Customer-Led Network Revolution

CLNR Trial Analysis

I&C Demand Side Response+ GUS Voltage Control

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Executive Summary

The application of DSR can yield numerous network benefits, such as reduction of the generation margin and improvements to the investment and operational efficiencies of both transmission and distribution systems [1]. In [2], it was demonstrated how DSR can also be used to solve distribution network voltage problems.

This report describes the results of demand side response (DSR) trials carried out with a test group of 6 large industrial and commercial (I & C) customers located throughout the Northern Powergrid region which were called as part of CLNR. The results of a selection of these trials are applied in simulation to the CLNR rural test network at Denwick, and used to draw conclusions of relevance to the UK as a whole.

Previous simulation results have demonstrated the impact of EVs and ASHPs on the voltages in LV networks. In the case-study network evaluated a 15% penetration of EVs and a 45% penetration of ASHPs in a localised LCT cluster, the voltage at the end of the longest feeder is found to drop below the statutory limit on three significant occasions in the course of a day. To mitigate against this a collaborative voltage control strategy incorporating EES and DSR was developed to mitigate the voltage drop. The simulation results demonstrate that EES and DSR can be operated collaboratively to mitigate the voltage drop problem successfully.

Furthermore it can be seen that the use of the two techniques in collaboration offers synergistic benefits beyond the use of a single technique.

1. Results from the trials indicate that in some cases DSR response could be substantially slower than EES (up to 30 minutes). Therefore, for short duration voltage excursions, due to the intermittency of renewables based generation and new LCT based load, the fast response of the EES coupled with DSR could reduce the number of calls and improve the response of the collaborative voltage control system.
2. The energy capacity of the EES required in a collaborative voltage control system is reduced because the DSR system can remove or reduce the need for storage intervention. Given that EES technology is currently expensive and the cost of DSR is lower than the cost of EES, this is a valuable contribution.

It should be noted however that the DSR contracts in CLNR provided DSR services only between 16:00 and 20:00. With the changes in network load and generation due to the anticipated large-scale proliferation of LCT the load (and possible generation) peaks are likely to change from 16:00 to 20:00 and therefore new future contracts will need to be cognisant of these changes.

1 Introduction

In this work, post-trial analysis of the Industrial and commercial (I&C) DSR service trial have been carried in order to evaluate the potential that this service has to provide voltage control. The Validation, Extension, Extrapolation, Enhancement and Generalisation (VEEEG) methodology is adopted to analyse trial results. An introduction to this methodology can be found in the following section. This is followed with an introduction to the I&C DSR profiles from the trials and low carbon technology (LCT) profiles. Detailed information about this I&C DSR can be found in [3]. In this work, LCT includes electric vehicle (EV) and air source heat pump (ASHP). In the following section, post-trial simulations results, including the validation, extension, extrapolation and enhancement studies are detailed. Finally conclusions are drawn.

2 Methodology and Assumptions

2.1 Overview

In order to ensure that the objectives of the CLNR project are met, a programme of systematic evaluation of the results from the network flexibility field trials has been developed. This approach is derived from previous experience of trials and from the outline approach referred to previously. It is required that the results from the trials are firstly used to validate the network and network component models [4]. The results from the trials should then be extended and augmented to ensure that the results are applicable to 80% of the GB distribution network.

The systematic approach proposed by Durham University consists of five steps: -

1. **V**alidation
2. **E**xtension
3. **E**xtrapolation
4. **E**nhancement
5. **G**eneralisation

This methodology is designated as VEEEG (Validation, Extension, Extrapolation, Enhancement, Generalisation) and is illustrated diagrammatically in Figure 1.

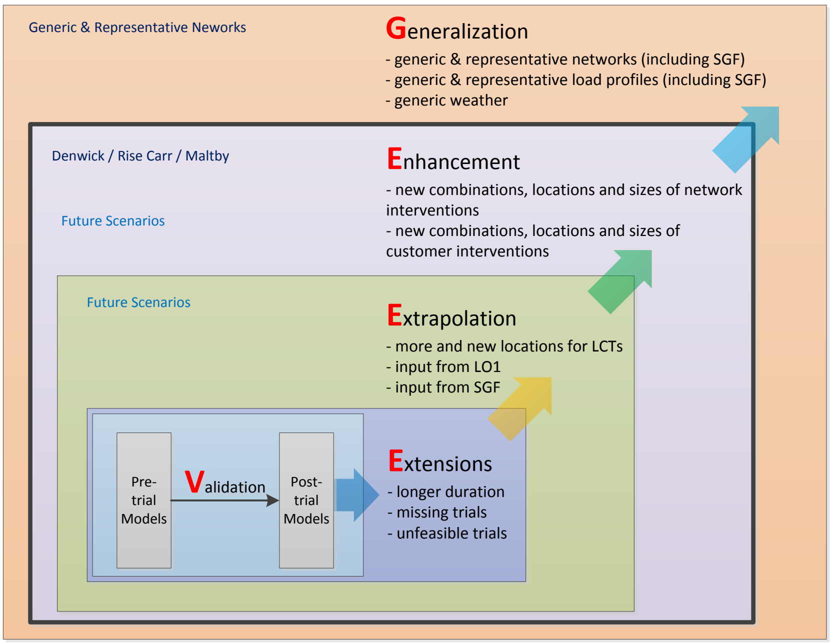

Figure 1 Post-trial methodology VEEEG

For further details of the post-trial analysis methodology please refer to [5].

3 Trial Results and Validation

The application of DSR can yield numerous network benefits, such as reduction of the generation margin and improvements to the investment and operational efficiencies of both transmission and distribution systems [1]. In [2], it was demonstrated how DSR can also be used to solve distribution network voltage problems.

In the CLNR project, I&C customers participated in demand response programmes. These trials are designed to investigate I&C DSR customers' flexibility and response characteristics. Trials were carried out in winter 2012 and in spring 2014.

Three I&C customers participated in the initial series of thirteen DSR trials in winter 2012. 13 DSR instructions were issued across the portfolio, 10 instructions resulted in a successful DSR response giving a reliability of 77% for utilisation.

14 I&C customers participated in the second series of trials in spring 2014. In these DSR trials, 33 DSR instructions were issued across the portfolio, 29 instructions resulted in a successful DSR response giving a reliability of 88% for utilisation. The reasons for the failed events included a diesel generator failure at one of the sites and DSR not being delivered in accordance with the contractual requirements at the other site.

Results from the first DSR trial period are used in this work to demonstrate the capability of DSR to control voltage in collaboration with an advanced voltage control system [6].

3.1 Customer A

Customer A: Web-Hosting

Contracted DSR: 0.8 MW

DSR Type: Diesel Generation

Availability: 3pm – 7pm, Weekdays

Response Time: 20 minutes

Season: February 2012

Figure 2 illustrates the half hourly energy consumption and average power consumption of customer A, during DSR trial A.1. The blue bar represents the half hourly consumption of customer A, obtained from meter readings, and the red trace represents the average real power consumption.

In this trial, the DSR command was issued from the Northern Powergrid control room at 14:50. On receiving the signal, a diesel generator was engaged, to supply power to meet the customer demand. The customer load was thus reduced by over 800kW for four hours. It should be noted however, that there was a delay of approximately 20 minutes before customer consumption was actually reduced.

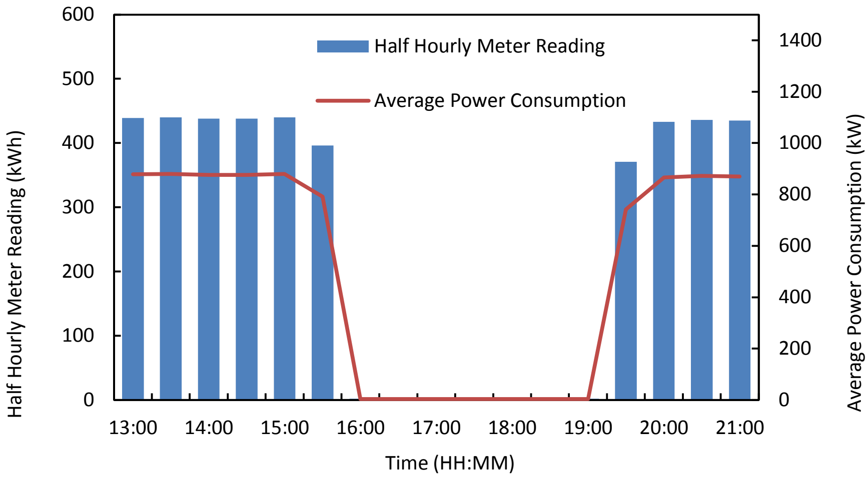

Figure 2. I&C Customer A DSR profile in DSR trial A.1

In trial A.2, the DSR instruction was confirmed before 11:00 and DSR commenced at 15:00. The half hourly meter readings and average power are shown below in Figure 3.

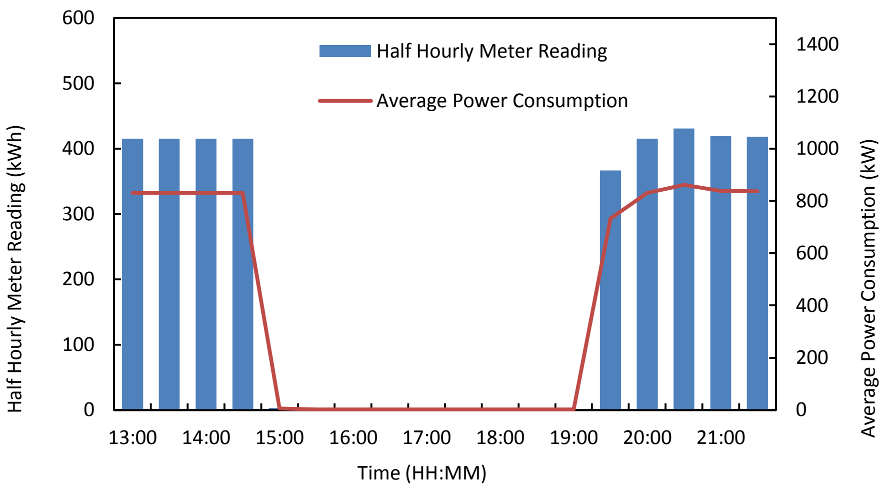

Figure 3. I&C Customer A DSR profile in DSR trial A.2

Comparing Figure 2 and Figure 3 it can be seen that the response of A.1 is much slower than that in A.2. Due to the use of the diesel generator to supply the local load, power consumption was reduced to 2kW within 2 minutes and remained constant. Similarly, when the invoked DSR came to an end, load was restored within a 2 minute period.

3.2 Customer B

Customer B: Refrigeration

Contracted DSR: 0.75 MW

DSR Type: Load Reduction

Availability: 3pm – 7pm, Weekdays

Response Time: 20 minutes

Season: January – February 2012

The load of Customer B consists primarily of refrigeration. In contrast to customer A, the load was varied by reducing consumption as opposed to engaging on site backup generation. A DSR profile, for this customer, (DSR trial B.1) is illustrated in Figure 4 DSR commenced at 15:00 and lasted until 19:00. During this period, the half hourly energy consumption of customer B was reduced from 1200kWh to approximately 600 kWh.

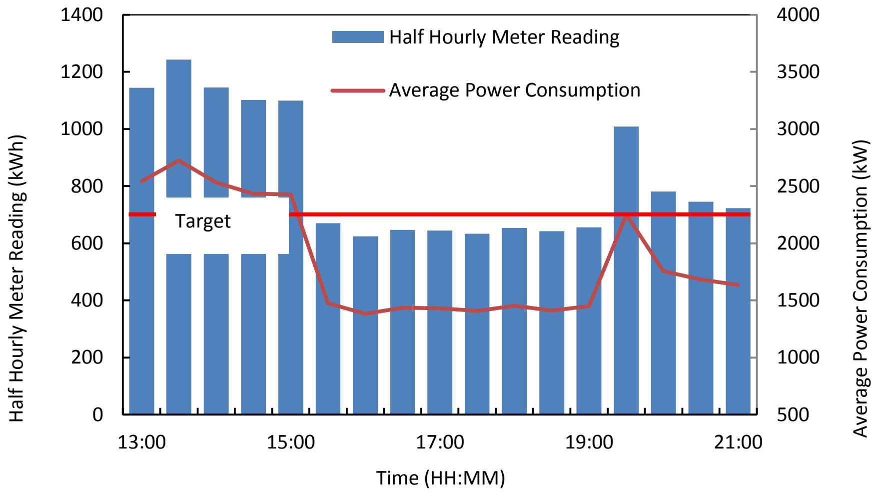

Figure 4. I&C Customer B DSR profile in DSR trial B.1

As mentioned previously, not all trials resulted in a successful response from the customers. Reasons for unsuccessful DSR include; failure to respond, or an inability to reduce enough load to meet the target half hourly energy consumption. For example, in one trial, the diesel generator used on the site of customer A experienced failure and therefore the site was unable to respond.

The half hourly energy consumption and average power curves from trial B.2 are given in Figure 5. The DSR command was confirmed before 11:00 and DSR started at 15:00. It can be seen that the half hourly energy consumption started to decrease and dropped from 1195.9kWh at 15:00 to 950.2kWh at 15:30. However the reduction was smaller than the agreed target and therefore the DSR was deemed to be unsuccessful. The load on the site did not drop below the target until 17:30, at which point the DSR was considered to be successful.

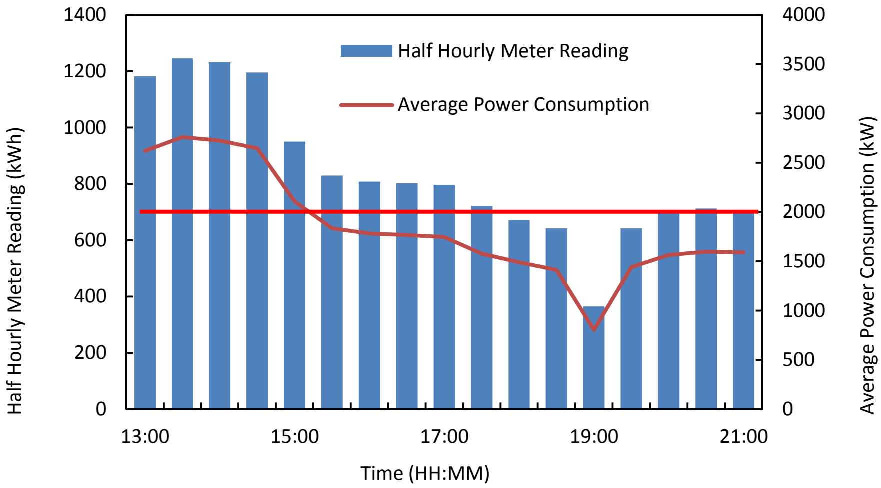

Figure 5. I&C Customer B DSR profile in DSR trial B.2

3.3 Electrical Energy Storage to enable I&C DSR

Energy storage and DSR have been used together for optimising network capacity [7] and cost reductions [8] previously. In this work, the two techniques are used collaboratively for voltage control purposes as it has been shown that the response of the I&C DSR can be 30 minutes or more to respond.

The ramp rate of the EES systems that are to be deployed is 20ms from zero to maximum power export [4]. In contrast, as seen in the previous section, the I&C DSR can react within two minutes and provide a response for a number of hours. This response is however conditional upon pre-arrangement of the necessary DSR. The fast response capability of the EES systems means that they are able to react in a far shorter timescale than even the fastest of the DSR facilities available. However a limitation of EES, relative to the DSR service, is that its capability to export real power is for a limited duration, dependent on the discharge current, initial state-of-charge (SOC) and the energy capacity of the battery bank. In contrast, where the local consumption during DSR is provided by a distributed generator, a diesel generator in this case, the duration of the DSR service can be as long as is required by the supervisory control system, albeit with an accompanying cost. It can also be seen also that DSR response is not guaranteed, (only nine of the thirteen DSR trials resulted in a response from the customers) and delays in the response are common. Moreover, when DSR relies on a thermal store e.g. refrigeration it is subject to some of the same limitations as EES e.g. limited time duration.

4 Post-trial analysis – Extension, Enhancement, Extrapolation and Generalization

4.1 Introduction

In the following sections, the results from an initial application of the VEEEG methodology, using a combination of a model of a distribution network voltage control system and the Denwick HV network.

4.1.1 Case Study Network

The Denwick EHV/HV network has been used in collaboration with the Wooler St Mary's HV/LV and the model of an electrical energy storage system to complete this study. The Denwick network in Northumberland, England, operated by Northern Powergrid has been selected as the case study network. Figure 6 shows the schematic diagram and the smart grid technologies which are to be installed.

As can be seen in Figure 6, a mechanically switched capacitor bank and two in-line regulators are already deployed on this system for voltage control purposes and at present, operate according to the standard DNO voltage control practice. The modelled network has two DSR customers A and B, and an LCT cluster added to it, plus associated EES systems located towards the remote end of one of the 20kV feeders. The apparent power rating and the capacity of the energy storage systems, are 100kVA and 200kWh, respectively (EES2). The Wooler St Mary's LV system has been modelled to be an LCT cluster and has 230 customers, and the penetration of EV and ASHP ownership is higher than in the remaining network.

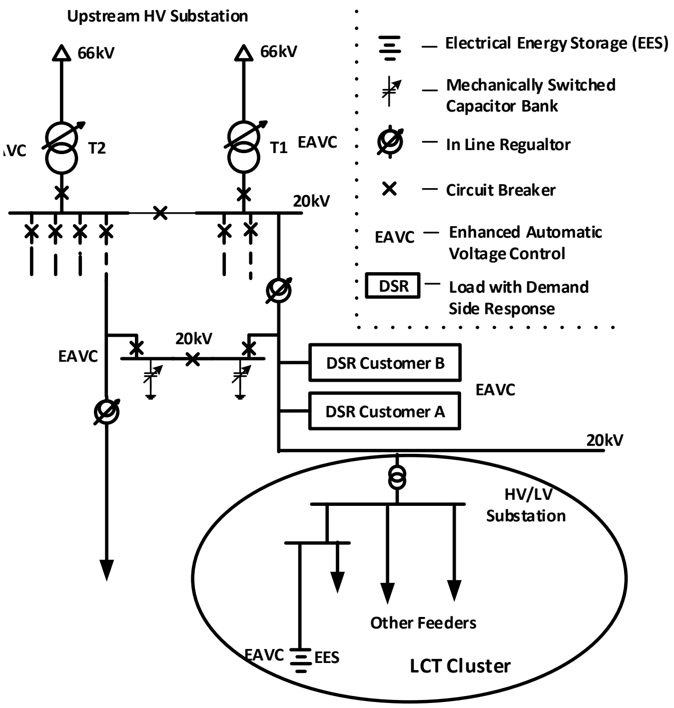

Figure 6. Schematic diagram of the 20kV case-study network based on Denwick EHV/HV system [6]

The demand profile of this distribution network, measured by the SCADA system, is illustrated in Fig. 7. The blue trace indicates the typical load profile during a winter day, when the highest load was recorded, in the period from December 2010 to January 2012 [6]. The peak demand which occurs between 02:00 and 03:00 is due to electrical storage heating and the high uptake of the economy seven tariff. The additional peak between 14:00 and 16:00 is the result of a Super Tariff in this area which gives a lower electricity price for six hours overnight and two hours in the afternoon.

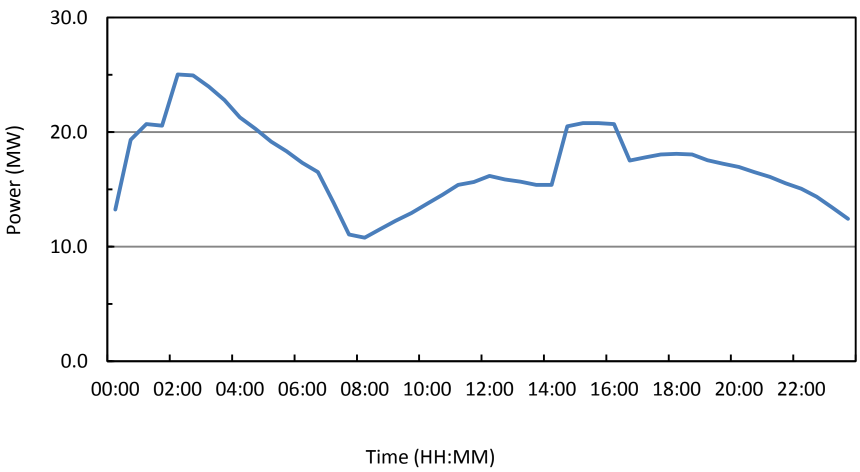

Fig. 7. Load profile in the case-study network.

4.1.2 Modelling Methodology

A network model has been developed using IPSA2. The model is based on detailed network data supplied by Northern Powergrid. The longest branch of the longest LV feeder has been modelled in detail, due to the likelihood of voltage problems occurring. The loading on Branch 2 of this feeder and the remaining LV feeders are represented by lumped loads.

EES has been modelled in this system such that it can import/export real and/or reactive power in any combination within ratings. The EES unit modelled in this work has twice the apparent power rating and energy capacity of the EES3 unit which has been deployed in CLNR (100kVA and 200kWh). This enhancement was necessary as the EES unit from the trials did not produce meaningful results to collaborate with the DSR services considered in this work. DSR is modelled as a controllable load. The EES model and DSR model capabilities are extended using Python 2.7, which has been adopted as a scripting language in IPSA2, to automate control of the network model and the load flow engine.

4.1.3 Model Validation

The network model has been validated against results from the iHost system deployed as part of CLNR [9, 10]. The busbar voltages and feeder currents calculated in both models have been found in good agreement.

The network model has also been validated using measured data from both the HV/LV and primary substation sites. Real load data have been used in the IPSA2 network model. Load flow calculations have been carried out and the results were compared to the measured data. The model was found to be able to predict LV voltages to within 1% accuracy.

4.1.4 Electric Vehicle Model Development

The EV charging model is derived from the CLNR customer trials data presented in *Dataset (TC6): Enhanced Profiling of Electric Vehicles (EV) Users on a Flat Rate Tariff* [11]. The mean of this worst case month (January 2013) is used to represent EV charging in this work. This EV charging profile is shown in Fig. 8.

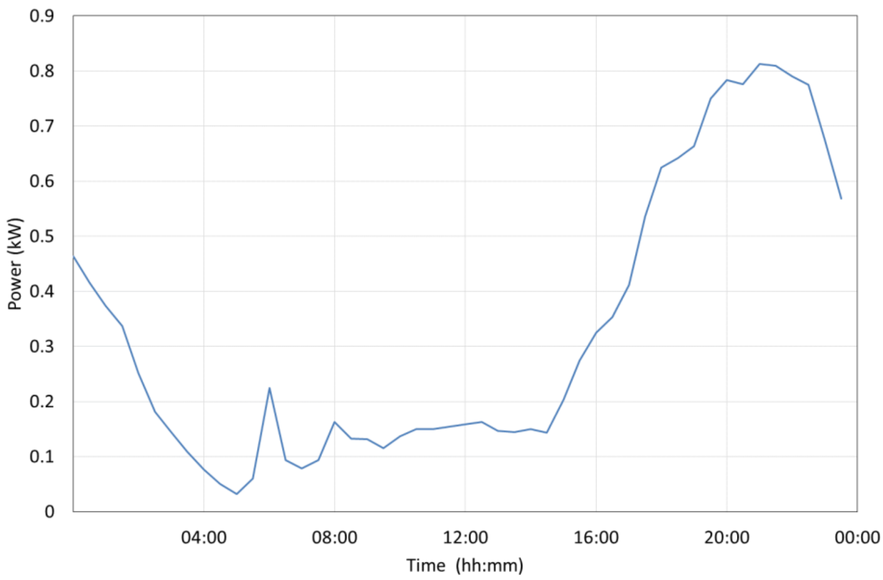

Fig. 8 Median EV charge curve during January 2013

4.1.5 Air Source Heat Pump Model Development

Work has been previously carried out in order to derive thermal profiles for typical UK building stock. Generic building data was used as an input to the models in combination with temperature data from a site in the UK.

Multiple occupancy scenarios for each considered building type (detached, semi-detached, flat, mid-terrace) are derived and aggregated in order to generate the final thermal profile [6, 12]. The results were found to agree favourably with UK national statistics.

In order to generate the electrical profile of the air-source heat pump (ASHP), the thermal profiles for the required building types have been scaled according to the methodology outlined in [6, 13]. The methodology requires that the thermal profile be scaled down by the coefficient of performance (COP) of the ASHP. A value of 3 has been chosen for the ASHP system under consideration in line with previous work [6, 13]. The derived electrical demand profiles of detached and semi-detached properties are given in 9

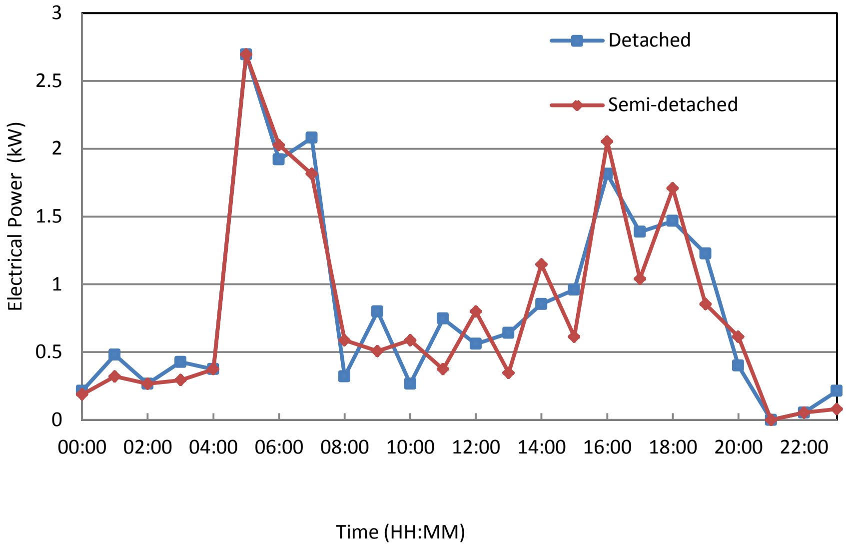

Figure 9. Derived electrical demand for detached and semi-detached properties.

To derive the ASHP electrical demand profiles for this work, detached and semi-detached properties have been used, in a ratio of 9:1 respectively. This is in accordance with previous simulations of rural networks [13]. 10 shows the total demand curve due to the ASHP load, with an assumed penetration of 45%. This does not violate the thermal rating of the Wooler St Mary HV/LV substation which is considered in this study.

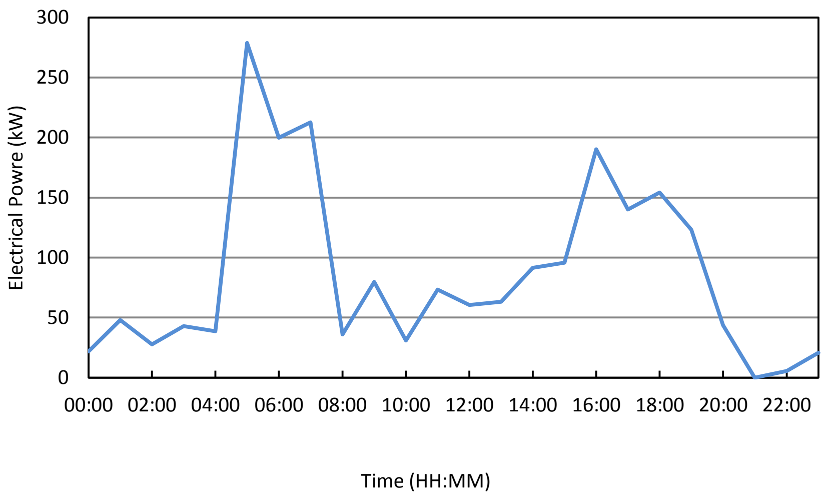

Figure 10. Aggregated ASHP electrical demand curve in the LCT cluster

4.2 Extrapolation

Using the model described previously, a steady-state study was carried out to evaluate the impact of large penetrations of LCTs, specifically ASHPs and EVs on remote end LV voltages.

The remote end of the longest LV feeder has been previously found to represent the worst case in terms of voltage variation in balanced and evenly distributed LV networks [14].

To enable this investigation, a number of load flow calculations were carried out with scenarios of increasing penetrations of ASHPs and EVs. According to Northern Powergrid data, there are over 15,000 customers on the Heckley High House and Heckley Switched Tee feeders emanating from Denwick EHV/HV substation. It is assumed that these customers take time-of-use price into consideration, which means they would tend to charge their EVs overnight. This study also assumed that in the LCT cluster, the penetration of customers owning an EV is 15% and 45% of customers have installed an ASHP. For all other customers in this area, the percentages of EV and HP owners are assumed to be 5% respectively.

Based on these assumptions and the aggregated models of EVs and ASHPs described earlier, the predicted load curves are illustrated in 11. The voltage profile under the predicted load is plotted in Fig. 12. This analysis assumes that all new ASHP customers are existing gas customers. It does not consider the effect of storage heater customers switching to ASHP based electric heating.

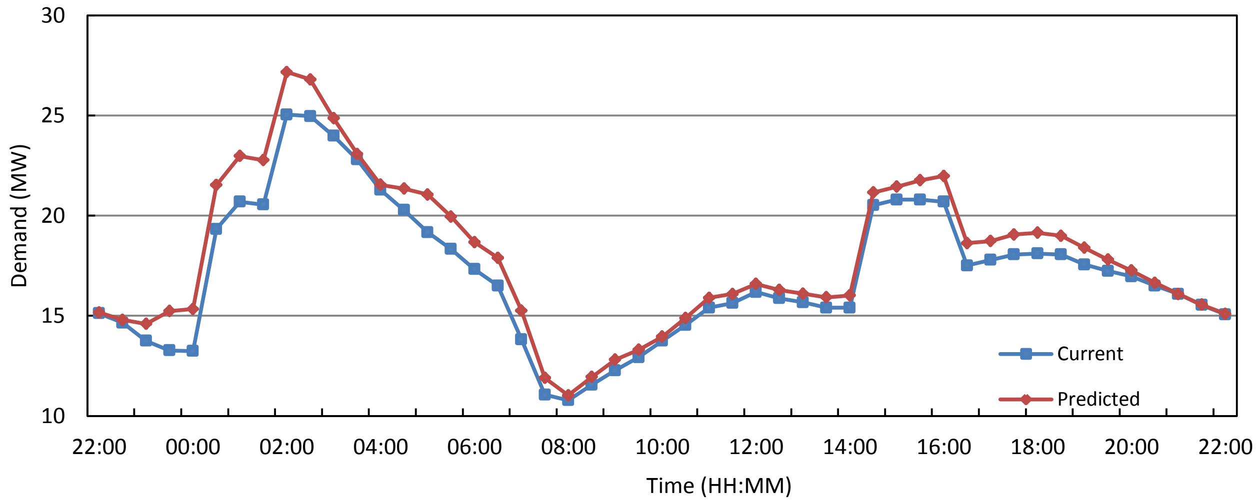

Figure 11. Current and predicted demand profile.

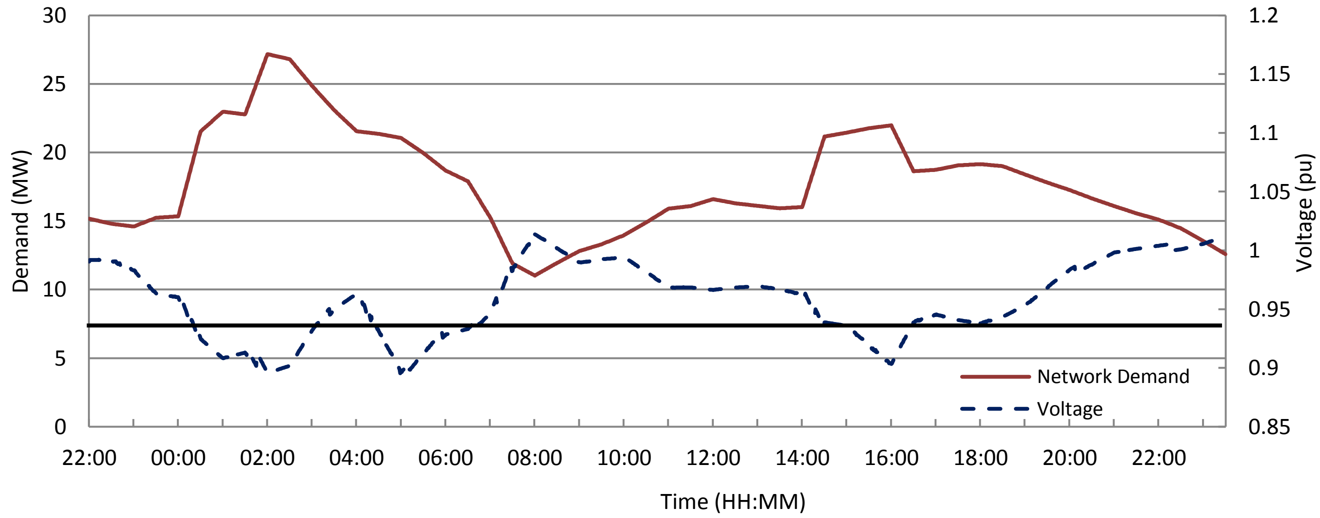

Figure 12. Voltage profile in 24 hours

Simulation results indicate that, with the higher penetrations of LCTs, detailed earlier, in the modelled LV network, and a 5% penetration of both EVs and ASHPs across the whole network, the voltage at the remote end of the longest LV feeder will drop below the statutory limit (0.94pu in the UK). This will occur during the night-time peak period, early morning and afternoon peak time. The voltage is lower than 0.94pu from 00:00 to 03:00 due to charging of EVs. The large power consumption of ASHPs in the early morning will result in a voltage drop between 04:00 and 07:00. From 14:00 to 16:00, another peak can be observed due to the additional ASHP consumption in combination with the present network peak.

In order to mitigate the violation of steady-state voltage limits caused by the increased penetration of LCTs, the collaborative control system will instruct the EES to operate first and export real power into the LV network to increase the voltage at the remote end. There is no reactive power output from EES because this network has a low X/R ratio and the impact of reactive power on voltage control is limited. The collaborative voltage control scheme will simultaneously call DSR.

Since the EES has a limited resource, a possible scenario arises such that if the voltage problem cannot be solved with the available capacity of the EES, the under voltage problem would remain. If DSR is available at the occurrence of the under voltage, the collaborative control scheme will therefore call this response in order to provide security to the operation of the EES. When operation of the DSR is confirmed and the steady-state voltage is within limits, the collaborative voltage control system will instruct the EES to reduce real power export and thus conserve its limited resource.

Due to the previously explained penetrations of EVs and ASHPs three separate under voltage incidents occur on the network under study.

4.2.1 Under Voltage Due to Night Peak

In this case, collaborative voltage control is carried out using EES and DSR customer B. Customer B is called due to its 24 hour operation.

The simulation results illustrating the operation of the EES and DSR customer B to control voltage during the mid-night peak period are shown below in Figure 1213and Figure 1314. In Figure 12, the voltage profile between 23:30 to 04:00 is plotted. It can be seen that the voltage dropped below the 0.94pu limit, at approximately 00:15 in the morning. The EES then injected 10kW of real power into the grid to bring the voltage back above the limit and, at the same time, the DSR command was issued. After 20 minutes, the consumption of DSR customer B started to reduce but did not reach a stable level until 01:00. At this time, installed monitoring equipment showed that the voltage of the network was close to the statutory limit therefore the collaborative voltage control scheme decided to maintain the output of the EES, in order to prevent a further voltage problem. However, around 45 minutes later, when the voltage again went below the limit, the EES started to inject more power into the network to maintain the voltage above limit.

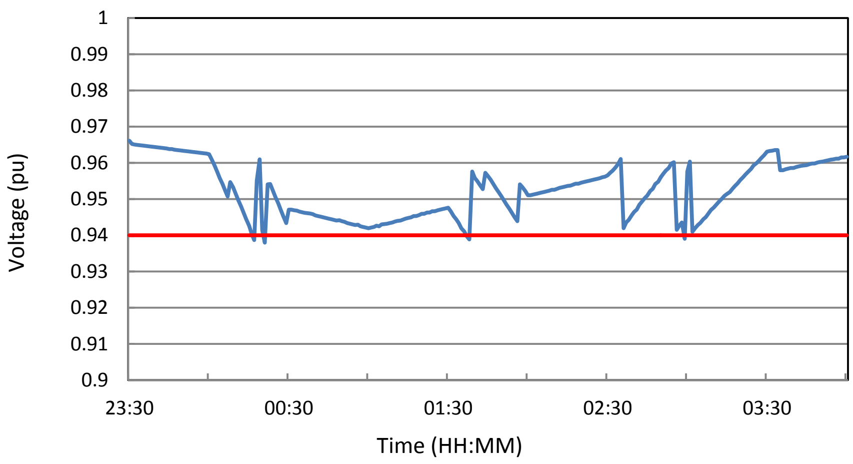

Figure 12. Voltage profile with DSR customer B and EES during the night peak period.

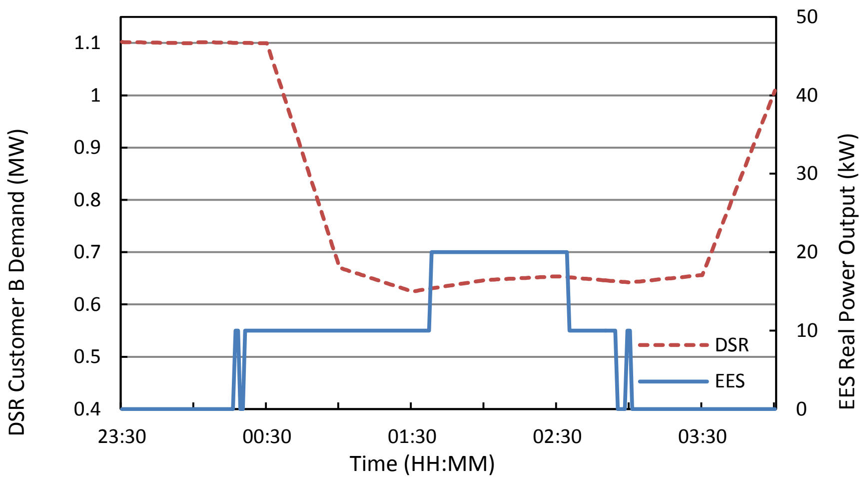

Figure 13. DSR customer B demand and real power output of EES.

4.2.2 Under Voltage Due to Morning Peak

During the early morning peak period, a voltage problem was fixed purely by the EES. A DSR operation was not called in consideration from Customer B as the number of DSR operations available in a day is limited for this customer. Customer A was unavailable as the voltage problem occurred in the early morning. This customer is assumed to operate a typical 09:00 to 17:00 working day and is not preferred to provide a DSR outside these hours. This case also helps to illustrate the potential unavailability of DSR as well as customer flexibility (the non-calling of customer A).

The voltage profile between 04:00 and 07:00 is plotted in Figure 14. Real power output of the EES will increase in steps when an under voltage problem occurs and will decrease in steps when the voltage goes up to 0.96pu to reserve available capacity.

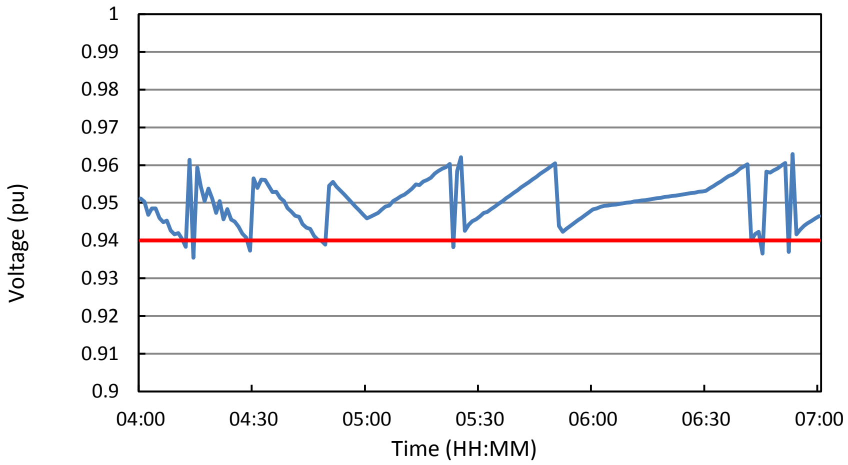

Figure 14. Voltage profile at the end of the feeder with EES control only during the morning peak period.

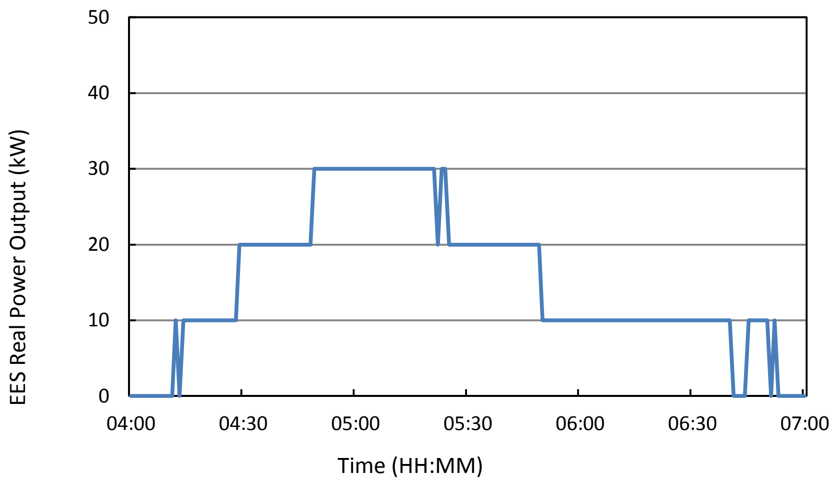

Figure 15. EES real power output during the morning peak period.

4.3 Generalisation

Using the validated networks from the CLNR project it is possible to define some metrics which characterise the impact of distributed new load or generation on the networks. This is similar to previous work which uses the concept of “apparent impedance” to evaluate the capability of networks to accept distributed small-scale embedded generation.

Previously voltage sensitivity factor has been defined to describe the sensitivities of network voltages to the real power P and reactive power Q injections, which can be analyzed through the use of the Jacobian Matrix [15], as shown in (1) :

$$\begin{bmatrix} \Delta\boldsymbol{\theta} \\ \Delta\mathbf{V} \end{bmatrix} = J^{-1} \begin{bmatrix} \Delta\mathbf{P} \\ \Delta\mathbf{Q} \end{bmatrix} = \begin{bmatrix} \frac{\partial\boldsymbol{\theta}}{\partial\mathbf{P}} & \frac{\partial\boldsymbol{\theta}}{\partial\mathbf{Q}} \\ \frac{\partial\mathbf{V}}{\partial\mathbf{P}} & \frac{\partial\mathbf{V}}{\partial\mathbf{Q}} \end{bmatrix} \times \begin{bmatrix} \Delta\mathbf{P} \\ \Delta\mathbf{Q} \end{bmatrix} \tag{1}$$

Voltage sensitivity factors relate the change in voltage at a network node due to a change in real or reactive power at a particular load or generation node elsewhere in the network.

Voltage sensitivity factors relate the change in voltage at a network node due to the import or export of real or reactive power at a particular load or generation node elsewhere in the network (in this study at the remote end). In this section, all the voltage sensitive factors (VSF) of the trialled network DSR locations are listed in **Table 1**. To illustrate the meaning of these metrics for if the VSF P (V/MVAr) is 9.0 for each MW injected at the node location of Hedgeley Moor Capacitor Bank (Heckley High House Feeder) the voltage at the remote end of the Wooler St Marys network, and the downstream LV network, will increase by 9.0V.

Table 1 VSFs for DSR locations on the Denwick HV system

Import/Export Node	VSF Q (%/MVAr)	VSF Q (V/MVAr)
Hedgeley Moor Capacitor Bank (Heckley High House Feeder)	2.2%	9.0
DSR Customer A	1.8%	7.1
DSR Customer B	1.9%	7.6

It can be seen therefore that the additional headroom created by a real power source can be easily estimated if these metrics are available.

Similarly, using the validated networks from the CLNR project it is possible to define some metrics which characterise the impact of distributed new load or generation on the networks. This is similar to previous work which uses the concept of “apparent impedance” to evaluate the capability of networks to accept distributed small-scale embedded generation.

In this work they have been extended and are defined as distributed voltage sensitivity factors (DVSF). A DVSF describes the change in voltage at a node (usually at the remote end where the greatest voltage variation is observed) due to a defined change in real or reactive power at a number of related nodes (e.g. all the customers downstream of an LV substation).

Table 2 DVSFs and % voltage increase at remote end due to evenly distributed penetrations of load LCT on CLNR rural networks

HV Cluster	DVSF (%/kW)	DVSF (Normalised)	10% 3kW	30% 3kW	50% 3kW
EV/ASHP					
Hedgeley Moor Capacitor (Heckley North SW Feeder)	0.64	1.11	0.2%	0.6%	1.0%
Hepburn Bell Regulator	0.59	1.01	0.2%	0.5%	0.9%
Glanton Regulator	6.93	11.95	2.1%	6.2%	10.4%
Hedgeley Moor Capacitor (Heckley High House Feeder)	5.96	10.29	1.8%	5.4%	8.9%

The DVSF therefore can be used to roughly evaluate the impact on remote end voltage of additional distributed generation or load. For example the DVSF would predict that assuming a voltage legroom of 1% it would be possible to connect a 50% penetration of EVs assuming a 3kW peak installation per customer.

Discussion and conclusions

Previous simulation results have demonstrated the impact of EVs and ASHPs on the voltages in LV networks. In the case-study network evaluated a 15% penetration of EVs and a 45% penetration of ASHPs in a localised LCT cluster, the voltage at the end of the longest feeder is found to drop below the statutory limit on three significant occasions in the course of a day. To mitigate against this collaborative voltage control strategy incorporating EES and DSR was used to mitigate the voltage drop. The simulation results demonstrate that EES and DSR can be operated collaboratively to mitigate the voltage drop problem successfully.

Furthermore it can be seen that the use of the two techniques in collaboration offers synergistic benefits beyond the use of a single technique: -

1. Results from the trials indicate that in some cases DSR response could be substantially slower than EES (up to 30 minutes). Therefore, for short duration voltage excursions, due to the intermittency of renewables based generation and new LCT based load, the fast response of the EES coupled with DSR could reduce the number of calls and improve the response of the collaborative voltage control system.
2. The energy capacity of the EES required in a collaborative voltage control system is reduced because the DSR system can remove or reduce the need for storage intervention. Given that EES technology is currently expensive and the cost of DSR is lower than the cost of EES, this is a valuable contribution.

It should be noted however that the DSR contracts in CLNR provided DSR services only between 16:00 and 20:00. With the changes in network load and generation due to the anticipated large-scale proliferation of LCT the load (and possible generation) peaks are likely to change from 16:00 to 20:00 and therefore new future contracts will need to be cognisant of these changes.

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