**Optimal Placement, Sizing, and Dispatch of Multiple BES systems on UK Low Voltage Residential Networks**

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# Abstract

*As the penetration of renewable technologies on UK low voltage networks increases, the likelihood of line utilisation and voltage violation rises. Whilst previous studies have examined the use of centrally controlled energy storage to manage violations, the economic feasibility of such methods are generally not considered. In this paper, a novel approach to the placement and dispatch of behind-the-meter battery energy storage for voltage and utilization control is presented. The placement strategy is formulated as a multi-period mixed integer linear programming (MILP) that allows for both variable and fixed size storage systems. The real time dispatch strategy is presented as a 2-stage convex linear programming (LP) heuristic that involves management of both real and reactive power, and incorporates ARIMA based generation forecasting methods to aid prediction of future generation, which is used to optimise for end user self-consumption, line loss reduction, storage efficiency loss reductions, and storage degradation minimisation. We apply both models to an unbalanced 3-phase openDSS model of a particularly sensitive LV feeder in the northwest of England, compare placements costs to the costs of reconductoring (which are calculated using a further novel MILP formulation), and use the real time dispatch strategy to identify self-consumption potential that cannot be determined from a placement calculation. We show that even with near ideal placement, costing, and control conditions, storage for voltage and utilization control at the 230 V level cannot compete economically with traditional means of reinforcement in the UK for our particular case study.*

**Keywords:** Energy Storage, LV networks, OPF, Sizing[[1]](#footnote-1)

# 1 Introduction

Since the impact of traditional fossil fuel generation on the environment and on the security and sustainability of supply has become a concern, the penetration of renewable and low carbon technologies in the UK energy mix has continuously increased. Current estimates suggest a total installed capacity of 12.7 GW solar photovoltaic (PV) [1] and 17.9 GW wind [2], CHP systems make up 560 MW of electrical power capacity and 2.3 GW heat capacity [3], and interest in poly-generation and microgrid systems and their operation is growing in literature [4], [5].

The rate of rooftop PV uptake in the UK has somewhat slowed since a significant reduction in feed in tariff [6], though sources still predict a potential for increase in penetration between 18% - 25% by 2035 [7]. Reductions in system costs may further influence uptake; IRENA show that the costs of PV modules have fallen by 80% over the last 8 years due to efficiency improvements and general economy of scale [8], and it is predicted that system costs could fall by a further 59%, which is in some part due to projected improvements in affordability of state of-the-art technologies such as concentrated silicon solar cells [9] and multi-junction solar cells, which have been shown to achieve efficiencies of 27.5% and 42% respectively [10]. Though individual array sizes are unlikely to increase above 4 kWp (as generation and export tariffs fall for systems that exceed this size [6]), the increase in number of systems could stress some low voltage (LV) network topologies to the point of violation.

With an increasing penetration of distributed PV generation on UK networks, it becomes increasingly likely that LV (230 V 1Ø, 400 V 3Ø) networks will experience utilisation and voltage conditions that violate network capacity constraints and statutory regulations [11]. It is therefore important to consider the methods that may be used to limit LV network violations to within acceptable levels. Previous work often concerns the installation and control of on-load tap changers (OLTCs) at secondary substations (SSSs) [12], reactive power compensation using PV inverters [13], traditional reconductoring [14], Curtailment of generation [15], and control of distributed battery energy storage systems (BESSs) [13]. Availability of affordable residential BESS systems with large enough capacities to handle feed in limiting tasks across multiple hours, such as the Tesla Powerwall 2 (13.2 kWh, 5kW max continuous) [16] and the Mercedes-Benz Energiespeicher (2.3 - 18 kWh, 1.25 - 4.6 kW max continuous) [17], have made violation control via BESS charging a potential solution. Furthermore, modern BESS inverters often have the capability to operate at non-unity power factors [16], [18], and research and development of inverters able to make operational decisions based on remote grid signals is ongoing; for example, Ippolito et al. [[19]] developed an inverter capable of determining the appropriate operation under frequency control, voltage control, load shifting, load prioritising under islanded conditions, and harmonics compensation, based on signals from the wider grid. SCADA based control systems have been developed to coordinate control of multiple battery sets [20] for frequency control, and this has made centralised BESS control for violation management a technical possibility.

Proposed BESS control schemes vary significantly in their placement methodology, dispatch logic, and BESS ownership assumptions. Previous work has considered the cost of behind-the-meter BESS installations for voltage control, and the way in which BESSs may be operated to greatest benefit. Wang et al [21] propose a BESS operation heuristic in which behind the meter BESSs are time-shared between DNOs (for voltage and utilization management during periods of pressure) and residents (for increased self-consumption) . Whilst potential cost savings are proposed, these are not fully analysed with regards to system install costs and alternative means of reinforcement. Ranaweera [22] proposes a more elaborate method using optimal operation forecasting to allow self-consumption and violation control operation to occur simultaneously. She then compares this to a simple self-consumption only heuristic via application of each dispatch scheme to an IEEE European low voltage test feeder. It is found that a centralised control scheme is required to ensure sufficient network control is maintained, though the degree of self-consumption is independent of complexity of the control scheme. Again, the economic feasibility of such an approach is not considered, and it is assumed that all residences have identical BESSs + PV arrays. Similarly, Anusha *et al.* [23] consider a DNO coordinated BESS approach [24], Marra et al. [25] proposed a decentralised feed in limiting based BESS control heuristic for customer owned BESSs, and Fortenbacher constructed a centralised MILP optimal power flow (OPF) control algorithm for residential BESSs to minimise network losses, storage losses, and BESS degradation whilst satisfying network constraints [13], though none consider the comparative costs of such a system.

Some recent studies have considered the impact of low carbon technologies and BESSs probabilistically i.e. performed Monte Carlo simulations with the same penetration of technologies at different locations to determine a statistical likelihood of violation at a given penetration level. Lamberti et al. propose 2 control heuristics for the reduction of voltage violations and increase in self consumption on a LV Italian distribution network [26]. Location and rating of PV arrays and rating of BESSs are assigned randomly and multiple network configurations are solved during summer and winter months to determine the statistical likelihood of violation under different PV penetration and BESS control scenarios. It was determined that feed in-limiting was more effective for voltage control than the simple self-consumption method (charge on net generation, discharge on net demand), and resulted in only a very small reduction in self-consumption across all penetration levels. Navarro-Espinosa et al. use the same Monte Carlo methods, but apply them to determine the probabilistic impacts of PV, air-source heat pumps (ASHPs), and micro-CHPs on LV distribution feeders, with no consideration of BESSs [11].

Whilst Ofgem do not currently permit DNOs to own or operate BESSs [27], if BESSs were to prove economically viable for control of LV networks, this may create an argument for DNO ownership. Furthermore, there is no legislation to prevent a 3rd party from owning and operating a network of BESSs, operating this in a way that is beneficial to the DNO, and selling this service to the DNO. 3rd party ownership of assets located at residences is relatively common for PV in the UK [23], and collaboration between home owners and 3rd party companies for BESS system profitability is being explored in numerous cases [28]. With the increased rollout of smart monitoring equipment, the proposition of utilizing an operational scheme that requires spatially and temporally resolute power and voltage data is becoming more feasible.

In this paper, we propose a LP-OPF to centrally control DNO or 3rd party owned behind the meter BESSs at properties with PV systems in a way that decreases utility bill costs (via maximisation of self- consumption and manipulation of Economy 7 tariffs), whilst ensuring compliance with voltage standards, preventing overutilization of feeder lines, and maintaining adequate control of power factor, line losses, and BESS degradation rates. We apply this model to a feeder located in the north west of England, compare the cost of BESS control to traditional reconductoring costs, and consider the effect that reclamation of customer bill reductions as a means of repaying capital costs may have on the economic viability of the system. We also consider the effect that a change from ESQCR voltage regulations to EN 50160, and a change in PV penetration, may have on this.

The objective of the study is to attain a preliminary understanding as to whether centrally controlled BESSs for voltage and utilization control on urban residential networks, even under near-ideal placement and dispatch conditions, is likely to prove competitive with traditional means of reinforcement in a 3rd party or DNO owned scheme. The work contributes novel methodologies for BESS placement, BESS dispatch, and planning for LV feeder reconductoring, and presents a probabilistic cost and performance comparison of these violation management solutions.

|  |
| --- |
| **Nomenclature** |
|  | Tensor product |  | Elementwise multiplication of vectors |
|  |  vector of 1’s |  |  vector of 0’s |
|  |  |  |  |
|  | Import cost for BESS (£) |  | 1 vector of values |
|  | 1 vector of values |  | Cost penalty for import/export of real power by BESS at time  |
|  | 1 vector of values | **,** | 1 vectors of line loss costs for all major line segments on all phases (£) caused by real and reactive power transfer respectively  |
|  | 1 vector of max trajectory penalties for each BESS (£) |  | 1 total excessive reactive power cost penalty for each phase at the feeder head (£) |
|  | 1 penalty for reactive demand/export from BESS inverters at each residential site at time t (£) |  | 1 vector of BESS losses at time t (£) |
|  | Sensitivity matrices that describe the change in voltage at each monitor point with change in real and reactive power inject/demand at each residence. |  | Sensitivity matrix that describes the change in voltage at each monitor point with reconductoring of each major line segment |
|  | Predicted cost of BESS capacity loss per change in power setting (£/ΔkW) |  | Cost per unit of BESS energy capacity (£/kWh) |
|  | Per kWh energy import costs for customer i at time t (£/kWh) |  | 1 vector of values |
|  | 1 vector of per kWh Penalty for export of power (£/kWh) – all elements equal |  | Per kWh penalty for line losses related to real power transfer (£/kWh)  |
|  | Per kWh penalty for line losses related to reactive power transfer (£/kWh) |  | Per kWh penalty for breach of the maximum SOC trajectory (£/kWh) |
|  | Per kvar penalty for excessive reactive power consumption (£/kvar) |  | Cost per unit inverter power capacity (£/kW) |
|  | 1 vector of conductor segment reinforcement costs |  | Cost of BESS (£) |
|  | Cost of installation per BESS (£/Installation) |  | Predicted demand that will not be served by either PV generation or the BESS at residence  |
|  | Change in daily capacity loss with increase in SOC by 1 kWh |  | Energy capacity of BESS (kWh) |
|  | 1 vector of BESS energy capacities (kWh) |  | 1 Per phase feeder head maximum acceptable ampacities (A) |
|  | 1 Per phase feeder head ampacities (A) |  | Total number of line segments |
|  | Total number of residences |  | Number of voltage monitoring Points |
|  | BESS charging/discharging efficiency |  | Power factor |
|  | 1 vector of real power flows across each phase of the feeder head (kW) |  | 1 vector of real power demand on network by load at time (kW) |
|  | 1 vector of predicted load demand values at each residence in prediction model |  | 1 vector of real power inject by generator at time (kW) |
|  | 1 vector of predicted generation values at each residence in prediction model |  | Real power discharged onto network by BESS at time (negative charging) (kW) |
|  | 1 vector of values |  | Real power discharged onto network by BESS at time (negative charging) (kW) |
|  | 1 vector of values |  | Change in real power discharged onto network by BESS at time (negative towards charging) (kW) |
|  | 1 vector of values |  | 1 vector of reactive power flow across each phase of the feeder head (kvar) |
|  | 1 vector of leading reactive powers injected onto network by each BESS at time (negative lagging) (kvar) |  | Leading reactive power injected onto network by BESS at time (negative lagging) (kvar) |
|  | 1 vector of values |  | 1 vector of changes in leading reactive powers injected onto network by each BESS at time (negative towards lagging) (kvar) |
|  | Total apparent power capacity of BESS inverter (kVA) |  | 1 vector of values |
|  | Maximum allowed SOC at the beginning of the next day for BESS  |  | 1 vector of voltages on each phase of each end monitoring point at time t |
|  | 1 vector of the minimum allowable steady state voltage – 216 V ESQCR, 207 V EN 50160 (V) |  | 1 vector of the maximum allowable steady state voltage – 253 V (V) |
|  | 1 vector of binary variables for the existence of reinforcement on conductor segments  |  | 1 vector of binary variables for the existence of each BESS |

# 2 Method

## 2.1 Placement and Sizing Model

We place BESSs using a multi-period mixed-integer linear programming (MILP) formulation. This aims to minimise the total cost of system installation, where the total cost is determined by multiplying the total number of BESSs placed by the unit installation cost **,** the total installed energy capacity by the per kWh cost **,** and the total installed inverter power capacity by the per kW cost, then summating the results. The MILP formulation is applied to a 14 hour clear sky summer generation profile at 1 hour intervals, and therefore the charging power of any given BESS can take multiple different values throughout the day.

This allows us to assess the best case placement scenario, and thus determine whether further work considering non-optimal ownership patterns may be of value. The formulation is subject to various constraints – constraint (2) predicts the change in end of line voltages for each phase of every monitored end point as a function of real power charging and reactive power injections by BESSs, , and ensures that the predicted change is at least as negative as that required to bring voltage below the maximum limit (253 V), .In this paper, we monitor the voltage at the end of 4 feeder branches (), as this is found to be the minimum required to ensure voltage control at all other customer nodes (locations of monitors are shown in fig. 1). It should be noted that whilst we consider all customer voltages in the results, we only control based on the voltage monitoring points.

Where,

The constraint uses linearized sensitivities of voltage to real and reactive power injects to predict end of line voltage changes with BESS operation, and these are stored in the sensitivity matrices and . Constructing the sensitivity matrices for specific network states is time consuming, and the actual element values of the sensitivity matrices vary only slightly across the range of network states encountered during modelling (not more than 5%), so we determine the values at zero generation and apply this matrix in all circumstances. The maximum error observed between predicted and actual voltages from one iteration of the MILP formulation with the sensitivity matrix method was 1.3 V. To further reduce the sizing and placement errors resulting from the linear approximations, we iterate until convergence of network maximum voltage and feeder head utilisations. This typically requires 2-3 iterations. The constraint must be satisfied at each hourly interval, and therefore ,varies with time.



*Figure 1 – Shows the topology of the 75 residence feeder model used in this study, with the location of the feeder head monitor shown in red, and the voltage monitors shown in blue.*

Constraints (3-8) are a hexagonal representation of the inverter capacity limit constraint (see fig. 2), and ensure that all BESS inverters are assigned a total apparent power capacity great enough to accommodate the real and reactive power demands, and , of their respective BESSs at all hourly time intervals. As in [13], this linear representation is used to avoid the introduction of difficult to solve quadratic constraints that barely affect the result of the formulation (system cost difference was always ≈0% where quadratic constraints were replaced with linear alternatives). The numbers 0.285 and 0.527 are empirically determined factors that allow construction of hexagonal constraints suitable for an inverter that may operate at power factors between 0.85 and 1, which is typical of modern home BESS inverters [16], [18]. Constraint (9) limits the inverter to this power factor range.



*Fig 2 – Shows the allowed operating region (shaded grey) of an inverter capable of the PF range 0.85 - 1. The hexagonal constraints (3-8) represent the hexagon within the circle, and the diagonal lines represent the PF constraint (9).*

The formulation utilises an octagonal representation of the feeder head ampacity limit constraint which states that the current magnitude across any phase measured at the feeder head must remain within the ampacity limit of that phase. For any given phase, this is achieved by taking the sum of all real power contributions (real power transfer at the feeder head on the chosen phase, plus any BESS operation) and the sum of all reactive power contributions, dividing each by the feeder head voltage to obtain and , and ensuring the coordinate described by this pair of values does not fall outside of the area described by the octagonal constraints (see fig. 3).

The polygonal approximation is used in both the placement and real time models as a compromise between optimality and computational cost, and uses the method presented in [13]. Whilst the ampacity limit method can be refined further, improvements to overall costs are insignificant with respect to increased detail in ampacity limit modelling for the network in question (as voltage violations always manifest before ampacity violations), and so we deem the polygonal approximation as sufficient for the current study. Furthermore, the use of such linear approximations increases the optimization rate and therefore increases the temporal resolution at which the dispatch heuristic can theoretically be applied.



*Fig. 3 – Shows the actual ampacity constraint on a power line with ampacity limit 1 A, and how the octagonal constraints are used to approximate this limit. Represents the component of current that is in phase with voltage, and represents the 90₀ out of phase component.*

Each element of the vector that describes the required usable energy capacity of each BESS, is equal to the sum of all charging events during the day for a given BESS e.g. element 1 of is equal to the sum of charging events at residence 1, corrected for a charging efficiency . The usable energy capacity of each BESS is limited between 2.5 kWh and 12 kWh, chosen to represent a BESS of capacity 15 kWh operating within 80% of its SOC range to prolong life. The 15 kWh limit is chosen to prevent BESSs becoming unreasonably large for residential premises, and the 2.5 kWh lower limit prevents impractically small BESSs from being placed.

We do not allow BESS inverter capacities to exceed the power capacities of the PV arrays that they are located at the same residence. This is necessary to prevent BESSs from being assigned to residences that do not own a PV array, and to ensure that BESSs do not import power from the grid (i.e. they only limit the power export from the PV array they are associated with). We also restrict the energy/power capacity ratio to 2 (i.e. the BESS must have an energy capacity at least 2x greater than its inverter power capacity), so that the BESS never operates above 0.5 C, which is in line with typical modern residential BESSs with Li-ion chemistries [16], [17]. Furthermore, BESSs are limited to charging only (as we are considering voltage reduction only, and the generation profile is symmetrical, meaning that no opportunities to discharge will arise between charging events).

The BESS existence variables for each residence, stored in , are declared as binary, and vector elements equal 1 on existence of any power or energy capacity e.g. if any BESSs capacity exists at residence ‘1’, then element 1 of , changes from 0 to 1.

A realistic typical minimum load demand of 0.160 kW (the typical diversified minimum summer demand produced by the CREST model) is applied to all residences during all placement and sizing simulations.

## 2.2 Reconductoring Model

In order to determine the economic viability of ESS, we must compare it to cost of reconductoring. As in [30], we break the network into major line segments that may be reinforced with a thicker conductor. Sizes and cost of the current network cables and the reinforcement cables are summarised in table 1. The reinforcement cable size is based on future ENWL reinforcement strategies [31], and LV reconductoring costs are based on figures from consultation with ENWL that are used in [32].

|  |  |
| --- | --- |
| *Property* | *Value* |
| Main conductor size (Typical) (mm2)  | 70-95 |
| Branch conductor size (Typical) (mm2)  | 35 |
| Reinforcement cable size (mm2)  | 300 |
| Cost of Reconductoring [32] (m-1) | £80 |

*Table 1 – Current conductor and reinforcement conductor properties and costs*

The reconductoring MILP objective function minimises the total cost of reconductoring. The total reconductoring cost is determined by multiplying the cost associated with reconductoring each line segment () by the binary variables that denote whether each major line segment reinforcement exists (these are stored in vector ),

Constraint (11) predicts how a chosen series of reinforcements will reduce the voltage on each phase of each monitored end point (given by the LHS of the constraint), and ensures that these reductions are all greater than that required to ensure voltage remains below 253 V, **.** is a matrix representing expected change in voltage on each phase of every monitored end point to each possible reinforcement e.g. the (7,4)th element of **,** , represents the expected change in voltage at end point monitor 3, Ø 1, when major line segment 4 is reconductored.

Additionally, the feeder head line segment is automatically reinforced if feeder head utilization is shown to exceed the cable ampacity on any phase in the absence of upgrade. We consider replacement of 7 major stretches of feeder cable (denoted ‘major line segments’), which are shown in fig. 4. This simplifies the problem of modelling every line segment in the model (of which there are 1230), and represents how a DNO may consider reconductoring i.e. replacing stretches of more than a few meters.



(a)

(b)

*Figure. 4 – (a) Topology of the feeder used in the case study (b) simplified 7-line segment topology of the network used for line loss approximations, and as the set of ‘major line segmnts’ that may be replaced using the reconductoring formulation.*

## 2.3 Generation and Demand Prediction

Because BESSs are used to maximise customer self-consumption in the real-time dispatch section of the algorithm, and because BESSs must not be full before they are required for network control, we require predictions of day-ahead generation to aid operational decisions. We also require an estimate of future demand so that we may determine whether there is likely to be any self-consumption value to charging BESSs. The generation and demand prediction process is carried out at the beginning of each simulated day.

To estimate day ahead PV irradiance, we apply an ARIMA (1,0,0)(1,1,0) prediction model (as suggested and explained in [33]), with suitable model parameters estimated from 30 days of hourly irradiance data prior to the day being simulated. We also predict two-day ahead generation, which is used to determine an end of day goal SOC for the day ahead. The MATLAB ARIMA tool is used for parameter estimation and simulation, and ARIMA+2σ is used as the irradiance prediction; this is cautious, but reduces the risk of irradiance underestimation, and hence reduces the risk of prematurely filling BESSs before they are required for network violation control. Per site generation is estimated using a simple power-irradiance-temperature regression model [34], [35], and the hourly demand prediction is estimated using persistence with consideration of day-type (weekday or weekend); this appears crude, but [36] shows that little forecasting improvement is seen with more advanced predictive methods.

We use a simple multiperiod LP heuristic to approximate the minimum total charging energy required to satisfy voltage and ampacity constraints for the 24h period. Although the operating regions of BESS inverters may be approximated using the hexagonal and power factor constraints (3-9) (Fig. 2), the resulting formulation is non-convex in the instance that BESSs are permitted to operate in either charging or discharging mode. We therefore operate a 2 stage LP optimisation heuristic to approximate optimal operation. The results produced using the heuristic are almost no different from those obtained using only hexagonal constraints (as the decision to operate at low power factors is very rarely the optimum), but assure BESS inverters operate only within allowed bounds.

The objective functions for both stages of the formulation are identical, and seek to minimise the total energy charged across all 24 hourly time intervals by all BESSs. This can be expressed mathematically as,

Both stages of the optimisation share the same maximum voltage and octagonal ampacity constraints, which are the same as those used in the placement and sizing model.

Because opportunities to discharge may arise during the 24 h period, constraint (13) allows BESSs to discharge at a maximum rate equal to the predicted load demands remaining at their respective sites after subtraction of PV generation from the total load demand, which is calculated before the optimisation as , where and here represent predicted demand and PV generation at each load site respectively,

Constraint (14) ensures that the SOC of each BESS at every timestep (expressed as vector ), is within the allowed range for the respective BESS. It should be noted that is now a vector of fixed values (decided upon using the placement and sizing formulation) describing the energy capacity of the BESS at each residence, rather than a set of variables (as it was in the placement and siing model)

Where denotes a tensor product and is a 24x24 lower triangular matrix of 1’s.

Stage 1:

In stage 1, BESS inverters are prohibited from supplying leading or lagging reactive power, but BESSs may charge or discharge at the full rated power of their inverters.

Stage 2:

Stage 2 uses the outcome of stage 1 to decide how the real power operation of each BESS should be constrained at each of the 24 hourly time intervals; each BESS is constrained to either ‘discharging only’ if the BESS was discharging in the stage 1 result, and ‘charging only’ if the BESS was charging in the stage 1 result. BESSs are allowed to operate at power factors between 0.85 and 1 in stage 2, and this is managed using constraints (3-9). Additionally constraint (14) is updated so that BESSs discharging during a given hour, t, experience an SOC change of , and BESSs that are charging experience an SOC change of .

From the results of step 2, we extract the predicted hourly SOC series for each BESS - these SOC series represent the predicted SOC evolution of BESSs if used only for violation control. We then determine the maximum allowable SOC for each BESS at the end of each hour, by adding the difference between the predicted future maximum SOC and the BESS maximum energy capacity to the predicted SOC at the current hour (depicted in fig. 5), which creates a maximum allowed SOC trajectory sequence. We also perform a 2nd day ahead SOC prediction and use the same maximum trajectory method to determine a suitable SOC to end the day ahead on. This ensures that we do not risk starting the 2nd day ahead without adequate capacity headroom to handle potential voltage and ampacity violations. We therefore modify the maximum trajectory to include the need to reduce SOC to the day ahead limit, , by limiting BESS SOC to be no greater than . The value 1.5 is chosen so that BESSs will never be required to discharge at a rate greater than 1.5 kW to satisfy the trajectory. The maximum trajectory sequence is implemented in the RT OPF heuristic to ensure that charging for violation control is spread effectively across BESSs, preventing BESSs that are more effective in controlling violations from being overused early and thus filling prematurely. It also informs the controller of the amount of spare energy capacity available to charge for self-consumption purposes at a given time, before further charging risks depleting the capacity required to mitigate future voltage and ampacity violations.



*Figure 5 – Shows the maximum SoC trajectory and required next day maximum starting SoC for a given hourly predicted SoC evolution. Arrows (a) and (b) are of the same magnitude, as the maximum allowed SOC at hour 3 must equal the SoC headroom at hour 15 plus the predicted SoC at hour 3. In the last 8 hours of the day, the max trajectory progresses towards the desired next day max starting SoC at a rate equal to discharging the BESS at a constant 1.5 kW.*

## 2.4 Real Time OPF Dispatch Model

The OPF cost function takes the form (15), which denotes the sum of all residences self-consumption BESS charging benefits , energy import and export penalties , BESS degradation penalties , deviation of SOC max trajectory penalties, , BESS efficiency loss penalties , and a very small penalty that prevents inverters from injecting reactive power when not required . We also add all cost penalties associated with real power losses along the feeder and , and penalties associated with excessive reactive power demand at the feeder head . The formulation and meaning of the penalty terms are discussed throughout this chapter.

The optimisation process runs as follows

* The state of the line and load powers, losses, and voltages at the timestep that has just occurred (denoted in the subscript as ), are extracted from the power flow simulator (openDSS).
* We optimise the change in each BESSs real power , and reactive power to find values that would optimise operation at , which accounts for the fact that we do not know what the state of network will be at the timestep we are about to reach. The optimisation progresses through 2 stages, for the same reason as in formulation (12).
* The new timestep, , is reached, and the and values are applied, and the process is repeated until all timesteps have been evaluated.

The input variables to the optimisation are and . Any other scalars and vectors used are pre-determined constants and coefficients. In the instance that a constraint requires an absolute BESS charging/discharging rate, we determine this using , i.e. the previous BESS setting plus the amendment to the BESS setting for the next timestep.

### 2.4.1 Typical OPF constraints

The RT OPF constraint (18) prevents overvoltage, and is identical to constraint (2) aside from absolute BESS powers being replaced by change in BESS powers, . Constraint (19) prevents under voltage by ensuring that the predicted change in voltage on each phase at all monitored end points that results from changes in BESS real and reactive powers, , is greater than that required to bring voltages above the lower limit, .

Feeder head ampacity constraints for the RT OPF formulation are identical to those used in the placement and sizing model, except absolute BESS powers are replaced by change in BESS powers.

Stage 1:

Stage 1 is identical to stage 1 in the prediction model in section 2.3, except real powers are expressed as to account for the inverter power at the previous time step.

Stage 2 only:

Stage 2 is identical to stage 2 in the prediction model in section 2.3, except real powers and reactive powers are expressed as and respectively to account for the inverter power at the previous time step. Additionally, BESSs are bound so that charging or discharging cannot result in a breach of the SOC limits – BESS efficiency, , is considered in calculation of the bounds.

### 2.4.2 Predicted Stored Energy Values

Because the reclamation of utility bill savings resulting from reduced grid demand (due to BESS operation) may be an effective mechanism for the BESS owner to pay back some system costs, we include a term in the cost function that considers the value of BESS charging at any given point in time for each BESS, . The value of any element of the vector , represents the value of charging BESS for purposes of self-consumption, and is determined by predicting whether SOC is likely to reach zero whilst load demand still remains () i.e. we predict whether further charging (that is not necessary for violation control) is likely to reduce the customers grid demand. From the predicted generation and demand profiles developed in section 2.3, the predicted charging profiles developed in the same section, and the current SOC, we are able to determine whether this is likely. Therefore takes the value,

Where takes the value £0.116/kWh at all times for standard tariff customers, which reflects a typical cost per kWh of electricity to customers in the UK, and results in a negative cost for charging where , thus encouraging charging. For example, if a customer with predicted unserved demand were to charge from PV generation at 2 kW, then would equate to £0.232, which is the actual cost saving the customer would experience by avoiding future import if this action were continued for a period of 1 hour; it is worth noting that all costs used in the RT OPF formulation are scaled to 1 hour of activity, regardless of the time interval used.

Customers with a usable BESS energy capacity greater than 10 kW were switched to an economy 7 (E7) tariff to examine whether charging during E7 hours could increase customer savings. The size limit was enforced to ensure that customers still had enough capacity to avoid significant import during peak hours on the majority of days. Customers on E7 tariffs were assigned values of £0.152/kWh, which reflects a typical peak tariff in the UK, and the fact that on observation the majority of energy consumption occurred in peak hours. Furthermore, was set to £0.071/kWh (a typical off peak E7 tariff in the UK) during off-peak hours if generation predictions suggested that the BESS would be able to serve demand via charging PV energy later in the day; this prevents customers from buying cheap energy over night that they likely to procure for free in the day.

This predicted energy value must be balanced against current import costs, so that energy is not bought at a cost equal to or greater than the cost of the future energy purchase that we are trying to avoid. Current energy import and export costs are managed by Constraints (21) and (22). The constraints form an epigraph which ensures that any element of (where each element represents the cost penalty/benefit associated with energy import/export at a given residence), is equal to the product of and the total import (if the residence is operating at a net import), or the product of the respective element of and the total export (if the residence is operating at a net export). As previously stated is always £0.116/kWh for standard tariff customers and £0.152/kWh for E7 customers during peak hours, but the value falls to £0.071/kWh during off peak hours.

Ideally should be equal to the per kWh export benefit for generators ≤ 4kW (currently £0.0503 [37], so all elements should equal -0.0503 in this formulation). However, in this instance we try to avoid export where not required to decrease the likelihood of unserved demand events. Furthermore, under current policy export tariff is paid only on an assumed export quantity of 50% generation, so would realistically provide no further economic benefit to the customer [6]. Therefore in this study a small cost is assigned to to limit export.

The result of these additional considerations is a tendency of BESSs to charge only during generation.

2.4.3 Degradation penalties

As BESSs are to be operated over long time periods, we must consider the effect of degradation, and the way in which this may impact operational costs. Using the predicted load demand time series and predicted charging profiles from section 2.3, alongside the present BESS SOC, we estimate the evolution of SOC over the day to obtain an hourly SOC time series. The magnitude and number of cycles experienced by each BESS over the day in question are extracted using a rainflow counting algorithm [38], as is typical in battery degradation modelling studies [39], [40]. The predicted daily degradation for each BESS is then calculated by feeding the rainflow output into the depth of discharge (DoD)-Capacity fade relationship developed in [41], which is coupled with the semi-emperical capacity fade algorithm in [42] that extends the former to include approximations for calendar fading. Such semi-emperical models are readily applicable to BESS planning and operation studies, as they only require inputs that can be readily obtained or approximated, as opposed to physical models that often require information regarding molecular level processes cannot be directly measured in operation. The depth of discharge-capacity fade curve used is derived from a typical curve for li-ion chemistries [42], and is adjusted to represent a cell with a cycle life of 10 years at 70% DoD, which represents the cycle life expectations of typical state of the art residential BESSs such as the Tesla Powerwall [16] (fig. 6).



*Fig. 6 – Shows the cycles to end of life vs. DOD used to calibrate the degradation model.*

To approximate the increase in degradation associated with increase in SOC of a given BESS, we add 1 kWh of charge to the BESS, predict (using demand and hourly charging predictions) how this will change the SOC hourly time series, and calculate the degradation associated with this time series using the rainflow and capacity fade algorithms discussed previously. The kWh degradation from the base case is then subtracted from the ‘+1 kWh’ case, to give the predicted change in degradation associated with further charging, . This is converted to a cost by dividing by 20% of the system size in kWh (to account for the fact that the BESSs no longer have the capacity to handle violations below 80% state of health and so must be replaced), and multiplying by total capital cost of the BESS,

Where the factor 1.25 arises to adjust the maximum usable BESS capacity to total BESS capacity (as we only operate BESSs within 80% of their maximum SOC range). The costs factors , which represent the £/kW charging penalty for each BESS at the given time step, are multiplied by the BESS charging rates in kW (0 if discharging), and stored in the vector . Additionally, we allow BESSs to charge with no penalty if they are ‘behind schedule’ on degradation; for example, if on the final day of year 1 the BESS has not lost 2% of its total energy capacity, it may charge with no penalty unless this limit is met on the day. Preliminary testing of the model without this consideration resulted in under-utilization of BESSs, with BESSs predicted to reach calendar lives after performing very few cycles.

2.4.4 Maximum SOC trajectory

If BESSs operate at an SOC that exceeds their maximum SOC trajectory at a given time interval, they are penalised using the epigraph formulation programmed into Constraints (24, 25). The term determines whether BESSs are charging at too high a rate/discharging at too low a rate to fall below the maximum trajectory at the next time interval, where denotes the absolute BESS real powers that would be required to fall below the trajectory. If the term is positive for a given BESS, then the BESS is penalised by (24) at a rate equal to the product of and the power in kW that the BESS will exceeds the maximum trajectory by. If negative, then the penalty is set equal to zero. The penalties for all BESSs on the network at the given time interval are stored in .

Constraints (26, 27) represent an epigraph formulation that penalises BESS operations when they are expected to result in reactive power demands on a given phase at the feeder head that exceed real power demand i.e. Power factors below 0.95 lagging are penalised. represents reactive power demand, represents real power demand, and is the penalty per kvar excess, and is based on current ENWL charges [43]. The constraints are effective in reducing the instances in which more reactive than real power is drawn from the wider grid.

As is typical in BESS power flow studies [44]–[46], the modelled Li-ion type BESSs are assumed to have a fixed charging and discharging efficiency of =0.95, and cost penalties for storage losses at each BESS are approximated by multiplying charging or discharging rate in kW by . The resulting penalties are the stored in . Though in reality efficiency does vary slightly across charging/discharging rates, it does not vary enough to significantly change the outcome of this work, so a fixed efficiency is deemed adequate for the purpose of this study.

Additionally, we penalise line losses resulting from reactive power transfer using the exact methodology presented and used in the power flow study [13]; the authors model line losses that actually vary quadratically with current as a piecewise linear epigraph approximation of the curve. Consideration of losses for each line segment in the feeder model produces an impractically large problem (the feeder model consists of 1230 line segments), so we simplify the network to 7 major line segments (Fig. 4). Preliminary testing showed that large losses resulting from unnecessary reactive power transfer between buses could be avoided by applying line loss constraints together with a very small cost penalty (£0.0001/kvar) on leading or lagging reactive power injection by BESS inverters (accounted for in ). The RIIO-ED1 electricity distribution price control document explains the obligation of DNOs to reduce network losses, but does not provide an exact economic incentive for loss reduction (i.e. in £/MWh), so constraints that limit losses due to real power transfer are used only to ensure unnecessarily large line losses are avoided.

### 2.4.5 Modelling Tools

The BESS OPF model is applied to a model of a feeder located in the north west of England [47]. The topology of the feeder is shown in Fig. 3. A 2 year time series of power demand data is randomly assigned to each residence from a set of profiles generated using the CREST model [48]. A comparison of monitored feeder consumption to CREST predicted consumption showed a typical demand over prediction of 7 - 10%, which we believe is acceptable for this study. The number of profiles in the set that represent different occupancies are proportionally scaled to UK national statistics, which suggest 1, 2, 3, and 4 or more occupant residences represent 29%, 35%, 16% and 20% of the UK housing stock respectively. 2 year PV generation profiles are generated using satellite irradiance data measured at the geographic location of the feeder in question with spatial resolution 90m2 and temporal resolution 1 min, and are converted from irradiance to power using irradiance-power and temperature-power regression models from [34], [35].The irradiance for the 2 years in question was chosen because when converted to a generation profile it was found to be reasonably representative of 2 years of typical generation for the area of the country in question (generation is typically 820-880 kWh/kW installed/annum, and the annual average of 2 years in question is 850 kWh/kW installed/year. Previous validation of the satellite irradiance model against ground measurements has shown average %RMSE values of daily=10%, hourly=15% with a monthly underestimation bias=1%, suggesting a small error in temporal distribution of generation [49]. Furthermore, recent literature suggests that satellite derived generation data presents a slightly lower RMSE than single-point derived ground measurements, and is adequate for long term power flow studies [50]. We therefore believe that the satellite estimated data is of high enough quality to represent a typical 2 year period for the area in question. As of [11], PV generator sizes are assigned probabilistically based on UK installation size data, that suggests 1%, 8%, 13%, 14%, 14%, 12%, and 37% of all rooftop systems are sized 1.0, 1.5, 2.0, 2.5, 3.0, 3.5 and 4.0 kW respectively. Voltage monitors are positioned at 4 extreme points on the network, and a power meter is placed at the feeder head, as this monitoring scheme was found to be the minimum required to manage network constraints.

Setup, logic, communication, and data analysis are carried out in MATLAB, 3 4-wire unbalanced power flow simulations are performed using openDSS, and the IBM CPLEX optimisation suite is used to solve the OPF problem. We find that the OPF can typically be generated and solved within 30ms.

### 2.4.6 Modelling Scenarios and data collection

BESS placement, forecasting, and operation are modelled at PV penetrations of 50%, 70%, and 90%. Because a 90% penetration requires that some PV be placed on non-south facing roofs, we apply east-west generation profiles where required. Within each penetration scenario, we model 3 network reinforcement scenarios:

* Business as usual – No reinforcement is used.
* Reconductoring – The network is reconductored to the extent that voltage and utilization limits are controlled for 100% of the simulation.
* BESS with E7 - Sufficient BESS capacity is installed on the network to ensure voltage can be controlled on a clear sky summer day (using placer method described in section 2.1), customers with BESSs of usable capacity ≥ 10 kWh are switched to an E7 tariff, and BESSs are centrally controlled using the aforementioned methodology (with the E7 extensions activated for appropriate BESSs). We operate to reach cycle life limit after approximately 10 years.

We repeat all runs at tap positions 1.05 p.u. (the current SSS setting) and 1.00 p.u., to assess the effect that a reduction in tap position may have on the required quantity of BESS capacity, and on overall compliance to voltage standards.

For each model run, we record;

* Total feeder line loss
* Total customer import from grid
* Total customer export to grid
* Total storage losses
* % voltage control at each load for each day (ESQCR standards)
* % voltage control at each load for each day (EN 50160 standards)
* % utilization control at the feeder head for each day

*Fig. 7 – Shows the hierarchy of simulation scenarios.*

The hierarchy of scenarios is shown in fig. 7. In order to consider how placement of generators may change the results for any given scenario, we run each scenario multiple times with different assignments of demand profiles and generator placements and sizes. Convergence of control and self-consumption statistics typically occurs between 10-30 runs, dependent on the scenario.

### 2.4.7 Analysis Methodology

#### 2.4.7.1 Voltage Control Capabilities

ESQCR regulations require steady state LV network voltage to remain between +10/-6% of 230 V with no specific explanation of how this should be measured, though it is implied that any breach of these bounds can be considered a violation of statute [51]. The European EN 50160 regulations require ±10% of 230 V to be maintained for 95% of 10 min averages across a 7 day period [51]; it is possible that a change to EN50160 regulations may occur, and so the effect that this may have on the % penetration at which reinforcement is required was seen as an interesting consideration in modelling scenarios. We therefore judge the voltage compliance capabilities of each control scheme using two methods;

* ESQCR – Compliance is approximated as the % of time periods in which voltage remains within ESQCR limits. We consider compliance for both a typical winter week and a summer week of particularly high generation, in terms of % residences within statute and % time within statute.
* EN 50160 – Compliance is achieved when 100% of 7 day periods remain within EN 50160 limits for 95% of 10 min averaged periods at all loads. We consider compliance across the entire 2 year period.

#### 2.4.7.2 Utilization Control, Line Losses, and Storage Losses

Control is simply the % of half-hourly periods within which utilization is below the feeder head capacity. Total line losses and storage losses are calculated internally by openDSS.

#### 2.4.7.3 System Costs and Adjusted System Costs

System costs are equal to initial placement costs plus the cost of monitoring equipment (Shown in Table 2), and we analyse results using both present and predicted 2035 cost projections. Costs are derived from typical present technology costs [52], [18], suggested costs from academic literature and industrial reports [32], and on optimistic projections of future system costs [53], [54].

Adjusted system costs are the system costs minus customer utility bill reductions. Adjusted values are calculated by summating grid imports and for each residence in the BESS scenario, assigning the correct costs depending on tariff and time (values from Table 3 used), and subtracting the BAU scenario utility bill costs from this. This reduction is then adjusted by a factor of 5 to account for a project lifetime of 10 years i.e. a pro rata increase in utility costs with inflation is assumed. This calculation allows us to assess the potential of self-consumption as an additional revenue stream.

Similarly, the system cost in reconductoring scenarios is adjusted by a factor of 0.4, to account for a minimum expected conductor lifetime of 25 years [55]. In this paper, we assume that all customer benefits are recovered by the 3rd party to pay for system installation as an ideal benchmark.

It is important to clarify that the cost analysis assumes that either:

* The DNO are allowed to purchase and install BESSs, and reclaim the entirety of bill savings from customers as a revenue.
* The DNO are paying a 3rd party to operate the set of BESSs, and that the DNO must pay (at least) the total cost of purchasing, installing and operating the system back to the 3rd party for the 3rd party to break even, minus the reduction in customer bills that the 3rd party reclaim as a revenue.

This is an idealistic way of considering the costs in both instances; in reality DNOs would likely have to pay a greater sum than the equipment costs calculated due to operations and maintenance, the need for the 3rd party to profit from their venture, and the very low likelihood that the 3rd party or DNO could actually reclaim much (if any) of the bill reductions from residents. However, the order of magnitude difference in costs between reconductoring and centralized BESS control (presented in section 4) suggests that this economic analysis was sufficient to meet the goal of the study, which was to gain a preliminary understanding of whether BESS control could likely compete economically with traditional reconductoring, even under near optimal placement and dispatch conditions.

|  |  |  |
| --- | --- | --- |
| Item | Cost £ (10 years)Current Scenario | Cost £ (10 years) Future Scenario |
| 1 kWh BES Capacity,  | 385 [52] | 94 [53] |
| 1 kW BES Inverter Capacity,  | 572 [18] | 201 [53] |
| Install Costs,  | 400 [32] | 200 [32] |
| Network Monitor | 1500 [54] | 800 [54] |
| Monitor install | 75 [54] | 75 [54] |

*Table 2 – The capital costs associated with system capacity, installation and monitoring.*

|  |  |  |  |
| --- | --- | --- | --- |
| Parameter | Value | Parameter | Value |
|  | 0.048 |  | 5 |
|  | 0.116 |  | 0.116 |
|  | 0.152 |  | 0.116 |
|  | 0.071 |  | 1 min |
|  |  |  | 60 min |

*Table 3 – Value of model input variables.*

# 3. Results

Voltage control is significantly improved by inclusion of BESSs in all 1.00 and 1.05 tap summer scenarios except 1.00 tap 50% pen, in which all loads are under almost 100% control even in the absence of reinforcement (Fig. 5). All BESS scenarios and BAU winter scenarios show near 100% control for all loads, though compliance is usually slightly worse in 1.00 tap scenarios due to short voltage dips below 0.94 p.u. that are missed by the algorithm. The control statistics for all ESQCR scenarios except BAU 1.0 and 1.05 summer are shown in table 4. Clearly, we cannot guarantee control 100% of the time for 100% of loads (see Fig. 8, left). This is due to unpredictable but infrequent changes in load that we cannot forecast correctly, resulting in most loads receiving an acceptable voltage between 99.8-100% of the total simulation time.



*Fig. 8 - % loads within ESQCR bounds vs % of simulation time for scenarios BAU 1.0 tap and BAU 1.05 tap during a high irradiance summer week.*

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  |  | 1.05 tap |  | 1.00 tap |
| BESS summer |  | 98<x<99% | 99<x<100% | x=100% |  | 98<x<99% | 99%<x<100% | x=100% |
| 50% pen. | 100% | 95% | 50% |  | - | - | - |
| 70% pen. | 100% | 95% | 55% |  | 99% | 96% | 18% |
| 90% pen. | 100% | 92% | 50% |  | 95% | 95% | 20% |
| BESS winter |  |  |  |  |  |  |  |  |
| 50% pen. | 100% | 98% | 55% |  | - | - | - |
| 70% pen. | 100% | 95% | 62% |  | 100% | 92% | 5% |
| 90% pen. | 100% | 92% | 58% |  | 100% | 88% | 14% |
| BAU winter |  |  |  |  |  |  |  |  |
| 50% pen. | 100% | 100% | 100% |  | - | - | - |
| 70% pen. | 100% | 100% | 100% |  | 97% | 85% | 10% |
| 90% pen. | 100% | 100% | 91% |  | 97% | 87% | 10% |

*Table 4 - % residential loads controlled (by ESQCR standards) for 98-99%, 99-100%, and 100% of all simulation time - averages for all runs of the same scenario type.*

An example of voltage control on a typical summer day at 70% PV penetration is shown in Fig. 9. It can be seen that the OPF dispatch algorithm successfully limits the voltage to 1.09 p.u. during periods of high generation, whilst a voltage rise is seen in the evening as a result of BESSs discharging to meet the allowed SOC trajectory.

**

*Fig. 9 – Voltage (at furthest residence from SSS) vs. time profiles with and without the application of BESSs and the OPF algorithm for a typical summer day at 70% PV penetration.*

An analysis of voltage compliance using EN 50160 standards shows that the regulations allow a PV penetration of 70% without any violation of statute (Table 5), provided that the tap position is adjusted to 1.00 p.u. Both BESS and reconductoring schemes achieve 100% EN 50160 compliance in all scenarios.

|  |  |  |
| --- | --- | --- |
|  | 1.00 Tap | 1.05 Tap |
| 90 BESS | o | O |
| 70 BESS | o | O |
| 50 BESS | o | O |
| 90 BAU | x | X |
| 70 BAU | o | X |
| 50 BAU | o | X |
| 90 Recon. | o | O |
| 70 Recon. | o | O |
| 50 Recon. | o | O |

*Table 5 – Shows whether 100 % EN 50160 compliance is achieved across all simulations within each scenario, where ‘o’ denotes 100% control, and ‘x’ denotes <100% control.*

Utilisation was below the feeder head ampacity limit for 100% of half-hourly average periods in 100% of simulations for all 50% and 70% penetration scenarios. Infrequent overutilization is seen in both BAU 90% penetration scenarios, and this improves to near 100% control BESS scenarios (Fig. 10).



*Fig. 10 – Shows the number of half hourly periods in which the feeder head is over utilised. Error bars show the upper and lower quartiles of results.*

Whist BESS scenarios always showed lower line losses than BAU scenarios, the addition of storage efficiency losses resulted in higher total losses in BESS scenarios. Total losses were always lowest in reconductoring scenarios. Annual losses across all scenarios are summarised in fig. 11.



*Fig. 11 - Shows average annual circuit losses associated with each BESS scenario circuit losses. Error bars represent 1σ around the mean.*

The overall reinforcement scenario costs for present and future cost schemes (with potential self-consumption benefit reductions indicated) are summarised in Fig. 12. Reconductoring scheme costs are adjusted for their comparatively longer lifetimes than BESS schemes as explained in section 2.4.7.3. Whilst self-consumption benefit recoup may return a significant portion of the capital BESS costs in future cost scenarios, this is still not sufficient to allow BESS systems to compete economically with reconductoring, with the latter typically 9-10 times cheaper than the former. At current BESS costs, self-consumption benefit recoup provides insignificant reduction to BESS costs, with reconductoring typically 30-40 times cheaper over its lifetime than BESS installation. It should be noted that no significant difference between savings were observed when E7 arbitrage control was included alongside self-consumption of generation. This is simply because generation at most sites is great enough to make E7 arbitrage the less economical option for the majority of the year.





*Fig. 12 – (top) Costs of implementing each reinforcement scenario at current costs. The total of the stacked bars represents the capital cost of the scenario, and error bars represent 1σ around the cost adjusted for self-consumption recoup. (bottom) the same information for future costs.*

BESS capital cost showed a large sensitivity to PV placement, with a cost range £0.15M-£0.29M for BESS 1.05 Tap 70% and £0.4m-£0.58m for BESS 1.05 Tap 90%. Furthermore, centralized BESS based control was not able to provide a solution in 48% of BESS 1.05 Tap 90% PV placement cases. It is therefore clear that examining only one renewable technology sizing and placement pattern is insufficient for network impact studies, and it is the statistical distribution of results across multiple placement scenarios that should be considered.

# 4 Discussion

The series of BESS placement, sizing and dispatch heuristics presented have been shown to provide an effective strategy with which to manage the operation of behind-the-meter BESSs such that network operational constraints and requirements are satisfied whilst self-consumption is maximised. It is however clear that, for the test feeder in question, reconductoring provides the more cost effective and compliant solution, even when potential self-consumption benefits are considered.

Misprediction in forecasting and minute ahead control results in less than 100% control of load voltages by ESQCR standards. Because some delay between evaluation of the current grid condition and application of new dispatch commands must exist in coordinated control schemes, it is unlikely that a coordinated BESS scheme could ever guarantee 100% control under current statute, making reconductoring the better option for compliance. However, both the reconductoring and BESS scheme would achieve 100% compliance with a statute change to EN 50160.

The reconductoring cost assumption of £80/m was made based on previous work [32], and it is accepted that this value may vary with the specific nature of the task. However, the results suggest that reconductoring costs would need to increase by at least an order of magnitude to equal BESS costs, before data communication and customer incentive costs are even considered. We also accept that an adjustment in the system lifetime refinement e.g. attempt to coordinate and operate the set of BESSs such that they last for 15 years, may affect results, though there is no way that the overall findings of the study could be altered by this change.

Whilst BESS requirements decrease with change in Tap from 1.05 to 1.00, reconductoring requirements also decrease due to the reduction in potential for voltage violations, though this may not be the case for feeders with topologies that result in a higher susceptibility to utilisation violations than voltage violations. Furthermore, significant load growth on the feeder (e.g. due to increased penetration of electric heating technologies), or the sharing of a SSS with a more heavily loaded feeder may devalue this strategy, as additional BESSs and reconductoring could be required to maintain steady state voltage above the lower limit. We therefore intend to study BESS placement on entire 230 V networks in following studies.

The RIIO-ED1 electricity distribution price control document explains the obligation of DNOs to reduce network losses. Whilst the current mechanism does not provide an exact quantitative value of losses (i.e. in £/MWh), the DNO is required to report on activities conducive to loss reduction in order to be eligible for a losses discretionary reward [56]. The document does not suggest how storage losses may be handled, making the results of this study somewhat ambiguous; BESS schemes reduced line losses but increased total losses in all scenarios, and It is therefore unclear as to whether BESSs may provide an economically beneficial loss reduction service. Regardless, the lowest line and total losses were always achieved in reconductoring schemes.

The notable cost differences between reinforcement methods suggest it is likely that partial reconductoring will offer a more cost effective route to voltage compliance than the BESS equivalent in the vast majority of short urban and suburban LV feeder cases. This is before non-optimal placement, reclamation of customer benefit, and system performance considerations are investigated, and before desired 3rd party profit margins and communications costs are defined – all of which will impact the cost of the BESS system negatively. Whilst additional revenue streams may arise in future (such as the sale of BESSs that are no longer suitable for the violation control scheme), it is unlikely that such revenue could offset the much greater capital cost of coordinated BESS control when compared to reconductoring. Therefore, whilst somewhat simplistic, we believe that the cost analysis is sufficient to show that coordinated BESS control is likely to remain the most expensive solution to violation issues.

Alternative approaches to centralised voltage control schemes may include fixed payments to customers with BESSs on the proviso that the 3rd party/DNO may take control of such BESSs for violation management when required. Such an approach, however, would require a very high incidence of BESSs ownership amongst customers in higher PV penetration scenarios, would still require the installation of expensive monitoring and communications equipment, and would rely on the occurrence of BESSs in the correct locations. However, it is likely that results are sensitive to network topology, and thus following work will examine the BESS and reconductoring costs for multiple topologies using the outlined methodology, with particular focus on longer feeders, and the potential for use of stochastically located customer owned BESSs. This will allow a comparison of costs to topological properties such as load count, load density and total path resistance.

Whilst the current work only considers PV, we aim to expand our modelling to examine the suitability of customer or 3rd party owned BESSs to the control of network violations arising from increasing penetrations of air source heat pump technology.

# Whilst the work examines the cost of centralized BESS control strategies relative to 230 V network reconductoring, there may be potential for this strategy to offer some further savings on reconductoring of the 11 kV network at very high widespread PV penetrations. Whilst this is beyond the scope of current studies, we intend to accrue the required data and examine this effect in future studies.

# 5. Conclusion

The paper presents placement and sizing, forecasting, and dispatch heuristics for behind the meter BESSs such that violations are managed and self-consumption is maximised. The results of the heuristic are analysed from the perspective of a DNO whom pays for and installs BESSs, or pays a 3rd party to purchase, install and operate BESSs. The remaining system costs are compared to reconductoring costs, and it is clear in the case studied that reconductoring is the cheaper option in all modelled scenarios. The results suggest that a similar outcome is likely for most short urban feeder test cases, but it is unclear whether the same results may be obtained for longer feeders that would potentially require more reconductoring. Further work is therefore required to analyse the sensitivity of results to network topology, and to alternative BESS ownership and control models.

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1. BES – Battery Energy Storage, BESS – Battery Energy Storage System, SSS – Secondary Substation [↑](#footnote-ref-1)