time-dependent electricity tariffs significantly miss out on the potential peak shaving that could otherwise be achieved through dedicated peak shaving incentives schemes and smarter storage control strategies.

1. Introduction

1.1. Background

With the rollout of smart meters in the UK, along with the regulator's desire to mandate half-hourly settlement of all electricity consumers based on their actual half-hourly consumption [1], there is considerable interest in the development of time-of-use (TOU) tariffs. These roughly align domestic electricity prices with demand, incentivising demand shifting [2,3] and use of energy storage systems (such as home batteries and hot water tanks) to reduce electricity demand at peak times. Similar developments are happening at varying rates around the world.

In the UK, TOU tariffs have historically existed as Economy 7 and Economy 10 tariffs, whereby consumers see lower off-peak electricity prices for seven or ten hours overnight. These were originally introduced in the late 1970 s to ensure consumption of overnight base-load power from coal and nuclear plants. With the decline in coal power, it is possible that fewer Economy 7 and Economy 10 tariffs will be available in the coming years. However, the growth of renewables, particularly variable renewables such as wind and solar, along with increasing penetration of embedded generation and active energy technologies such as electric vehicles (EVs) and heat pumps, exerts new stresses on the grid. The cost of network reinforcement in the UK is expected to reach up to £36bn by 2050 if we maintain passive approaches to network reinforcement and demand management [4], but these costs could be reduced significantly by taking advantage of smart demand technologies and appropriately incentivising their activity. These incentives could include new types of TOU tariffs.

Economy 7 and 10 tariffs have two price tiers, and are henceforth known as two-tier tariffs. Smart meters make it possible to add further tiers, allowing for tariffs that more closely reflect the full short-run social marginal cost of generating and distributing electricity, thus increasing economic efficiency [5]. Three-tier tariffs already exist in several countries (for example Canada [6]), and typically use a peak price tier to disincentivise use of electricity at peak times. A recent survey in the UK has shown that over a third of bill payers are in favour of switching to a three-tier TOU tariff, indicating a substantial potential market, with electric vehicle owners significantly more willing to switch [7]. Recently, the first three-tier TOU tariff was launched in the UK by Green Energy [8]. This tariff is known as 'TIDE', and at the time of writing (April 2018) its three tiers are an overnight off-peak rate of

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Nomenclature

η_c	Charging efficiency of the storage between 0 and 1
η_d	Discharging efficiency of the storage between 0 and 1
d	Raw power demand of the house (i.e. with no embedded generation or storage) ≥ 0
e	Energy contained in the storage ≥ 0
$E_{\max}$	Maximum allowable energy level in the storage, >0
$E_{\min}$	Minimum allowable energy level in the storage, ≥ 0
N	Number of houses
pNet	power demand of the house, after taking account of embedded generation and storage
$P_{c,\max}$	Maximum allowable charging power of the storage, >0
$P_{d,\max}$	Maximum allowable discharging power of the storage, >0
s	Output from the house's embedded generation (e.g. rooftop solar PV), ≥ 0
t	Time
u	Charging power of the storage, or discharging power if negative
ADMD	After Diversity Maximum Demand
ADME	After Diversity Maximum Export
CDM	CREST Demand Model
COP	Coefficient of performance of a heat pump
DNO	Distribution network operator
DUoS	Distribution use of system charge
EV	Electric vehicle
HH	Household
HW	Hot water
LV	Low voltage
RAG	Red-amber-green electricity tariff
SoC	State of charge of an energy storage device
TOU	Time-of-use tariff

6.41 p/kWh between 23:00 and 06:00, an evening peak rate on weekdays only of 29.99 p/kWh between 16:00 and 19:00, and a mid-peak rate of 14.02 p/kWh at all other times. Green Energy also offer a discount on the purchase cost of a home battery as an incentive to sign up to the tariff.

The price spread in Green Energy's TIDE tariff is particularly high; in Ontario, for example, there is a province-wide residential three-tier TOU tariff set by Ontario Energy Board, and prices range from 0.065 CAD/kWh off-peak to 0.132 CAD/kWh on-peak [6]. In Ontario, distinct summer and winter tariffs are used to account for the changing load profiles through the year, primarily because of significant variations in heating and cooling demands over the year. In Australia, typical off-peak prices in residential TOU tariffs are around 0.15 AUD/kWh, and typical on-peak prices are around 0.55 AUD/kWh [9,10]. This is a higher spread than in Ontario, but lower than that set by Green Energy in the UK.

In Great Britain, differential charging is also used by distribution network operators (DNOs) to cover the cost of operating the distribution networks. As a whole, these charges are known as Distribution Use of System (DUoS) charges, and three-tier tariffs known as red-amber-green (RAG) tariffs are used for non-domestic consumers with half-hourly settlement. A RAG tariff as used for DUoS charging typically has an off-peak *green price* time band overnight, a peak *red price* time band in the early evening, and *amber price* time bands in between [11]. DUoS charges for domestic consumers currently exist as a single rate (rather than being tiered), and are paid by suppliers acting as 'supercustomers', who pass the charges onto customers by factoring the costs in when developing tariffs.

Two-tier electricity tariffs have also been implemented in an effort to reduce reverse flow from solar PV in areas with high penetrations of solar power. In Cornwall, Regen SW, on behalf of the local DNO, Western Power Distribution, recently trialled a two-tier tariff known as the Sunshine Tariff [12]. This offered off-peak electricity from 10:00-16:00 for six months of the year (April to September). In that study, it was found that households with automation technology (such as a timed hot water immersion system) were able to shift 13% of their consumption into the 10:00–16:00 period, compared with 5% for those without automation [12]. Similarly low levels of engagement have been found in other TOU tariff trials, with field trials of TOU tariffs in 1500 German households resulting in average percentage reductions in peak demand of around 6% [13], and a pilot trial in 300 Cypriot households reducing total consumption in peak hours by no more than 3.5% [14]. In response to these low levels of engagement without automation, it has been recommended that automation and aggregators should be used for demand management [15].

Much research has looked at the possibilities for using energy storage for peak shaving on distribution networks. Recently, Pimm et al. investigated the potential of battery storage for peak shaving [16], assuming perfect foresight of net demand and perfect coordination of the storage. It was shown that in the UK, 3 kWh of battery storage per household could potentially allow a 100% switch to heat pumps without increasing peak demands at the secondary substation level. It was also shown that the export peak brought about by high levels of solar PV penetration (3 kW per household) could potentially be reduced to the level it would be if there were no PV by using 5 kW h of battery storage per household. These findings of large potentials for peak shaving using battery storage have been confirmed by Schram et al. [17], who also highlighted the importance of collaboration between households and other stakeholders, such as distribution system operators and retailers, to achieve the peak shaving potential at neighbourhood level.

Leadbetter and Swan [18] conducted investigations into the optimal sizing of battery storage systems for residential peak shaving, with results suggesting that typical system sizes should range from 5 kW h/2.6 kW for homes with low electricity usage, up to 22 kWh/5.2 kW for homes with high usage and electric space heating. Peak shaving of between 42% and 49% was reported in five regions of Canada. It was also found that very little cycling is required for peak shaving, and that as such the system's life is limited by the calendar life of the batteries.

Yunusov et al. [19] used smart meter data to assess the impact of battery storage location (i.e. position on the feeder as well as whether on one or all three phases) on performance for peak shaving and phase balancing, focusing on two real low voltage (LV) networks. Some of the same authors have also considered real-time optimisation of DNO-owned storage being used for peak shaving, developing storage controllers that take into account demand forecasts and consumer clustering [20].

Zheng et al. [21] developed a control technique for peak shaving with battery energy storage systems using a demand limit. Whenever grid import is greater than the demand limit, the battery is discharged in an effort to bring import down to the demand limit, and whenever grid import is less than the demand limit, the battery is charged in an effort to bring import up to the demand limit. More recently, Babacan et al. [22] developed a convex optimisation approach to storage scheduling, and showed that residential electricity tariffs featuring demand charges and supply charges (proportional to monthly peak import and export) can reduce peak flows of electricity, reduce power fluctuations in net demand profiles, and increase self-consumption of solar PV.

1.2. Objectives

There exists a significant gap in the literature surrounding the effects on the distribution network of energy storage responding to time-of-use tariffs, even though it is likely that distribution networks will

need considerable reinforcement to cope with the presence of EVs and heat pumps, just as they have needed reinforcement to cope with the presence of high penetrations of solar PV in certain areas. It is important to understand what kind of effect household-level storage might have on distribution networks when responding to time-dependent tariffs, in order to improve network planning and potentially inform future electricity tariffs and charges.

Therefore this paper addresses this knowledge gap, comprehensively investigating the effects on the distribution network of home batteries responding to time-dependent tariffs, and asking the question:

> What levels of peak shaving occur as a result of residential battery storage operating according to time-of-use and time-of-export tariffs?

As well as comprehensively investigating the possible effects of time-of-use tariffs on peak demands, we also present and thoroughly investigate a novel approach to reducing export of solar PV (time-of-export tariffs), and investigate methods of avoiding rebound peaks caused by time-of-use tariffs in areas with many home batteries or EVs.

An existing household energy demand model is used to generate demand data for households, and this data is analysed to investigate the effects of home batteries operating to maximise cost savings in areas with various penetrations of solar PV and heat pumps. The rest of this paper is laid out as follows. Section 2 details the methodology that is used for the analysis. Section 3 presents results from the time-of-use tariff analysis, including the peak shaving that will occur if home batteries respond to various three-tier electricity tariffs. Section 4 details approaches to counteracting the rebound peak caused by storage or EVs responding to time-of-use tariffs. Section 5 presents results from the time-of-export tariff analysis, showing the effects of charging for export of solar PV generation at certain times. Finally, our conclusions are presented in Section 6.

2. Methodology

The approach used in this work can be summarised as follows: household-level net demand data in areas with various penetrations of solar PV and heat pumps are generated using a stochastic demand model, then for many different time-dependent electricity tariffs, the operation of battery storage is determined using a time-stepping approach, assuming that the storage is operated to maximise cost savings. The peak power flows (both import and export) at the low voltage substation level are calculated both with and without storage, assuming that 100 houses are connected to the substation. Since a stochastic demand model is used, this process is repeated many times, and the effects of storage on peak power flows are averaged.

Before continuing to explain the methods in more detail, it should be made clear that in this work, we disregard the effects of time-dependent electricity tariffs on consumer behaviour, and instead focus on the effects of home batteries operating according to time-dependent tariffs. There are two main reasons for disregarding the effects of such tariffs on consumer behaviour. Firstly, as mentioned in the introduction, several field trials have found low levels of engagement in time-of-use tariffs in terms of consumer behaviour, often concluding that it is important to leverage technology and automation rather than relying on consumer behaviour [12,13,15], so disregarding consumer behaviour in the analysis will have little effect on the results presented here. Secondly, consumer behaviour is difficult to model and so to fully take it into account in this analysis, it would be necessary to obtain high resolution electrical and thermal demand data for many households exposed to a wide range of time-of-use tariffs. To the authors' knowledge, such data does not exist.

2.1. Quantifying peak flows on distribution networks

In areas with low levels of embedded generation, infrastructure requirements have traditionally been evaluated using the concept of 'After Diversity Maximum Demand' (ADMD). For a group of houses/dwellings being fed from a substation in such areas, the expected peak power demand of the whole group over a long period of time is what sets the required capacities of the substation equipment and the cables running to each house. ADMD is the peak power demand of the group divided by the number of houses in the group, and is given by

$$\mathrm{ADMD} = \frac{1}{N}\max\left(\sum_{i=1}^{N} p_i\right) \tag{1}$$

where N is the number of houses and p_i is the demand profile of house i over the course of a certain period of time (e.g. one year). ADMD is typically expressed in kW, so values of p_i are specified in kW. For p_i we have used data at one minute resolution in this work, and in all cases we set the number of houses $N = 100$, the typical number of houses connected to a low voltage substation (also known as a secondary substation) in the UK. ADMD typically reduces to less than 2 kW for large groups of houses (e.g. $>$ 20 houses) [23]. A curve of ADMD against N flattens out as N is increased, as a result of the diversity in electricity usage patterns.

In areas with high levels of embedded generation, peak export can again be expressed on a per-household level, using the same method as used for ADMD. In this paper, we refer to this as 'After Diversity Maximum Export', given by

$$\mathrm{ADME} = \frac{1}{N}\max\left(0,\ \max\left(\sum_{i=1}^{N} -p_i\right)\right) \tag{2}$$

This paper is focused on peak shaving, whereby energy storage or demand response is used to reduce peak power flows in distribution networks. Peak shaving allows the deferral of distribution network infrastructure reinforcement as loads increase (e.g. from the addition of new properties, heat pumps, and electric vehicle chargers) and as embedded generation increases (e.g. from the addition of rooftop solar panels and micro wind turbines).

2.2. Generating household net demand data

In order to understand the effect of introducing electricity storage within residential distribution networks, it is necessary to acquire data on the electricity demand profiles of domestic properties. To this end, the CREST Demand Model (CDM) [24], developed at the Centre for Renewable Energy Systems Technology (CREST) at Loughborough University, has been used. The CDM uses time use survey logs taken by thousands of UK householders as part of the UK Time Use Survey [25], along with data on the numbers and types of appliances found in UK households, to stochastically synthesise a realistic load profile for a household based upon many parameters, including number of residents, time of year, and whether it is a weekday or weekend day. The resulting demand data is at one minute resolution, and can be aggregated over a number of households.

The CDM is an integrated thermal-electrical model, with sub-models for occupancy, irradiance, external temperature, electrical demand (itself comprising sub-models for lighting and appliance demand), thermal demand, solar PV, and solar thermal collectors. Being an integrated model, many of the different sub-models are interlinked, so for example a change in irradiance will affect four sub-models: solar thermal collector, solar PV, thermal demand (changing passive solar gains), and electrical demand (for lighting in actively occupied dwellings).

Several of the sub-models have been separately validated, and the whole model has been validated by comparing its output with independent empirical data. The CDM is an open-source development in Excel VBA, and its authors make clear that it is primarily for application in low voltage network and urban energy analyses, exactly the type of

analysis presented in this paper.

The most recent version of the CDM does not have a multiple day feature, so in order to simulate multiple consecutive days, separate days were modelled while maintaining the same household and appliance properties between days. Therefore within the resulting data there is some discontinuity in demand at midnight, however as this is not a time when the distribution network is under stress, we don't consider this to be an issue in the context of this work.

Average UK household electricity demand profiles, as synthesised by the CDM, are shown against time of day in Fig. 1. Morning and evening peaks are clear, with both being higher in winter than in summer. Also clear is that the evening peak is wider during winter than during summer. These increases are all related to increased lighting and heating demands in winter (while at this point we are assuming that the heating system is a gas boiler, there are electrical loads associated with pumps in the heating system). The maximum average demand is shown to be 0.84 kW; this is not the same as the average peak demand ('After Diversity Maximum Demand', explained above), which is higher. The maximum average demand is very similar to the 0.91 kW found in smart meter trials conducted within the Customer-Led Network Revolution project run by Northern Powergrid [26]. The shape of the curve, and time of maximum average demand, are also very similar.

It should be noted that the average demand values rise from zero at midnight at the start of the day. This is because the demand model doesn't have a multiple day feature, as explained above. Since the distribution network is not under stress at midnight, this is not an issue and does not affect the results shown later in the paper.

The demand profile of one house over 24 h in mid-winter is shown in Fig. 2. It is clear that the demand profile at a single household level is very spiky, as high power appliances are only occasionally used. The intermittent operation of the compressor in a fridge-freezer is also clear, particularly overnight.

2.3. Modelling heat pumps

As mentioned above, the CREST Demand Model includes a thermal sub-model, generating realistic heat demands for space and hot water heating based upon the synthesised occupancy and irradiance profiles. For an individual household, the heat output profile of a heating system has a characteristic 'spikiness', due to thermostat deadbands (set in the CDM at 2 °C for space heating and 5 °C for hot water) and the thermal inertia inherent in buildings. Heat pumps produce heat over longer periods than gas boilers because they do not produce heat at such high temperatures, so they have a less spiky heat output profile.

To take heat pumps into account in the net demand profiles at certain points in the analysis, we configured the CREST Demand Model such that the heating unit has a heat output of 10 kWth (ϕ_h = 10,000 W), typical for an air source heat pump [27], and included a 125 L domestic hot water tank. The hot water tank is heated using the heat pump, and has a 5 °C thermostat deadband. The emitters have a nominal temperature of 50 °C, and space heating and hot water thermostat settings maintain the probability densities set in the CREST Demand Model v2.2 (with ranges of 13–27 °C for space heating thermostats and 42–62 °C for hot water thermostats), based on national survey data [28,29]. The energy demands for space and water heating have been converted into electricity demands by using a fixed heat pump coefficient of performance (COP) of 3. This COP is within the typical range of 2–4 [30]. To model different penetrations of heat pumps, each household's total thermal demand profile is scaled by the heat pump penetration.

2.4. Analysing time-dependent tariffs

To study the effect of fixed time-dependent electricity tariffs on peak shaving in residential areas with battery storage, we use household net demand data generated using the CDM. It is assumed that the storage is just operated to maximise monetary savings through the tariff, with peak shaving being consequential.

In considering peak shaving of demand, a fixed three-tier time-of-use tariff is used, similar to Green Energy's TIDE tariff. In some analyses presented in this paper, the storage is fully charged up overnight in the *green band*, and in some analyses the storage is only charged using excess solar power.

The storage is only discharged in a single discharge window, also known as the *red band*, around late afternoon / early evening each day, the start and end times of which are varied in the analysis. The start and end times remain fixed from day to day. The storage is discharged as rapidly as possible from the start of the discharge window in an attempt to bring net demand down to zero, as if incentivised by a high electricity price at that time. Since battery degradation is not taken into account in this work, discharging as rapidly as possible in the discharge window maximises the savings from using storage when exposed to such a tariff.

Amber bands run between the green and red bands. In many of the UK's distribution tariffs, the tariff cost in the amber band is so close to that in the green band that storage inefficiencies would make it uneconomical to charge battery storage during the green band and discharge it during the amber band. We assume that this is also the case in the TOU tariffs studied here.

Using this approach, battery operating schedules can be generated using a simple time-stepping procedure (rather than requiring use of an optimisation algorithm, such as convex optimisation), and the potential peak shaving from TOU tariffs can be found without considering prices. For each tariff of interest, the effects of this approach on ADMD are found, and since the CDM is a stochastic model, 150 different aggregations of 100 households are simulated, and the results averaged. The house sizes are randomly taken from a distribution representative of the UK.

For the studies tackling reduction of peak solar PV export, a fixed two-tier time-of-export tariff is used, penalising export in the middle of the day. Penalising export might be regarded as an unrealistically drastic measure, however we are setting out to examine the effects of such a scheme on peak shaving of export in areas with high penetrations of solar PV. It is assumed that the storage can only be charged in a single charge window, also known as the *export red band*, in the middle of each day. The start and end times of the export red band are fixed for any particular simulation, but we investigate the effect of a range of times. An example two-tier time-of-export tariff is shown in Fig. 3. In this case the storage is charged as rapidly as possible from the start of

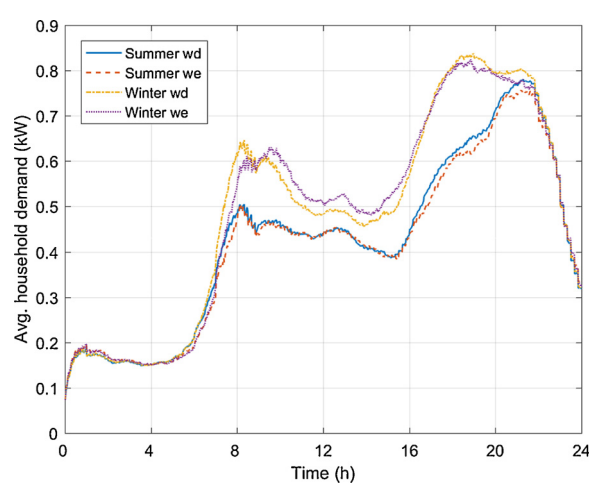

Fig. 1. Average UK household electricity demand against time of day for weekdays and weekend days in mid-July and mid-January, as synthesised by the CREST Demand Model. No solar PV. Demands averaged over five weekdays and two weekend days in each season, for 15,000 households.

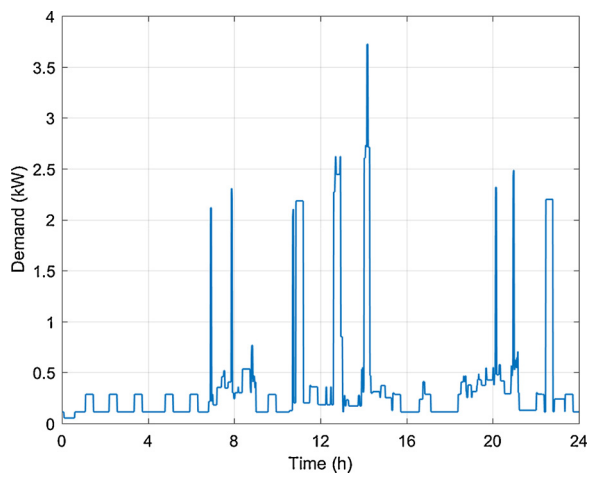

Fig. 2. Electricity demand profile for one house in mid-winter, as synthesised by the CREST Demand Model.

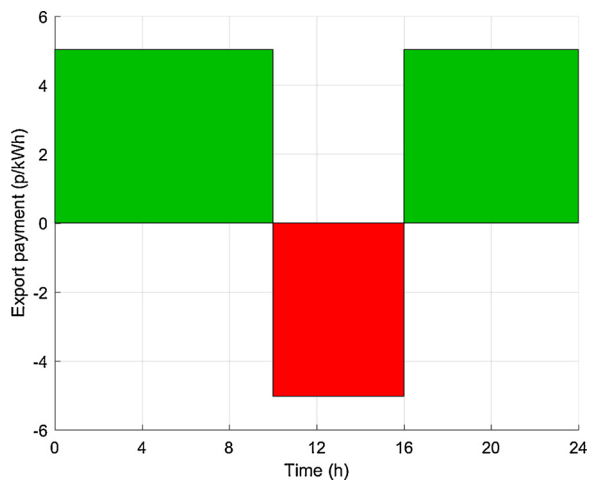

Fig. 3. An example two-tier time-of-export tariff.

the export red band using any excess solar power, in an attempt to reduce the level of export to zero. The storage is then discharged as hard as possible outside of the export red band, without causing the household's net demand to become negative, to bring its State of Charge (SoC) down as low as possible before the start of the next day's export red band. Such operation would maximise the monetary savings available from using storage.

In this work it is assumed that the storage in each house never acts to reverse the flow of power to/from the house at any instant, because there is currently no incentive to do so in the UK. The results would be different if batteries were also incentivised to cause export from a house (i.e. an export tariff for batteries) or import to a house (like National Grid's Demand Turn Up service for large energy users [31]).

In all cases, the storage operating schedule is determined through a time-stepping procedure, where for a given household, the algorithm steps through each minute t of each day and determines whether charging or discharging should take place (according to whether or not the minute is within a green or red band, or whether there is excess solar generation in that minute, depending upon the scenario under investigation).

Fig. 4 shows the power flows in a household with rooftop solar PV and a battery storage system. Note that in Fig. 4(b), p is bidirectional because export can sometimes occur. The net power demand of the household at time t is given by

$$p(t) = d(t) - s(t) + u(t) \tag{3}$$

where d is the raw electricity demand of the household (ignoring the effects of solar PV or storage), s is the power being generated by any embedded generation such as rooftop solar PV, and u is the rate at which electricity is being transferred to the storage (or from the storage if negative). In this work, s and u are defined on the AC side of inverters.

If it is determined that discharging should take place, then the discharging power is calculated as

$$u(t) = -\min(P_{d,max}, (e(t) - E_{min})\eta_d/\Delta t,\ \max(0, d(t) - s(t))) \tag{4}$$

where $P_{d,max}$ is the discharging power capacity of the storage, e is the energy in the storage, E_{min} is the minimum allowable energy level in the storage, η_d is the discharging efficiency of the storage, and Δt is the length of the time step. Since data at one minute resolution is used in this analysis, Δt is constant and equal to 1/60 h.

If it is determined that charging should take place without regard for the level of solar PV generation (e.g. as a result of the current time step t being within the overnight green band of a time-of-use tariff), the charging power is calculated as

$$u(t) = \min(P_{c,max}, (E_{max} - e(t))/(\eta_c \Delta t)) \tag{5}$$

where $P_{c,max}$ is the charging power capacity of the storage, E_{max} is the maximum allowable energy level in the storage, and η_c is the charging efficiency of the storage.

If charging using excess solar power is being prioritised, then the charging power is calculated as

$$u(t) = \min(P_{c,max}, (E_{max} - e(t))/(\eta_c \Delta t),\ \max(0, s(t) - d(t))) \tag{6}$$

Once $u(t)$ has been determined, $e(t+1)$ is then calculated as follows, ready to be used as $e(t)$ in the next time step.

$$e(t+1) = \begin{cases} e(t) + u(t)\eta_c \Delta t, & u(t) \geq 0 \\ e(t) + \frac{u(t)\Delta t}{\eta_d}, & u(t) < 0 \end{cases} \tag{7}$$

The time-stepping process continues until all minutes within the week of data have been stepped through. This process is carried out separately for all houses in an aggregation of 100 houses (explained in more detail below). The resulting net demands p are calculated using Eq. (3), and these are used in Eqs. (1) and (2) to calculate the ADMD and ADME of the aggregation. Conducting this process both with and without storage shows the aggregated effects of storage operating according to time-dependent electricity tariffs.

2.5. The Monte Carlo method

To generate datasets for use in this analysis, the demand profiles of aggregations of 100 houses are found using the CREST Demand Model. This is a typical number of houses connected to a secondary substation

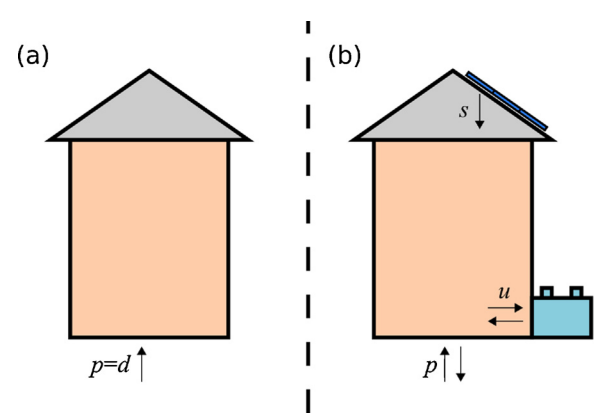

Fig. 4. Power flows within a household. (a) No solar PV or storage, so net demand p equals the raw demand d of the house. (b) With solar PV and storage.

in the UK, which transforms electricity from medium voltage down to low voltage for distribution to households. The CREST Demand Model is a stochastic model of domestic energy demands; the household sizes, building types, and appliances are assigned randomly based on UK distributions, and every time the model is run a different set of electrical and thermal demands are generated based on various factors including household occupancy, irradiance, and the set of appliances in the house. Therefore the demand profiles are generated for many different aggregations of 100 houses, and the effects of storage responding to time-dependent tariffs are found for all of these, then the average effects are found and presented. In all of the analyses presented here, 150 different aggregations of 100 houses are used, and in each analysis, the peak flows to and from the aggregation are averaged over the 150 aggregations. Each of the 150 aggregations is a different set of houses.

To account for the time it takes for energy storage to reach what might be considered as steady-state operation, each demand profile consists of one week of net demands. For each household, two separate weeks of net demand data are generated: one week in summer and one week in winter. In each case, five weekdays are followed by two weekend days. When analysing peak demands, only the winter data is used and the storage starts the week full (100% SoC). This maximises the ability of the storage to meet demand peaks, ensuring that peaks are not unnecessarily missed because initial conditions caused the storage to be empty at the times of peak demand on the first day. Similarly, when analysing peak exports, only the summer data is used and the storage starts the week empty (0% SoC), ensuring that export peaks in the first day are not missed because the storage was full. Different seasons are used in each analysis because changing amounts of daylight throughout the year make it a good idea to have different tariffs for different seasons, and peak demands tend to occur in winter and peak exports from solar PV tend to occur in summer.

2.6. Storage characteristics

Throughout this paper, charging and discharging efficiencies of 92.2% have been used, giving a round-trip efficiency of 85%, typical for battery storage [32]. It has been assumed that the full storage capacity can be used (i.e. 100% depth of discharge). In reality, battery storage is typically not used with 100% depth of discharge to increase the battery's life, however manufacturers typically quote "useable storage capacity" or "effective storage capacity", which is equivalent to what we have used. Degradation is not considered here, though it could be considered in future work in this area. We use a maximum discharging C rate of 1, typical for a Li-ion battery, so that the battery can be completely discharged from full to empty in no less than one hour. The maximum charging C rate varies depending on the analysis. In the first analysis, a maximum charging C rate of 1/7 is used (for reasons explained in section 3). In all of the following analyses, we use a maximum charging C rate of 1/3, again typical for a Li-ion battery, so that the battery can be completely charged from empty to full in no less than three hours.

It is assumed that the storage is able to conduct load following, thus rapidly responding to changes in net demand. In discussions with battery developers it has been found that in some cases it can take a few minutes for battery inverters to prepare to allow discharge of the battery, due to precautions that must be taken to ensure that a grid supply is present in case maintenance or repair work is being carried out on local cables (in the UK, this is known as G59 and G83 compliance). However, it is known that the time taken for these procedures can be reduced to seconds using always-on inverters.

3. The impacts of time-of-use tariffs

In this section, we determine the effects of TOU tariffs on demand peaks at the secondary substation level, looking at ranges of times for the peak price bands, and paying special attention to existing and recently-trialled TOU tariffs.

3.1. Effect on peak demands in areas without heat pumps

We begin by investigating the effect of TOU tariffs on the potential contribution of home batteries to reducing peak demands, initially using the first TOU tariff to be introduced in the UK in 2017. A fixed three-tier TOU tariff is implemented, as explained above.

We begin by assuming that the storage is always charged gradually within a 7-hour overnight green band (23:00–06:00, the off-peak band in Green Energy's TIDE tariff and in many Economy 7 tariffs), at a rate of C/7. This is the slowest charging rate that can be used while ensuring that a full charge will always occur in the off-peak period of 23:00-06:00 every night. A peak red band runs at some point in the late afternoon or evening, and the storage is discharged as hard as possible within this band without causing the household's demand to become negative. The start time of the red band, along with its length, are varied in order to understand the effect of the red band parameters on peak demand at the secondary substation level. Amber bands run between the green and red bands and, as explained previously, it is assumed that the storage is neither charged nor discharged in the amber bands.

Fig. 5 shows a contour plot of percentage reduction in ADMD against the red band start time and length, for an aggregation of 100 houses with 3 kWh of battery storage per house but no solar PV. The presence of negative values throughout shows that ADMD is in fact slightly *increased* when batteries operate according to this tariff in areas with no solar PV. By way of example, we can see that Green Energy's TIDE tariff, with its 3-hour red band from 16:00-19:00, might lead to a 1.7% increase in ADMD in areas where households have 3 kWh of battery storage but no solar PV, if the storage was charged at the slowest rate possible to ensure a full charge can occur every night.

The increase in ADMD is a result of the overnight charging of the batteries, increasing the late night demand such that the time of ADMD is actually moved into the late-night period. This effect has been seen in other studies (both because of storage operation [22] and because of behaviour change [33,34]), and is sometimes known as a "rebound peak". The rebound peak is evident from Fig. 6, a plot of aggregated demand profiles with and without storage over the course of 24 h. Evidently, the net demand of the aggregation is considerably reduced in the red band, with the reduction tailing off slightly towards the end of the red band when some of the batteries have become depleted. It can clearly be seen that charging of batteries from the start of the green

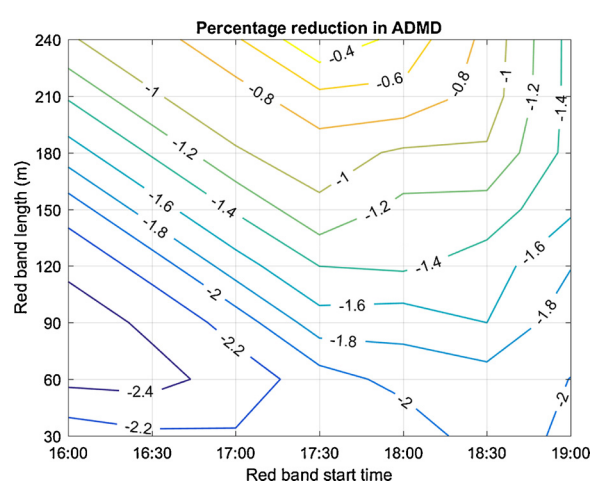

Fig. 5. Percentage reduction in mid-winter ADMD against red band start time and length for a three-tier TOU tariff incentivising overnight charge and discharge only in the red band, for an aggregation of 100 houses with 3 kWh of battery storage per house but no solar PV.

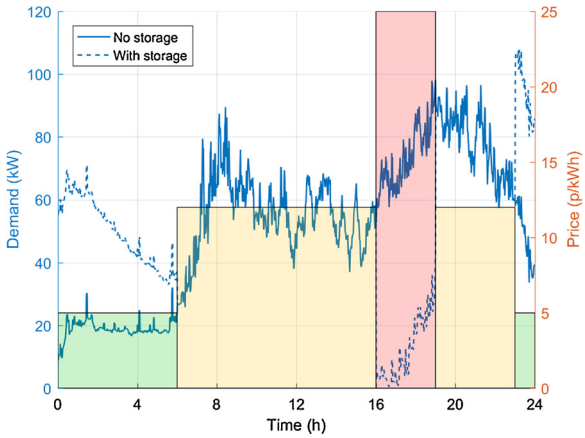

Fig. 6. Aggregated demands of 100 houses over the course of one day in mid-winter, showing the possible effects of adding 3 kWh of battery storage per house when houses are signed up to the first three-tier time-of-use tariff in the UK. No solar PV.

band at 23:00 has shifted the peak demand to this time.

In the analysis presented in Figs. 5 and 6, the storage was always charged at a rate of C/7. As explained above, this is the slowest rate possible while ensuring a full charge can always occur in the off-peak period of 23:00–06:00 every night. The increases in ADMD could be even higher if the batteries were charged at a faster rate than C/7, or if the storage capacity were higher. The latter is particularly relevant when considering areas with large numbers of electric vehicle chargers responding to TOU tariffs. ADMD increases could be reduced or avoided by incentivising battery charging when domestic demands are lower (for example by starting the off-peak band at 00:00 or 01:00). Other approaches to avoiding a rebound peak are proposed and investigated in Section 4.

In terms of home batteries, it is likely that they will mainly be installed in houses with solar PV, at least in the near-term, in which case charging using excess solar power may be prioritised. However, it should be noted that in the first three-tier TOU tariff in the UK (Green Energy's initial version of their TIDE tariff, launched in 2017), the price in the seven-hour overnight off-peak price band was 4.99 p/kWh, lower than the export Feed-in Tariff at the same time of 5.03 p/kWh [35]. If export tariffs are paid based on metered export volumes (rather than deemed to be a fixed percentage of generation volumes), then it would have been more economical for batteries in households signed up to that tariff to be charged overnight, rather than to be charged using excess solar power. However, in early 2018, the off-peak price in that tariff was raised above the export Feed-in Tariff.

In areas with solar PV and with relatively low export tariffs, it is likely that battery controllers will forecast solar irradiance and household demand, and focus on charging the battery using excess solar power, thus reducing overnight charge. Fig. 7 shows how the results look if the batteries are only charged using excess solar power, in areas with 3 kW of solar PV per house (the average domestic PV installation size in the city of Leeds). The maximum charging rate is set to C/3, typical for a Li-ion home battery [36]. It can be seen that percentage reductions in peak demands at the secondary substation can be over 12% in this case, with the optimal red band running for at least six hours from around 17:00. This timing is consistent with the average household electricity demand profiles shown in Fig. 1.

An example of the effects of a five hour red band running from 17:00 to 22:00 is shown in Fig. 8. It can be seen that in residential areas with large numbers of batteries and reasonably large amounts of installed solar PV, it might be worth having two red bands to capture both the morning and evening peaks, particularly when those batteries have moderate or large storage capacities.

With charging from solar PV, the peak demand reductions of around 12% are significantly lower than the potential reduction of over 60% that previous work has found to be possible with perfect foresight of local demand and the same level of storage capacity [16], as can be seen in Fig. 9. With 10 kW h of battery storage per house, again being charged only using excess solar generation from 3 kW of solar PV per house, the percentage reductions in ADMD from fixed TOU tariffs are shown in Fig. 10. Comparing this with Fig. 7, it can be seen that with larger amounts of storage, there is less of a drop-off in ADMD reduction as the red band length is increased. This makes sense, as a large storage capacity is less likely to become depleted during the red band. With 10 kW h of battery storage per house, 16% ADMD reduction could be achieved with a six hour red band starting at 16:30, again assuming that the storage is only charged using solar PV.

From these results we can conclude that home batteries operating according to TOU tariffs cause only small reductions in peak demand on LV networks, because LV demand peaks are spread out over time. This is clear from Fig. 11, which shows relative frequency distributions of the times at which peak flows occur. The inter-day variance is clear, and intra-day variance can be clearly seen in Figs. 6 and 8. Fixed TOU tariffs don't sufficiently anticipate demand peaks at the LV level. It has even been found that if solar PV is not utilised for charging, the overnight charging of home batteries could cause increases in peak demands at the LV level. This has some significance for future home charging of battery electric vehicles, which are typically charged overnight, and whose battery capacities are often considerably higher than the home battery capacities considered here. Significant peak demand reductions are only possible using smarter strategies, such as voltage/current monitoring [37] and forecasting levels of demand and embedded generation; these improved strategies could be used to control storage according to some other type of incentive scheme, such as maximum demand tariffs [21,22] combined with TOU tariffs for national energy objectives, for example.

3.2. Effect on peak demands in areas with heat pumps

We now consider the effects of introducing heat pumps into residential areas with battery storage operating according to time-of-use tariffs. In all cases, it is assumed that a 10 kWth air source heat pump with COP of 3 is included in each house, and used to provide space and hot water heating. A 125 L hot water tank is also included. Again, it is assumed that the storage is only charged using excess generation from 3 kW of solar PV on each house.

Fig. 12(a) shows the peak shaving against red band start time and

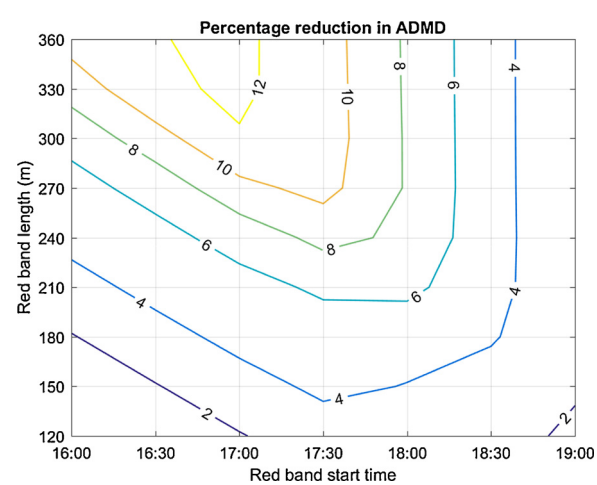

Fig. 7. Percentage reduction in mid-winter ADMD against red band start time and length for a TOU tariff incentivising charge only from excess solar power, and discharge only in the red band, for an aggregation of 100 houses each with 3 kWh of battery storage and 3 kW of solar PV.

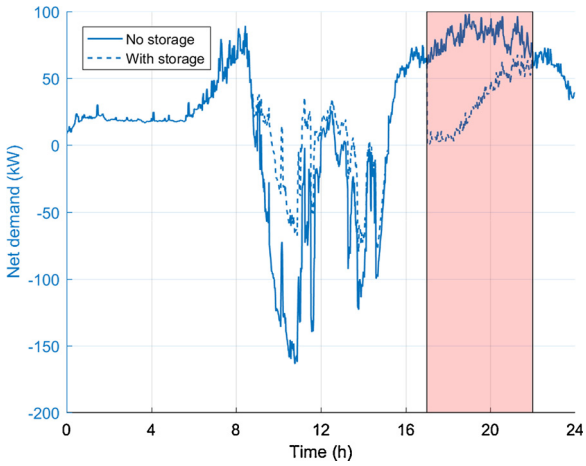

Fig. 8. Aggregated net demands of 100 houses over the course of one day in mid-winter, showing the possible effects of adding 3 kWh of battery storage per house when the storage is only charged using excess solar PV and only discharged in a peak period of 17:00-22:00 (shown using a red band). 3 kW of solar PV per house. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

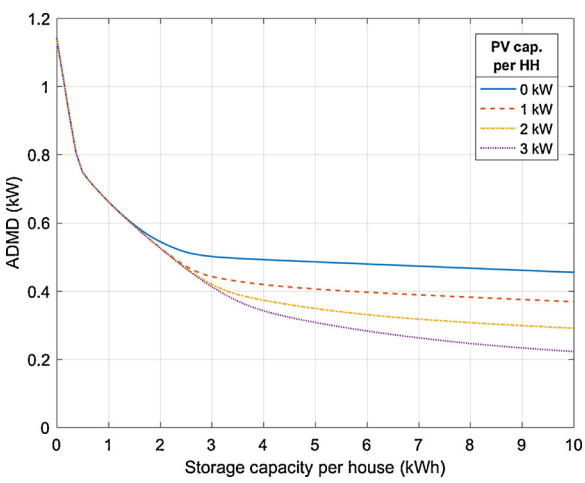

Fig. 9. Lowest possible ADMD against battery storage capacity per house in areas with varying penetrations of storage and solar PV. Assumes perfect foresight of net demand patterns, and coordinated operation of the installed storage [16].

length, in areas with 3 kWh of battery storage per house, being charged only using excess generation from 3 kW of solar PV per house. Clearly the optimal red band in this case runs for three hours from 17:00, however this only achieves a 3.5% reduction in peak electricity demand at the secondary substation. This compares with a potential 45% reduction in peak demand with full foresight of net demand patterns and the same level of PV and storage capacity [16].

Fig. 12(b) shows the effect of larger storage capacities, in this case 10 kW h per household. Again, a larger storage capacity has the effect of increasing the optimal red band length and moving the optimal start time earlier in the evening. In the best case here, LV peak demand reduction is less than 6%; with full foresight of net demand patterns and the same level of PV and storage, peak demand reductions could be over 60%, bringing ADMD down from around 2.05 kW to less than 0.8 kW [16]. It can be concluded that TOU tariffs incentivising operation of home batteries in areas with heat pumps have very little effect on peak demands at the low voltage level and considerably miss out on the potential peak shaving that could be achieved.

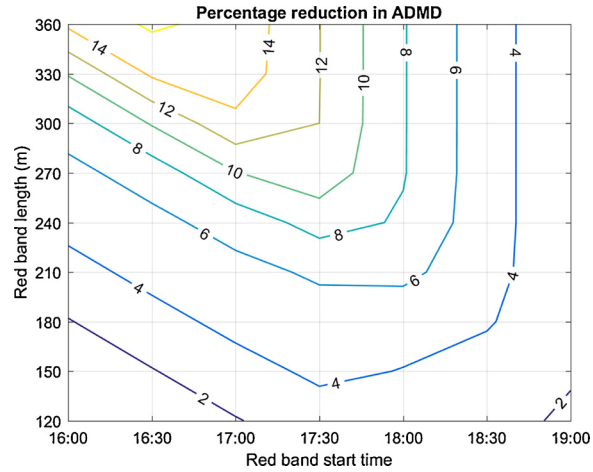

Fig. 10. Percentage reduction in mid-winter ADMD against red band start time and length for a TOU tariff incentivising charge only from excess solar power, and discharge only in the red band, for an aggregation of 100 houses each with 10 kW h of battery storage and 3 kW of solar PV.

4. Avoiding rebound peaks

As shown in Section 3.1, time-of-use tariffs can have the effect of causing an increase in peak demand at the secondary substation level, as a result of all of the storage in the area charging at the same time. This increase in peak demand is known as a rebound peak, and it is most likely to occur in areas with high levels of stationary storage capacity and low levels of installed solar PV capacity. A rebound peak is most likely to occur the night before cloudy days, since storage controllers in households with solar PV will utilise forecasts of local generation, and prioritise overnight charging before cloudy days.

The rebound peak effect is also likely in areas with moderate or high numbers of EVs. It is particularly concerning when considering home charging of EVs, with current home chargers in the UK typically being capable of powers between 3.6 kW and 22 kW. Also, since EVs are often away from home during daytime, charging using solar PV is usually not an option, and so overnight charging during off-peak price bands will be prioritised, increasing the simultaneity of demand.

There are several possible approaches to reducing or avoiding a rebound peak, including:

- Staggered off-peak price bands between households
- Coordinated control of residential energy storage and EV charging
- Maximum demand tariffs

Coordinated charging of EVs has been investigated by several others [38–40], considering approaches to minimise costs and studying the interactions between distribution system operators, charging system providers, and retailers. Remotely-controlled switching of EV chargers was trialled within the My Electric Avenue project. The technology was known as Esprit, and worked by instigating temporary curtailment of recharging on a rolling basis (typically for 15 min each) across the local cluster of EVs [41]. It was shown that sufficient curtailing of EV loads took place to allow an additional 10% of customers to connect EVs before voltage problems occur. However, such a system requires consumers to allow an external actor to control their charging system.

Similar to staggered off-peak price bands, Hayes et al. [33] have investigated the effect of individualised demand-aware price policies, such that the average price received by each end user is non-discriminatory. In that work it was shown that such individualised price policies can avoid rebound peaks, increase the load factor, and reduce network losses.

We investigate the effect of staggered off-peak price bands here, by

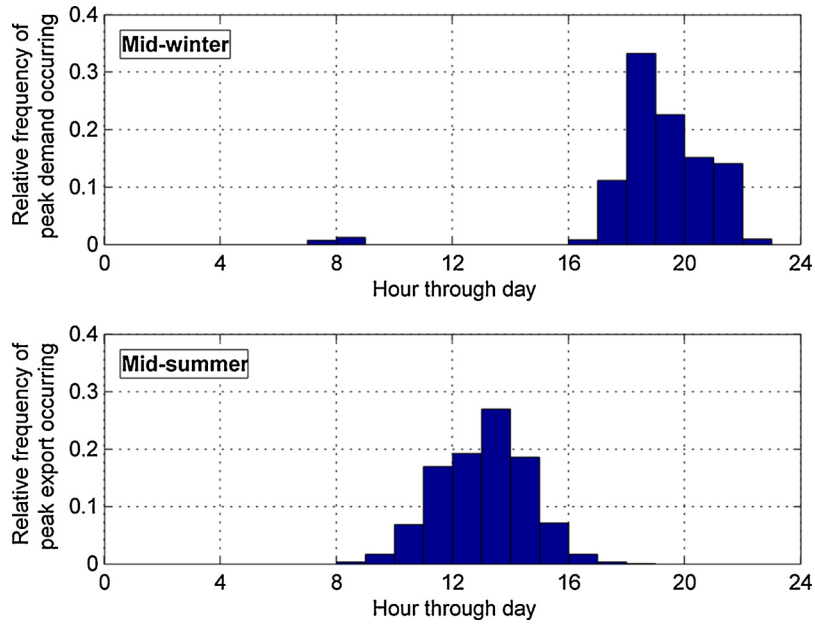

Fig. 11. Relative frequency distributions of times of peak demands and peak exports in winter and summer, respectively, for an aggregation of 100 houses each with 3 kW of solar PV.

applying a randomised offset to the times of each household's off-peak price band on each day. The effectiveness of randomised offsets for the off-peak band is shown in Fig. 13, whereby each house is randomly assigned one of the following offset times each day: {0,306,090,120} minutes. In this way, the off-peak price band always starts at some point between 23:00 and 01:00. Seven hour charging windows are maintained in all cases, and in this analysis, each house is given 3 kWh of battery storage. It can be seen that by spreading out the times over which charging of storage commences, such randomised offsets can prevent a rebound peak from occurring when the maximum charging rate is set to C/7. However, when the maximum charging rate is set to C/3, a rebound peak still occurs as long as the red band is longer than ~140 min.

From these results it is clear that when considering the effect of staggered off-peak price bands on rebound peaks, it is necessary to look at various factors including household demands and the installed capacity of embedded generation and energy storage. It is also clear that unless there is some incentive to charge domestic energy storage or EVs at lower rates of power, it is quite possible that rebound peaks will still occur even if staggered off-peak price bands are used.

Therefore we propose that residential maximum demand tariffs are investigated as a means of explicitly incentivising consumers to reduce the stresses they place on the electricity distribution network. Similarly, maximum export tariffs would incentivise consumers to reduce stress on distribution networks in areas with high levels of rooftop solar PV capacity. The latest generation of smart meters in the UK (SMETS2) already have the capability to record maximum import and maximum export [42]. Therefore the effect of capacity charges (i.e. some combination of maximum demand and maximum export tariffs) on peak residential electricity demands will be the focus of a future research paper.

5. The impacts of time-of-export tariffs

As well as using time-dependent tariffs to incentivise demand reduction at certain times, it is also possible to use them to incentivise reduction of export from rooftop solar PV at certain times (e.g. the middle of the day), thus reducing stress on the grid at times of high solar PV output. This can be achieved with a simple two-tier export tariff, whereby charges are paid if solar power is exported within a time band in the middle of the day. A two-tier TOU tariff was recently trialled in Cornwall in an attempt to increase electricity consumption in the middle of the day; known as the 'Sunshine Tariff', this ran from April to September and comprised a low price of 5 p/kWh for electricity consumed between 10:00-16:00, and a much higher price of 18 p/kWh from 16:00 to 10:00 [12]. Unlike the Sunshine Tariff, which was a time-of-use tariff, we are considering time-of-export tariffs, which explicitly penalise export at certain times.

To investigate the effect of time-of-export tariffs on reducing peak export of solar PV using electricity storage, we use a similar approach as that used in the previous section. In this case, we set up a two-tier tariff whereby an export red (charging) band runs at some point in the middle of the day, and the start and end times of this are varied. The storage is only charged in the export red band, and outside of the export red band the storage is discharged as hard as possible to try and bring net demand down to zero – any effects of this operation on increasing demand peaks are disregarded here as we are focusing on the effects on peak export. Again, full details of the methodology are given in section 2. As previously, the maximum charging C rate is set to 1/3 (3 h full charge) and the maximum discharging C rate is set to 1 (1 h full discharge).

Results of this analysis for houses with 3 kWh of battery storage and 3 kW of solar PV (the average size of domestic solar PV installations in the city of Leeds [43]) are shown in Figs. 14 and 15 shows example aggregated net demand profiles with a six hour export red band of 10:00-16:00. Evidently, the optimal time for the centre of the export red band is in the early afternoon, with longer export red bands providing the greatest peak export reductions. It is clear that the effects of time-of-export tariffs on After Diversity Maximum Export (ADME) are small, with even the best case giving reductions in ADME at the secondary substation level of only 6%. Previous work has shown that the best possible peak export reduction (i.e. with perfect foresight of net demand profiles) with the same capacities of storage and solar PV is around 40% [16].

It can be seen in Fig. 15 that little reduction in export is achieved towards the end of the export red band, since many of the batteries have become full. While not shown here, it has also been found that peak export reductions from time-of-export tariffs remain reasonably low even when considering much greater levels of battery storage (e.g. 10 kW h per house); as shown in ref. [16], with perfect foresight, peak exports could be more than halved when storage capacity is greater

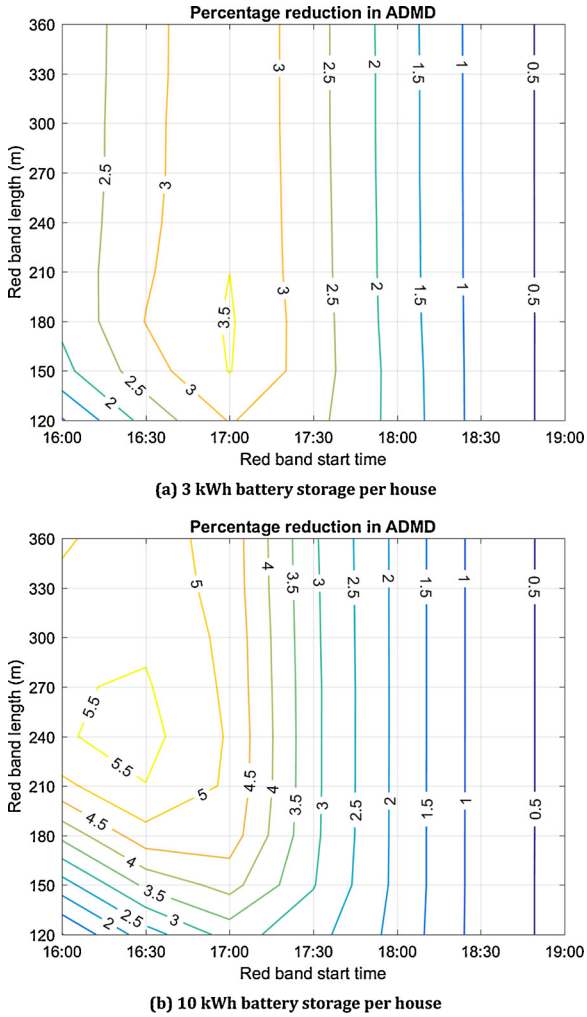

Fig. 12. Percentage reduction in mid-winter ADMD against red band start time and length for a TOU tariff incentivising charge only from excess solar power, and discharge only in the red band, for an aggregation of 100 houses each with battery storage, 3 kW of solar PV, and a 10 kWth heat pump providing all of the space and hot water heating.

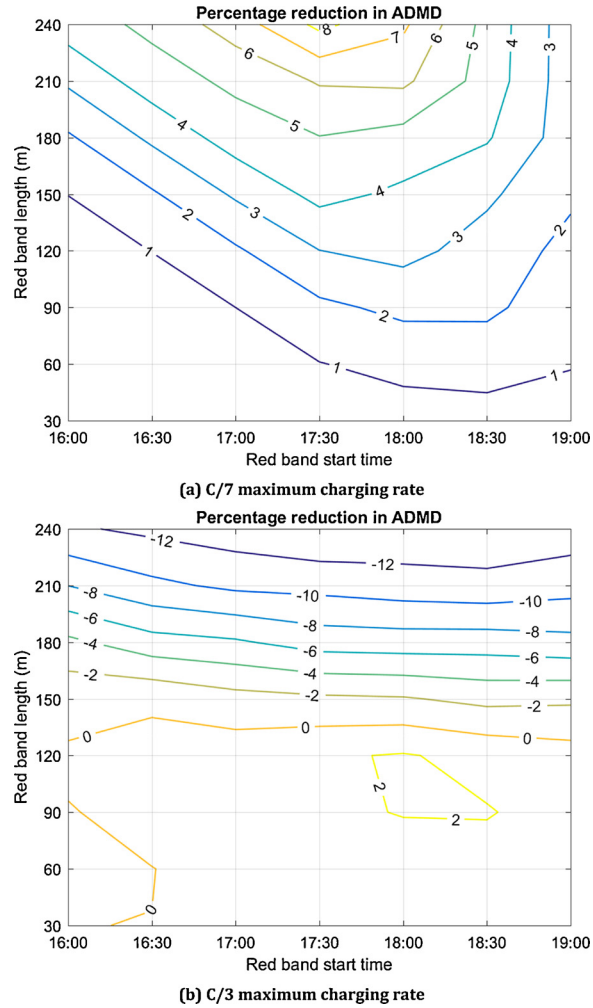

Fig. 13. Percentage reduction in mid-winter ADMD against red band start time and length for a three-tier TOU tariff incentivising overnight charge and discharge only in the red band, for an aggregation of 100 houses with 3 kWh of battery storage per house but no solar PV. For each house on each day, a randomised offset of one of {0,306,090,120} minutes is applied to the times of the off-peak price band.

than 4 kW h per house.

So, as with time-of-use tariffs for peak demand reduction, we can conclude that electricity storage being operated according to fixed time-of-export tariffs will have little effect on peak solar PV export. This is because the times of peak demand and peak export are spread over periods of several hours, as is evident from several figures including Figs. 11 and 15.

Time-dependent tariffs do not sufficiently anticipate peak flows at the secondary substation level, and other schemes could provide much greater benefits. Such schemes might take the form of capacity charges proportional to a household's peak import and export powers; limits on Feed-in Tariff payments for solar PV systems if the system owner does not have a means of limiting peak export to a certain percentage of the installed PV capacity (as is the case in Germany); or a requirement to fit some form of curtailment device on certain high power equipment (such as solar PV systems and electric vehicle chargers).

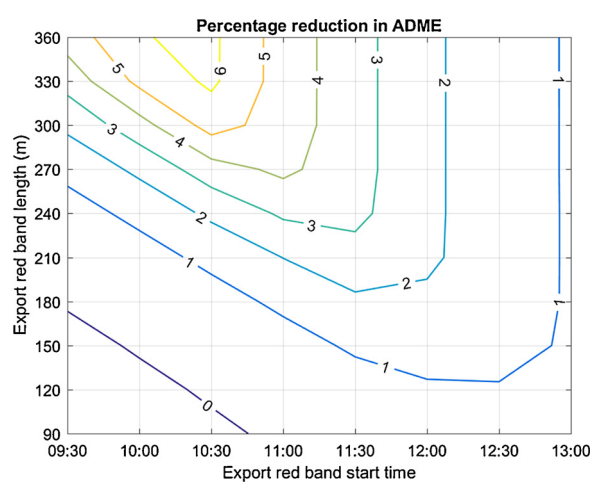

Fig. 14. Percentage reduction in mid-summer After Diversity Maximum Export from solar PV against export red band start time and length for a time-of-export tariff incentivising charge only in the export red band and discharge at all other times, for an aggregation of 100 houses each with 3 kWh of battery storage and 3 kW of solar PV.

6. Conclusions

If energy storage's potential for low voltage peak shaving is to be realised, a key outstanding question is how to encourage consumers to adopt and appropriately operate energy storage technologies. Our exploration of fixed time-of-use and time-of-export tariffs as a means of

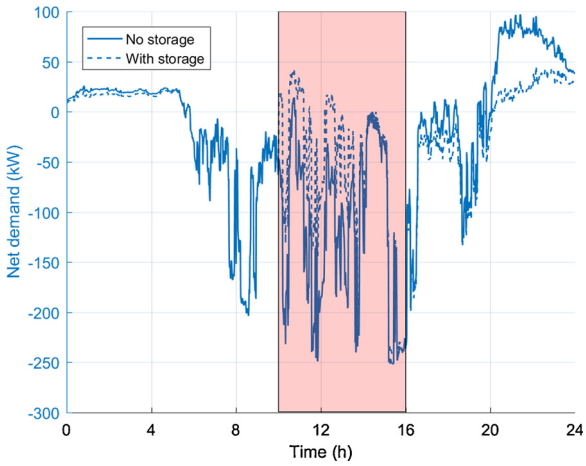

Fig. 15. Aggregated net demands of 100 houses over the course of one day in mid-summer, showing the possible effects of adding 3 kWh of battery storage per house when the storage is only charged using excess solar PV within an export red band of 10:00-16:00 (shown using a red band), and only discharged outside of the export red band. 3 kW of solar PV per house.

incentivising the operation of battery storage has demonstrated that time-dependent electricity tariffs have little effect on peak flows of electricity at the low voltage level, even in areas with high penetrations of solar PV and heat pumps, and significantly miss out on the potential peak shaving that could be achieved. This is because demand and generation peaks are typically spread out over the course of several hours.

Surprisingly, it was found that operating electricity storage according to the first three-tier time-of-use tariff to be introduced in the UK could actually increase peak electricity demands at the low voltage substation, if the storage all begins to charge at the start of the overnight off-peak band when average electricity demands are still moderately high, causing a “rebound peak”. Upon the launch of that tariff, the overnight off-peak electricity price was lower than the export tariff for solar PV, so it would actually have been more economical for storage in houses with solar PV to be charged overnight rather than using excess solar power, thus causing these small increases in peak demands at the low voltage substation. These findings raise questions around the appropriate level of the export Feed-in Tariff for solar PV.

It is likely that the issue of increased evening peak demands caused by time-of-use tariffs will become significant as electric vehicles are increasingly adopted. It has been shown that staggering the times of off-peak price bands for the households in an area can help to counteract the rebound peak effect, but this approach is limited in areas with large numbers of home batteries or EVs. In such areas it is also important to provide some explicit incentive to reduce maximum demands, such as a maximum demand tariff.

Considering what little positive effect time-of-use and time-of-export tariffs have on low voltage demand and export peaks in residential areas with home battery storage, we believe that other measures of incentivising use of energy storage to provide low voltage peak shaving should be investigated. These measures might include capacity charges proportional to maximum import and export over a certain time period; storage sharing/rental arrangements between householders and aggregators/DNOs; exposure of storage to dynamic electricity prices, e.g. through use of premium export Feed-in Tariffs [44]; only awarding export Feed-in Tariff payments when generation is below a certain percentage of capacity (and possibly even charging for export above a certain level); and mandatory fitting of curtailment devices to high power equipment such as PV systems and electric vehicle chargers.

Considering the findings presented in this paper, future work in the C-MADEnS research project will focus on the potential of capacity charges (i.e. electricity tariffs with components that are proportional to maximum import and maximum export) to incentivise low voltage peak shaving when combined with time-of-use tariffs for national peak demand reductions. Given the very rapid response possible with battery storage, it is expected that an intelligent control system responding to an explicit incentive to reduce import and export peaks would be much more effective than time-of-use tariffs in incentivising low voltage peak shaving.

Acknowledgments

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