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The value of electricity storage to large enterprises: A case study on Lancaster University

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Abstract

Co-locating electricity storage with demand has significant potential to increase consumption of locally-generated electricity, defer infrastructure investments, and contribute to the task of balancing supply and demand on the wider network. In the UK, unlike domestic consumers, large enterprises are already incentivised to reduce peak demand through exposure to time- and demand-dependent network charges. This paper considers the potential of electricity storage to reduce the bills of large enterprises, focusing on Lancaster University as a case study. Through analysis of Lancaster University's recent demand and generation data and current and future charges, it is shown that recent widening of red distribution charge time bands has reduced the value of electricity storage to enterprises, and that in 2015 an enterprise such as Lancaster University could have expected electricity storage to deliver annual savings of around £27 per kWh of storage capacity, by reducing network charges. An analysis of these charges around Great Britain shows that the opportunity for storage to provide savings to enterprises is greatest in the south-west (at least £70/kWh.yr in 2017) and lowest in the north of Scotland (at least £20/kWh.yr). Whether investment in storage provides positive value to enterprises is shown to be strongly dependent upon location.

Keywords: Electricity Storage; Economics; Distributed Energy Storage; Business

Highlights:

- Electricity storage can be used by enterprises to reduce network charges.
- An optimisation algorithm with price-switching based on net demand is presented.
- In 2017, storage could provide savings of >£33/kWh.yr in the north-west of England.
- Savings in the south-west will be >£70/kWh.yr, twice the average elsewhere in GB.
- Payback period for batteries is 8 years in the south-west, 36 in the north-west.

Nomenclature:

d	Demand
g	Generation
i	Time
p	Electricity price
p_{buy}	Effective electricity price seen by the storage if charging
p_{et}	Export tariff (for export of FiT-registered generation)

p_{sell}	Effective electricity price seen by the storage if discharging
p_{spill}	Spill price seen by the storage (for export to the grid)
P_{es}	Power into storage (negative indicates discharge)
P_{net}	Net power exported from the site (negative indicates import)

BEV	Battery electric vehicle
BS	Black start
BSUoS	Balancing Service Use of System
CES	Cloud Energy Storage
CfD	Contracts for Difference
DECC	Department of Energy and Climate Change
DNO	Distribution network operator
DUoS	Distribution Use of System
EFR	Enhanced Frequency Response
FFR	Firm Frequency Response
FiT	Feed-in Tariff
FR	Fast Reserve
GB	Great Britain
HDC	High distribution costs
HH	Half hour
HV	High voltage (11 kV)
LU	Lancaster University
NPV	Net present value
RO	Renewables Obligation
SoC	State of charge
SME	Small and Medium Enterprise
SP	Settlement period
STOR	Short Term Operating Reserve
TNUoS	Transmission Network Use of System (charged for demand using "Triads")

1 Introduction

A number of recent reports have suggested that significant future cost savings are likely to be delivered through implementation of energy storage, with two recent projections suggesting annual savings to Great Britain in 2030 of up to £2.4bn [1] and up to £8bn [2]. Electricity storage will play a significant role in this, with increased electricity system stress resulting from a growing penetration of variable renewables. While large-scale electricity storage technologies such as pumped storage and compressed air are typically regarded as having the lowest costs per unit of storage capacity and power capacity [3], it is more likely that small- and medium-scale distributed storage devices will be built in the near-term. Experience in Germany is already showing this to be the case [4], with reduced capital costs being more appealing to investors faced with the uncertainty surrounding future revenue streams and government support for storage. Smaller-scale distributed storage (i.e. storage connected below the grid supply point) also offers a larger potential customer base than centralised systems (including many consumers looking to maximise the potential of on-site generation), as well as allowing improved utilisation of distribution infrastructure.

Large enterprises, such as businesses, hospitals, prisons and universities, account for significant levels of energy use. Many have on-site generation in the form of diesel generators or CHP plants, allowing them to reduce their electricity import at times of peak demand, and providing backup power. Many also actively look to improve the environmental impact of their operations, such as by installing on-site renewables, switching to low emission vehicle fleets, enhancing thermal efficiency of buildings and installing electric heating systems that can be powered using renewables. These changes improve the public's perception of the organisation, and in many cases provide lower cost energy. With surging interest in energy storage as a way of providing flexibility to the grid and so allowing increased penetrations of inflexible generation technologies, it is likely that storage will be increasingly adopted by large enterprises in the coming years. Questions remain as to the value of electricity storage within these contexts, so this work seeks to improve understanding of the value of electricity storage to large enterprises.

There exist a number of revenue streams from which electricity storage can derive economic value. Some studies have looked at the value of electricity price arbitrage using storage [5-8], however most of these have disregarded the impact of transmission and distribution charges, coming to the conclusion that, in the UK at least, there is currently insufficient revenue potential for storage from arbitrage alone to make investment worthwhile. More recently, studies have looked at the use of electricity storage to provide reserve as well as to arbitrage on electricity prices, showing that providing reserve on top of arbitraging on market prices can triple the revenue for electricity storage in the British electricity market [9]. Such consideration of the stacking of multiple revenue streams for storage is becoming increasingly important.

Coupling of storage to wind and solar farms has also been well investigated [9-13], and more detailed economic analysis of storage considering risk has been carried out [14, 15]. Recently, researchers have started to consider the potential for storage to be directly integrated with generation [16], however few studies have looked specifically at the economics of distributed electricity storage and co-location of storage with demand. A study by Koh [17] assessed the viability of electricity storage in a building in Malaysia, finding that it provides financial benefits to multiple parties through reduced load variability, reduced network losses, and improved power system stability.

Several studies have looked at the value of energy storage to enterprises, mainly focusing on small businesses. Scozzari [18] investigated the economic value of installing hydrogen storage at small and medium enterprises (SMEs) with solar PV in Italy, showing that costs, particularly of the electrolyser, currently make such a system unprofitable. The authors also presented a set of economic and regulatory conditions that would make the system profitable. Recently, Liu

[19] looked at the potential of using a 'Cloud Energy Storage' (CES) system for residential and small commercial consumers, whereby portions of large centralised storage units are rented out to nearby householders and businesses. It was shown that in certain circumstances CES could provide the same services as distributed energy storage but at a lower social cost. At a larger scale, Barbour [20] considered the value of behind-the-meter electricity storage installed on the University of Birmingham campus in reducing transmission charges, though distribution charges were not considered as the University of Birmingham is directly connected to the transmission network at 132kV and sees no time-varying distribution charges [21].

Increasing numbers of buildings, both domestic and non-domestic, have small-scale generation installed, be it solar PV, wind turbines, or combined heat and power (CHP). Maximising self-consumption of on-site generation is of importance to the consumer (to maximise cost savings), the network operator (to reduce peak demand and reverse flow on the network), and the system operator (to maintain system stability and an adequate capacity margin at a low cost), and electricity storage provides a means of achieving this. Operators of electricity storage devices will typically operate storage according to price signals, and self-consumption of on-site generation can be considered in terms of a price signal, with the export tariff paid for exported energy from embedded generation typically known in advance and less than the retail price of electricity. In Great Britain, time-varying electricity prices are currently seen by half-hourly metered properties (typically those meters with peak demand >100 kW) in the form of time-banded Distribution Use of System (DUoS) charges, Transmission Network Use of System (TNUoS) charges (also known as Triad charges), Balancing Service Use of System (BSUoS) charges, and in some cases variation in commodity price, though the commodity price that is seen by a large enterprise depends upon the procurement approach, with many consumers requesting flat prices from their broker over the course of a certain period (e.g. one month).

Policy that introduces mandated levels of storage capacity and incentives is gaining interest in some parts of the world. Of note is the situation in the USA, where California recently mandated a capacity of 1.3 GW in operation by 2024 [22] and suppliers are offering incentives of over $2,000 per kW of capacity [23, 24]. As a result, increasing numbers of large enterprises are interested in installing storage [25], however little research has been carried out into this potentially significant opportunity.

The electricity demand of large enterprises is considerable. In Great Britain in 2014, only 8% of the electricity meters were in the non-domestic sector, but 63% of electricity was consumed in the sector [26]. By region, this varied from 58% in the south-east up to 68% in Wales and London. The mean annual non-domestic electricity consumption per meter in Great Britain was 76,402 kWh, and total non-domestic consumption was 186,150 GWh. The spread of non-domestic consumption volumes for the UK in 2013 is shown in Fig. 1, and the breakdown of forecasted high/low voltage consumption by distribution tariff in the North West distribution area is given in Fig. 2. In the latter, it is clear that high voltage half-hourly (HV HH) metered consumption accounts for almost 25% of total high/low voltage consumption in the North West distribution area in 2016, and large enterprises typically fall into this category. High levels of high voltage half-hourly metered consumption are also found in the other distribution areas of Great Britain.

In order to understand the value of electricity storage to large enterprises, a case study on a typical large organisation is carried out. Lancaster University, a medium-sized, campus-based university in the north-west of England, is considering installation of a range of energy storage devices for experimentation purposes as well as to benefit from electricity cost savings, and the university provides a good example of a large enterprise looking to invest in storage. The university also has good data available on its energy use and on-site generation, and is supplied through a single grid connection. This paper looks at the value of storage to such consumers in the current charging regime, while also looking at the effect of projected changes to electricity charges in the near future. An algorithm is developed which can be used to find the optimal operating schedule (i.e. set of charge and discharge powers) of an energy storage system which is incentivised to maximise on-site generation, and the effect of the level of on-site generation on the value of storage is investigated. The effect of location within the UK on the value of storage to large enterprises is studied, and other potential revenue streams for small- and medium-scale electricity storage are considered. The optimisation algorithm presented in this paper is very powerful and efficient, and can be used in many other circumstances, including any time the user has knowledge (or predictions) of energy prices and net demand profiles.

2 Energy at Lancaster University

Lancaster University is a collegiate, public university based on a self-contained, 360-acre campus just outside the city of Lancaster in the north-west of England. It has approximately 13,000 students and 2,500 staff, with 8 halls of residence on campus and a campus electricity demand in excess of 33 GWh/year, resulting in a total spend on electricity of around £2m p.a. With this level of annual consumption, the university fits into DECC's 'Large' size category for non-domestic consumers [27]; these range from 'Very Small', at 0-20 MWh/year, up to 'Extra Large', at >150 GWh/year. The university also owns three halls of residence in the city centre and has a campus in Ghana, but these will not be considered in this work.

The campus is connected to the local distribution grid through two high voltage (11 kV) feeders acting as a single feed, with a combined capacity of 8 MVA. Campus import and export is metered half-hourly using two meters (one on each HV feeder), and non-half-hourly using seven other meters, however the latter carry less than 2% of the annual load. Therefore Lancaster University falls into the 'HV HH metered' category in Fig. 2. The two half-hourly meters share the bulk of the load evenly, so each carries slightly over 49% of the campus load, and it is the consumption on these two meters that is used in the analysis presented here. From these meters, a high voltage ring main transmits power around the campus, with 12 substations converting power down to low voltage (415/230 V).

On campus the university has a 2.35 MW wind turbine and 1.9 MWe / 2.1 MWth of CHP connected to the HV ring, and 50 kW of solar PV connected at low voltage, bringing peak on-site electricity generation capacity up to 4.3 MW, over half the capacity on the 8 MVA high voltage feeder. There are approximately 1 MW of distributed immersion heaters connected at low voltage, providing domestic hot water on campus. There is also a small heat network on the campus powered by 14.4 MW of gas boilers, a 1 MW biomass boiler, and the 2.1 MWth CHP mentioned above. Another 7.8 MW of distributed gas boilers provide the rest of the campus heat demand.

Monthly electricity import and generation from the CHP plant and wind turbine are shown in Fig. 3. Export volumes are not included in the figure because they would not be visible, typically being around 0.02 GWh per month. As a result, the sum of the import and on-site generation is approximately the monthly campus electricity demand, which drops over the summer months of July to September, due to a combination of lower on-site population and reduced heating load. Interestingly, campus import is greatest during the summer months as the CHP plant is shut down over that period and the wind resource is lower. In December 2015 the north-west of England was hit by flooding, and the city of Lancaster's electricity supply was severely affected because the local substation is sited next to the River Lune, which burst its banks. As a result, Lancaster University was caught in a blackout for approximately two days near the start of the month, which contributed to the low demand in December (along with the usual Christmas break).

3 The value of electricity storage to Lancaster University

3.1 Methodology

Many large enterprises considering installation of storage, including Lancaster University, have some on-site generation but do not have an export contract with a supplier and so do not benefit from export of energy to the grid aside from collecting the export Feed-in Tariff (FiT) on generation from any FiT-registered sources. In order to calculate the value of storage to such an enterprise, as well as to enterprises that do have an export contract, an existing algorithm for optimal storage scheduling [5, 8] based on perfect foresight of electricity prices has been extended to take account of the levels of demand and generation, such that the effective marginal purchase and sale price of electricity seen by the storage (p_{buy} and p_{sell}) at time i switches between the total purchase price p (paid for importing power, including price paid to the supplier and additional charges), the export Feed-in Tariff p_{et} plus the added spill price p_{spill} that is paid to the enterprise for spilling electricity onto the local distribution grid (zero for Lancaster University as it has no export contract), and just the spill price, depending upon the net power output from the site P_{net} as seen by the import and export meters (where a positive value of P_{net} indicates export and a negative value indicates import).

This methodology can be applied in many other circumstances where the use of storage for arbitrage is limited by local demand or generation. Such uses include: assessment of the economic value of domestic storage, where export of embedded generation to the grid is typically worth less than self-consumption; and the value of storage co-located with renewables, where it may only be desirable to charge the storage using the generators (rather than by importing from the grid). While the algorithm uses perfect foresight of prices and net demand, it can also be used within real-time storage controllers (such as those using model predictive control or stochastic receding horizon control) which utilise predictions of future demand and knowledge/predictions of future prices.

The methodology is very efficient since computational time isn't inflated by the large number of constraints inherent in storage scheduling in the same way as many other optimisation techniques.

P_{net} depends upon the total site demand d as if there were no storage (i.e. import + generation - export), the level of on-site generation from FiT-registered sources and non-FiT registered sources (g_{FiT} and $g_{\mathrm{non-FiT}}$ respectively), and the storage charge/discharge power P_{es} (where a positive value indicates charging and a negative value indicates discharging), and is given by

$$P_{\mathrm{net},i} = g_{\mathrm{FiT},i} + g_{\mathrm{non-FiT},i} - P_{\mathrm{es},i} - d_i \tag{1}$$

All buy and sell prices are initially set to the purchase price p, then before each iteration of the algorithm the following equations (explained in detail below) are used to determine the new prices:

$$\text{If } P_{\text{net},i} < 0, \text{ then } p_{\text{buy},i} = p_{\text{sell},i} = p_i \tag{2}$$

$$\text{If } P_{\text{net},i} = 0, \text{ then } p_{\text{buy},i} = p_i \text{ and } p_{\text{sell},i} = p_{\text{et}} + p_{\text{spill}} \tag{3}$$

$$\text{If } 0 < P_{\text{net},i} < g_{\text{FiT},i}, \text{ then } p_{\text{buy},i} = p_{\text{sell},i} = p_{\text{et}} + p_{\text{spill}} \tag{4}$$

$$\text{If } P_{\text{net},i} = g_{\text{FiT},i}, \text{ then } p_{\text{buy},i} = p_{\text{et}} + p_{\text{spill}} \text{ and } p_{\text{sell},i} = p_{\text{spill}} \tag{5}$$

$$\text{If } P_{\text{net},i} > g_{\text{FiT},i}, \text{ then } p_{\text{buy},i} = p_{\text{sell},i} = p_{\text{spill}} \tag{6}$$

Equation (2) states that if the site is a net importer at time i, the buy and sell prices are set to the purchase price of electricity because charging the storage would require extra electricity to be imported, and discharging the storage would displace some import of electricity (which would otherwise cost the enterprise the purchase price of electricity).

Equation (4) states that if the site is a net exporter at time i, but that the export level is less than the output from FiT-registered sources at that time, the buy and sell prices are set to the sum of the export tariff and the spill price. Equation (3) bridges the gap from negative P_{net} to positive P_{net}, keeping the buy price equal to the purchase price of electricity.

Equation (6) states that if the site is a net exporter at time i, and that the export level is greater than the output from FiT-registered sources at that time, the buy and sell prices are set to the spill price. Equation (5) bridges the gap between P_{net} being lower than g_{FiT} and being higher than g_{FiT}.

Switching prices in this way ensures that the scheduling algorithm prioritises charging at times of excess generation, hence maximising self-consumption. The algorithm has also been modified such that a single charge/discharge event pair cannot change the sign of P_{net} from positive to negative or vice-versa, and cannot change the sign of $P_{\text{net}} - g_{\text{FiT}}$ from positive to negative or vice-versa, thus ensuring that the correct values of p_{buy} and p_{sell} are always used. An example of the schedule arising from the algorithm is shown in Fig. 4. Three weekdays, a weekend, and then four more weekdays are shown, with the weekdays being evident from discharge in the red DUoS band (the time in late afternoon when distribution charges are particularly high, as explained later). The limiting of discharge by net demand (because currently $p_{\text{spill}} = 0$ for Lancaster University) is clear in the weekdays after the weekend, and can be contrasted with the unrestricted discharge in the three weekdays before the weekend.

It should be noted that Fig. 4 shows 100% discharge of the storage device on each weekday. This would have particularly detrimental effects on the life of certain battery technologies, however a usable capacity of 10 MWh was used to calculate state of charge (SoC) in this case, and if, say, only 50% depth of discharge was recommended then the total storage capacity could just be increased to 20 MWh to give the same usable capacity of 10 MWh.

Note that the algorithm assumes perfect foresight of demand and generation levels, which is clearly not realistic in practice, though it allows us to make use of historic data. The assumption of perfect foresight of electricity prices is not an issue when electricity is procured in advance by a broker (as it is currently in the case of Lancaster University), as the electricity prices paid by the enterprise are known well in advance. However, if electricity is procured on the spot market (e.g. the day-ahead market or, closer to delivery, the imbalance market) then prices would not be known in advance, though in this case an optimisation algorithm based on perfect foresight of price, demand and generation still has two important uses: 1) It gives an upper limit to the earnings that could have been achieved over a given period of time using an energy storage system, and 2) Using predictions of future spot prices and levels of generation and demand, it can provide the central component of a practical control algorithm for an energy storage system (such as one using model predictive control).

3.2 Data

In the analysis presented in this paper, a round-trip efficiency of 85% is used for the storage, which is reasonably conservative for most small- and medium-scale electricity storage technologies [28], and it is assumed that the charge and discharge efficiencies are equal. Costs of storage are not included as this work is focused on the revenue streams available to large enterprises with storage, against which capital costs of storage could be assessed, however in making investment decisions the potential for electricity prices and charges to change in future must be taken into consideration.

Lancaster University campus's electricity import and on-site generation volumes have been logged at half-hourly intervals for several years, and data from 1st February 2015 to 31st January 2016 have been used for this analysis as it is the most complete recent data set that is available (though there were approximately two days without power in early December 2015 due to flooding at the nearby substation). Unfortunately, export volumes are not automatically logged half-hourly, and the export meters are instead read manually by a meter reader once per month, so it is not possible to determine what the export level was within any half-hour interval, though the amount of on-site generation at that time provides an upper limit (e.g. if in a certain half-hour on-site generation was recorded as 1.5 MWh and import was recorded as 0.1 MWh, then the export volume could have been anything between 0 and 1.5 MWh and total demand could have been anything between 0.1 and 1.6 MWh). Therefore because of the uncertainty over the time at which export occurred, the export volumes are not included when calculating total campus demand at each half-hour, though they are later used to place an upper limit on the additional savings from self-consumption of on-site generation. As mentioned in section 2, export volumes at Lancaster University are relatively small when compared with total campus demand, typically less than 1%.

The marginal electricity charges seen by Lancaster University campus's two main half-hourly meters from April 2015 to March 2016 are given in Table 1. In this case, "marginal charges" means the charges that are dependent on volume, and it is these which affect the value of storage; there are several standing charges which are not dependent upon volume, and so do not need to be included in the price signal seen by the store. In reality, BSUoS charges vary with time, however they depend upon the cost of balancing the system at each half-hour (so are not known in advance) and they always comprise a small fraction of the total charge. Therefore, as the opportunity for savings by anticipating changes in BSUoS charges is small, a flat BSUoS charge is used in this work, taken as the average BSUoS charge seen by Lancaster University.

Triad charges (the demand component of Transmission Network Use of System, or TNUoS, charges) are not included in this list of marginal charges as they're a fixed charge each month based upon the university's demand in the three Triad periods in the previous winter. However, Triad avoidance plays an important role in the value of energy storage to enterprises, as shown further on.

These charges are explained below:

DUoS (Distribution Use of System): A charge levied upon electricity consumers and generators by distribution network operators, for maintaining the distribution network. For consumers in the North West distribution area whose consumption is metered half-hourly, this is broken into red, amber and green time bands (see Table 2), reflecting the time-dependency of the stresses on the distribution network.

RO (Renewables Obligation): A charge levied upon consumers by suppliers to cover the cost of meeting their Renewables Obligation levels. The Renewables Obligation is being closed to new technologies in 2017 and will effectively be replaced by Contracts for Difference.

BS (Black Start): The cost of maintaining black start capability, passed from generators onto suppliers and ultimately consumers.

BSUoS (Balancing Service Use of System): A charge levied by National Grid upon suppliers (and passed onto their customers) to cover the cost of day to day operation of the transmission system.

HDC (High Distribution Costs): Assistance for areas with high electricity distribution costs, recovered by National Grid through a charge on suppliers. This revenue is passed on to Scottish Hydro Electric Power Distribution Ltd., enabling distribution charges in the north of Scotland to be reduced.

FiT (Feed-in Tariff): Charges passed from the power utility to the consumer to cover the cost of the Feed-in Tariff, which provides support to small-scale renewables.

CfD (Contracts for Difference): Charges passed from the utility to the customer to cover the cost of Contracts for Difference, which provides support to large-scale renewables. Along with the Capacity Market, Contracts for Difference form the central component of Great Britain's Electricity Market Reform, or EMR.

Energy Cost: The commodity cost per unit of electricity as procured by the university's broker. In Lancaster's case, these vary slightly from month to month but are fixed at a flat rate through any given month, so the average unit cost over the course of the year is shown in Table 1, and this value is used in all analysis. This price remains fixed to the university as long as its electricity use over the course of the month remains within a certain band; this work does not consider the potential for storage to ensure that any maximum power limit set by the supplier is not exceeded.

3.3 Results

3.3.1 Reduction of transmission charges

In the North West TNUoS charging zone, the half-hourly (HH) TNUoS demand tariff for 2015/16 is £35.683316/kW. The date/time of each Triad in the last three years is shown in Table 3 along with Lancaster University's average import power through each Triad.

In winter 2014/15, Lancaster University's potential savings from demand reduction in Triads were £162,520 (based on the 2015/16 TNUoS tariff), however in order to achieve all of these savings using storage, the device would need to be able to sustain an output power of at least 5.56 MW throughout each half-hour Triad period. Lancaster University's electricity supplier sends it Triad warning notices many times throughout the Triad season of November to

February, up to a day in advance of when it thinks a Triad may occur. The Triad warning periods issued to Lancaster are not always the same length: they are typically 2 hours long but some have been as short as 30 mins and some have been as long as 3 hours. Taking the upper end of this range (3 hours) as the Triad warning period over which the storage will be steadily discharged, the storage capacity would need to be at least 18.09 MWh to be able to provide 5.56 MW for 3 hours (assuming discharge efficiency is 92.2%). However, given that all Triads in the 25 years since their introduction have occurred between 17:00 and 18:30, a 2 hour discharge time may be sufficient, though the financial consequences of missing a Triad are high.

The savings available to Lancaster University from hitting the 2014/15 Triads using storage are shown against discharge power in Fig. 6, in all cases assuming that the energy storage capacity is large enough that the storage can be discharged at this power throughout warning periods.

Steep increases in Triad charges have been projected by Lancaster University's energy broker and National Grid, as shown in Table 4. Based on these, the potential annual savings from using storage to hit Triads are shown against discharge power in Fig. 7. Both projections converge by 2020/21, so that Lancaster University's annual savings from hitting Triads are projected to be £67,500/MW in 2021, up by ~90% from £35,680/MW in 2015.

There is clearly an amount of risk surrounding business models for storage based on demand reduction in Triads. If a Triad is missed because of inaccurate forecasting or because the storage isn't available (for example because of an unplanned outage during either the Triad period or the period when the store would normally be charged), then approximately one-third of the annual savings available from Triad avoidance will be lost, so missing one Triad in winter 2014/15 would mean a loss in savings of about £12,000 per MW of discharge power capacity. A simple way of avoiding forecasting inaccuracies is to discharge the store at a constant power during a pre-defined Triad window every day throughout winter (i.e. the Triad season of Nov-Feb). A cautious pre-defined window might be 16:00-19:00 on weekdays, which is the same as the red DUoS time band and which would have caught all Triads since their introduction in the winter of 1990/91 at the time of market liberalisation in the UK.

Since their introduction, over 80% of Triads have been in the HH ending 17:30, with all others in the HH ending 17:00, the HH ending 18:00, and the HH ending 18:30; to date no Triads have fallen on a weekend and only one has fallen on a Friday (with Lancaster's supplier failing to provide a warning of that Triad as a result). Until there is significantly more behind-the-meter generation (excluding PV as Triads fall in darkness hours), electric vehicles, heat pumps, electricity storage, or demand response (e.g. because of smart meters and time-of-use tariffs), this is likely to remain the case.

3.3.2 Reduction of distribution charges

Because of the lengths of the red and green DUoS time bands in the North West distribution zone since 1st April 2015, Lancaster University would maximise savings on distribution charges if the storage's minimum discharge time is less than or equal to 3 hours and the storage's minimum charge time is less than or equal to 12.5 hours. Unless the storage's round-trip efficiency is particularly high (e.g. greater than approximately 90%), it will not be economical to discharge in the amber time bands having charged in the green time bands if using DUoS prices as the sole means of generating income.

Using the algorithm presented in section 3.1 and Lancaster University's demand, generation, and electricity charges data for 2015, it is found that an electricity storage device with 85% round-trip efficiency could reduce Lancaster University's annual spend on distribution charges by £10,000 per MWh of storage capacity (Fig. 8), though these savings do not scale up limitlessly with storage capacity, and they are entirely dependent upon the difference between the red and green DUoS charges which changes slightly each year. As an example of this, in the North West distribution zone in 2014 the red time band was 2 hours long with a difference between red and green charges of 10.6 p/kWh. Since 2015 the red band has been 3 hours in the North West zone (and will remain so until at least 2018), with a drop in red-green difference to 5.3 p/kWh in 2015 to ensure that consumers weren't adversely affected by the increased length of the red band. This halving of the red-green difference halved the savings available from using a given amount of storage capacity to shift demand to times of lower DUoS charges, though it increased the minimum required discharge time to maximise DUoS savings from two hours to three hours, thus allowing reduced storage discharge rates and hence increasing the cycle life of many technologies [29].

Fig. 9 shows the DUoS savings available to Lancaster University in 2015 against storage capacity, for a storage device with 85% round-trip efficiency, charge time ≤12.5 hours and discharge time ≤3 hours. Evidently the savings level off at high storage capacities, and no more savings are possible when the storage capacity exceeds approximately 20 MWh, at which point the annual DUoS savings are £149,700. With this level of capacity, there are no times when the storage capacity limits the amount of energy that can be discharged during the red time band, and instead the limit on the amount of energy that can be discharged in the red time band is always Lancaster University's demand. (Recall that this analysis assumes that if at any given time demand has been completely met using storage, extra units of electricity would not be exported from the storage to the grid because the university does not have an export contract.)

The DUoS and Triad savings available to Lancaster University from discharging storage, as well as the required expenditure to charge the storage, are shown in Fig. 10, for a storage device with 85% round-trip efficiency being fully discharged at a steady rate over 2 hours (16:30-18:30) during the red DUoS time band each weekday of 2015, and charged in the green time band. In reality, it might well be that the storage would be discharged over three hours (the length of the red DUoS band) outside of the winter Triad season, to reduce stress on the device and maximise cycle life [29], but this would have no effect on savings. Savings available from Triad avoidance could be higher at the lower storage capacities (and hence lower discharge powers) with accurate Triad forecasting allowing shorter bursts of higher discharge power during predicted Triads, but this would increase the risk of missing a Triad and so missing out on significant revenue. To a large enterprise such as Lancaster University in the North West distribution zone, the annual savings available from Triad avoidance are clearly less than those available from reducing DUoS charges, but since Triads can only occur in the winter months of November to February, and in theory only require 1.5 hours of discharge over the whole year to achieve the full amount of possible savings, it might be that other revenue mechanisms would be more lucrative in the rest of the year than reducing distribution charges.

The resulting total savings available to Lancaster University from reducing transmission and distribution charges are shown in Fig. 11. At storage capacities below 8.4 MWh, the total annual savings scale linearly with storage capacity at £27,370 per MWh of storage capacity. As mentioned above, the red DUoS time band in the North West distribution zone was two hours long (16:30-18:30) until 1st April 2015, when it was widened to three hours (16:00-19:00). To offset the 50% increase in red band length, the local DNO reduced the red charges such that the difference between red and green charges dropped from 10.6 p/kWh to 5.3 p/kWh. This has quite a significant impact on the savings available using a given capacity of electricity storage: in 2014, the annual savings available to Lancaster University were £37,800/MWh, 38% higher than in 2015 (again assuming 85% round-trip efficiency and a 2 hour Triad discharge window of 16:30-18:30). However, outside of the Triad season at least, with a wider red band the storage can be discharged at a lower power without affecting savings, reducing degradation and hence increasing the cycle life of the storage device.

3.3.3 Effect of on-site generation

In 2015, Lancaster University exported 241 MWh of electricity generated by its wind turbine, equivalent to an average daily export of 0.66 MWh (compared with an average daily demand of around 90 MWh). An upper limit on the economic impact of using this to charge a storage device is found by assuming that the storage is large enough that all of the volume could be used for charging (unlikely to be the case given that activity at the university reduces considerably over holiday periods). At 7.26 p/kWh for electricity in the green time band, and taking into account the opportunity cost of the FiT export tariff at 4.91 p/kWh, 241 MWh of electricity from the wind turbine could reduce spend on electricity for charging storage by up to £5,664 per year. Without finer resolution data on export volumes, it is not possible to say how much of this extra saving could have been achieved with a given storage device. With on-site renewables, savings are maximised by accurately forecasting the renewable resource and the site's electricity demand, in order to minimise the total spend on electricity for charging.

3.3.4 Near-delivery electricity trading

The analysis presented so far has all been based upon Lancaster University's current arrangements whereby their total projected electricity requirement for any given month is secured by the end of the previous month, so that they receive a flat commodity price of electricity for each month regardless of time-of-use. However, it is possible to trade into the delivery month on the day-ahead market and the imbalance market, and for particularly large enterprises it may possibly be worth the added expense of employing a trader to carry out this task, so the potential effect of trading on these markets is now investigated. The generality of the optimisation methodology laid out previously makes this analysis reasonably straightforward.

The analysis presented thus far has been simplified by the fact that any reasonable Triad warning window (e.g. 16:30-18:30, or more conservatively 16:00-19:00) is completely contained within the DUoS red band (currently 16:00-19:00 in the north-west), combined with the fact that the commodity price and red band charge are both flat. Replacing the flat commodity price with a varying wholesale price then adding a flat equivalent Triad charge over the course of a Triad warning window would cause the algorithm presented previously to prioritise discharge at the times of highest wholesale price, possibly emptying a small storage device away from a Triad. For example, if the highest wholesale price of the day arose at 18:00-18:30, then the algorithm would first look to discharge at this time, and if the storage could be discharged in less than 30 minutes then the storage would be completely emptied within this half-hour. Hence, if the Triad actually occurred at 17:00-17:30, no demand reduction in the Triad would be achieved.

Therefore in order to find the optimal storage schedule when some charges are proportional to maximum power demand in certain periods (as is the case with Triads), it would be necessary to create a modified optimisation algorithm, which could be improved (e.g. for implementation into a model predictive control system) by associating a probability to a Triad occurring in each half-hour of a Triad warning window. The authors understand how this could be accomplished through modification of the existing algorithm, but its implementation is considered beyond the scope of this work.

To deal with Triads in a straightforward manner, two approaches are taken:

1. Triads are ignored entirely and the optimal schedule is found for the whole year based on the wholesale prices and DUoS charges alone.
2. The storage is discharged at the highest steady rate possible between 16:30 and 18:30 on every weekday of the Triad season, then the optimal schedule is at all other times based on the wholesale prices and DUoS charges.

Volume-weighted average hourly day-ahead market prices are published by APX [30], and the prices between 1st February 2015 and 31st January 2016 have been used here (so matching up with the demand data for Lancaster University). Prices at the half hour intervals are created by simply duplicating the hourly prices, and the resulting commodity price vector is added to the DUoS charges and other charges to form the marginal price as if power was purchased on the day-ahead market, then used along with Lancaster University's total demand data in the optimisation algorithm presented in section 3.1.

Following approach 1, it is found that if Triads are ignored entirely and just the wholesale prices and DUoS charges are used, the economic value of electricity storage in the north-west when trading on the day ahead market could be up to £23,000/MWh.yr, as compared with £10,000/MWh.yr if a flat commodity price is used. However, due to fluctuations in wholesale prices, discharge sometimes occurs at times away from what might be considered as a Triad window.

The savings available from following approach 2 are shown against storage capacity in Fig. 12, for a storage device with 2 hour charge and discharge times and 85% round-trip efficiency. Annual savings of up to £40,000/MWh are possible, approximately £13,000/MWh more than if the commodity price were flat, however this analysis assumes perfect foresight of day ahead prices, so not all of these savings would be achievable in practice.

4 Effect of location

The savings available to large enterprises through use of storage to reduce distribution and transmission charges are entirely dependent upon the charges, which vary between years and distribution zones. Fig. 13 shows the transmission and distribution charges (red-green) in 2017 for high voltage half-hourly metered demand, for each of the GB distribution zones, with the associated values given in Table 5. The distribution charges are taken from each DNO's Use of System Charging Statement for 2017 (e.g. [21]), and the transmission charges are National Grid's latest estimates for 2017 at the time of writing [31]. The difference in red and green DUoS charges is clearly highest in the South West zone and lowest in London. The high charges in the South West zone are likely to be a result of various factors, including low population density meaning long cable runs per person (with the opposite being true in London), few connections to the transmission grid (with much of the south-west being a peninsula), and the rapid recent growth of embedded renewables in the area (with an increase in renewable energy capacity of nearly 88% in 2014/15 [32]). Another factor is that in the South West zone the red band is only two hours long in 2017, while the red band in most other distribution zones is three hours long. Similarly, London's particularly low DUoS charges are partly a result of it being the only distribution zone with two red bands (11:00-14:00 and 16:00-19:00).

If an enterprise installs a relatively large capacity of storage but doesn't have an export contract (so that discharging of the storage is sometimes limited by the net demand profile of the enterprise), then the relative importance of transmission and distribution charges to the economic value of energy storage will depend upon the enterprise's demand profile. In areas with high Triad charges and low DUoS charges (e.g. London), storage will bring the greatest savings to those consumers whose demand is particularly high at peak times in winter (such as consumers with high electric heating and lighting demands). In areas where DUoS charges are relatively high compared with Triad charges (e.g. the south-west and southern Scotland – the Scots Power distribution zone) storage is more valuable for consumers with peak demands spread more evenly throughout the year, and particularly for those whose winter peak demands are relatively lower as compared with peak demands in summer (such as consumers that require lots of cooling but little lighting, like refrigerated warehouses and data centres).

For smaller scales of storage (so assuming that operation of the storage is not limited by the site's demand), the value of electricity storage in reducing distribution and transmission charges for HV HH metered consumers in 2017 is shown for each GB distribution area in Fig. 14. In Lancaster University's case, these values are valid for storage capacities below 8.4 MWh. Interestingly, the value of storage to enterprises in the north of Scotland (the Scots Hydro distribution zone) is the lowest in Great Britain, due to a combination of low distribution charges and low transmission charges. Electricity storage used in the south-west could generate savings of £70k/MWh.yr, approximately twice the average in the rest of Great Britain and 3.5 times the savings available in the north of Scotland. These results agree with other work showing that the optimal location for distributed storage is in southern England (particularly as the heat and transport sectors are electrified) and the optimal location for bulk storage is predominantly in Scotland [33].

5 Storage cost and payback period

The analysis presented thus far is effectively technology-agnostic, however in order to calculate investment appraisal metrics such as payback period and net present value (NPV), it is necessary to obtain storage costs and a cycle life. For these purposes, we use the Tesla Powerpack, one of the few commercially-available electricity storage devices aimed at commercial/industrial customers. The Powerpack is a modular Li-ion battery system available in modules of 100 kWh capacity, with each module having peak discharge power of 50kW (so 2 hour minimum discharge time). The specifications of the Tesla Powerpack (as of mid-July 2016) are listed in Table 6.

Costs for a 1 MWh Powerpack system with 500 kW maximum discharge power (so 2 hour minimum discharge time) work out at £429,352 per MWh of storage capacity. Based on these costs, regular annual savings of £26,000 per MWh (using the Powerpack's 82% efficiency rather than the 85% used previously), and a 5% discount rate, the discounted payback period is 35.8

years, much longer than the life of the batteries (projected to be 15 years). The net present value after 15 years would be -£159,481/MWh.

If the savings were £65,000 per MWh of capacity (as would be expected using a Powerpack in the south-west in 2017) then the discounted payback period would be 8.2 years. Over a 15 year life, the NPV is £245,326/MWh, an annual rate of return of 12.58%. Other commercial-/industrial-scale storage devices exist, with some of these being sold at lower costs than the Powerpack (e.g. the EOS Aurora battery system which is advertised at $200,000/MWh – approximately £150,000/MWh in July 2016 – for order volumes below 40 MWh). It should also be noted that storage costs have been dropping in recent years, with Li-ion battery costs declining by approximately 14% per annum between 2007 and 2014 [34], and will likely continue to drop in the near term as the technologies continue to mature. Furthermore, use of system charges are projected to continue to rise as the energy and transport system is further decarbonised [35].

When considering battery storage to reduce use of system charges, the limited cycle life lowers the attractiveness of reducing distribution charges through daily discharge. Cycle life is affected by charge and discharge powers as well as by depth of discharge, so the designers of battery storage systems need to take these factors into account when designing the scheduling and control system; for large enterprises, higher discharge powers and greater depth of discharge will tend to be more appropriate throughout predicted Triad periods.

6 Other mechanisms

Many potential revenue streams exist for electricity storage, and evaluation of these is particularly important for investment decisions. For small- and medium-scale storage, ancillary services are likely to provide the greatest opportunities in the near term. Details of these are given in Table 7, and it is possible that some of these could have some complementarity with the opportunities for savings through reduction of network charges. Market size is given using the most recent available data, with ranges given for services whose requirements vary between seasons. Another service that may potentially lead to a future revenue stream for storage is demand turn up [36], whereby participants are paid to increase demand or reduce generation at times of particularly low demand in May-September (overnight, and in the middle of the day at weekends and bank holidays), however it is not yet clear if storage owners and operators will be able to bid into this.

While many enterprises may not consider installing storage of 3 MW capacity or above, storage of smaller capacity can still participate in Firm Frequency Response, Fast Reserve, and Short Term Operating Reserve (STOR) through aggregation, and many demand aggregators are looking to include storage in their portfolios.

Clearly the ability of a storage device to discharge as required to provide Fast Reserve and STOR capacity in availability windows depends upon the tendered power capacity and the storage capacity. STOR has two availability windows per day in which generation might be required; these vary by season but are roughly 07:00-14:00 and 16:00-21:00. In 2014, STOR was utilised on 334 days, however no summary information is available on utilisation of individual units. While a response time of up to 240 minutes is acceptable for STOR, in 2014 almost 99% of all STOR units had a response time of less than 20 minutes [37].

Importantly, capacity for ancillary services can be provided through increased generation or steady demand reduction, so even if an enterprise's electricity demand exceeds the power capacity of its storage throughout a utilisation period, the reduction in demand caused by discharge of the storage is still valued through these mechanisms. National Grid have specific methods of calculating demand reduction from Short Term Operating Reserve participants who have within-day variable demands [38], and it is possible that metering of electricity storage could be used to show its contribution to demand reduction.

Enhanced Frequency Response is aimed predominantly at fast-response electricity storage, however the details of the requirements and market are still evolving as of June 2016. Due to the many complexities surrounding the technical requirements and market for each of the mechanisms presented in Table 7, they are not investigated further here.

7 Other benefits and demand response

Up to this point, we have largely considered the economic benefits of electricity storage to large enterprises. We now turn attention to the additional benefits that storage can present to an enterprise, as well as the benefits presented to other stakeholders, and give a brief discussion of the potential of demand response to bring similar gains.

From the perspective of a large enterprise, there are a number of benefits associated with use of storage behind-the-meter:

- Reduction of use of system charges
- Provision of ancillary services
- Lower grid connection cost
- Provision of backup power

Of these, provision of backup power is of particular interest to large public institutions, such as universities, hospitals and prisons. Through use of backup power, the availability of important services, such as life support equipment, lighting, heating and refrigeration, can be enhanced, and electricity storage could potentially provide these benefits. Indeed, battery storage is already used at very small scales in the form of uninterruptible power supplies within data centres.

Using storage to reduce use of system charges lowers the peak loads on the distribution and transmission networks. This is often known as "peak shaving", and it allows a larger number of consumers to be served by a given network. To network operators, this means that infrastructure reinforcement (such as upgrading of cables, transformers and switchgear) can be deferred, providing financial benefits. Similarly, storage can be used for "valley filling", where charging of storage can increase demand at times when it is very low and would otherwise cause problems on the network (e.g. low voltage, or extreme reverse flow from sites with significant embedded generation). Clearly the level of benefit that behind-the-meter storage provides to network operators depends upon the installed storage capacity and the way that the storage is incentivised to operate.

When considering these network benefits, network operators must be careful to appreciate that unless a contract is in place with the storage owner (e.g. allowing the network operator to take control of the storage at certain times), the storage owner won't necessarily always operate the storage in a way that provides benefits to the network, and there always exists the possibility that the storage won't operate sometimes because of planned or unplanned outages.

Behind-the-meter electricity storage can also assist with the large-scale grid integration of renewables, and in this respect its use is incentivised through the ancillary services discussed previously.

When considering the value of electricity storage, the question arises of other methods of providing similar flexibility, and the main alternative to storage in this respect is demand response. This can take many forms, including modification of temperature setpoints for electric heating, air conditioning, and refrigeration units, curtailed use of powerful machinery at peak times, and delayed charging of electrical equipment, including electric vehicles. Focusing on the example of Lancaster University, we will now give a brief discussion of the potential of electric vehicles, which could not only provide flexibility through delayed charging but could also release energy back onto the grid at times of high demand (known as vehicle-to-grid).

There are roughly 3,000 car parking spaces on the Lancaster University campus. Being a campus-based university set among open fields, space for car parking is not as limited as it is for organisations based in urban areas, however the availability of car parking is fairly typical for a large enterprise of its size. The amount of energy that can be stored within the fuel tanks of 3,000 cars is considerable. A filled 60-litre petrol tank holds approximately 560 kWh of energy, meaning that 3,000 petrol cars hold up to 1.7 GWh of energy. Current battery electric vehicles (BEVs) have storage capacities ranging from around 15 kWh in hatchbacks to around 100 kWh in sports saloons. Taking an average capacity of 20 kWh, the storage capacity in the batteries of 3,000 BEVs is 60 MWh, and assuming typical discharge C rates of 1.2 (peak) and 0.2 (continuous), these batteries could provide between 12 and 72 MW of demand response. Clearly not all of these vehicles would be plugged in at the same time and not all could be called upon for demand response, but the potential for taking advantage of vehicle-to-grid is clearly still significant.

In colder countries such as the UK, peak electricity demands occur around the end of typical work hours, or at some point in the evening, when vehicles have mostly left places of work, so their potential to reduce national peaks isn't great. However, with careful management they could still be used to deal with local network issues.

8 Conclusions

The economic value of electricity storage to large enterprises, such as businesses, hospitals and universities, has been investigated. A powerful storage scheduling optimisation algorithm has been developed which could be applied to a wide variety of storage scheduling problems, including for various types of businesses. Using this to analyse time-dependent network charges while focusing on Lancaster University as a case study, it has been shown that large enterprises with no on-site generation who pay a flat commodity price for electricity could use electricity storage to achieve annual savings of between £20 and £70 per kWh of storage capacity in Great Britain in 2017, with the exact amount depending upon location. Furthermore, savings could be increased by up to around £13 per kWh from purchasing electricity on the day ahead market, and would also be increased if there is on-site generation (by an amount that depends upon the site's load profile and the generation technology and capacity). Due to a lack of half-hourly export data it was not possible to quantify the exact effect on savings of Lancaster University's on-site wind turbine and CHP plant (respectively having power capacities of ~40% and ~30% of maximum demand), though an increase in savings of around 50% might be expected. Unless the enterprise has an export contract, the savings flatten off at larger storage capacities, depending upon import in the red distribution charge band and the three Triads.

Savings available in the south-west are more than 50% higher than in the next best location, and twice the average in the rest of Great Britain. The available savings vary across the country because the costs of maintaining the transmission and distribution networks depend upon the local demand, population density and generation. The optimal discharge time of the storage depends upon the ability to predict Triads (the three half-hour periods between November and February in which the country's electricity demand is highest), along with the length of the peak distribution charge band, which varies slightly by location. In most areas a discharge time of two hours would be recommended. Optimal charge time depends upon the type and capacity of any on-site generation, but for enterprises without on-site generation, charge times can be very long (e.g. 12 hours) without a reduction in savings, because in all locations the low distribution charge band is overnight, typically running for 12 hours from 21:00.

Using the results found with a flat commodity price, the investment value of a commercially available Li-ion battery system (the Tesla Powerpack) has been calculated. With a 5% discount rate, the payback period is shown to be 36 years in north-west England (where Lancaster University is located), and 8 years in the south-west, where an NPV of £245,326/MWh could be expected over the Powerpack's 15 year life, giving a 12.58% annual return.

Clearly when evaluating the savings available from using electricity storage, certainty surrounding revenue streams is important, however distribution and transmission charges are both subject to change. In particular, peak distribution charges are associated with time bands which have been known to be changed in length, with associated changes in the charge. A good example of this is the increase in red band length from two to three hours in the north-west distribution zone in April 2015, with the red band charge being halved to compensate, reducing the revenue available from using a given capacity of electricity storage. However, time-dependent network charges have been in existence for some time (since the liberalisation of the electricity market in 1990 in the case of Triads) and increases in both distribution and transmission charges have been projected by the network operators. At smaller scales (e.g. domestic), it is likely that time of use tariffs will be introduced as the smart meter rollout is completed by 2020, providing similar price signals to storage.

Aside from economic value, distributed electricity storage holds other value to the system, including reducing peak flows on the distribution network (and hence reducing infrastructure costs), and allowing increased levels of renewable generation on the system while maintaining security of supply. As the energy and transport system continues to be decarbonised, distributed electricity storage is becoming increasingly important. Many scales of stationary electricity storage exist, ranging from small domestic batteries up to large centralised systems, and the adoption of small- to medium-scale storage by large enterprises will be an important step on the road to a clean and secure future energy system.

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FIGURES AND TABLES

For ideal placement, see marked submission. These are presented here in the order they appear in the marked submission.

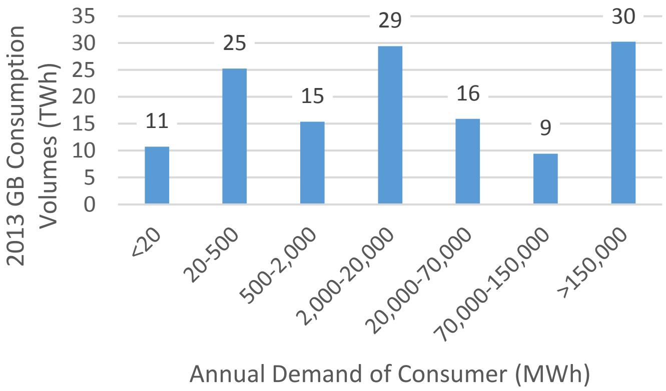

Fig. 1 Non-domestic electricity consumption statistics for the UK in 2013 [39], using Eurostat consumption bands for industrial electricity [40]

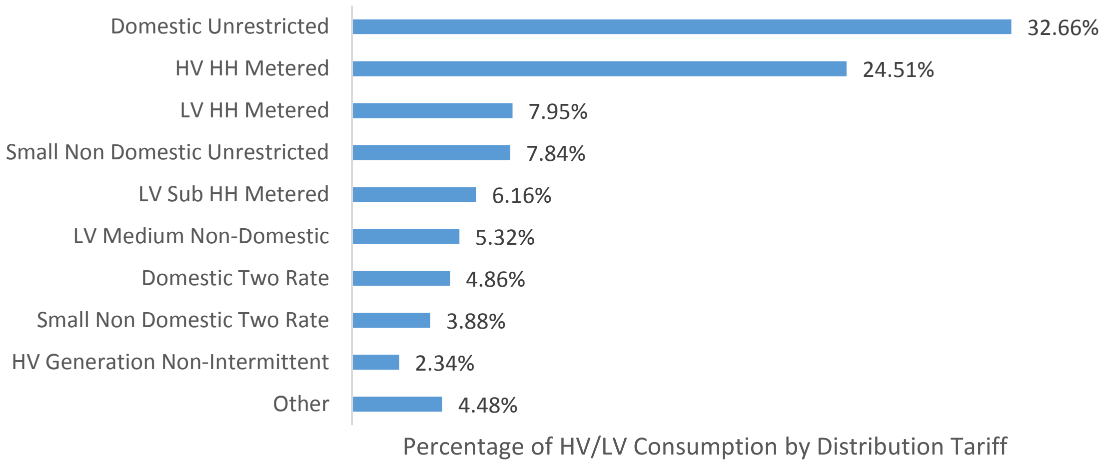

Fig. 2 Breakdown by distribution charge (DUoS) tariff of forecasted high/low voltage consumption in the North West distribution area in 2016 [41]

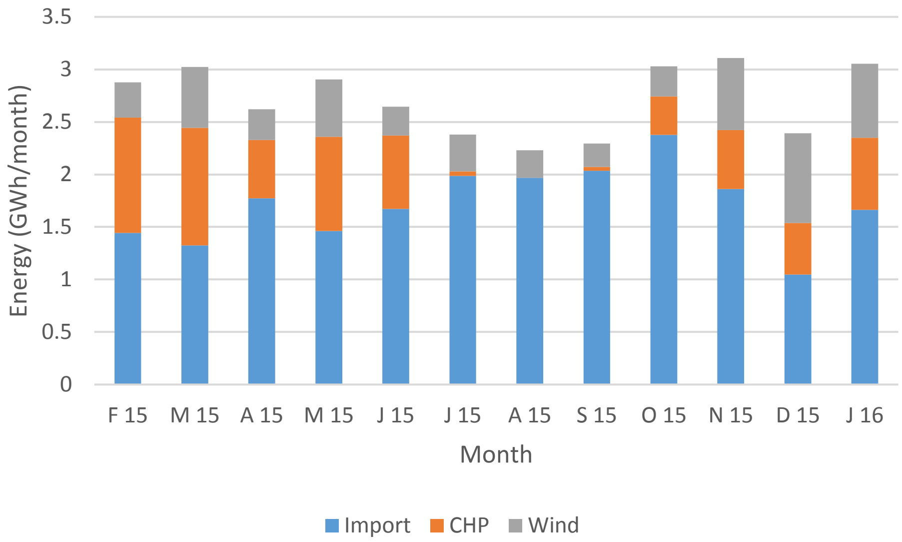

Fig. 3 Monthly electricity import and generation in 2015 by Lancaster University campus

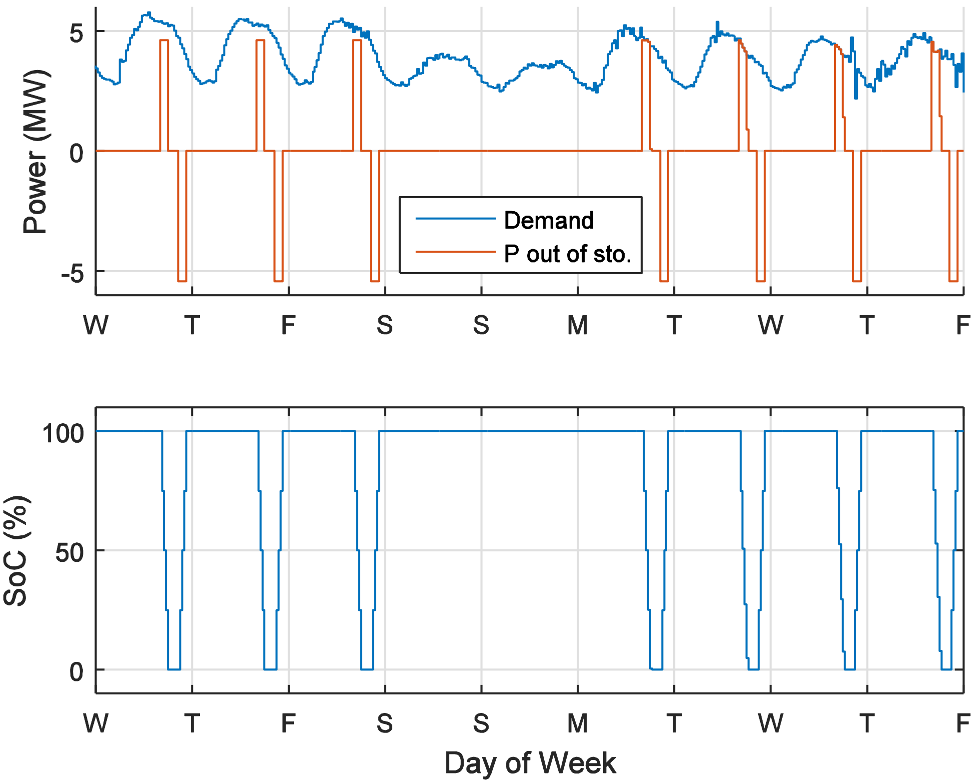

Fig. 4 Example of the charge/discharge schedule for Lancaster University arising from the optimisation algorithm with price switching based on net demand, for a 10 MWh storage device with 2 hour charge and discharge times

Item	Charge (p/kWh)

<table>
<tr><td rowspan="2">DUoS</td><td>Red</td><td>Amber</td><td>Green</td></tr>
<tr><td>5.328</td><td>0.437</td><td>0.056</td></tr>
<tr><td>RO</td><td colspan="3">1.29</td></tr>
<tr><td>BS</td><td colspan="3">0.06</td></tr>
<tr><td>BSUoS (avg.)</td><td colspan="3">0.182178</td></tr>
<tr><td>HDC</td><td colspan="3">0.0214</td></tr>
<tr><td>FiT</td><td colspan="3">0.361855</td></tr>
<tr><td>CfD</td><td colspan="3">0.00494</td></tr>
<tr><td>Energy Cost (avg.)</td><td colspan="3">5.24</td></tr>
<tr><td rowspan="2">Total</td><td>Red</td><td>Amber</td><td>Green</td></tr>
<tr><td>12.48837</td><td>7.597373</td><td>7.216373</td></tr>
</table>

Table 1 Components of the marginal price of electricity seen by Lancaster University from April 2015 to March 2016 (not including Triad charges or VAT)

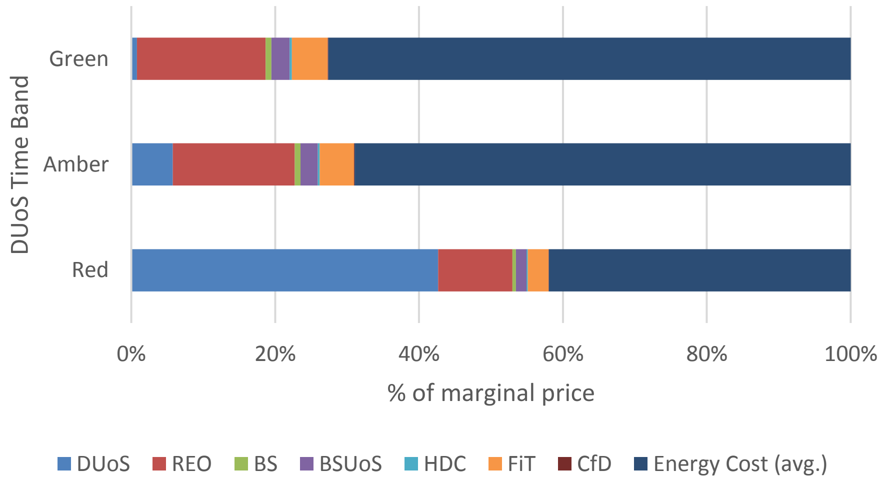

Fig. 5 Each charge as a percentage of total marginal price seen by Lancaster University from April 2015 to March 2016, in the three DUoS time bands (not including Triad charges or VAT)

Time periods	Red Time Band	Amber Time Band	Green Time Band
Mon to Fri	16:00 - 19:00	09:00 - 16:00 19:00 - 20:30	00:00 - 09:00 20:30 - 24:00
Sat and Sun		16:00 - 19:00	00:00 - 16:00 19:00 - 24:00

Table 2 Electricity North West's DUoS time bands for half-hourly metered properties since April 2015

Triad Date	Triad Time	LU Avg. Import (MW)
25/11/2013	17:00 - 17:30	3.9998

06/12/2013	17:00 - 17:30	3.7620
30/01/2014	17:00 - 17:30	3.2376
04/12/2014	17:00 - 17:30	4.2244
19/01/2015	17:00 - 17:30	5.5516
02/02/2015	17:30 - 18:00	3.8874
25/11/2015	17:00 - 17:30	5.6416
19/01/2016	17:00 - 17:30	5.6506
15/02/2016	18:00 - 18:30	5.8432

Table 3 **Lancaster University's average import powers during the Triad periods between winter 2013/14 and winter 2015/16**

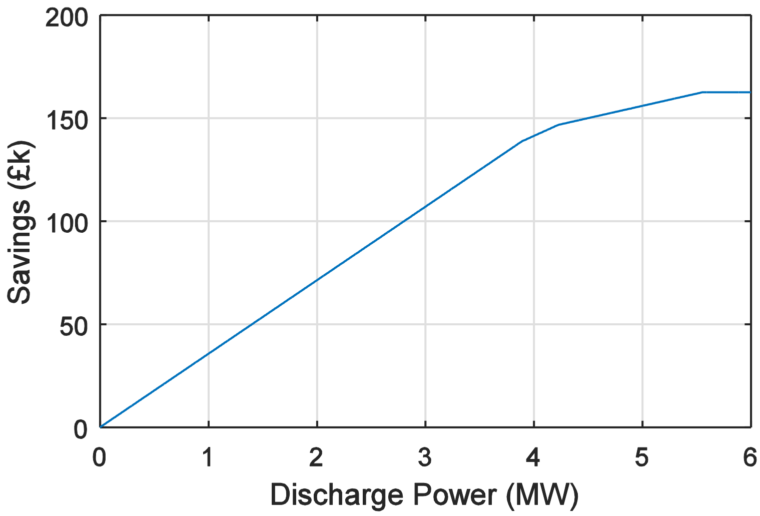

Fig. 6 Annual savings available to Lancaster University from hitting all three Triads in winter 2014/15 using storage, shown against discharge power. Levels of embedded generation, the cost of charging, and VAT are not taken into account in this analysis

Year	Projected Increase (%)	
	LU Broker	National Grid
2016	18.71	20.04
2017	11.4	1.77
2018	15	13.93
2019	12	8.98
2020	12	25.41

Table 4 **Increases in TNUoS charges forecasted by Lancaster University's broker and National Grid**

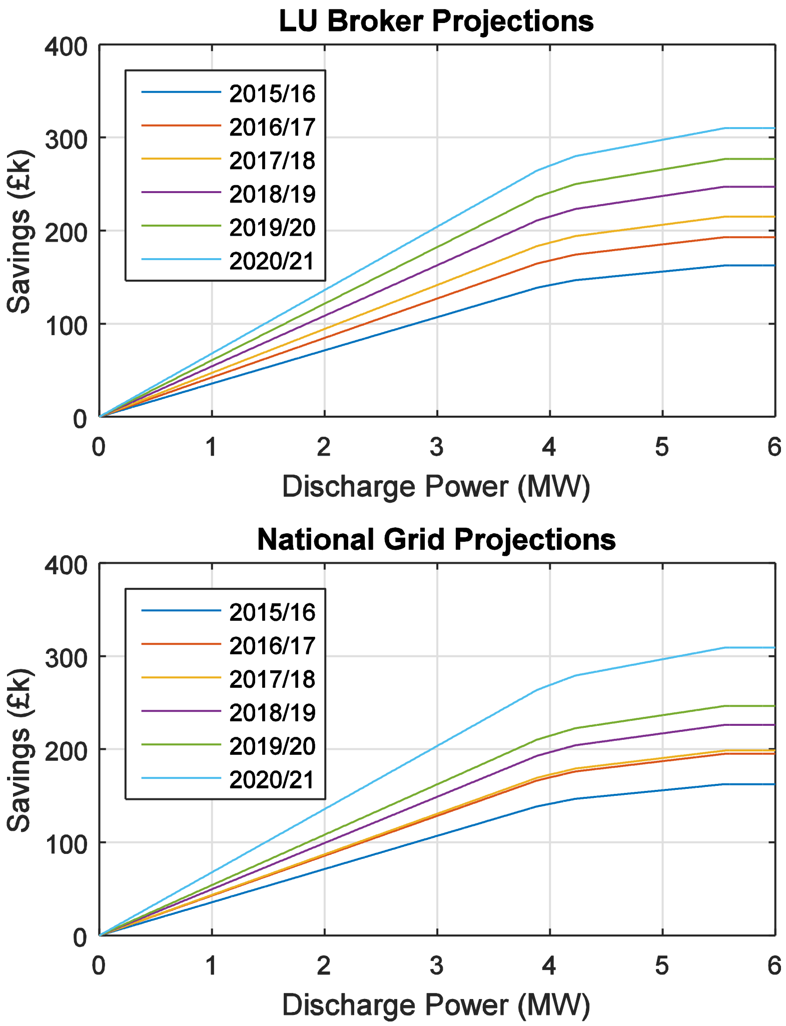

Fig. 7 Annual savings available to Lancaster University from hitting all three Triads using storage, for future Triad charge increases projected by Lancaster University's broker and National Grid. Based on the university's winter 2014/15 demand. Levels of embedded generation, the cost of charging, and VAT are not taken into account in this analysis

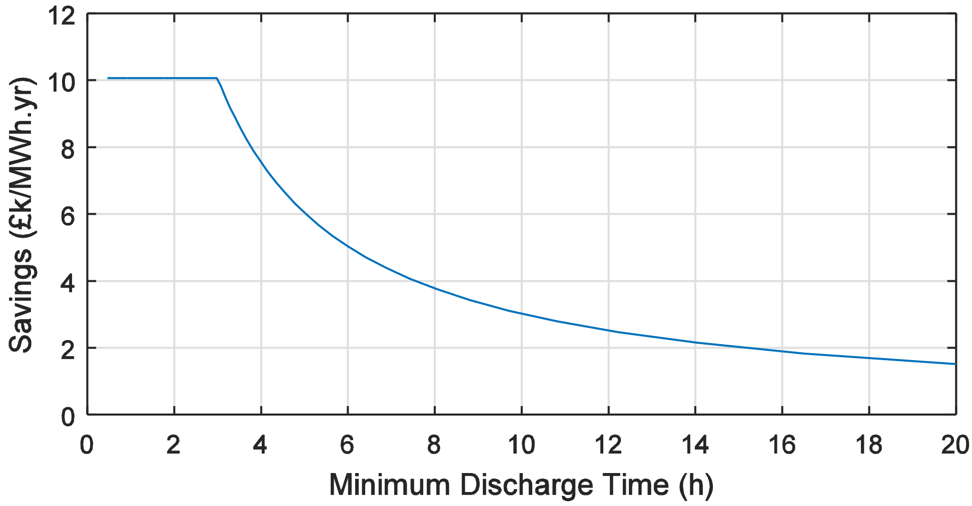

Fig. 8 Total DUoS savings (i.e. savings minus expenditure) available to Lancaster University in 2015 against discharge time for a storage system with 85% round-trip efficiency and charge time ≤12.5 hours, including 5% VAT. These savings don't scale limitlessly with storage capacity, as shown in Fig. 9

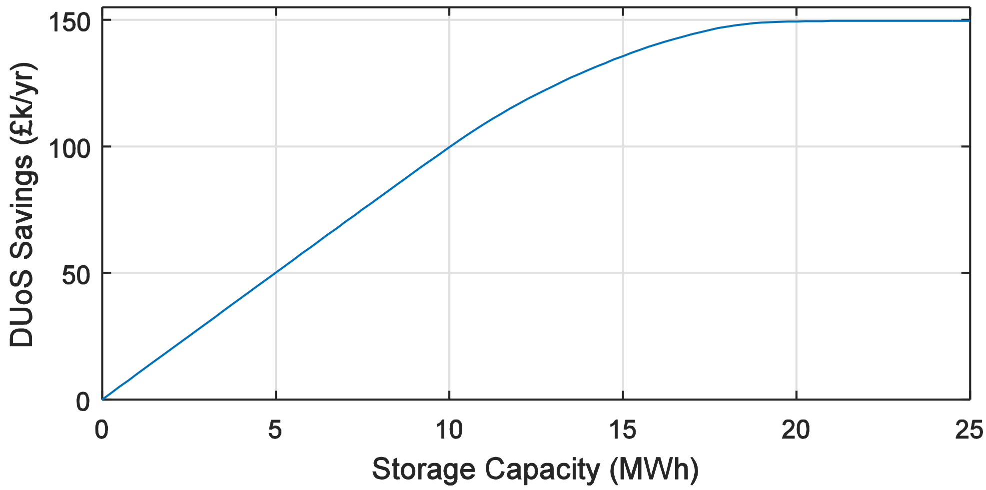

Fig. 9 Total DUoS savings (i.e. savings minus expenditure) for Lancaster University in 2015 against storage capacity for storage with 85% round-trip efficiency, charge time ≤12.5 hours and discharge time ≤3 hours, including 5% VAT

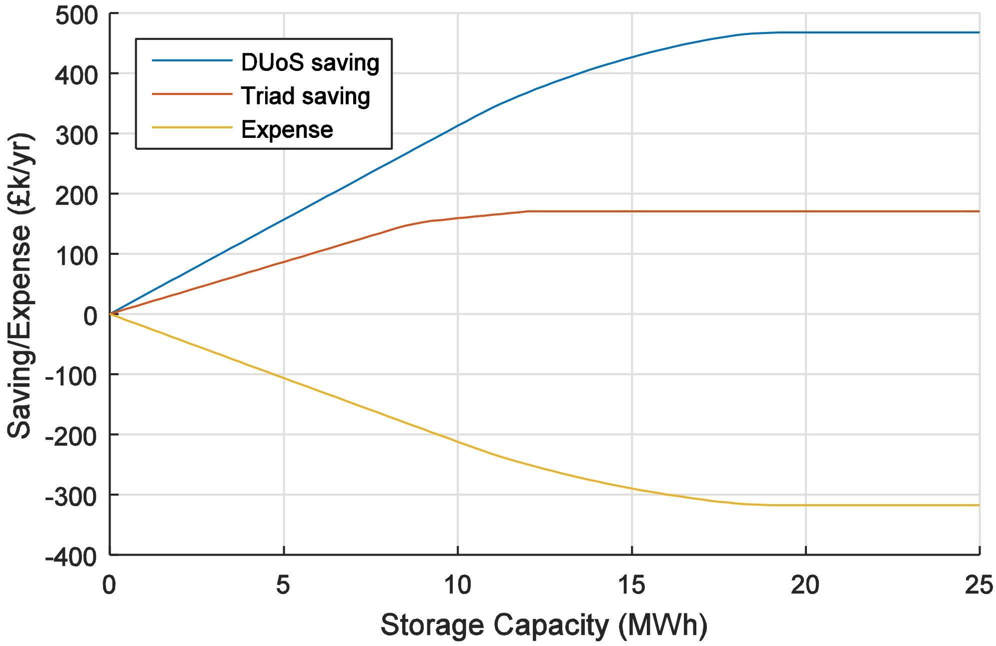

Fig. 10 Savings available to Lancaster University in 2015 from using storage to reduce distribution and transmission charges, and expenditure required on purchase of energy for charging. 85% round-trip efficiency, 2 hour Triad discharge window (16:30-18:30), including 5% VAT

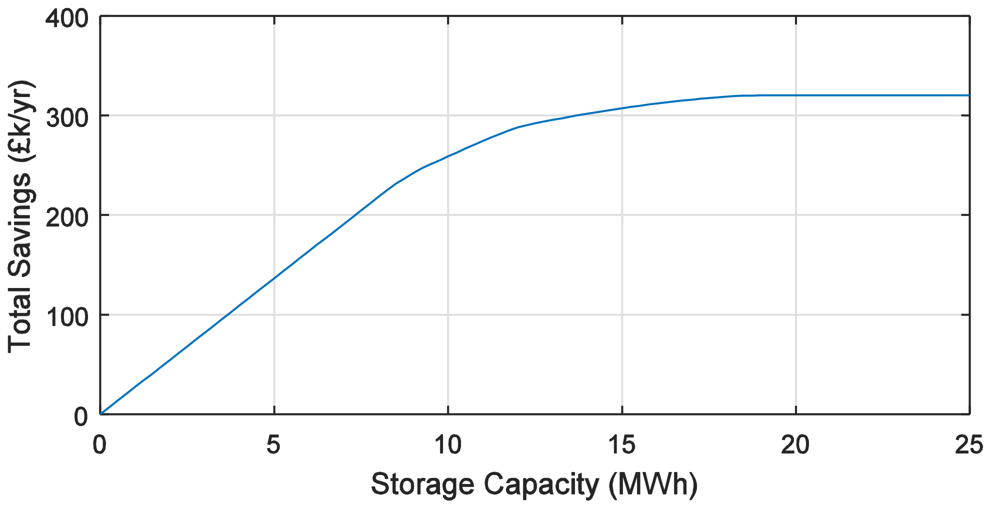

Fig. 11 Total savings available to Lancaster University in 2015 from using storage to reduce distribution and transmission charges. 85% round-trip efficiency, 2 hour Triad discharge window (16:30-18:30), including 5% VAT

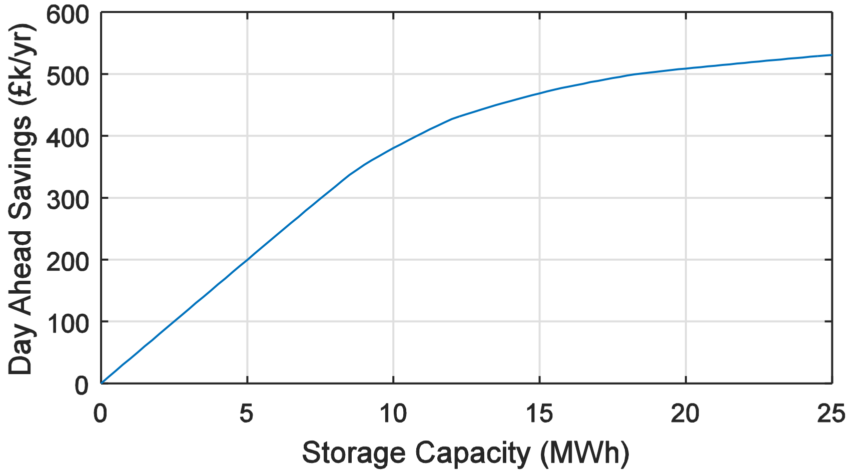

Fig. 12 Maximum savings available from using electricity storage at Lancaster University to reduce network charges and trade on the day ahead market in the UK in 2015. Steady 2 hour discharge at the maximum rate possible at 16:30-18:30 on weekdays in the Triad season. 85% round-trip efficiency, 2 hour minimum charge and discharge times, 5% VAT included

Area ID	Area	DUoS for HV HH Metered (p/kWh)			Length of Red Band (hours)	TNUoS Demand (£/kW)
		Red	Amber	Green		
10	Eastern	6.384	0.020	0.004	3	49.02
11	East Mids	7.391	0.121	0.021	3	47.01
12	London	1.921	0.017	0.000	6	54.37
13	Manweb	10.508	0.348	0.180	3	45.50
14	West Mids	7.156	0.392	0.007	3	48.26
15	North East	7.556	0.364	0.036	3.5	38.16
16	North West	6.265	0.463	0.057	3	43.59
17	Scots Hydro	4.044	1.393	0.313	3	29.73
18	Scots Power	7.856	0.470	0.017	3	30.45
19	South East	7.632	0.097	0.008	3	51.83
20	Southern	6.572	0.210	0.044	3	52.83
21	South Wales	9.942	1.155	0.055	2.5	45.44
22	South West	19.170	0.117	0.046	2	51.43
23	Yorks	6.253	0.476	0.033	3.5	44.13

Table 5 Published distribution charges for HV HH meters in the UK in 2017, and National Grid estimates of transmission charges for HH metered demand in 2017 [31], not including VAT

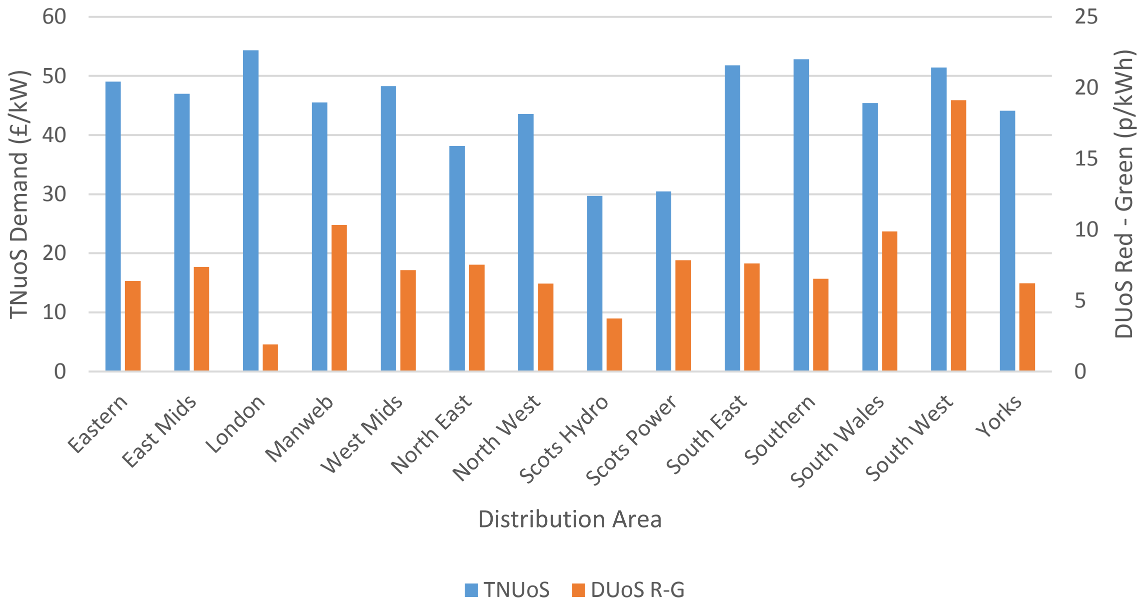

Fig. 13 Transmission and distribution charges (difference between red and green charge, HV HH metered) in 2017 in each GB distribution zone, not including VAT

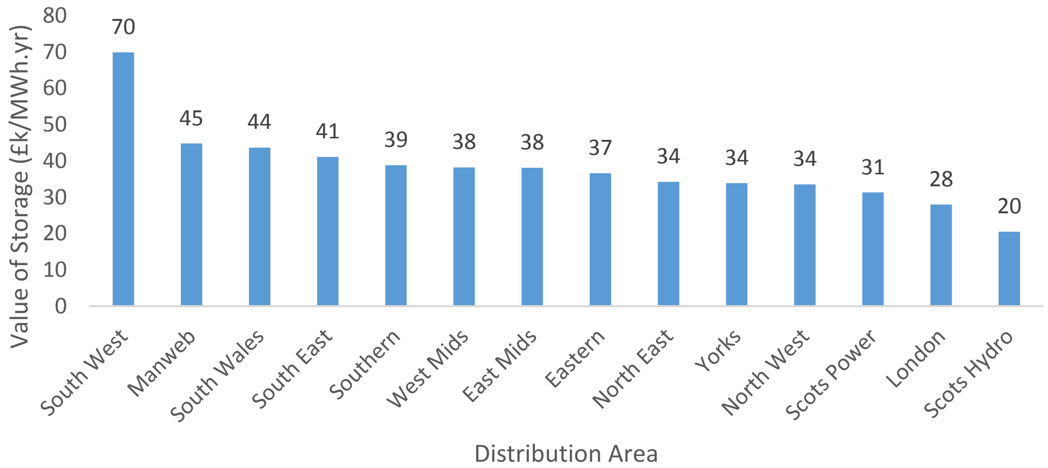

Fig. 14 The value of electricity storage in reducing half-hourly transmission and distribution charges for HV demand for the different distribution zones of the GB system in 2017. 85% round-trip efficiency, 5% VAT included, 2 hour Triad window (17:00-19:00)

Tesla Powerpack	
Technology	Li-ion
Storage capacity per module	100 kWh
Peak discharge power per module	50 kW
AC-AC efficiency (2 hour system)	82%
AC-AC efficiency (4 hour system)	83%
DC-DC efficiency (2 hour system)	91%

DC-DC efficiency (4 hour system)	93%
Cost per module	£34,265
Cost per bi-directional 250 kW inverter	£40,425
Cost of cabling & other hardware	£2,002+£770/module
Warranty	10 years
Projected cycle life	15 years

Table 6 Tesla Powerpack specifications and costs [42]

Service	Response Time	Max. Duration	Min. Power	Market Size
Enhanced Frequency Response	1 s	9 s	1 MW	200 MW
Firm Frequency Response (Primary)	10 s	30 s	10 MW	400 - 700 MW
Firm Frequency Response (Secondary)	30 s	30 m	10 MW	1,200 - 1,450 MW
Fast Reserve	2 m	15 m	50 MW	300 - 600 MW
Short Term Operating Reserve	4 h	2 h	3 MW	2,500 - 3,500 MW

Table 7 Ancillary services of interest to operators of small- and medium-scale electricity storage devices in Great Britain [43]

FIGURE AND TABLE CAPTIONS

Fig. 1 Non-domestic electricity consumption statistics for the UK in 2013 [21], using Eurostat consumption bands for industrial electricity [22]

Fig. 2 Breakdown by distribution charge (DUoS) tariff of forecasted high/low voltage consumption in the North West distribution area in 2016 [23]

Fig. 3 Monthly electricity import and generation in 2015 by Lancaster University campus

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