Validation of Photovoltaic (PV) Connection Assessment Tool

Closedown Report

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ukpowernetworks.co.uk

Foreword

Both the last and the current coalition governments have set binding targets in law for the UK to reduce its contribution to carbon emissions, and UK Power Networks knows that it will play a leading role in enabling this low-carbon transition. The renewable and low-carbon technologies needed to meet these targets will pose significant challenges on distribution networks and the wider electricity system.

The UK's Feed-in Tariff scheme challenged DNOs to assess unprecedented volumes of PV connection applications. In response, we developed new tools, procedures, and design assumptions; and initiated a LCNF Tier 1 project to validate that they are fair to customers, minimise the risk of adverse impacts on our network, and incorporate the best practices, knowledge, and solutions available in GB.

This report details the methods, outcomes, and learning from our LCNF Tier 1 project: "Validation of Photovoltaic (PV) Connection Assessment Tool".

I trust the following report will be of use to the DNO community, and will progress the UK knowledge base on PV generation.

Martin Wilcox

Head of Future Networks

Contents

Glossary

ADMD	After-diversity maximum demand
AVC	Automatic voltage control
BAU	Business as usual
DCC	(Smart Metering) Data and Communications Company
DG	Distributed Generation
DNO	Distribution Network Operator
ENA	Energy Networks Association
Endpoint	A location or premises towards the end of an LV feeder where monitoring equipment is installed
EPN	Eastern Power Networks (One of UK Power Networks' licence areas)
FiT	Feed-in Tariff (scheme)
G83 / G59	The ENA standards for embedded generators
GB	Great Britain
GSoPs	Guaranteed Standards of Performance
Headroom	Capacity available for connection of new PV generation
HV	High voltage
LCNF	Low Carbon Networks Fund

LV	Low voltage
LPN	London Power Networks (One of UK Power Networks' licence areas)
LRE	Load-related expenditure
MPAN	Meter Point Administration Number
OLTC	On-load tap changer
PME	Protective multiple earthing (systems)
Power-Factory	A commercially available power systems modelling/analysis package that was used in this project
PV	Photovoltaic
PV Penetration	A measure of how much PV generation is installed on a part of the network.
RTU	Remote terminal unit
SPN	South Eastern Power Networks (One of UK Power Networks' licence areas)
SSEG	Small-scale embedded generation
STATCOM	Static synchronous compensator
THD	Total harmonic distortion

1. EXECUTIVE SUMMARY

1.1 Background

On 1 April 2010, the UK introduced a Feed-in Tariff (FiT) scheme to encourage low-carbon electricity generation using small-scale (≤5MW) systems.

The uptake of small-scale PV installations was rapid. Tariff reviews in 2011 and 2012 moderated the uptake, but caused short-term spikes in applications as installers rushed to commission systems before the reduced tariffs came into effect.

As a result, DNOs were presented with influxes of:

- Notifications of G83 single-premises connections (single systems rated ≤3.68kW/phase), which can be connected without DNOs' prior permission,
- Applications for G83 multiple-premises connections (multiple systems rated ≤3.68kW/phase), and
- Applications for G59 connections (any system rated >3.68kW/phase).

For G83 multiple-premises and G59 applications, DNOs must assess the proposed installation's impacts on the network, and if necessary, design a network reinforcement scheme before making a connection offer.

The volumes of PV connection notifications and applications in 2011 and 2012 were unprecedented. To process them within the periods prescribed in the guaranteed standards, UK Power Networks had to develop new tools, procedures, and design assumptions, despite having had limited experience and understanding of PV's impact on the LV network.

UK Power Networks' business plan expects that 371,000 FiT-eligible PV installations will be connected to its networks by 2023, representing a continued growth from today's penetration levels. In context, this means that 1 in 10 customers will neighbour a PV installation, which will increase their risk of experiencing voltage rise.

UK Power Networks hence initiated this project to ensure that its PV connection assessment tools, procedures, and design assumptions are fair to customers, minimise the risk of adverse impacts on the network, and incorporate the best practices, knowledge, and solutions available in GB.

1.2 Scope and objectives

The project comprised six main activities:

Activity	Scope and objectives
Trial Design	**Collected real-life data needed to inform the trial methods**, by deploying monitoring equipment to **20 distribution substations and 10 customers' PV installations**.
Trial Method 1: Validate the PV connection assessment tool	**Ensured that UK Power Networks' spreadsheet-based connection assessment tools were fit for purpose**, by comparing them to PowerFactory models and real-life measurements.
Trial Method 2: Validate assumptions in UK Power Networks' PV connection assessment policies	**Validated existing and recommended new design assumptions** by analysing real-life data, and **documented them in a formal design procedure.**
Trial Method 3: Understand the impacts of PV generation on LV distribution networks	Analysed real-life data to **understand how PV generators behave**, and **which issues need the most consideration** in a connection assessment procedure.
Trial Method 4: Understand solutions available to address network constraints	Conducted a desktop review of available solutions to **inform the DNO community of which are the best solutions to trial or adopt** in likely constraint scenarios.
Trial Method 5: Understand how information available to PV installers could be used by DNOs	**Obtained data that PV installers had collected from their PV generators**, and determined if it could **reduce DNOs' need to deploy LV network monitoring schemes**.

1.3 Expected benefits

The project is expected to deliver the following benefits, which will become increasingly important as the uptake of small-scale PV generation continues:

Reduced processing time for PV connection applications, resulting in:

- Improved customer satisfaction; and
- Reduced processing costs.

More-accurate assessments of PV generators' impact on the network, resulting in:

- Customers able to connect more PV without having to pay for network reinforcement;
- Customers less likely to be impacted by voltage issues; and
- DNOs spending less on resolving voltage complaints.

Cheaper and more-effective alternatives to traditional network reinforcement, resulting in:

- DNOs able resolve voltage complaints more cheaply and quickly; and
- New PV schemes that would traditionally require network reinforcement are more likely to be feasible.

1.4 Outcomes

The project delivered the following outcomes:

- **A validated and pragmatic connection assessment approach**, comprising a formal design procedure and an improved tool, that UK Power Networks will adopt into business as usual and share with other GB DNOs during 2015:
    - The formal design procedure includes recommended design assumptions, based on real-life data.
    - The improved tool calculates voltage rise in three steps: the first step provides a worst-case result using minimal inputs, and if required, subsequent steps provide more-accurate results, using more-detailed inputs.
- **A rich dataset, available for GB DNOs and academic institutions to use**, comprising:
    - Measurements from 20 distribution substations and 10 customers' PV installations;
    - 25,775 days of valid data, spanning 16 months;
    - Over 171 million individual observations; and
    - Nearly three months of high-resolution (one-minute) measurements over summer 2014.
- **A review of voltage control solutions** that could be trialled or adopted in GB, including recommendations of which solutions best suit likely constraint scenarios.

1.5 Key Learning

1.5.1 Key learning about PV generators' behaviour and impacts on the LV network

- Overall, less than 1% of EPN/SPN substations with any PV attached to them have more than 50kW attached. This indicates that in the short term, UK Power Networks is unlikely to experience the same issues currently facing network operators in countries that have much higher PV penetrations.
- The six endpoint sites were amongst the most heavily PV-penetrated locations in EPN and SPN, yet PV did not cause any voltages to exceed statutory limits. This indicates that in general, the EPN and SPN networks are performing well with current PV penetration levels, and most LV feeders will continue to perform well in a low-carbon future, where more renewable energy is connected.
- However, voltages at some sites were approaching statutory limits. This indicates that as the uptake of PV generation continues, new voltage control solutions will be needed to mitigate issues in areas of unusually high PV penetration.
- PV generation caused measureable voltage rise along LV feeders. However, this had relatively little influence on endpoint voltages, which depended mainly on voltage regulation on the HV network and distribution transformer.
- Small-scale PV generation did not cause any increase in harmonics or phase voltage imbalance on LV feeders.
- Variations in panel orientation do not necessarily create diversity in the output of PV clusters, if they include undersized inverters.
- Many PV generators are capable of generating 100% of nameplate rating, and exporting at >94% of nameplate rating, and hence should not be de-rated for planning purposes.
- PV generators can potentially achieve higher peak output on cloudy days than on clear sunny days, due to temperature's effect on efficiency.
- Nameplate ratings are often recorded incorrectly on G83 notification forms.

1.5.2 **Recommended design assumptions for PV connection assessments**

- The project found that the accuracy of any voltage rise calculation is limited by the accuracy of its inputs, some of which are difficult or impracticable to determine accurately (i.e. phase imbalance, substation busbar voltage, and details of existing generators), requiring conservative assumptions or site measurements to assure confidence in the results. Smart meter data, when available, may help address these issues.
- The project validated assumptions in UK Power Networks' existing connection assessment procedure, and recommended several new design assumptions to include in an updated procedure:
    - PV generators do not increase the risk of unacceptable harmonic voltages or currents on LV feeders;
    - Substation busbar voltage = 248V;
    - Minimum demand = 0W (<10 customers); 200W per customer (≥10 customers); up to 400W per customer (≥10 customers and high-energy-use demographic);
    - Phase imbalance of existing 1ph PV = 25% (urban); 50% (rural); all on same phase (<10 customers); and
    - Not all PV installations are registered – check for unregistered installations using public-domain aerial photography.

1.5.3 **Main Lessons learnt for future projects**

- UK Power Networks now better understands the challenges of DNOs recruiting trial participants directly, such as data protection, incentive payments, low response rates, complex stakeholder relationships, and rarity of suitable customer premises.
- When deploying LV network monitoring schemes in future innovation projects, DNOs need to consider issues such as availability of field staff, reliability of mobile communications, equipment failure, and data archiving.
- G83 notifications are not accurate, and DNOs need access to better information about the existing PV generation connected to their networks.

1.6 Recommended areas for future work

UK Power Networks has identified a need to conduct further work in the following areas:

- Improving the quality of information used in PV connection assessments, including:
    - The locations, ratings, and phase imbalance of existing PV generators;
    - Substation busbar voltages;
- Trials of alternative, probabilistic, risk-based methods to estimate PV/DG headroom on feeders; and
- Trial and adoption of smart voltage control solutions.

2. PROJECT OVERVIEW

The following sections describe the project as per the registration pro-forma dated 18 January 2012.

2.1 Project background

Small-scale renewables such as PV panels are usually connected to the low-voltage network without a DNO's prior consent in accordance with Engineering Recommendation G83 (single-premises), and had not so far been considered to be a significant problem. UK Power Networks had been assessing requests for large numbers of PV connections in relatively small geographical areas (G83 multiple-premises). In response, UK Power Networks developed a draft policy to provide guidelines for planners when more-intensive studies were required, but this policy necessarily had to make some simplifying assumptions.

The project aimed to carry out the following:

- Validate the assumptions within UK Power Networks' draft guidelines and develop an approved policy.
- Gain a detailed understanding of the impact of PV on the LV network by monitoring several PV clusters (G83 single-premises and multiple-premises) and covering different types of LV network (suburban and rural). This was achieved by equipping 20 secondary substations and 10 PV installations with LV network monitoring equipment. The monitoring included networks without PV connections to create a clear baseline and develop a better understanding of the differences in voltage profiles and power flows. The trial was planned to run for 24 months to capture seasonal variations.
- Assess to what extent the information available to PV installers (e.g. monitoring of PV output) could be used by DNOs.
- Investigate what innovative solutions could be applied to address network constraints. It was expected that the networks selected for this project would be used as trial areas for the solutions being identified.

2.2 Scope and objectives

The project monitored networks with PV clusters in the Eastern and South Eastern licence areas of UK Power Networks. Sites were selected based on the number of photovoltaic connections. The objectives were to:

- Validate UK Power Networks' guidelines for assessing PV connection requests and develop a formal policy.
- Develop a better understanding of the impact (including weather-related behaviour) that PV clusters have on the LV network by monitoring 20 secondary substations and 10 PV connection points.
- Understand how information available to PV installers could be used by DNOs.
- Gain a better understanding of the solutions available to address network constraints.

2.3 Success criteria

The following were considered when assessing if the project had been successful:

- Guidance and methodologies for assessing PV connection requests have been validated and developed into a formal policy.
- Successful 24 months of data gathering at 30 locations.
- Generation diversity along a feeder is understood.
- The impact of PV on different types of LV network is understood and documented.
- Data from a PV installer is available for UK Power Networks to view and assess.
- An understanding of how network constraints can be mitigated has been developed.

3. DETAILS OF THE WORK CARRIED OUT

Key messages	
	• The project gathered network data and used it to understand PV's impacts on the LV network, and validate connection assessment tools and procedures. • It also investigated voltage control solutions that could be trialled or adopted in GB, and the potential usefulness of data collected by PV installers.

3.1 Overview

The work carried out in this project can be divided into six activities, summarised below:

Table 1 – Summary of the work carried out

Activity	Scope	Details
Trial Design	• Selected trial sites • Customer engagement – recruited trial participants and selected suitable homes with PV installations • Deployed and maintained network monitoring equipment, and removed it at the end of the trial • Collected and archived the trial data	3.3
Trial Method 1: Validate the PV connection assessment tool	• Developed an improved connection assessment tool • Modelled 20 feeders in PowerFactory • Compared the existing and improved tools to PowerFactory results and trial data	3.4
Trial Method 2: Validate assumptions in UK Power Networks' PV connection assessment policies	• Used the trial data to confirm existing assumptions, and recommend new design assumptions to include in an updated procedure	3.5
Trial Method 3: Understand the impacts of PV generation on LV distribution networks	• Analysed the trial data to investigate the behaviour and impacts of PV generation	3.6
Trial Method 4: Understand solutions available to address network constraints	• Conducted a desktop review of voltage control solutions that could be trialled or adopted in GB	3.7
Trial Method 5: Understand how information available to PV installers could be used by DNOs	• Obtained and reviewed data from two PV installers	3.8

3.2 Project partners and suppliers

UK Power Networks collaborated with the following project partners and suppliers to deliver this project:

Table 2 – Project partners and suppliers

Organisation	Role
UK Power Networks	• Led and managed the project • Installed monitoring equipment in substations and on overhead lines, and removed it at the end of the trial
LIG Consultancy Services	• Reviewed learning available from other DNO projects • Analysed trial data • Validated spreadsheet tools against PowerFactory results
Ormazabal	• Supplied monitoring equipment • Provided training to equipment installers • Provided data collection and archiving services
Cyient *(Formerly Infotech Enterprises)*	• Built power systems models and calculated voltage rise using DigSILENT PowerFactory
Cofely *(Formerly Balfour Beatty Workplace)*	• Installed monitoring equipment in customers' homes, and removed it at the end of the trial *(This activity was outsourced because it required domestic installer qualifications)*

3.3 Trial Design

The following sections explain how the network data was collected.

3.3.1 **Substation/site selection**

The trial covered 20 distribution substations, which were selected according to the following criteria:

1. **A fair representation of UK Power Networks' LV networks:** The trial included a mix of rural and suburban substations, and an equal number of substations from EPN and SPN. LPN was excluded because it has much lower PV penetration, and was already being studied as part of the Low Carbon London project[1].
2. **PV penetration:** The trial included 18 substations with high PV penetration, and two baseline substations with no PV penetration. The PV penetration at each substation was estimated using UK Power Networks' G83 notification register, which lists registered PV installations and their MPANs; and UK Power Networks' MPAN connectivity model, which maps those MPANs to substations.
3. **Network strength (impedance):** The trial substations included a range of transformer sizes (50kVA – 1000kVA), LV feeder cable sizes (0.05in^2 overhead Cu to 300mm^2 underground Al), and lengths, so that the project could observe how these factors influence supply quality issues such as harmonics and voltage rise.
4. **Suitability for equipment installation:** Prospective trial substations were inspected to ensure that the monitoring equipment could be installed safely.

[1] "Impact of Low Voltage - Connected low carbon technologies on network utilisation: Low Carbon London Learning Lab Report B4", http://bit.ly/1LhAhtq, Retrieved 19 February 2015

3.3.2 **Comparison of trial sites to EPN/SPN substation population**

Figure 1 shows that based on UK Power Networks' G83 notifications register, approximately 25,000 distribution substations in EPN and SPN (about 30%) have some PV generators attached to them.

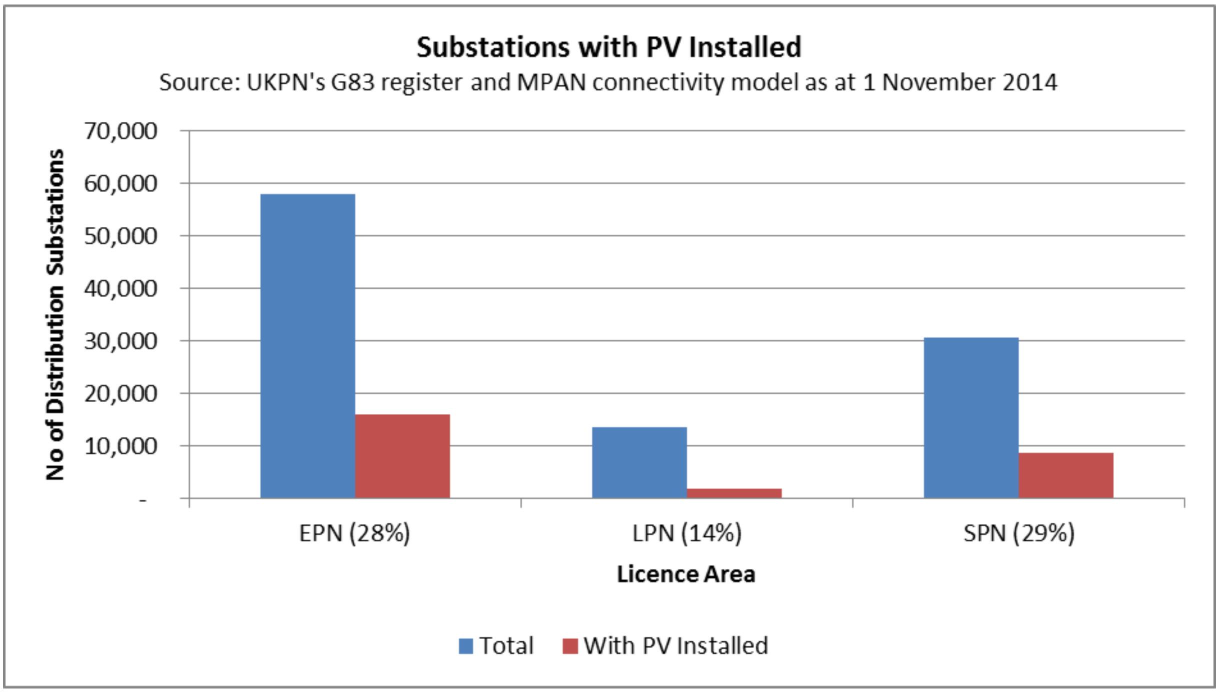

Figure 1 – PV Penetration – Substations with PV Installed as at 1 November 2014

When all 25,000 substations in EPN and SPN with some PV attached are ranked in terms of total PV connected (kW):

- 13 trial sites, including all six sites with PV monitoring inside the customer's premises, were ranked in the top 1.5% (refer Figure 2).
- Another four trial sites (not shown) were ranked in the top 10% (refer Table 3).

When ranked in terms of PV connected per customer (kW/customer) (refer Table 3):

- 11 trial sites were ranked in the top 10%.
- Another six trial sites were ranked in the top 20%.

Overall, less than 1% of EPN/SPN substations with any PV attached to them have more than 50kW attached. This indicates that in the short term, UK Power Networks is unlikely to experience the same issues currently facing network operators in countries that have much higher PV penetrations.

However, this also means that a single connection application (for example, a G59 50kW installation on a shopping centre or factory, or a G83 multiple-premises scheme comprising 20x 2.5kW installations), could easily elevate a substation into the top 1%. DNOs' policies, procedures, and tools must be able to handle these types of scenarios, which are credible today, and likely to become more common in future.

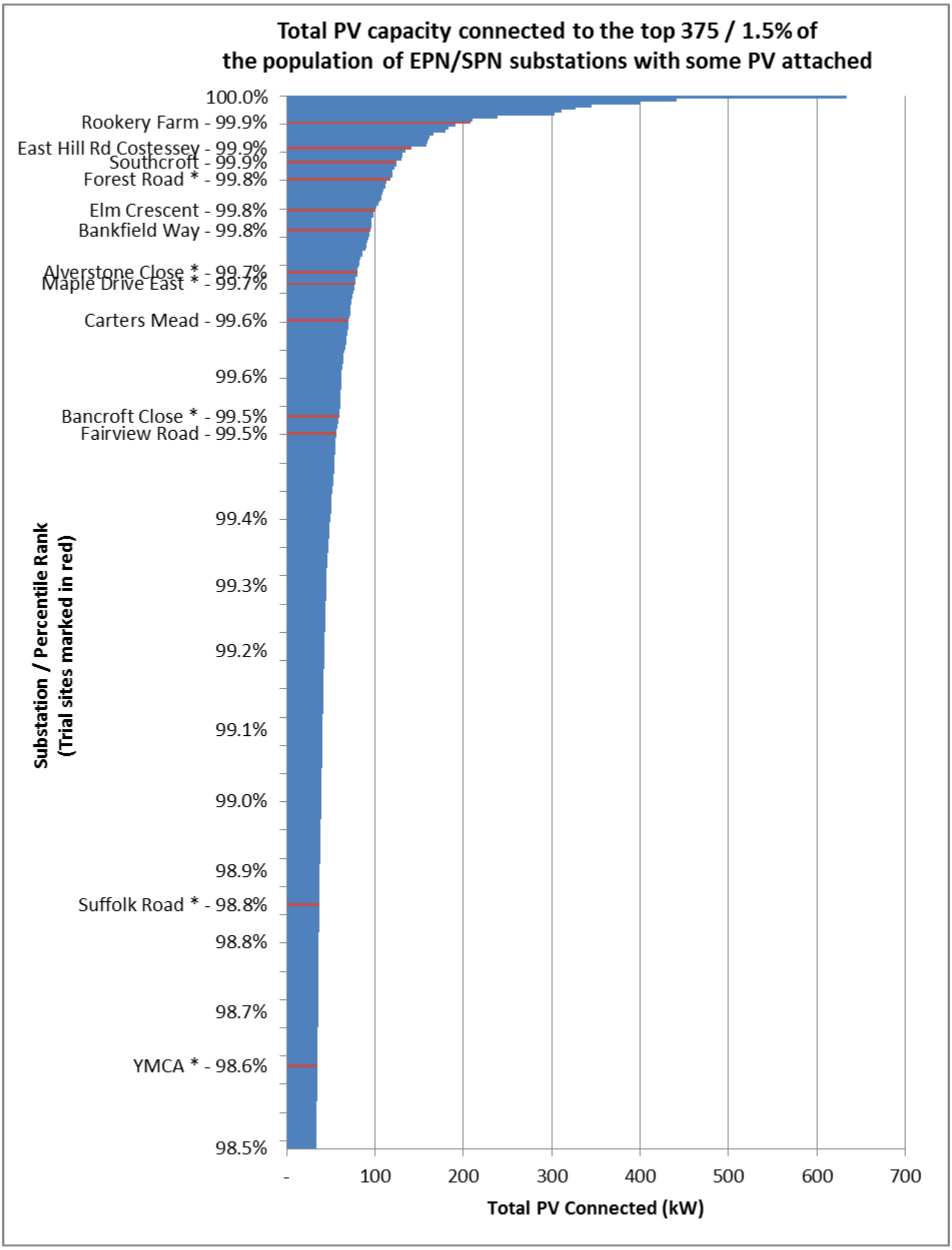

Figure 2 – Total PV Connected to the top 375 / 1.5% of the population of EPN/SPN substations with some PV attached
* indicates sites with monitoring inside customer's premises

Table 3 – Total PV connected and PV connected per customer for all trial sites
* indicates sites with monitoring inside customer's premises

Site	Total PV Connected (kW)	Percentile Rank	No of Customers	PV Connected per Customer (kW/Customer)	Percentile Rank
Alverstone Close*	80	99.7%	655	0.1	69.9%
Bancroft Close*	60	99.5%	226	0.3	84.1%
Bankfield Way	95	99.8%	244	0.4	88.6%
Carters Mead	70	99.6%	183	0.4	88.5%
Chapel Lane	23	96.4%	55	0.4	89.5%
East Hill Rd Costessey	142	99.9%	157	0.9	94.8%
Elm Crescent	101	99.8%	127	0.8	94.1%
Fairview Road	56	99.5%	126	0.4	90.0%
Forest Road*	117	99.8%	167	0.7	93.3%
Maple Drive East*	77	99.7%	147	0.5	91.5%
Old Mill Nordelph	14	90.8%	15	1.0	95.1%
Priesthawes	31	98.1%	14	2.2	98.2%
Rampling Court	-	-	27	-	-
Rookery Farm	208	99.9%	28	7.4	99.6%
Southcroft	125	99.9%	195	0.6	92.8%
Suffolk Road*	37	98.8%	394	0.1	63.1%
Upper Staplefield Common	-	-	27	-	-
Village, Bircham Newton	18	94.1%	31	0.6	92.1%
Warninglid Lane	4	48.9%	3	1.3	96.6%
YMCA*	35	98.6%	80	0.4	89.7%
Trial sites' average: *(excluding baseline sites)*	**72**	**95.7%**	**158**	**1.0**	89.5%
EPN/SPN average: *(of sites with some PV attached):*	**7.0**	**N/A**	**121**	**0.26**	**N/A**

3.3.3 Trial site locations

The following maps show the trial sites' locations and details:

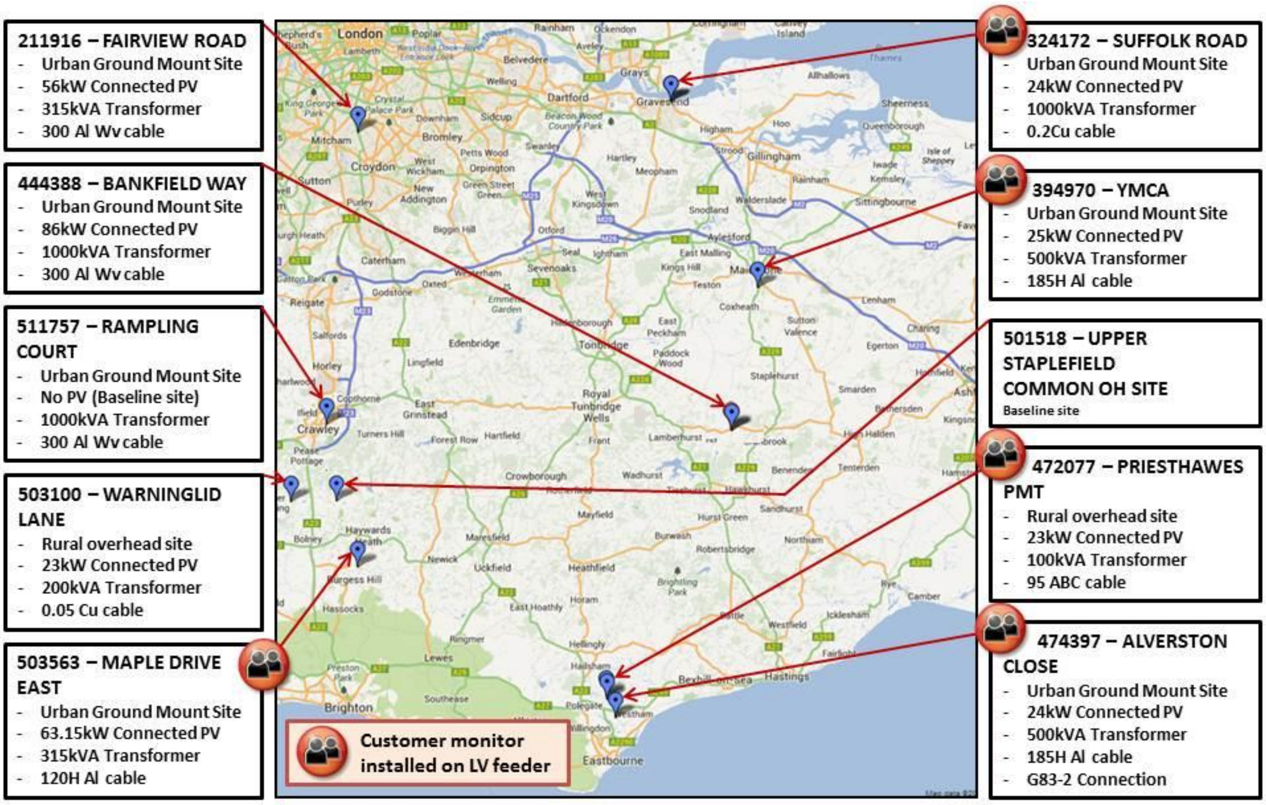

Figure 3 – SPN trial sites (Map Data © 2015 Google)

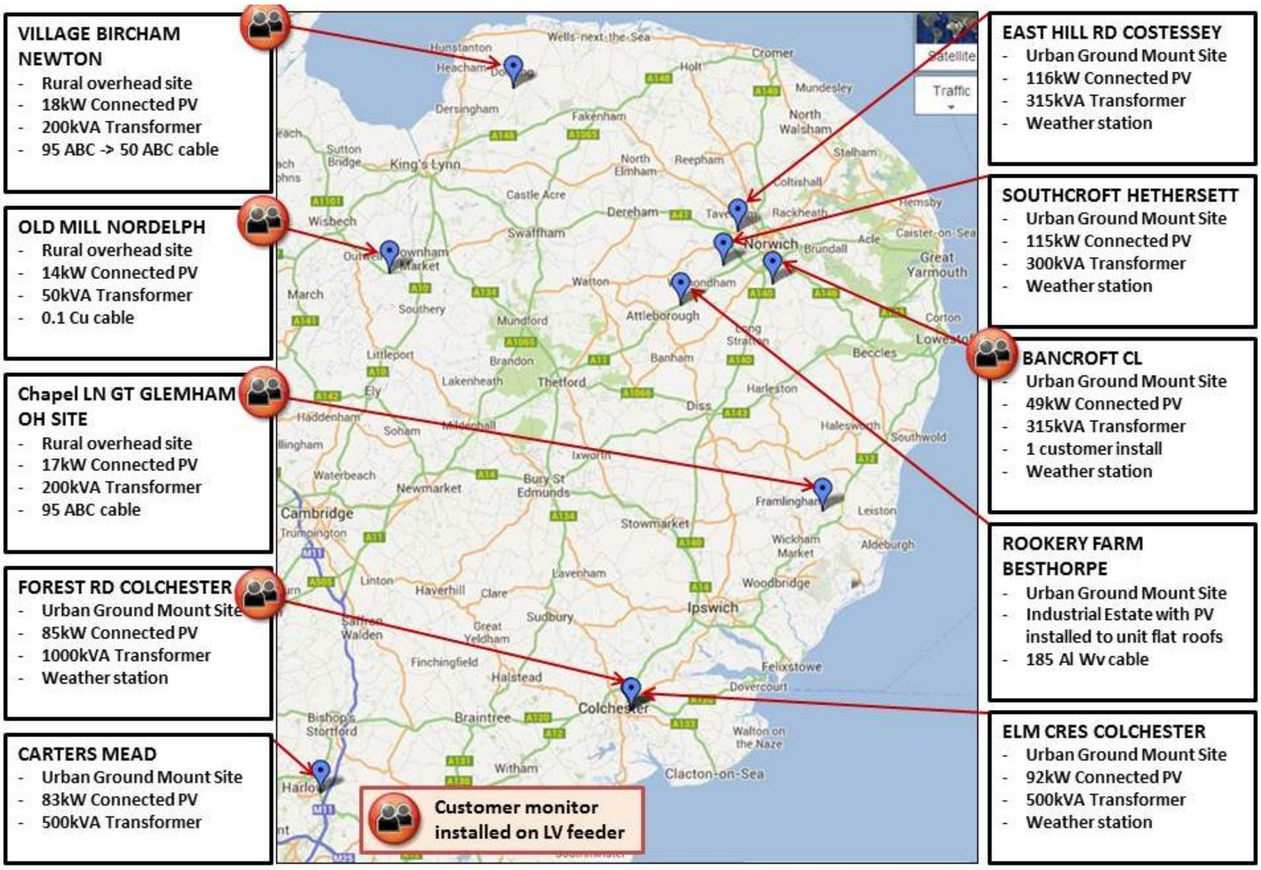

Figure 4 – EPN trial sites (Map Data © 2015 Google)

3.3.4 Customer engagement

The project aimed to install monitoring equipment on 10 customers' PV installations, each supplied from one of the 20 trial substations.

The process to recruit and engage these customers was as follows:

1. The project developed customer engagement and data protection plans, which were both approved by Ofgem before proceeding to engage customers.
2. Prospective trial participants (i.e. customers with PV installations) were identified from UK Power Networks' G83 notifications register, public-domain aerial photography (e.g. Google Maps), and site visits.
3. Customers were sent a recruitment pack containing information about UK Power Networks, the Low Carbon Networks Fund (LCNF), the trial, eligibility criteria, and incentives for trial participation.
4. Customers confirmed their interest via email, telephone, or post.
5. Interested customers were interviewed by phone to determine whether their premises might be suitable, and to identify any other parties (e.g. landlords) who might need to consent.
6. Suitable customers reviewed and signed an agreement setting out the terms and conditions of their participation in the trial. In some cases, the occupier, landlord, and owner of the PV installation all had to sign the agreement separately, which slowed this part of the process.
7. Customers' premises were inspected to confirm that the equipment could be installed safely.
8. If the customer's premises were found to be suitable, monitoring equipment was installed for the duration of the trial. The project identified six suitable premises with PV installations, all of which were monitored for the full duration of the trial. To make up the 10 endpoint sites planned for the trial, another four PV installations were monitored on the overhead network just outside the customers' premises. This is discussed further in sections 6.3 and 0.

The benefits and incentives offered to customers included:

1. A £25 retail voucher to thank customers for their interest, if the site inspection found their premises to be unsuitable;
2. A £250 payment after the equipment was installed;
3. A £100 payment after the equipment had been installed for one year;
4. A £100 payment after the equipment had been removed; and
5. Quarterly reports detailing the customers' generation, export, consumption and voltage (See example in Appendix B: Example Customer Energy Report).

Feedback from customers at the end of the trial was generally positive – most said that they found the quarterly reports interesting, and would be happy to participate in future trials. For full responses, see Appendix C: Customers' responses to end-of-project survey.

3.3.5 **Network monitoring**

Figure 5 shows a typical monitoring equipment setup:

Figure 5 – Typical monitoring equipment setup

1. PV inverter
2. Feed-in Tariff meter
3. PV generation (feed-in) current sensor*
4. Consumer unit (fuse board)
5. Main switch
6. Net import/export current sensor*
7. Import meter
8. Cutout
9. Data logger*

* These are the equipment installed during this project.

For full details of the hardware and software used in this trial, see Section 10.1.

The following data were collected to measure PV clusters' impacts on the LV network:

Table 4 – Measured data

Parameter	Symbol	Units	Measurement Interval/Type	Measured at substations	Measured at customers' premises
Voltage	V	V	1min or 10min instantaneous	Yes *(Separate measurements for each phase)*	Yes
Voltage THD	thdV	%			
Frequency	f	Hz			
Current	I	A	1min or 10min instantaneous	Yes *(Separate measurements for each LV feeder way and each phase)*	Yes *Net import/export measured at 10 of 10 sites* *Generation (feed-in) measured at 6 of 10 sites* *Customer power consumption = net import/export + generation*
Current THD	thdI	%			
Real Power	P	kW			
Reactive Power	Q	kvar			
Apparent Power	S	kVA			
Energy	E	kWh	1hr totals		
Solar Irradiance	E_e	W/m^2	30min instantaneous	Yes *(Weather stations[2] were installed at 9 of 20 substations)*	No
Solar Insolation	H_e	Ly(Note 3)	30min totals		

[2] The weather stations also collected other data e.g. temperature, rainfall, wind speed, but they were not used in this project.

[3] 1 Langley (Ly) = 41,840 J/m2

3.4 Trial Method 1: Validate the PV connection assessment tool

This method aimed to validate UK Power Networks' PV connection assessment tool, i.e. ensure it was sufficiently accurate and fit for purpose.

The project also developed and validated an improved tool that calculates voltage rise in three steps: the first step provides a worst-case result using minimal inputs, and if required, subsequent steps provide more-accurate results, using more-detailed inputs.

In brief, the existing tool calculates voltage rise assuming that all generators are balanced three-phase and located at the end of the feeder; whereas the improved tool allows generators to be single-phase or imbalanced, and located at any point along the feeder. For a more detailed description and comparison of both tools, see Appendix A: Description of the tools.

Both tools were validated by comparing their voltage rise results to:

- Voltage rise modelled in DigSILENT PowerFactory[4]; and
- Voltage rise measured from the trial data.

3.4.1 **Comparison to DigSILENT PowerFactory**

Voltage rise results from the spreadsheet tools were compared to voltage rise modelled in DigSILENT PowerFactory.

- The existing tool was designed to provide a first-pass, worst-case assessment, and was hence expected to produce more conservative results than PowerFactory.
- The improved tool was expected to produce similar results compared to PowerFactory.

Voltage rise was modelled in DigSILENT PowerFactory as follows:

- Feeder topologies, cable sizes, and customer connection information were taken from Netmap (UK Power Networks' GIS system).
- Where customers' phases were not documented in Netmap, they were assigned sequentially i.e. customer 1 = A phase, customer 2 = B phase, customer 3 = C phase, customer 4 = A phase, etc.
- Details of existing PV installations were taken from UK Power Networks' G83 notifications register.
- Minimum load was assumed to be zero during daylight hours.
- This information was used to build a model of each feeder, perform a full power flow analysis, and plot each feeder's voltage profile.

Voltage rise was calculated using the spreadsheet tools as follows:

- Input data and assumptions were identical to the PowerFactory models, subject to the tools' limitations:
- The spreadsheet tools are unable to model feeders with multiple branches/termini, so voltages were only calculated up to the point where the endpoint monitoring equipment was connected.

[4] DigSILENT PowerFactory is a commercially available, full-featured power system modelling, analysis, and simulation software package. UK Power Networks mostly uses WinDEBUT for low-voltage network design, but PowerFactory was used for this project because (at the time when the project was scoped) WinDEBUT was not able to model embedded generation.

- For the improved tool, PV installations on other branches were modelled as if they were connected where their branch tees off.
- For the existing tool, all PV installations were modelled as if they were connected at the end of the branch being considered, and all PV installations were assumed to be balanced three-phase.

3.4.2 Comparison to trial data

Voltage rise results from the spreadsheet tools were compared to actual voltage rise caused by PV generation, measured from the trial data using the method described in section 4.4.2.

3.5 Trial Method 2: Validate assumptions in UK Power Networks' PV connection assessment policies

This method aimed to validate assumptions in UK Power Networks' PV connection assessment policies. These assumptions fell into several categories:

- Existing documented assumptions – i.e. written in an approved procedure;
- Existing undocumented assumptions – i.e. unwritten rules of thumb; or
- Proposed assumptions (not previously used).

The assumptions and the methods used to validate them are as follows:

Table 5 – Assumptions and validation methods

Assumption	Status	Validation method
Total PV (or DG) capacity on a substation should not exceed 50% of the transformer's nameplate rating (81% for sole-use transformers)	Existing, documented	Measured PV's impact on LV networks approaching this level of PV penetration
PV generators do not increase the risk of unacceptable harmonic voltages or currents.	Existing, undocumented	Measured PV's impact on harmonic voltages and currents
Substation busbar voltage during peak PV generation: Existing assumptions varied from 230V to 250V.	Existing, undocumented	Measured substation busbar voltages during peak PV generation
Minimum demand during peak PV generation: Existing assumptions ranged from 0 to 200W per customer.	Existing, undocumented	Measured minimum demand during daylight hours
Phase imbalance of PV clusters: This was not previously considered.	Proposed	Measured load imbalance on feeders, and inferred that PV generators are similarly imbalanced

Assumption	Status	Validation method
All existing PV (and DG) installations are accurately documented in UK Power Networks' G83 notifications register.	Proposed	Compared maximum measured generation/export (kW) to registered nameplate ratings Checked that PV panels visible in public-domain aerial photography or site inspections were documented in the register, and vice-versa

3.6 Trial Method 3: Understand the impacts of PV generation on LV distribution networks

This method analysed the trial data to investigate the behaviour and impacts of PV generation, in particular:

- How PV generators' output varied with season, weather, and panel orientation;
- How PV generators affected the LV distribution network in terms of voltage rise, reverse power flow, harmonics, and phase imbalance; and
- How these effects varied between different types of networks (e.g. rural vs urban).

3.7 Trial Method 4: Understand solutions available to address network constraints

This method conducted a desktop review of alternative (non-reinforcement) solutions to address network constraints that might prevent connection of new PV generation. Potential solutions were identified from past and present GB innovation projects, and EU conference papers. The solutions were compared to identify their relative strengths and weaknesses, and the scenarios where they might each be most useful.

3.8 Trial Method 5: Understand how information available to PV installers could be used by DNOs

Many PV installers monitor and collect data from the PV installations that they own, which often comprise G83 multiple-premises schemes. The project obtained and reviewed data from two PV installers, to determine whether it (or similar data) could be useful to DNOs, and/or reduce the need for DNOs to deploy their own LV network monitoring schemes.

4. THE OUTCOMES OF THE PROJECT

Key Messages	• The project validated assumptions in UK Power Networks' existing connection assessment procedure, and recommended several new design assumptions to include in an updated procedure. • The six endpoint sites were amongst the most heavily PV-penetrated locations in EPN and SPN, yet PV did not cause any voltages to exceed statutory limits. This indicates that in general, the EPN and SPN networks are performing well with current PV penetration levels, and most LV feeders will continue to perform well in a low-carbon future, where more renewable energy is connected. • However, voltages at some sites were approaching statutory limits. This indicates that as the uptake of PV generation continues, new voltage control solutions will be needed to mitigate issues in areas of unusually high PV penetration. • PV generation caused measureable voltage rise along LV feeders. However, this had relatively little influence on endpoint voltages, which depended mainly on voltage regulation on the HV network and distribution transformer.

4.1 Summary of the data collected

Key Messages	• The project collected a rich dataset, comprising 25,775 days of data, and over 171 million individual measurements.

The following tables present the key facts and statistics of the project's dataset:

Table 6 – Dataset key facts

No. of monitored locations	**30**	These locations comprised 20 substations and 10 customers' premises.
No. of monitoring devices	**57**	Substations had one device for each LV feeder way.
Measurement period	**480 days** *(16 months)*	The trial ran from 27 July 2013 to 19 November 2014 – a span of 480 days (16 months). All substation monitors were installed by 27 July 2013. On average, each substation monitor collected 467 days (15 months) of valid data. The last customer premises monitor was installed on 9 November 2013. On average, each customer premises monitor collected 411 days (13.5 months) of valid data.
Measurement interval	**10 minutes** *(For all 480 days)* **1 minute** *(For 79 days in summer 2014)*	The measurement interval was temporarily decreased to 1 minute between 18 June and 7 September 2014, to capture more data during the summer (i.e. peak PV generation). Due to data archiving constraints, the 10-minute measurements prior to 10 June 2014 were aggregated to hourly minima and maxima.

Table 7 – Dataset statistics

Data Interval	Days of data *(average per device)*	Days of data *(total)*	Data rows *(total)*	Data points *(total)*	Availability *(per device)*
Hourly	452	25,775	544,745	21,781,847	85%
10 minutes	157	9,084	1,321,010	27,376,646	99%
1 minute	79	4,583	6,651,398	135,423,502	99%
Combined	**452**	**25,775**	**7,852,013**	**171,039,645**	

4.2 Trial Method 1: Validate the PV connection assessment tool

Result:	• The existing tool is likely to underestimate voltage rise if PV generation is sufficiently imbalanced, and is hence not fit for purpose. • The project developed and validated an improved tool that calculates voltage rise in three steps: the first step provides a worst-case result using minimal inputs, and if required, subsequent steps provide more-accurate results, using more-detailed inputs. • However, the accuracy of any voltage rise calculation is heavily dependent on input data that are often poorly documented (i.e. phase imbalance, substation busbar voltage, and details of existing generators), requiring conservative assumptions or site measurements to assure confidence in the results.

Both the existing and improved tools were validated by comparing their voltage rise results to:

- Voltage rise modelled in PowerFactory; and
- Voltage rise measured from the trial data.

4.2.1 **Existing tool**

The existing tool was used to calculate voltage rise for each site at the point where the endpoint monitoring equipment was connected.

The existing tool makes three unrealistic assumptions:

- A pessimistic assumption that all customers on the feeder have zero load during daylight hours;
- A pessimistic assumption that all PV generators are located at the feeder endpoint, which exaggerates the network impedance that each generator sees, and hence exaggerates the voltage rise; and
- An optimistic assumption that all PV generators are balanced three-phase.

The first assumption was not expected to affect the results, because the PowerFactory models also assumed zero load, and the way voltage rise was measured from the trial data ignored any load-related voltage drop (i.e. reduction of voltage rise)[5].

It was hence expected that the existing tool would overestimate voltage rise on balanced feeders, but might underestimate voltage rise if the PV generation was sufficiently imbalanced.

Figure 6 compares the existing tool to PowerFactory and measurements:

[5] This is explained on page 49.

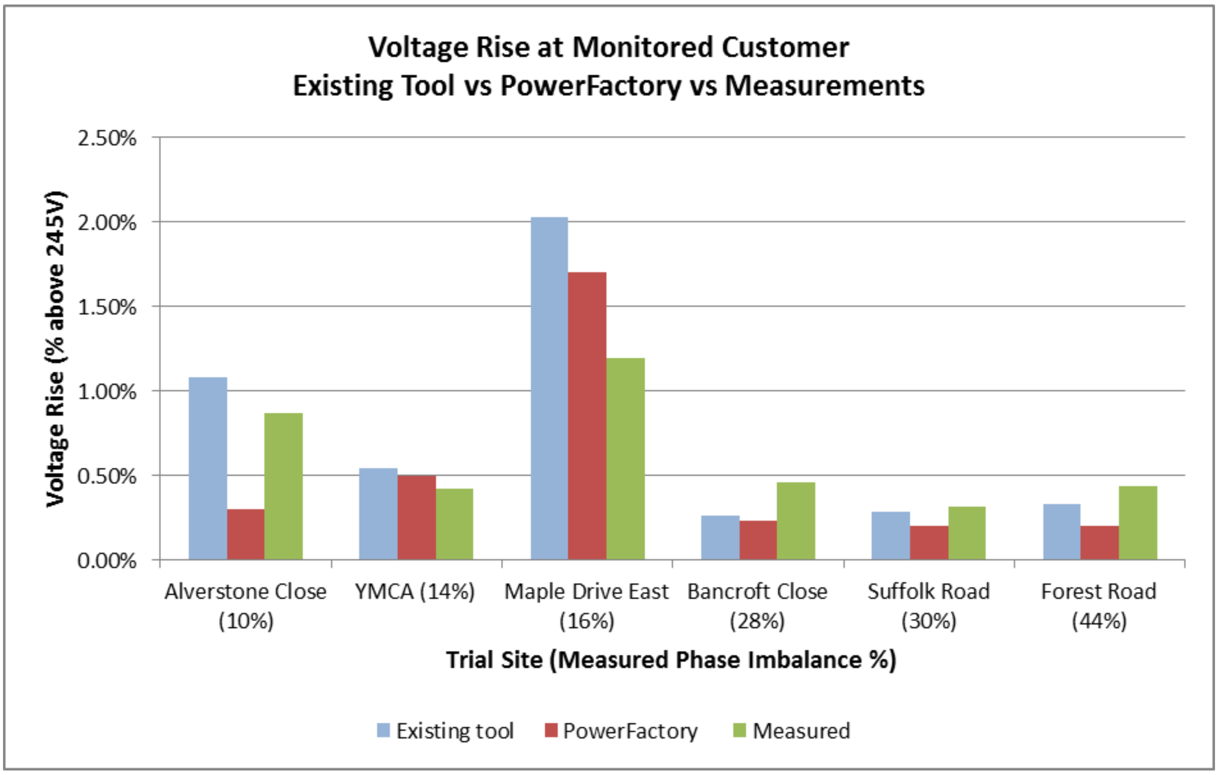

Figure 6 – Voltage rise – existing tool

Compared to PowerFactory (red), the existing tool (blue) overestimated voltage rise for all sites, as expected.

However, compared to measurements (green), the existing tool (blue) consistently underestimated voltage rise at sites where measured phase imbalance was more than 20% (Bancroft Close, Suffolk Road, and Forest Road).

This indicates that:

- **The existing tool is likely to underestimate voltage rise if PV generation is sufficiently imbalanced, and is hence not fit for purpose**;
- The PowerFactory models may have also underestimated the phase imbalance of existing generation; and
- Voltage rise, and consequently, headroom available for new PV generation, is heavily dependent on how imbalanced the existing PV generation is.

4.2.2 **Improved tool**

The improved tool calculates voltage rise in three steps: the first step provides a worst-case result using minimal inputs, and if required, subsequent steps provide more-accurate results, using more-detailed inputs:

- Step one – worst case: all generators connected at the endpoint, no load;
- Step two – realistic case: generators connected at actual locations, no load;
- Step three – realistic case with 200W of load per customer.

The improved tool was used to calculate voltage rise for each site at the point where the endpoint monitoring equipment was connected.

The improved tool allows generators to be assigned to phases; however, customers' phases were only documented in Netmap for one site (YMCA). For other sites, customers' phases were assigned sequentially.

4.2.3 Improved tool step one – worst case

This step uses the same assumptions as the existing tool, i.e. **all generators connected at the endpoint and no load, but allowing for phase imbalance**. Figure 7 compares this step's results to the existing tool, PowerFactory, and measurements:

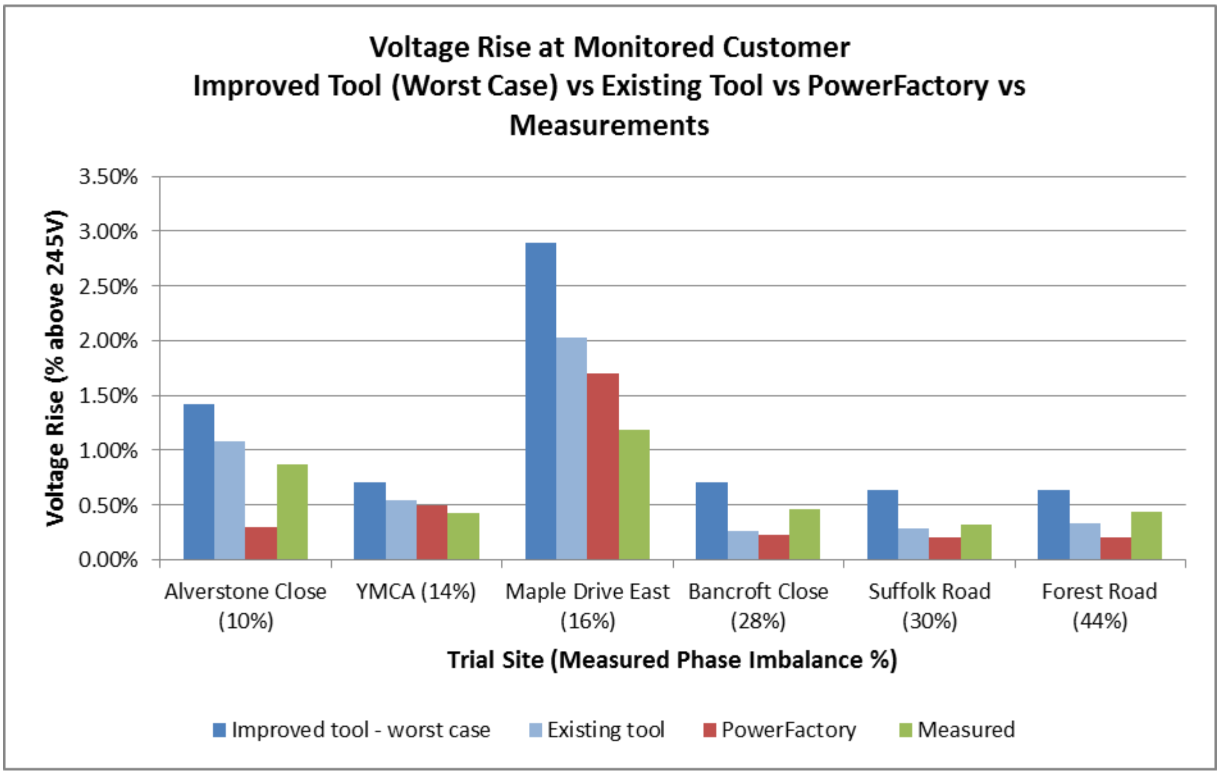

Figure 7 – Voltage rise – improved tool (worst case)

The improved tool (dark blue) gave higher voltage rise results than the existing tool (light blue) for all sites, with larger relative differences for sites with higher phase imbalance. This further indicates that **the existing tool is likely to underestimate voltage rise where PV generation is imbalanced.**

As expected, the improved tool (dark blue) gave higher voltage rise results than both PowerFactory (red) and measurements (green) at all sites, indicating that **the improved tool's worst-case scenario does not underestimate the effect of phase imbalance**, and will always overestimate actual voltage rise.

This validates that **the improved tool's worst-case calculation can be used as a first-stage assessment:** an acceptable result confirms that it is safe to offer a connection without reinforcement, and an unacceptable result means that a more detailed assessment is needed.

4.2.4 Improved tool step two – realistic case

This step considers **all generators at their actual locations on the feeder**, which was expected to give more realistic (lower) voltage rise results. Figure 8 compares this step's results to PowerFactory and measurements:

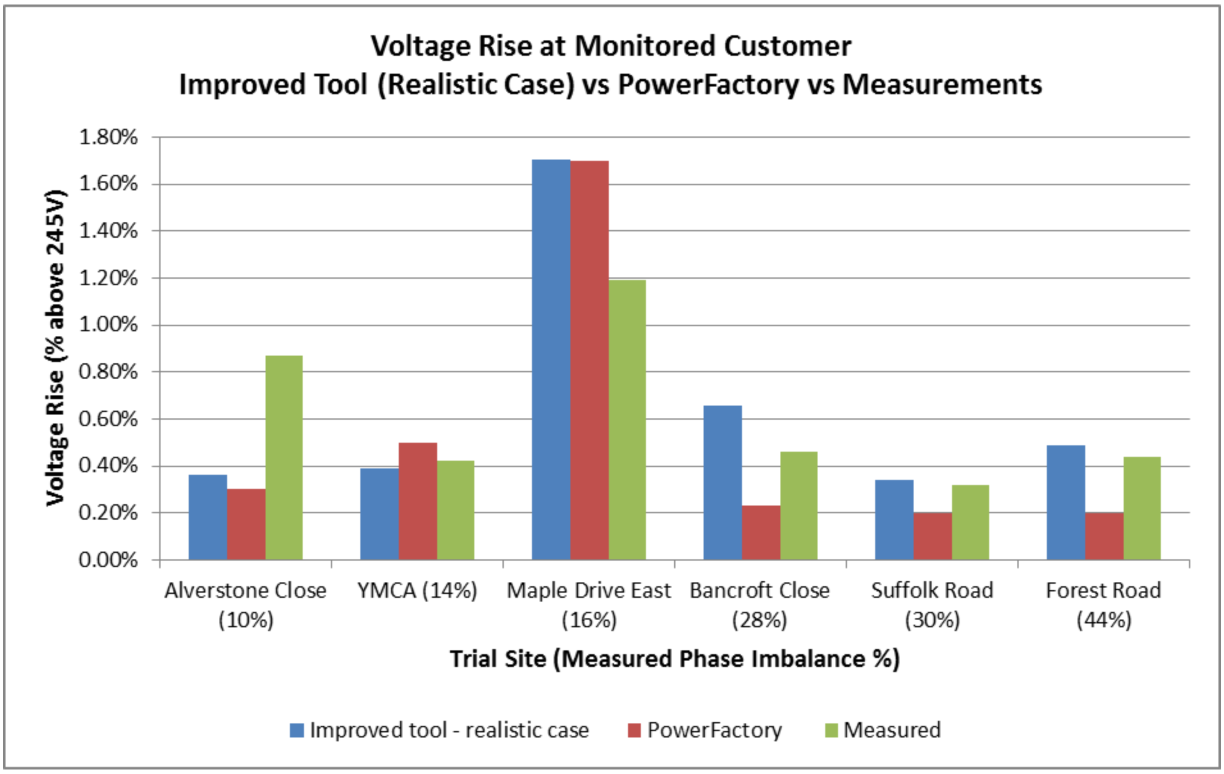

Figure 8 – Voltage rise – improved tool (realistic case)

The improved tool's results (blue) were similar to or slightly higher than measurements (green) as expected, at all sites except Alverstone Close. This discrepancy is possibly because the PV generators were not as balanced as assumed: the three installations furthest from the substation were assumed to be on three separate phases. (The feeder had 12 installations / 27kW in total.) It was found that putting all three installations on one phase increased the voltage rise result from 0.37% to 0.95%, which was higher than the measured voltage rise (0.87%). This further indicates that **voltage rise calculations are very sensitive to phase imbalance**.

The improved tool's results (blue) were similar to or higher than PowerFactory (red) at all sites, with larger differences for sites with higher measured phase imbalance. As inferred previously, this is possibly because the PowerFactory models underestimated the phase imbalance of existing generation.

These results validate that:

- **The improved tool's realistic-case calculation gives a relatively accurate voltage rise result;**
- **The improved tool's realistic-case calculation can be used as a second-stage assessment**:
  - An acceptable result confirms that it is most likely safe to offer a connection without reinforcement; whereas
  - An unacceptable result means that without reinforcement, there is a high risk of overvoltage incidents.

4.2.5 **Improved tool step three – realistic case with 200W of load per customer:**

This step adds of 200W of load per customer.

All voltage rise results presented previously (i.e. the existing tool, improved tool steps one and two, PowerFactory, and measurements) indicated the increase in voltage rise due to PV, which ignores any load-related voltage drop[6].

By contrast, this last step's results indicate maximum voltage rise, which includes load-related voltage drop, and is hence a more accurate estimate of the actual voltage rise that would occur along the feeder. This also means that this last step's results are not comparable to the measured voltage rise.

Figure 9 compares this step's results to the previous steps, confirming that each step gives a progressively lower (more accurate, less conservative) result.

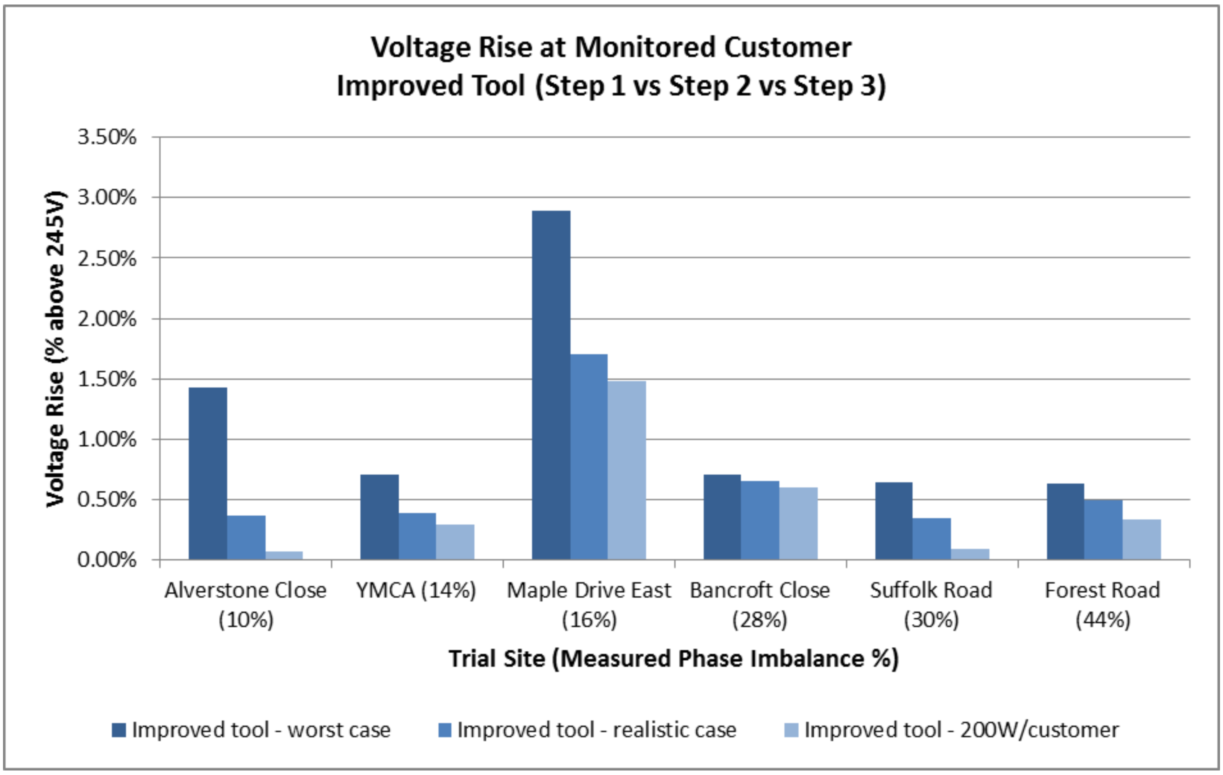

Figure 9 – Voltage rise – improved tool (200W/customer case)

[6] Page 49 explains why the voltage rise measurements ignore load-related voltage drop.

4.2.6 Limitations of the improved tool

The trial found that the improved tool gives a relatively accurate voltage rise result. However, **the accuracy of any voltage rise calculation is limited by the accuracy of its inputs**, some of which are difficult or impracticable to determine accurately:

Table 8 – Limitations of the improved tool

Input	Limitations	Impact on result
Amount of PV generation on the feeder	PV installations are often misreported to DNOs. According to Ofgem's FiT register, PV penetration may actually be 50% more than reported to UK Power Networks in its licence areas (refer section 4.3.5).	Voltage rise may be underestimated at sites with unreported PV installations.
Maximum substation busbar voltage	Substation busbar voltages vary widely (refer Figure 12, page 37). In LPN, 60% of substations' voltages can be measured remotely; but in EPN and SPN, they must be measured at site, or assumed conservatively.	The customers' maximum voltage (maximum substation voltage + calculated voltage rise) will generally be overestimated if a conservative assumption is applied.
Generators' phase allocations (imbalance)	Customers' phase allocations are not well documented in UK Power Networks (or most other DNOs). There is generally no practicable way to determine them, hence a conservative phase imbalance assumption must be applied.	Voltage rise will generally be overestimated due to conservative assumptions about phase imbalance.

4.3 Trial Method 2: Validate assumptions in UK Power Networks' PV connection assessment policies

Result:	• The project validated assumptions in UK Power Networks' existing connection assessment procedure, and recommended several new design assumptions to include in an updated procedure: ○ PV generators do not increase the risk of unacceptable harmonic voltages or currents on LV feeders; ○ Substation busbar voltage = 248V; ○ Minimum demand = 0W (<10 customers); 200W per customer (≥10 customers); up to 400W per customer (≥10 customers and high-energy-use demographic); ○ Phase imbalance of existing 1ph PV = 25% (urban); 50% (rural); all on same phase (<10 customers); and ○ Not all PV installations are registered – check for unregistered installations using public-domain aerial photography.

Table 9 summarises the assumptions that were tested, the results, and recommendations:

Table 9 – Summary of assumptions, results, and recommendations

Assumption	Result	Recommendation	More Details
Total PV (or DG) capacity on a substation should not exceed 50% of the transformer's nameplate rating (81% for sole-use transformers).	**Not relevant at present PV penetration levels:** No trial sites exceeded this ratio, and less than 10 substations in EPN/SPN are currently likely to exceed it.	No immediate change is necessary, but the assumption should be reviewed when more substations are likely to exceed this ratio.	Section 4.3.1
PV generators do not increase the risk of unacceptable harmonic voltages or currents on LV feeders.	**Validated:** The trial data indicated no correlation between PV generation and harmonic voltages or currents on LV feeders.	No change to this assumption.	Section 4.4.4
Substation busbar voltage during peak PV generation: Existing assumptions varied from 230V to 250V.	Substation busbar voltages varied widely between sites and over time at each site, with an overall median of 245V and a standard deviation of 3V.	Assume substation busbar voltage is 248V if site measurements are not available.	Section 4.3.2

Assumption	Result	Recommendation	More Details
Minimum demand during peak PV generation: Existing assumptions ranged from 0 to 200W per customer.	Diversified minimum daytime demand varied from 200W to 400W per customer, depending on the area's demographic.	On feeders with at least 10 customers: assume 200W-400W per customer, depending on the area's demographic. On feeders with less than 10 customers, assume demand is zero.	Section 4.3.3
Phase imbalance of existing PV generators: This was not previously considered.	Phase imbalance varied widely, with an overall median of 15% and standard deviation of 10% on urban feeders; higher on rural feeders.	On feeders with at least 10 customers, assume that the phase imbalance of existing single-phase PV generators is 25% on urban feeders / 50% on rural feeders. On feeders with less than 10 customers, assume that all existing generators could be on the same phase unless network plans clearly indicate otherwise.	Section 4.3.4
All existing PV (and DG) installations are accurately documented in UK Power Networks' G83 notifications register.	The project found several instances where the register was incorrect. Ofgem's FiT register suggests that actual PV penetration may be 50% more than reported.	Check for unregistered installations using public-domain aerial photography (e.g. Google Maps). Further work is required to provide better information about existing PV installations.	Section 4.3.5

4.3.1 PV/Transformer ratio

UK Power Networks' existing procedure for "Assessment of generation applications" restricts total PV (or DG) capacity to 50% of the transformer's nameplate rating (or 81% for sole-use transformers).

Figure 10 shows that none of the trial sites exceeded this ratio, and Figure 2 (page 16) indicates that less than 10 substations in EPN/SPN are currently likely to exceed it.

This indicates that this assumption is **not relevant at present PV penetration levels**, but **should be reviewed when more substations are likely to exceed this ratio.**

Furthermore, Figure 11 shows that PV/Transformer ratio does not appear to be a reliable indicator of median, maximum, or spread of endpoint voltages.

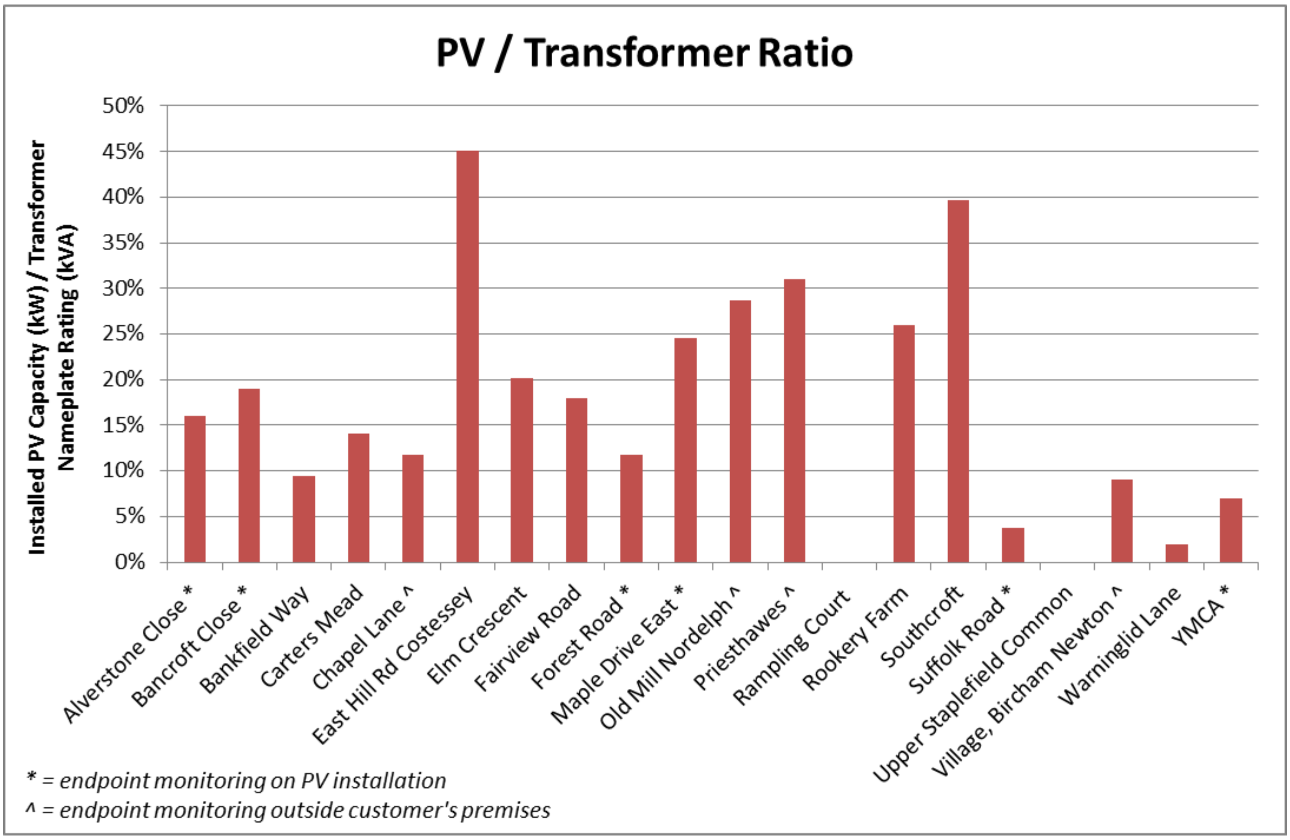

Figure 10 – Installed PV capacity/transformer rating ratio

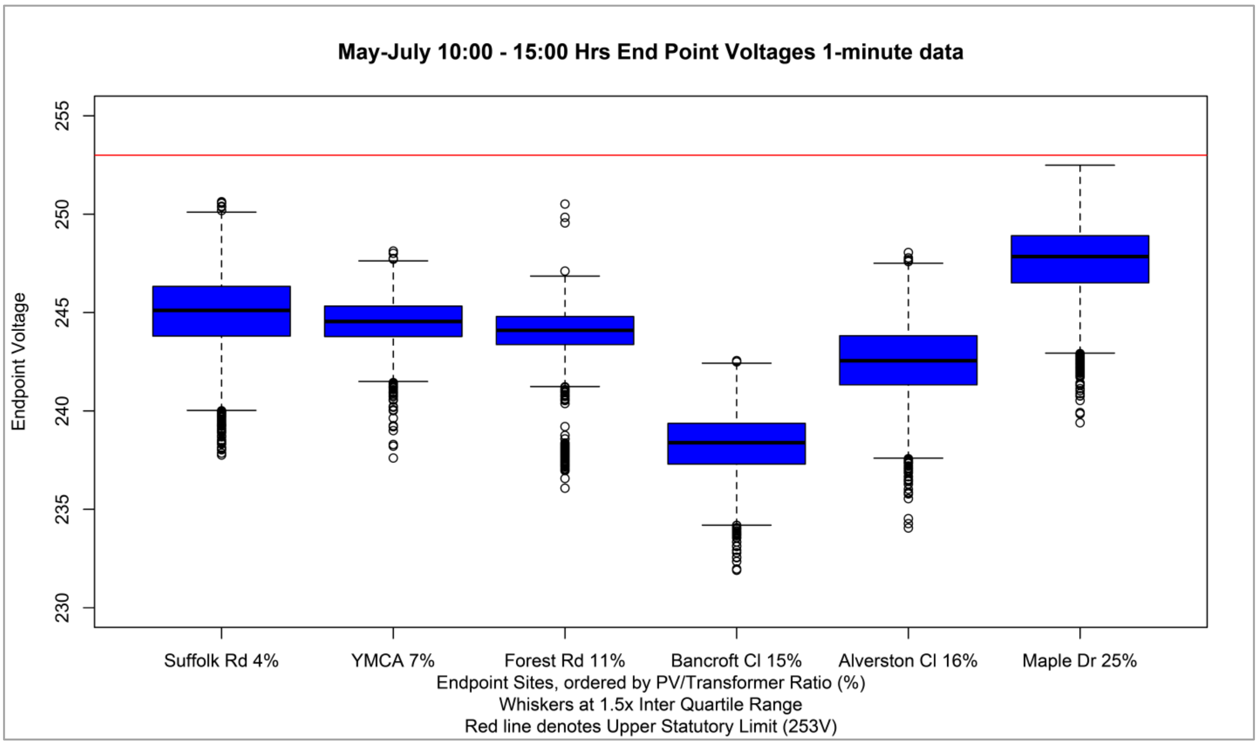

Figure 11 – Endpoint (customers') voltage at sites with endpoint monitoring installed.

4.3.2 **Busbar voltage**

The outcome of voltage rise assessments depends heavily on the maximum substation busbar voltage, because it directly determines the maximum voltage rise that can be accepted.

LPN's LV network is unusually well monitored: about 60% of LPN substations' busbar voltages can be measured remotely via RTUs and the "Distribution Network Visibility" tool[7], allowing designers to set realistic design assumptions on a case-by-case basis.

Unfortunately, most other LV networks, including SPN and EPN, have few RTUs. Smart meter data may provide a similar level of visibility in future; however, in the meantime, the only way to measure actual maximum substation busbar voltages is to deploy temporary data loggers at site.

This is not practicable or necessary for every connection assessment, so the initial calculation needs to use a busbar voltage assumption that is:

- Low enough to quickly confirm an acceptable result for low-risk connections, but
- High enough to ensure that high-risk connections are assessed in more detail.

The assumptions previously used in UK Power Networks varied between 230V and 250V.

Figure 12 shows that busbar voltages varied widely between sites, and over time at each site. The data indicates that an assumption of about 251V would virtually eliminate the risk of underestimating the busbar voltage. However, this would cause many initial voltage rise assessments to fail, necessitating time-consuming site visits to deploy and retrieve data loggers, which would defeat the purpose of using an assumption.

In the meantime, to achieve a pragmatic balance between an efficient connection assessment process and an acceptable level of risk, **it is recommended to assume that the busbar voltage during peak PV generation (if unknown) is 248V.** Figure 12 shows that this is about one standard deviation above the overall median observed in this trial, meaning it will be valid 84% of the time.

This allows for a voltage headroom of 253V – 248V = 5V, or about 2%. Using the improved tool (refer Figure 9, p31), five of the six trial sites would have been accepted based on step 1 (worst-case assessment), and the remaining site would have been accepted after step 2 (realistic-case assessment, no load).

There is a small residual risk of overvoltage incidents where the actual busbar voltage is above 248V, <u>and</u> PV penetration has approached the allowed limit, <u>and</u> maximum PV output coincides with minimum demand. It is expected that many of these incidents can be addressed using smart voltage control solutions (refer section 4.5), or by adjusting distribution transformer tap settings.

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[7] "Distribution Network Visibility: LCN Fund Tier 1 Close Down Report", page 2, http://bit.ly/1LkcEk5, Retrieved 20 February 2015

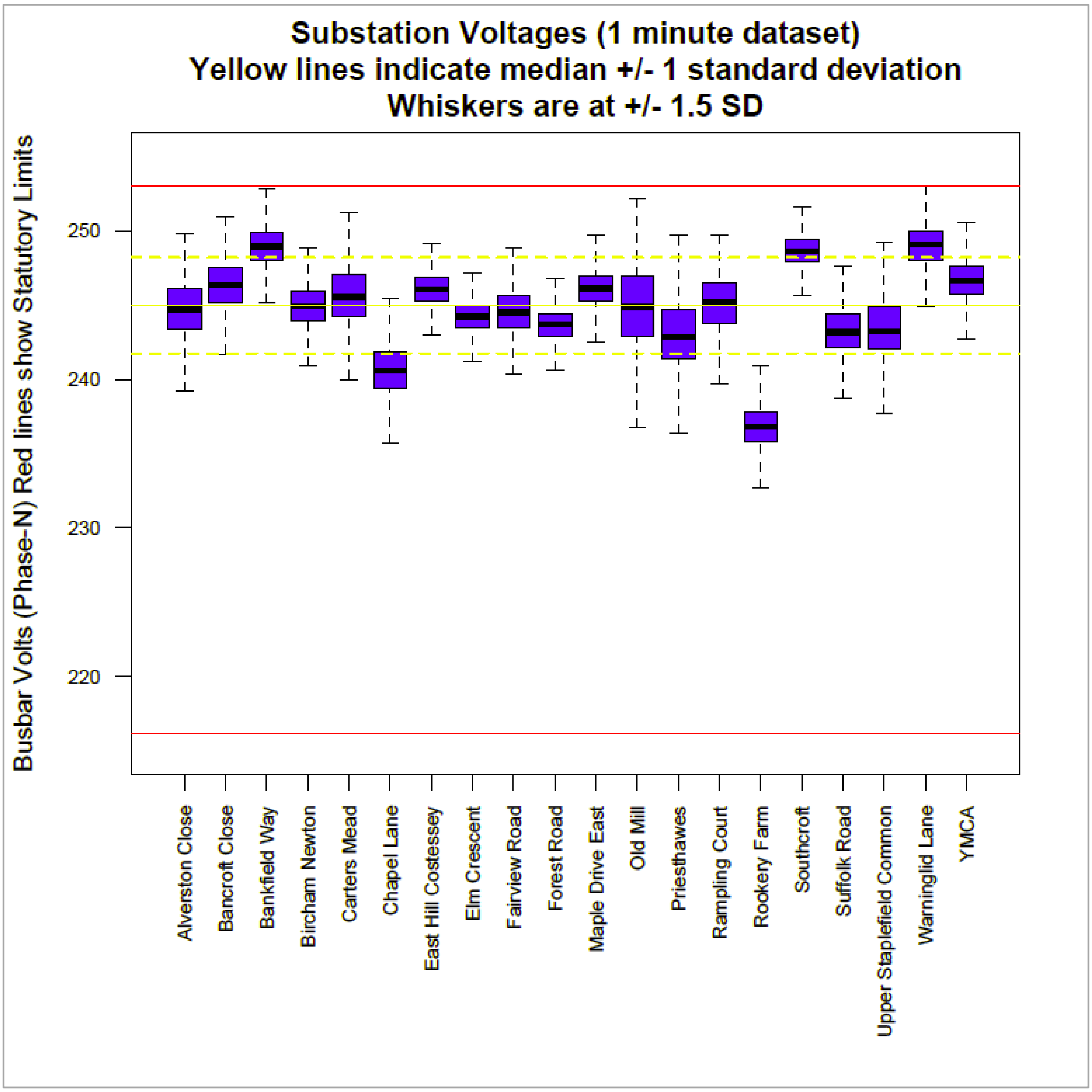


Figure 12 – Substation voltages during periods of low load

4.3.3 Minimum demand

Demand on the same feeder as the PV generators reduces PV-caused voltage rise, by reducing the likelihood and magnitude of reverse power flow. The assumptions previously used in UK Power Networks varied between 0W and 200W (10% of ADMD) per customer.

The Low Carbon London project monitored half-hour consumption of c. 5,600 smart meters from a diverse population for one year. Figure 13[8] shows that minimum diversified daytime demand ranged from about 200W to 400W, depending on the demographic.

[8] "Residential consumer responsiveness to time-varying pricing: Low Carbon London Learning Lab Report A3", Figure 5.29, http://bit.ly/1LhllfO, Retrieved 20 February 2015

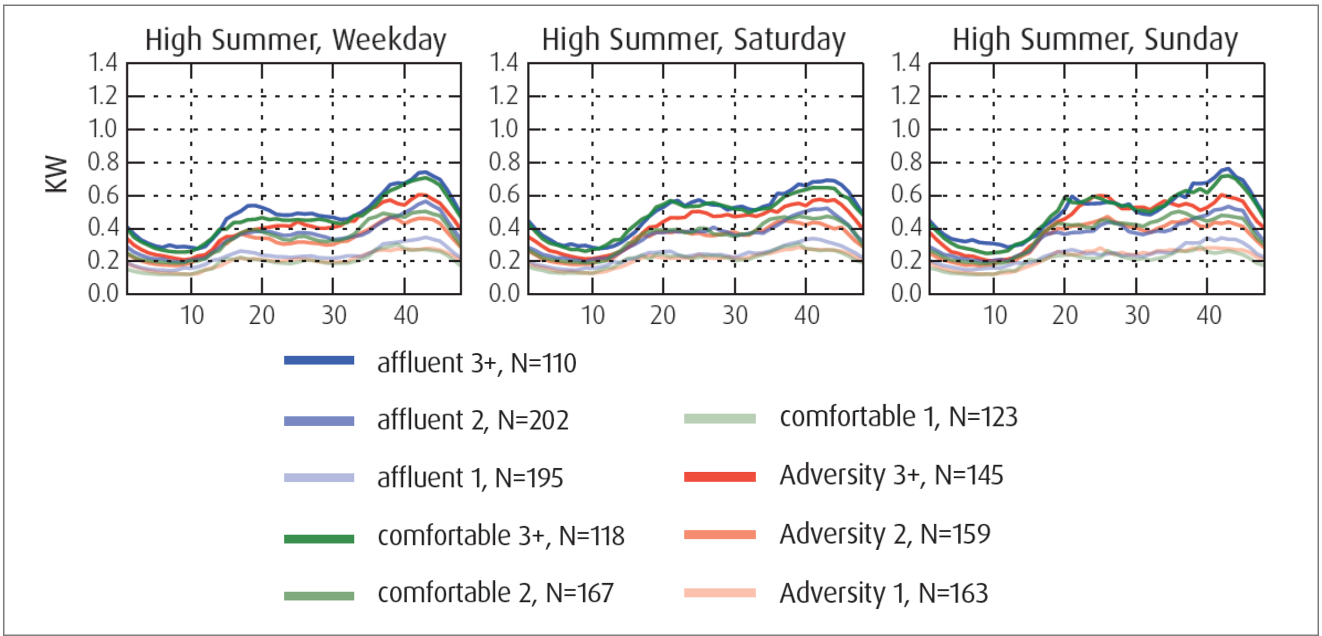


Figure 13 – Average daily profiles for high summer

Based on these data, the recommended assumptions for minimum daytime demand are as follows:

Table 10 – Recommended assumptions for minimum daytime demand

Scenario	Recommended assumption
Feeders with at least 10 customers	200W per customer
Feeders with at least 10 customers AND the area's demographic indicates high energy use	Up to 400W per customer *(This would only be applied when necessary to obtain an acceptable voltage rise result. High energy use can be confirmed by checking total annual consumption of houses in the area.)*
Feeders with less than 10 customers	0W per customer *(to allow for lack of diversity)*

4.3.4 **Phase imbalance**

PV generators are unlikely to be perfectly balanced across phases. UK Power Networks previously assumed that existing PV generators were balanced, which may have led to optimistic voltage rise assessments.

The imbalance of PV generators could not be measured directly, but was inferred to be similar to the imbalance of average loads, which <u>can</u> be measured.

Figure 14 and Figure 15 show the imbalance of average loads on urban and rural residential feeders.

- The dataset is restricted to 5pm to 8pm to ensure that the power measurements are dominated by demand rather than PV.
- Urban and rural feeders were considered separately, because rural feeders tended to have higher phase imbalance (likely because they had less customers, and often had single-phase or two-phase feeders.
- Warninglid Lane was considered separately from other rural feeders, because it only serves three customers, two of whom are on the same single-phase spur. All other rural feeders served at least 10 customers.

Based on these data, the recommended assumptions for phase imbalance of existing single-phase PV generators are as follows:

Table 11 – Recommended assumptions for phase imbalance of existing single-phase PV generators

Scenario	Recommended assumption	How 30kW would be distributed
Urban residential feeders	25% *(one standard deviation above the mean observed in this trial)*	A=12.5kW B=8.75kW C=8.75kW
Rural residential feeders with at least 10 customers	50%	A=15kW B=7.5kW C=7.5kW
Rural residential feeders with less than 10 customers	Assume all on same phase unless network plans clearly indicate otherwise	A=30kW B=0 C=0

These recommendations assume a need to prevent phase imbalance from causing overvoltages. Once smart solutions are available to quickly diagnose and rectify phase imbalance, these recommendations could be relaxed.

In rural areas, some PV customers are the only customer at the end of a long single-phase feeder. In these scenarios, the voltage rise can be up to **six times higher** than expected for an equivalent three-phase generator:

- The phase current for a single-phase generator is three times higher than for a three-phase generator of the same kW rating, which **triples the voltage rise** on the phase conductor; and
- Single-phase generators will also cause an equivalent voltage drop on the neutral conductor, **which doubles the phase-neutral voltage rise** seen at the customer’s terminals (assuming all current returns via the neutral conductor, and the neutral and phase conductors are the same size).

The improved PV connection assessment tool allows for these effects. **If modelling a single-phase generator in a tool that assumes all generators are three-phase balanced, either the generator size or the voltage rise result should be multiplied by six**.

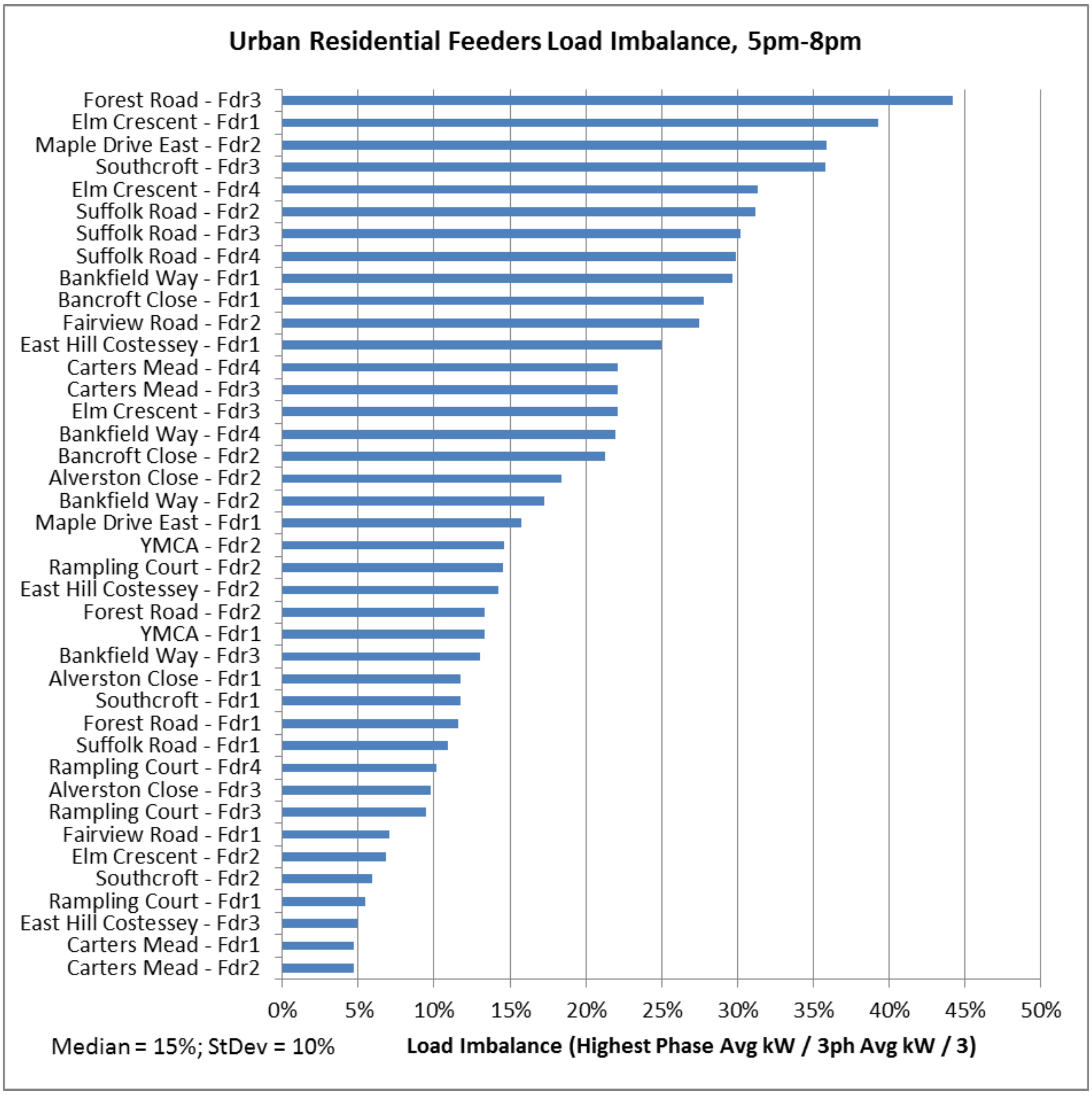


Figure 14 – Load imbalance at urban residential substations

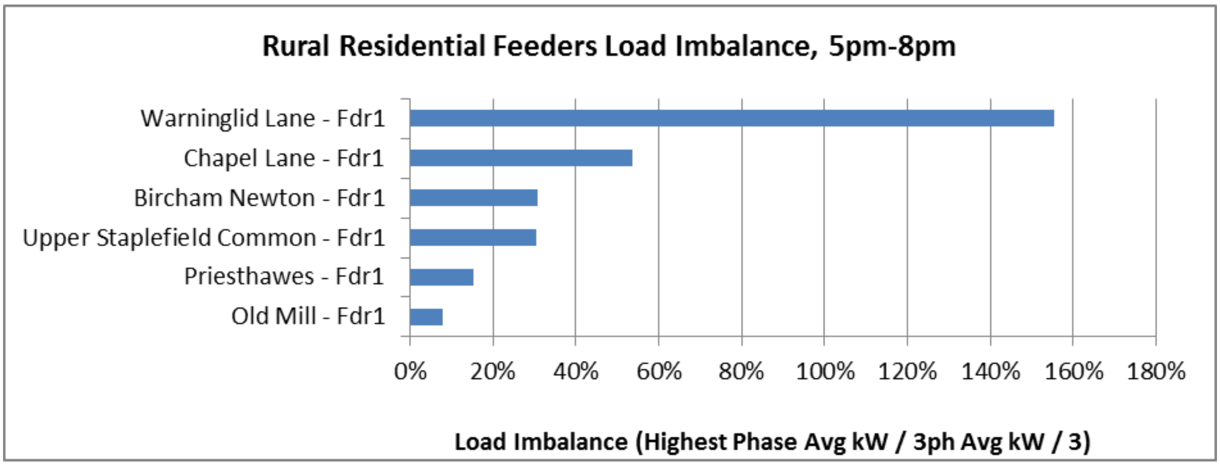


Figure 15 – Load imbalance at rural residential substations

(NB Warninglid Lane is mostly single phase)

4.3.5 **Accuracy of G83 notifications register**

This project found several instances where UK Power Networks' G83 notification register was incorrect, including:

- Installations that were notified to UK Power Networks with incorrect ratings – see Table 13 (page 46);
- Installations that were notified to UK Power Networks as having been commissioned, but could not be found at site; and
- Installations that were visible at site or in aerial photos, but had not been notified to UK Power Networks. For example, Google Maps showed many PV panels at the Rampling Court trial site, but none were recorded in the G83 notifications register.

Figure 16 – PV panels at Rampling Court

Table 12 shows that according to Ofgem's FiT register, PV penetration may actually be 50% more than reported to UK Power Networks in its licence areas.

Table 12 – UK Power Networks G83 Notifications Register vs Ofgem's FiT Register

Installations ≤4kW	UK Power Networks' G83 Notifications Register *As at 1 November 2014*	Ofgem's FiT Register *As at 30 September 2014*
No of PV Installations	62,000	91,000
Total PV kW	178,000	271,000

These findings demonstrate that:

- **G83 notifications are not accurate, and DNOs need access to better information about the existing PV generation connected to their networks**.
- In the meantime, public-domain aerial photography, if recently updated, can be a useful tool for identifying unreported PV installations.

4.4 Trial Method 3: Understand the impacts of PV generation on LV distribution networks

Result:	• The six endpoint sites were amongst the most heavily PV-penetrated locations in EPN and SPN, yet PV did not cause any voltages to exceed statutory limits. This indicates that in general, the EPN and SPN networks are performing well with current PV penetration levels, and most LV feeders will continue to perform well in a low-carbon future, where more renewable energy is connected. • However, voltages at some sites were approaching statutory limits. This indicates that as the uptake of PV generation continues, new voltage control solutions will be needed to mitigate issues in areas of unusually high PV penetration. • PV generation caused measureable voltage rise along LV feeders. However, this had relatively little influence on endpoint voltages, which depended mainly on voltage regulation on the HV network and distribution transformer. • Small-scale PV generation did not cause any increase in harmonics or phase voltage imbalance on LV feeders. • Variations in panel orientation do not necessarily create diversity in the output of PV clusters, if they include undersized inverters. • Many PV generators are capable of generating 100% of nameplate rating, and exporting at >94% of nameplate rating, and hence should not be de-rated for planning purposes. • PV generators can potentially achieve higher peak output on cloudy days than on clear sunny days, due to temperature's effect on efficiency. • Nameplate ratings are often recorded incorrectly on G83 notification forms.

This part of the trial analysed the collected data to understand how PV generation was impacting the LV network.

4.4.1 **PV output and diversity**

Result:	• PV output depends on time of year, time of day, solar radiation, and panel orientation. • Four of six PV installations generated at 100% of nameplate output in at least 4 hours of the day. • Four of six PV installations exported >94% of their nameplate rating at least once during the trial. • Timing of PV output depends on panel orientation, but variations in panel orientation do not necessarily create diversity in the output of PV clusters, if they include undersized inverters. • All six PV installations in the trial had been notified to UK Power Networks with incorrect ratings. • It is unclear whether peak PV ratings in UK Power Networks' licence areas are overstated to the same extent as found by other DNOs.

Figure 17 confirms that **PV output depends on time of year and time of day**:

- The highest peak PV output occurred in summer, around solar noon.
- Peak PV output was higher in summer and lower in winter.
- PV output duration (hours) were longer in summer and shorter in winter.

There were also some days of atypically low PV output during summer, e.g. on days 191 and 192 (10 and 11 July 2014), indicating that PV output may also depend on weather.

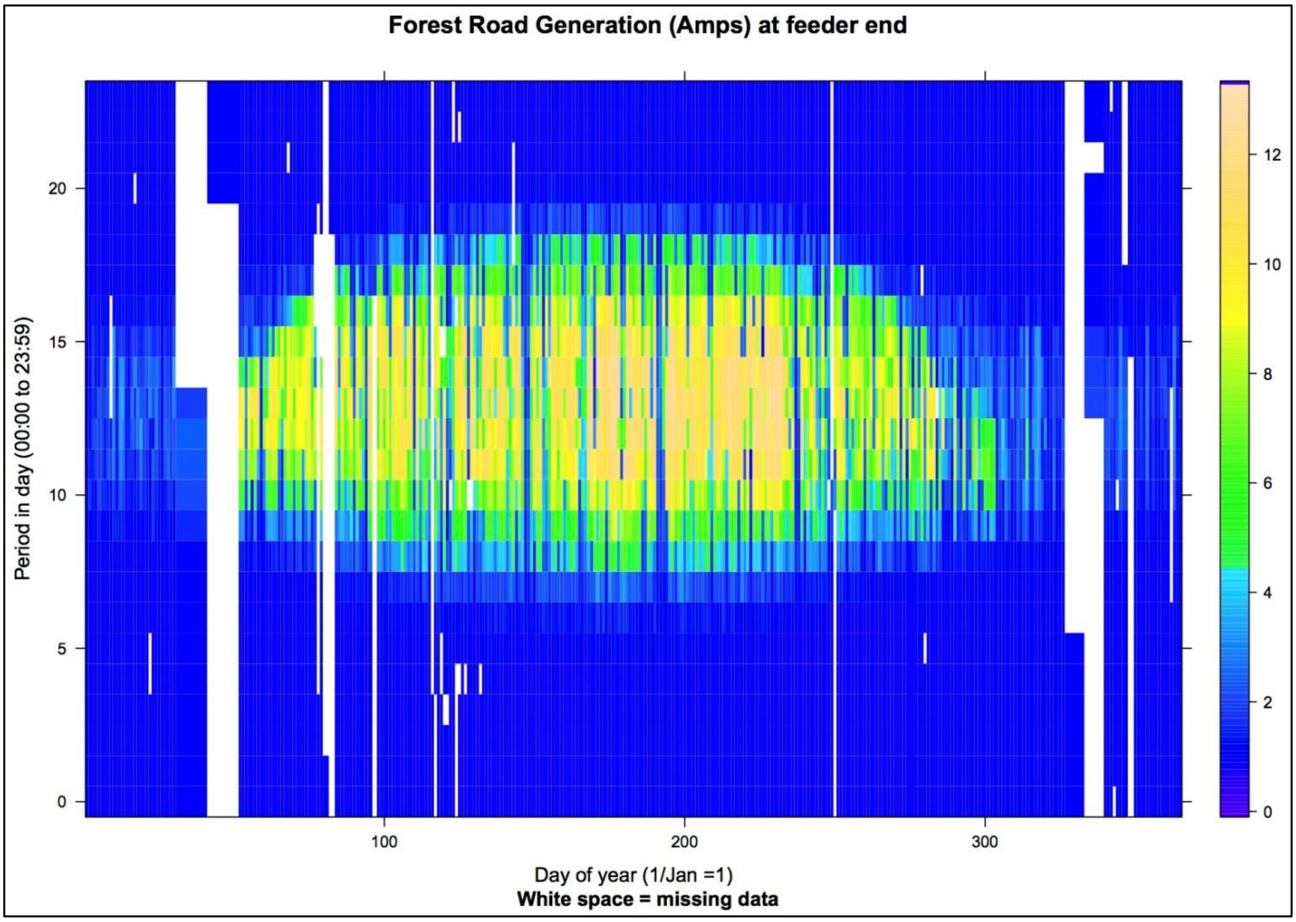


Figure 17 – PV generator output at Forest Road

Figure 18 shows the correlation between PV output and solar radiation, and confirms that **PV output depends on solar radiation**.

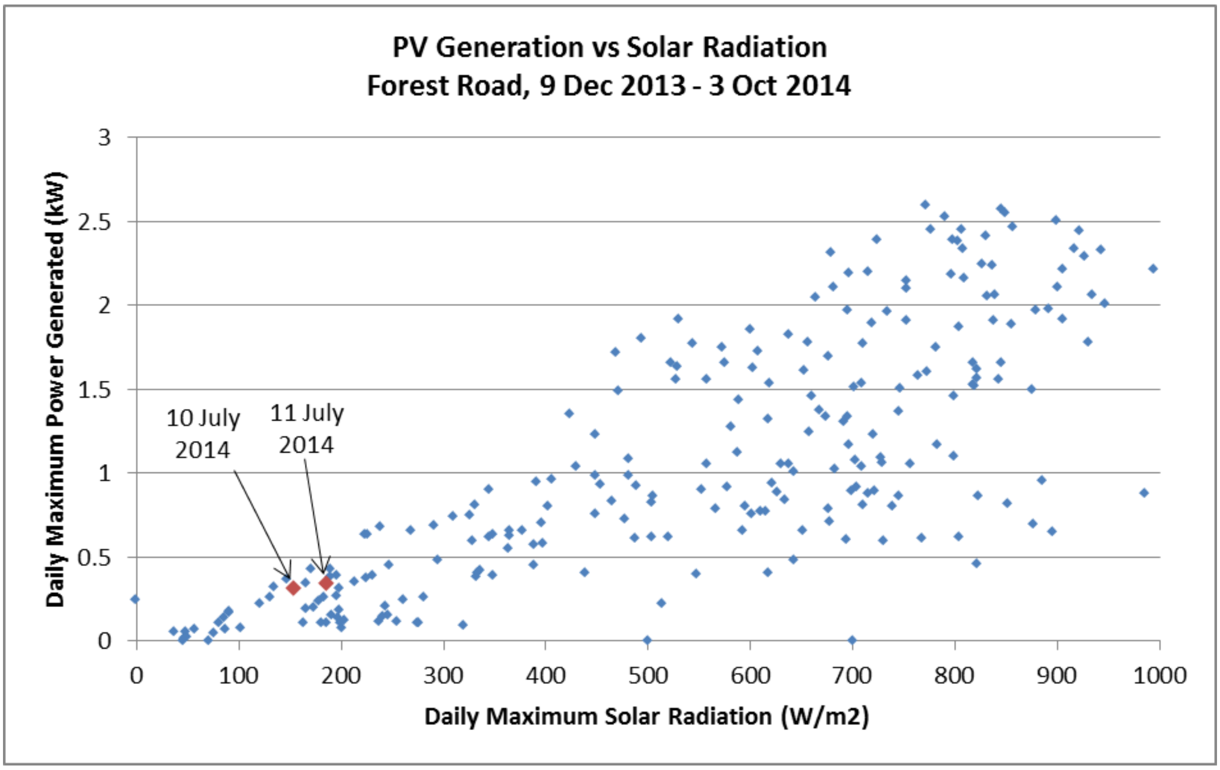


Figure 18 – PV generation vs solar radiation at Forest Road

Figure 19 (per unit) and Figure 20 (kW) show each PV installation's maximum output envelope for three weeks around the 2014 summer solstice. The results show that:

- **Four of six PV installations generated at 100% of nameplate output in at least 4 hours of the day:** For example, Suffolk Road generated at its nameplate output (0.5kW) in every hour between 9am and 5pm. This installation comprised a 0.74kW array connected to a 0.5kW inverter, causing its output profile to be lopped at 0.5kW. The other installations with lopped output profiles most likely also had undersized inverters.
- **Timing of PV output depends on panel orientation**: the output profiles of East-facing installations (e.g. YMCA) peaked earlier in the day than West-facing installations (e.g. Suffolk Road).
- **However, variations in panel orientation do not necessarily create diversity in the output of PV clusters, if they include undersized inverters:** It was expected that a PV cluster's peak output may be about 10% less than the sum of its nameplate ratings, due to individual installations peaking at different times[9]. However, these six PV installations' peaks coincided at about 10-11am, indicating that this 'virtual' PV cluster had no diversity, despite varying panel orientations. The same effect would occur in real PV clusters that include enough lopped output profiles caused by undersized inverters. Further research may be required to understand how often this occurs in practice.

[9] "Voltage control in low voltage networks by Photovoltaic Inverters – PVNET.dk", http://bit.ly/16z5r02, retrieved 6 February 2015

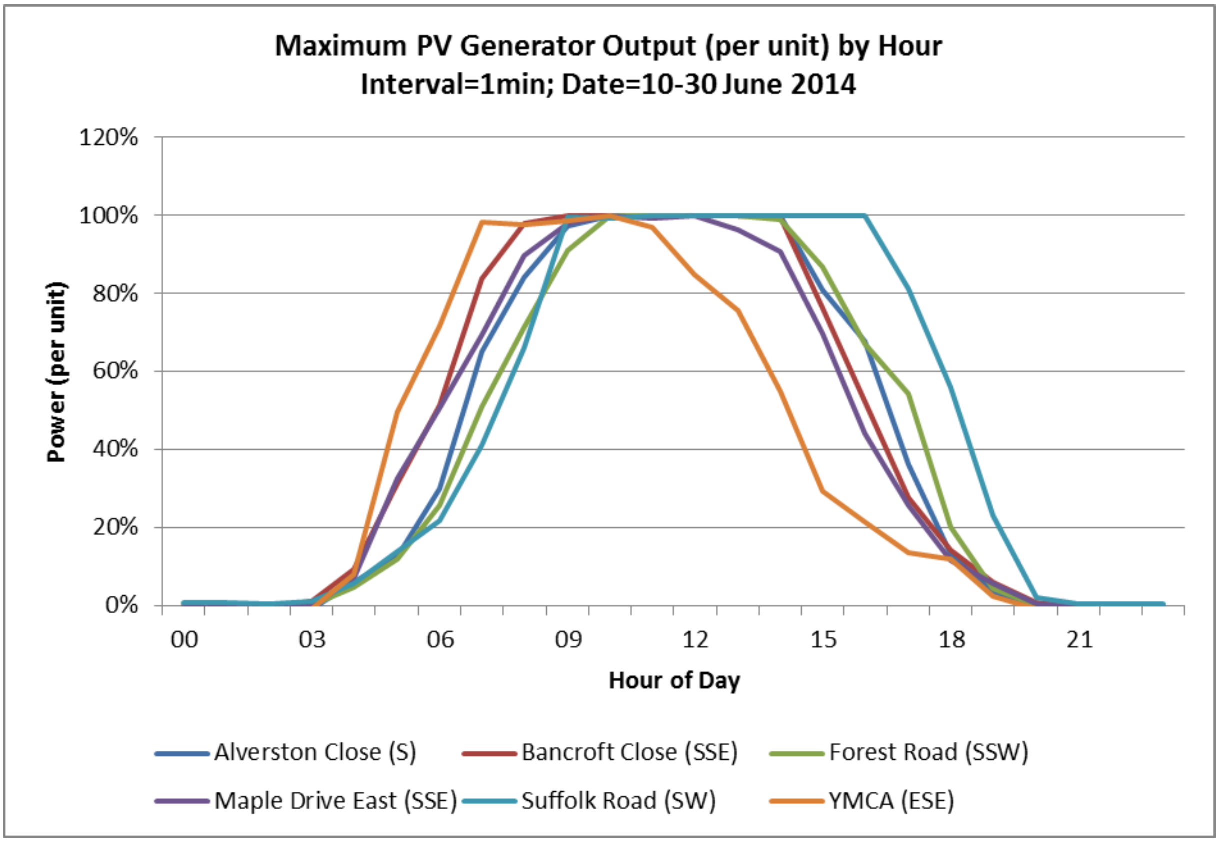


Figure 19 – Maximum PV generator output (per unit) by hour

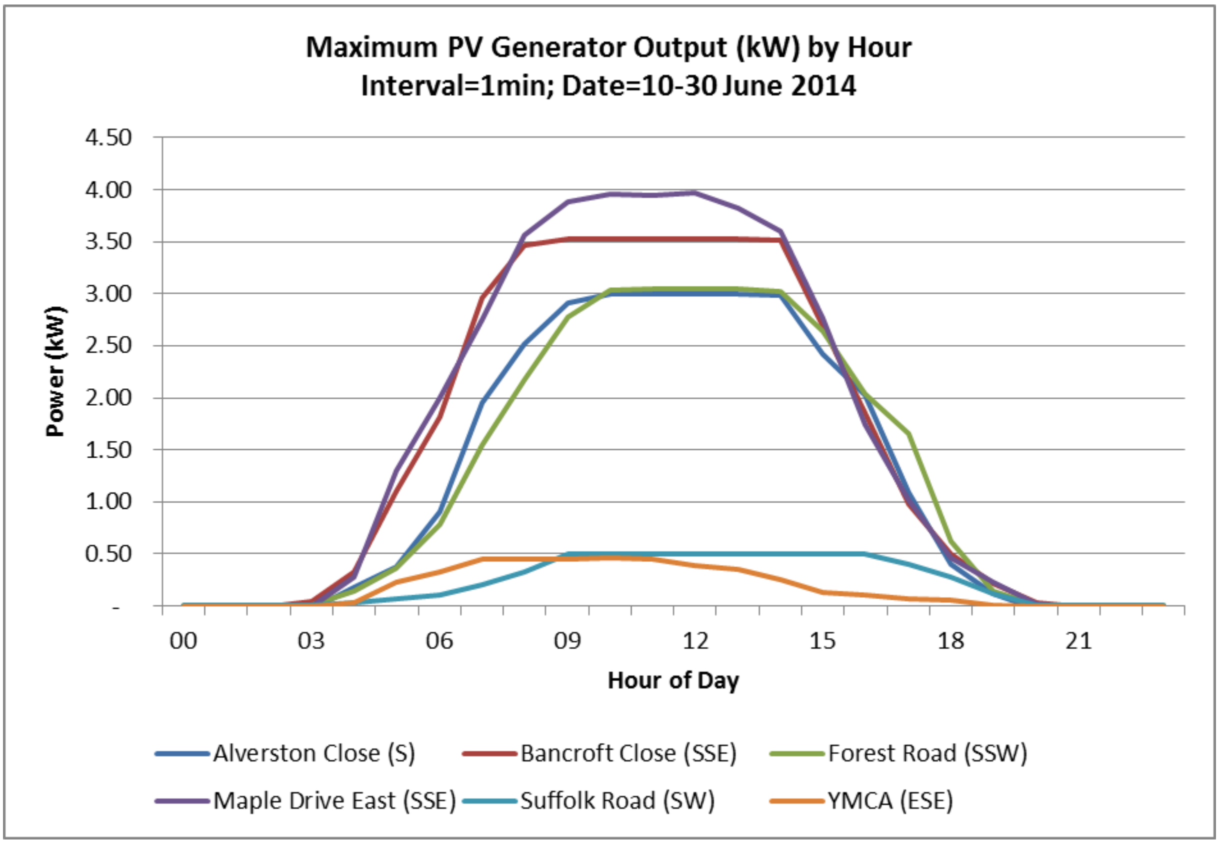


Figure 20 – Maximum PV generator output (kW) by hour

Table 13 shows that **all six PV installations in the trial had been notified to UK Power Networks with incorrect ratings.**

- In two cases (indicated in **red**), the notified rating was significantly different from the actual rating. In both these cases, it was found that the installer had made a mistake on the G83 notification form.
- In three other cases (indicated in **blue**), the notified rating was about 10% more than both the observed and nameplate inverter ratings.

Table 13 – PV installations ratings – G83 notification vs nameplate vs measured

PV Installation Site	Output (kW)			
	As per G83 Notification	Inverter Nameplate	Panels Nameplate	Measured Peak
Forest Road	**3.29**	3.00		3.00
Suffolk Road	**1.52**	0.50	0.74	0.50
Bancroft Close	**1.89**			3.50
Alverstone Close	**3.29**	3.00		3.00
Maple Drive East	3.83	4.00	3.92	4.00
YMCA	**0.60**	0.52		0.45

This further supports Trial Method 2's finding that

G83 notifications are not accurate, and DNOs need access to better information about the existing PV generation connected to their networks.

Figure 21 shows that **four of six PV installations exported >94% of their nameplate rating at least once during the trial**.

Figure 22 – PV Output at Maple Drive East on 21 June 2014 vs 25 June 2014 – shows that **PV generators can potentially achieve higher peak output on cloudy days than on clear sunny days, due to temperature's effect on efficiency**:

- On the clear sunny day (21 June 2014), the PV generator's output was limited to about 80% of its nameplate rating. Some reduction was expected, because the panels would have remained warm (and hence operated at reduced efficiency) for the entire day.
- On the day with scattered cloud (25 June 2014), the PV generator's output peaked at 100% of its nameplate rating. This appears to be because the cloudy periods allowed the panels to cool down, so that when the sunshine returned, the panels could operate at full efficiency for a brief period before they warmed up. This can also be observed on the sunny day at about 9am, and again at about 2pm.
- The second day also had slightly lower ambient temperature, and slightly higher peak solar radiation, which may have also contributed to this effect.

This effect was most pronounced at Maple Drive East, because it did not have an undersized inverter. The effect was observable, but less pronounced, at other sites that did have undersized inverters.

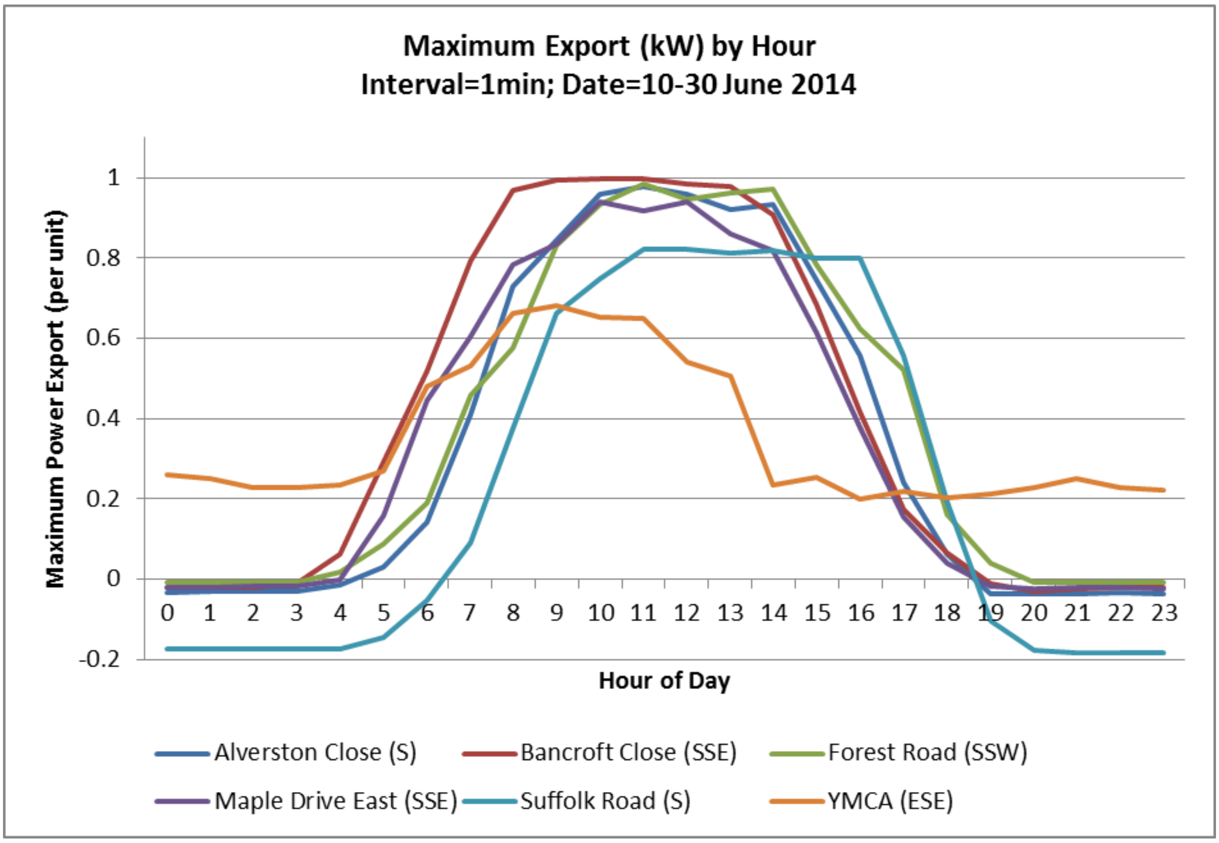


Figure 21 – Maximum Export (kW) by Hour

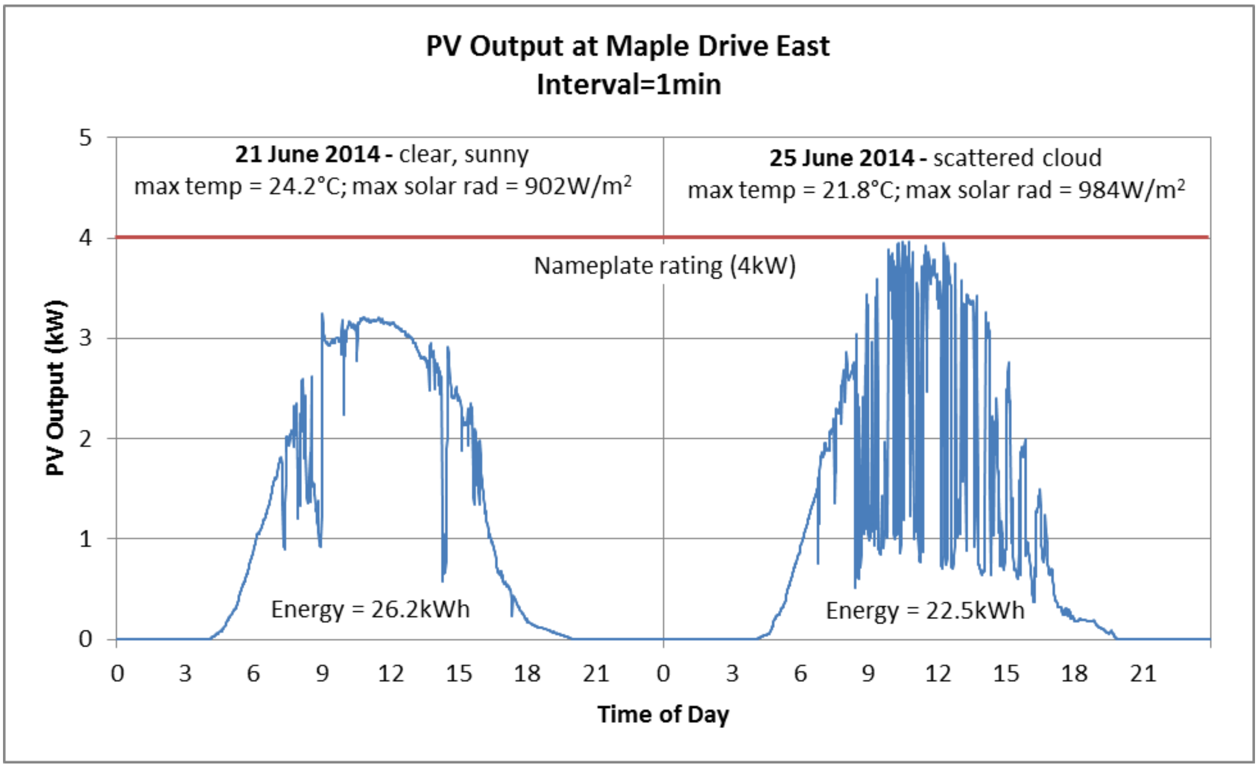


Figure 22 – PV Output at Maple Drive East – clear sunny day vs scattered cloudy day

Western Power Distribution's "LV Network Templates" project[10] concluded that:

- "*the maximum proportion [of actual to potential output] observed at any installation [during the project] was 81.1%*";
- *"There is likely to be even more than 19% overstatement of peak rating in more northerly parts of the UK from South Wales, and slightly less to the South Due to the variation in solar irradiation"*; and
- *"The impact to network planning in its simplest view is that an additional 20% network headroom as been identified, allowing for further distributed generation to be connected to the network without the need for reinforcement".*

Based on the findings of this project, **it is unclear whether peak PV ratings in UK Power Networks' licence areas are overstated to the same extent as found by other DNOs**.

The difference in results can possibly be explained by the difference in measurement intervals:

- WPD's project measured <u>average</u> kW at <u>30min intervals</u>. This is appropriate for considering compliance with thermal ratings; whereas
- This project measured <u>instantaneous</u> kW at <u>1min intervals</u>. This is appropriate for considering compliance with statutory voltage limits, for which the ESQCR does not specify any acceptable over/undervoltage duration.

[10] "LV Network Templates For A Low-Carbon Future – Close Down Report" http://bit.ly/1vw0tx7, Retrieved 06 February 2015

4.4.2 Voltage rise

Result:	• PV generation caused measureable voltage rise along LV feeders. However, this had relatively little influence on endpoint voltages, which depended mainly on voltage regulation on the HV network and distribution transformer. • On average, the endpoint voltage rise due to PV occurred 60% on the LV feeder, and 40% on the HV network and distribution transformer. • Substation and endpoint voltages were both generally within statutory limits. Only one endpoint site experienced regular overvoltage incidents, and these were caused by a faulty AVC relay, not by PV generation. • PV generation may pose a greater risk of overvoltages on small transformers (<200kVA), which are more common on rural/overhead networks.

Voltage measurements were analysed to determine how they depended on PV generator output:

- Endpoint voltage;
- Substation voltage (three-phase average); and
- Voltage rise along the LV Feeder (the difference between endpoint voltage and substation voltage).

Individual voltage measurements could not be used to directly measure the voltage rise due to PV, because individual measurements were highly dependent on other randomly varying variables such as demand.

Instead, the method of least squares was used to approximate a linear relationship between each set of voltage measurements, and the corresponding PV output measurements:

- It was assumed that the aggregate output of all PV generators in the locality (and their effect on the endpoint voltage) follows the output of the monitored PV generator.
- The dataset was restricted to 11am–1pm and June–August to ensure that any variations in demand and OLTC operations would be random with respect to PV generation, and hence not influence the slope of the fitted line. (Average demand rises in late afternoon as PV output is falling, causing a change in voltage that would appear to depend on PV.)
- PV generator output was expressed in per-unit terms, so that the slope of the fitted line directly indicated the voltage increase caused by PV generation.
- NB when measuring the voltage rise along the LV feeder, the slope indicates the <u>increase in voltage rise caused by PV</u>, as distinct from the <u>maximum voltage rise</u>:

  maximum voltage rise =
  increase in voltage rise caused by PV – voltage drop caused by minimum load

  In other words, **the voltage rise measurements presented in this report ignore any load-related voltage drop, and will hence be slightly higher than the actual maximum voltage rise**.
- Where it was not known which phase the endpoint was supplied from, it was assumed to be on the phase that resulted in the strongest correlation between PV output and voltage rise along the LV feeder.

The results are shown in Table 14, which shows that:

- PV generation caused a measureable voltage rise along the LV feeder at all six sites.
- PV generation caused measureable substation and endpoint voltage rises at all but two sites (Suffolk Road and YMCA). This reflects the fact that these sites had much lower PV penetration than the other endpoint sites (refer Figure 2, page 16).
- On average, the endpoint voltage rise due to PV occurred 60% on the LV feeder, and 40% on the HV network and distribution transformer.
- Endpoint voltage correlated more strongly with substation voltage than with PV output, indicating that overall, endpoint voltage is mainly determined by voltage regulation on the HV network and distribution transformer.

Table 14 – Voltage increases caused by PV Generation

Site	Endpoint Voltage			Substation Voltage		Rise along LV Feeder		
	Rise (V)	ρ(PV)	ρ(SV)	Rise (V)	ρ(PV)	Rise (V)	ρ(PV)	Phase
Alverstone Close	2.99	0.44	0.71	1.18	0.29	2.13	0.44	C
Bancroft Close	2.05	0.33	0.95	0.93	0.16	1.13	0.68	C
Forest Road	2.08	0.47	0.89	0.82	0.23	1.07	0.66	A
Maple Drive East	3.66	0.48	0.64	1.13	0.26	2.92	0.52	C
Suffolk Road	0.39*	0.08	0.70	-0.35*	-0.08	0.78	0.22	A
YMCA	0.62*	0.12	0.93	-0.26*	-0.05	1.03	0.48	C

** weak correlation indicates that PV generation did not have a measureable influence*
ρ(PV) = correlation with PV output; ρ(SV) =correlation with substation voltage

Figure 23 shows that PV output did cause average endpoint voltage to increase, but had relatively little influence, as indicated by the large spread of measurements. This concurs with WPD's finding that *"PV has little direct influence to the voltage at the feeder level although there is some increase of the average voltage at the feeder ends"*[11]. In particular, note that the highest voltage occurred when PV output was 0.3pu, indicating that it was not (entirely) caused by PV.

[11] "LCN Fund Tier 1 Close out Report - Early learning of LV network impacts from estate PV cluster", http://bit.ly/1CB2ytH, Retrieved 6 February 2015

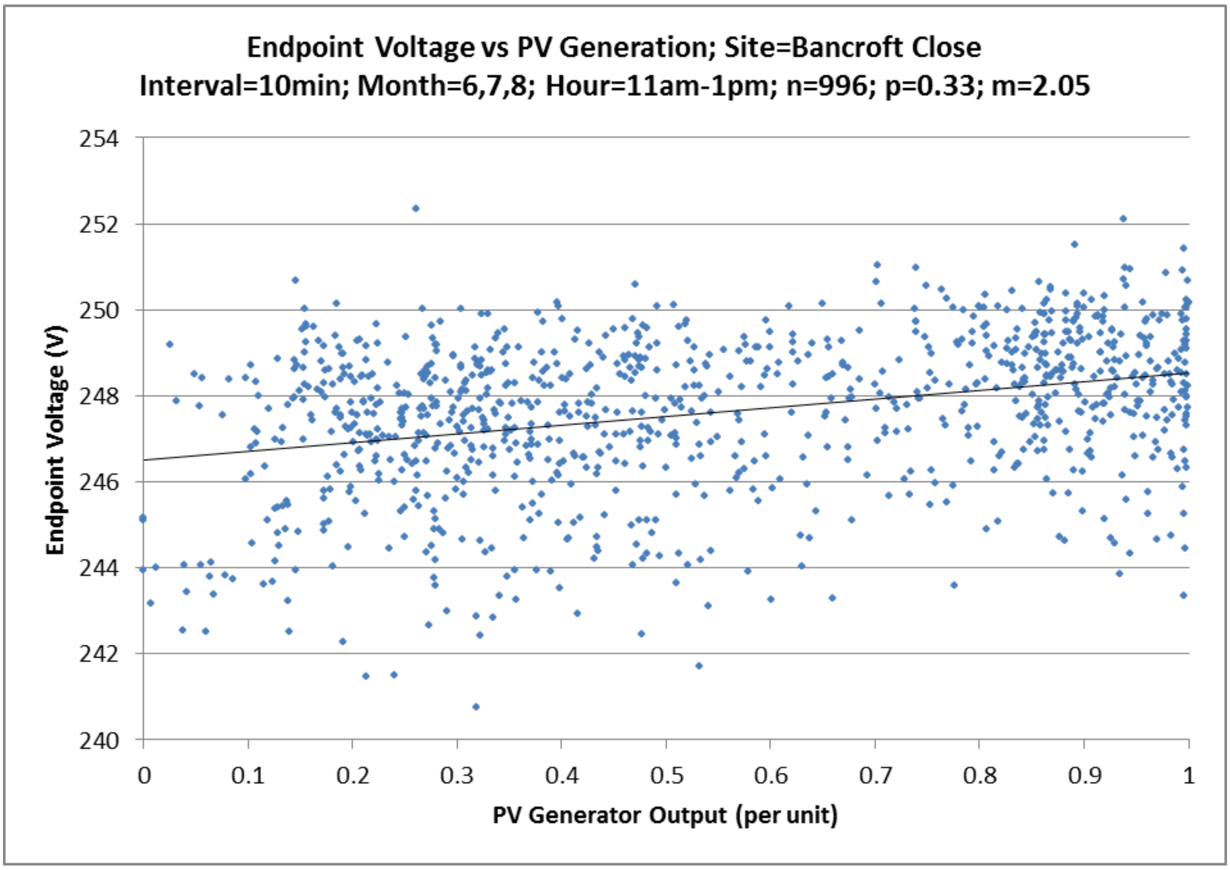


Figure 23 – Endpoint Voltage at Bancroft Close

n = number of measurements, ρ = correlation coefficient; m = slope

Individual measurements of voltage rise along the LV feeder would have been influenced by:

- Demand on the same phase, which reduces voltage rise;
- Demand on other phases, which may increase customers' phase-neutral voltage by displacing the neutral voltage;
- Measurement error, specified as ±0.5% for the equipment used in this project; and
- Imperfect synchronisation of timestamps.

Individual substation and endpoint voltage measurements would have been further influenced by:

- Voltage regulation on the distribution transformer, which mainly depends on its size;
- Voltage regulation along the HV feeder, which mainly depends on distance from the primary substation; and
- Voltage regulation by the primary substation AVC scheme, which depends on: the size of the tap steps, typically 1.25%; the time deadband, typically 90-120 seconds; and any load-drop compensation settings.

Figure 24 shows that four of six sites (Alverstone Close, Maple Drive East, Suffolk Road, YMCA) had their highest average voltages between midnight and 5am, confirming that at these sites, **the highest average voltages were caused by minimum demand, not by PV generation.**

Figure 25 shows measurements of the only significant overvoltages observed during the trial, which were caused entirely by a faulty AVC relay at the upstream primary substation. The overvoltages occurred at night, and returned to acceptable limits as soon as the fault was rectified, confirming that **these overvoltages were not caused by PV generation.**

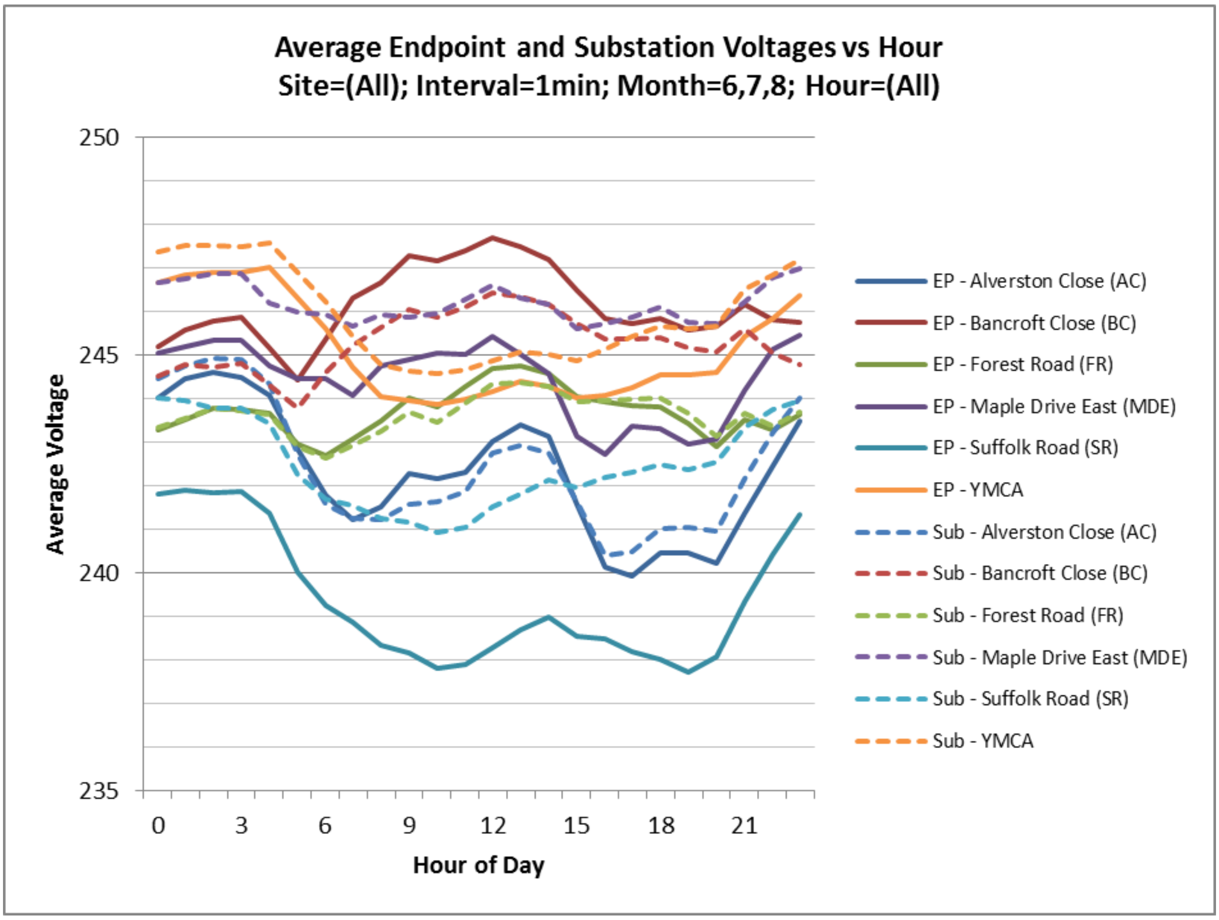


Figure 24 – Average endpoint and substation voltages vs hour[12]

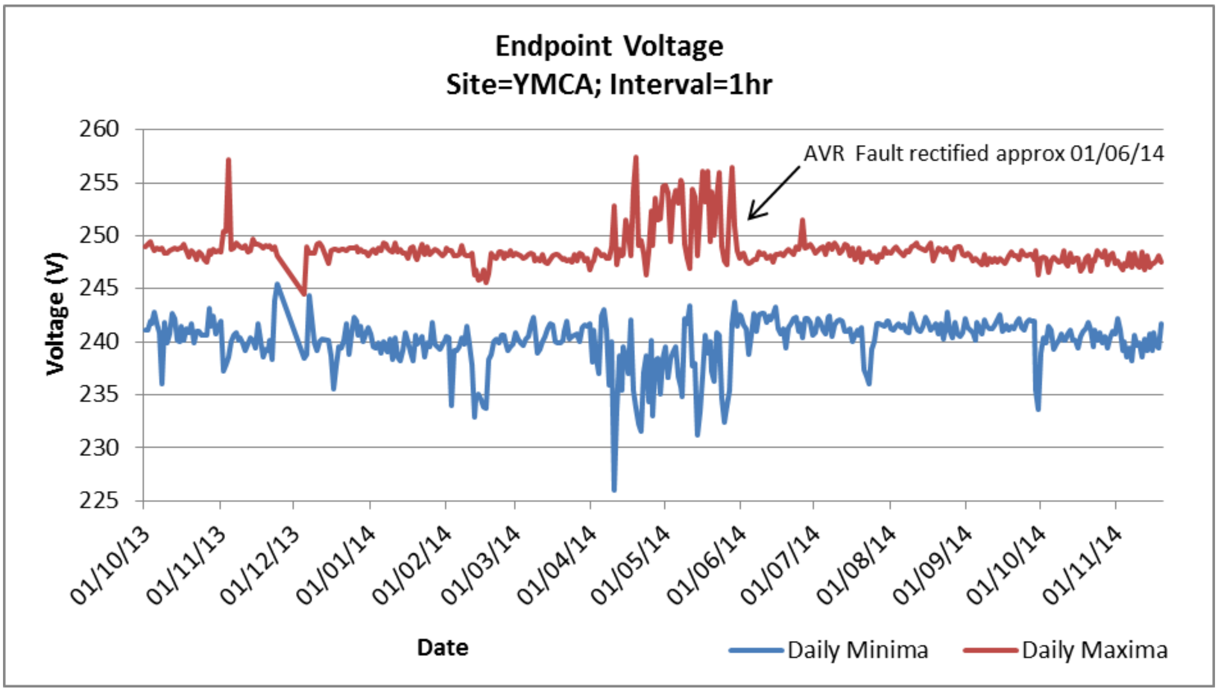


Figure 25 – Endpoint voltage at YMCA, showing AVR fault

[12] The substation voltages shown are from A phase, which is not necessarily the phase the endpoint was connected to – this is the mostly likely explanation for why at Bancroft Close, endpoint voltage appears to be higher than substation voltage even at night.

Figure 26 shows that **substation voltages approached, but were generally within statutory limits**.

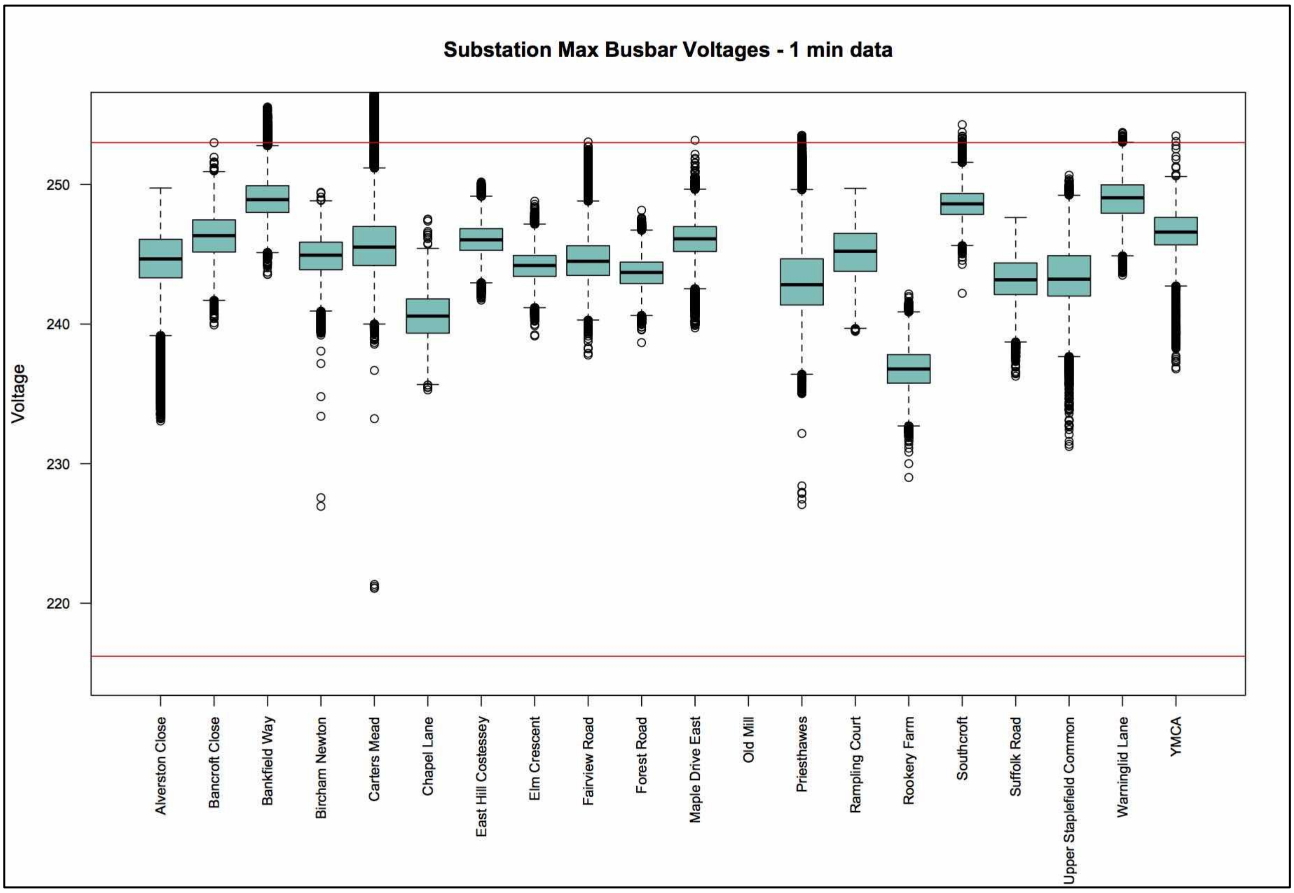


Figure 26 – Substation voltages boxplot – all sites

Figure 27 shows that **voltages varied over a wider range at the smallest substations (50/100kVA)**, as indicated by higher standard deviations. For substations larger than 200kVA, the range of voltage variations did not appear to depend on transformer size. (The higher standard deviations at Alverstone Close and Carters Mead are considered outliers.)   This indicates that **PV generation may pose a greater risk of overvoltages on small transformers (<200kVA), which are more common on rural/overhead networks.**

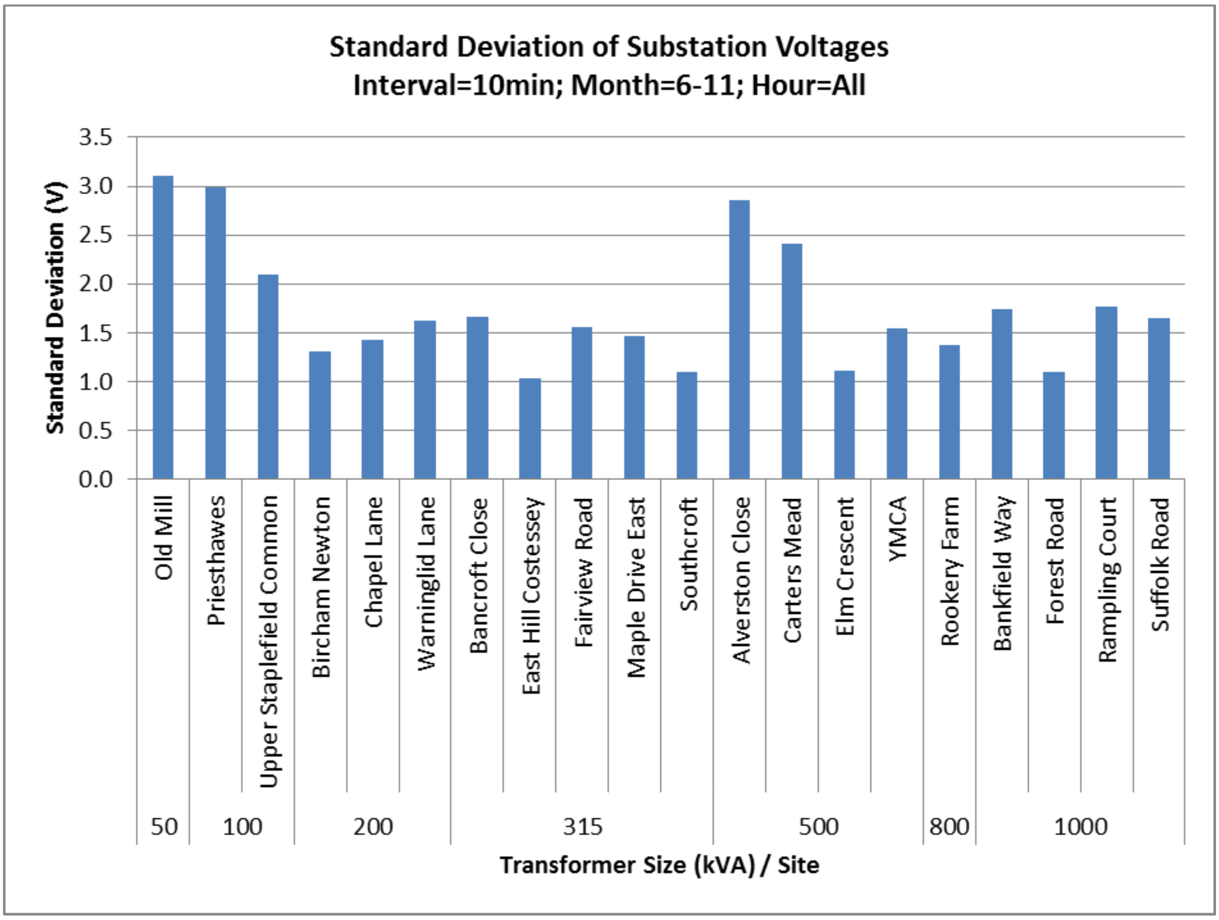


Figure 27 – Standard deviation of substation voltages

4.4.3 Reverse power flow

Result:	• Moderate reverse power flow occurred on domestic feeders. • Very high reverse power flow occurred on industrial/commercial feeders.

Figure 28 shows that moderate reverse power flows occurred on domestic feeders, typically up to 50kW.

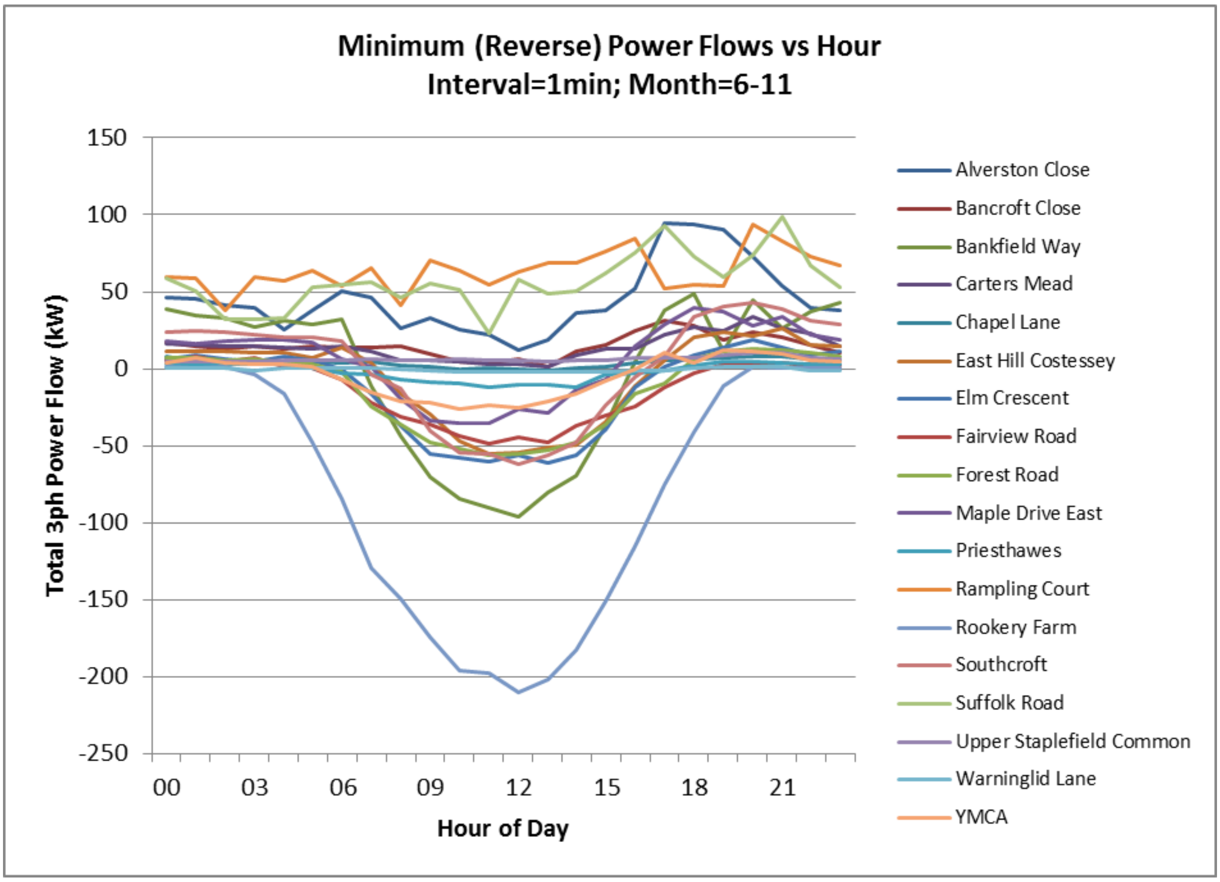


Figure 28 – Reverse Power Flows

Rookery Farm had large reverse power flows of up to 200kW. This reflects that it was an industrial/commercial site with large roof areas per customer, and had 7.4kW of PV generation for every customer connected to the substation. Table 3 (page 17) shows that other (domestic) trial sites only had an average of 1.0kW per customer.

4.4.4 Harmonics

Result:	
	• Small-scale PV generation did not cause any increase in endpoint voltage THD . • Substation voltage THD was higher during periods of low load (overnight, and weekends). • Most PV inverters' harmonic emissions were highest when operating at less than 10% output.

Figure 29 shows that **small-scale PV generation did not cause any increase in endpoint voltage THD** (total harmonic distortion). The measured voltage THD levels were well below the planning limit of 8%[13].

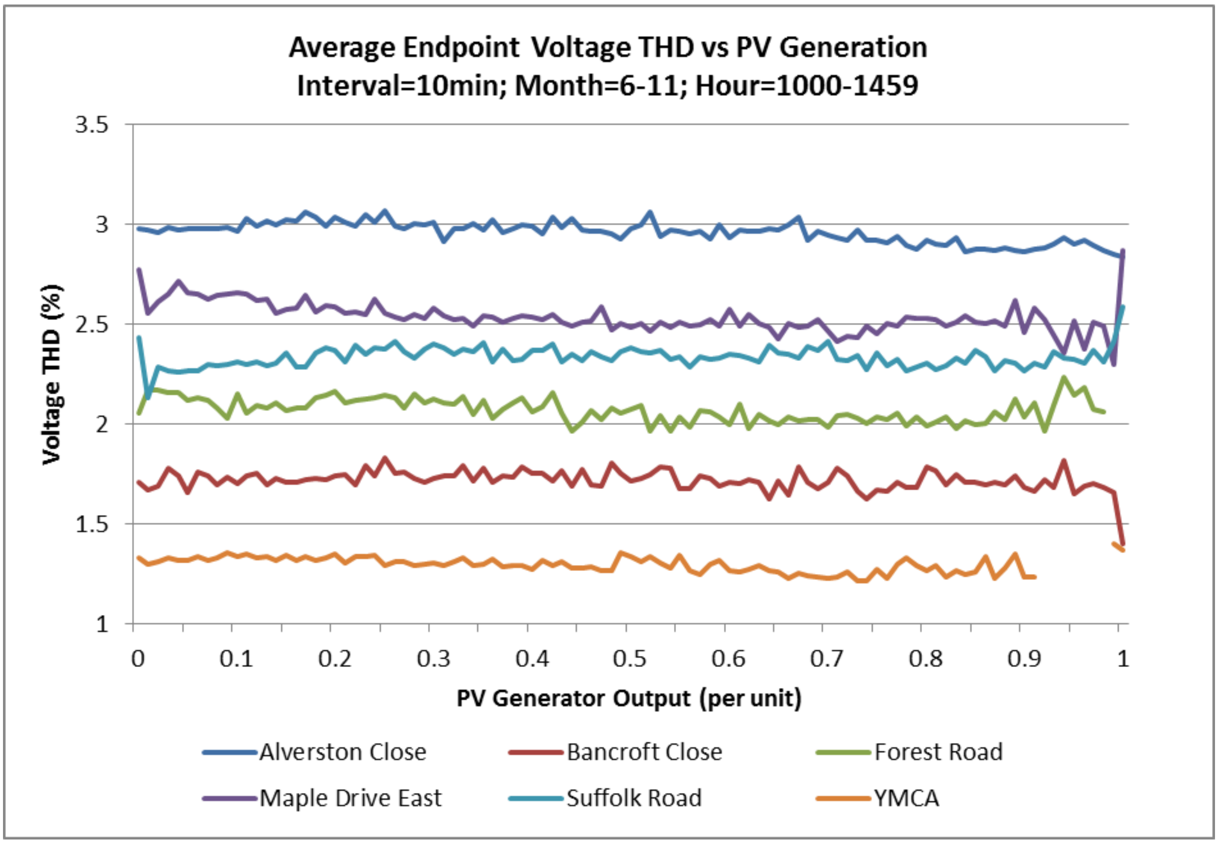


Figure 29 – Average voltage THD at endpoint vs PV Generation

Figure 30 and Figure 31 show that at most sites, **substation voltage THD was higher during periods of low load (overnight, and weekends)**, which is consistent with the findings of SSEPD's "Chalvey" project[14]. Low Carbon London[15] also observed a similar phenomenon with motor-driven domestic loads (i.e. heat pumps) and inverter-connected loads (i.e. electric vehicles).

[13] ENA Engineering Recommendation G5/4: Planning Levels For Harmonic Voltage Distortion And The Connection Of Non-Linear Equipment To Transmission Systems And Distribution Networks In The United Kingdom, October 2005

[14] "LCNF Tier 1 Close-Down Report: Demonstrating the Benefits of Monitoring LV Networks with embedded PV Panels and EV Charging Point SSET1002", http://bit.ly/1LhtZKz, Retrieved 20 February 2015

[15] "Impact of low voltage-connected low carbon technologies on power quality: Low Carbon London Learning Lab Report B3", http://bit.ly/1AoEiYd, Retrieved 20 February 2015

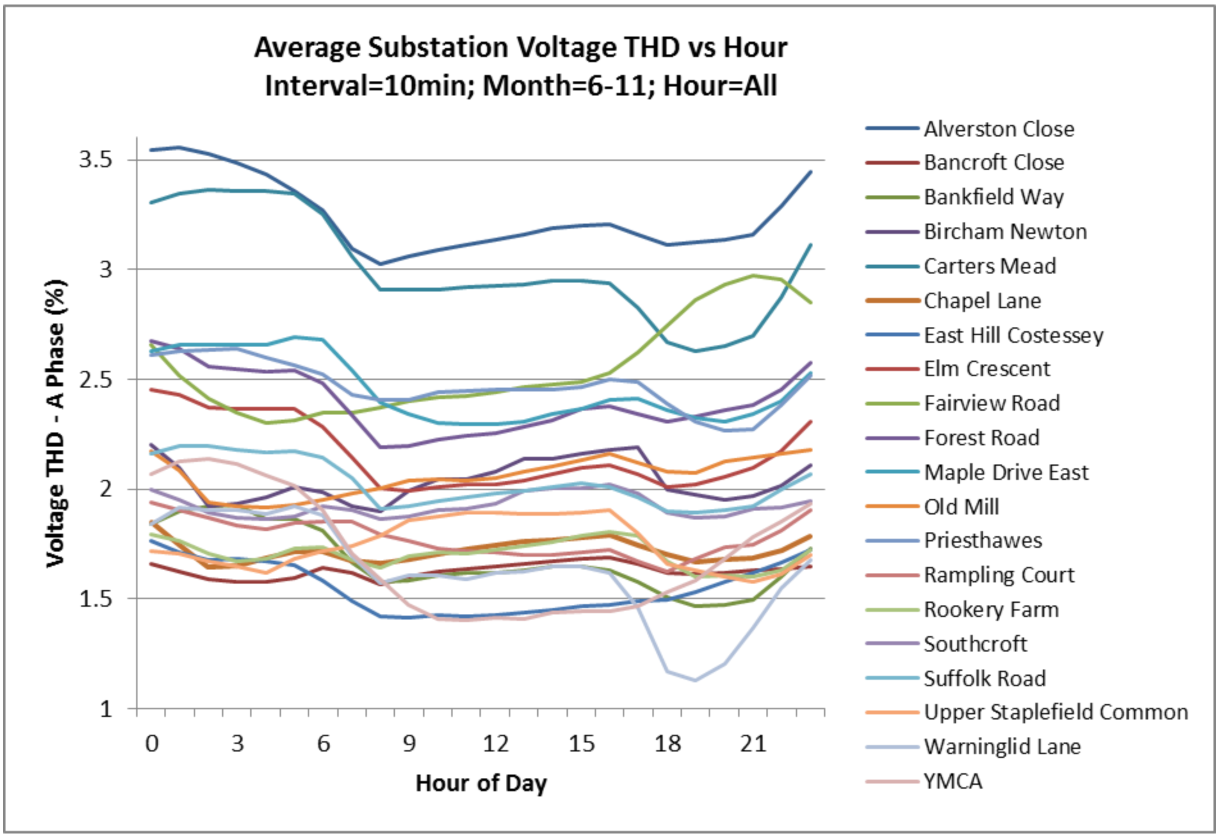


Figure 30 – Average substation voltage THD vs hour

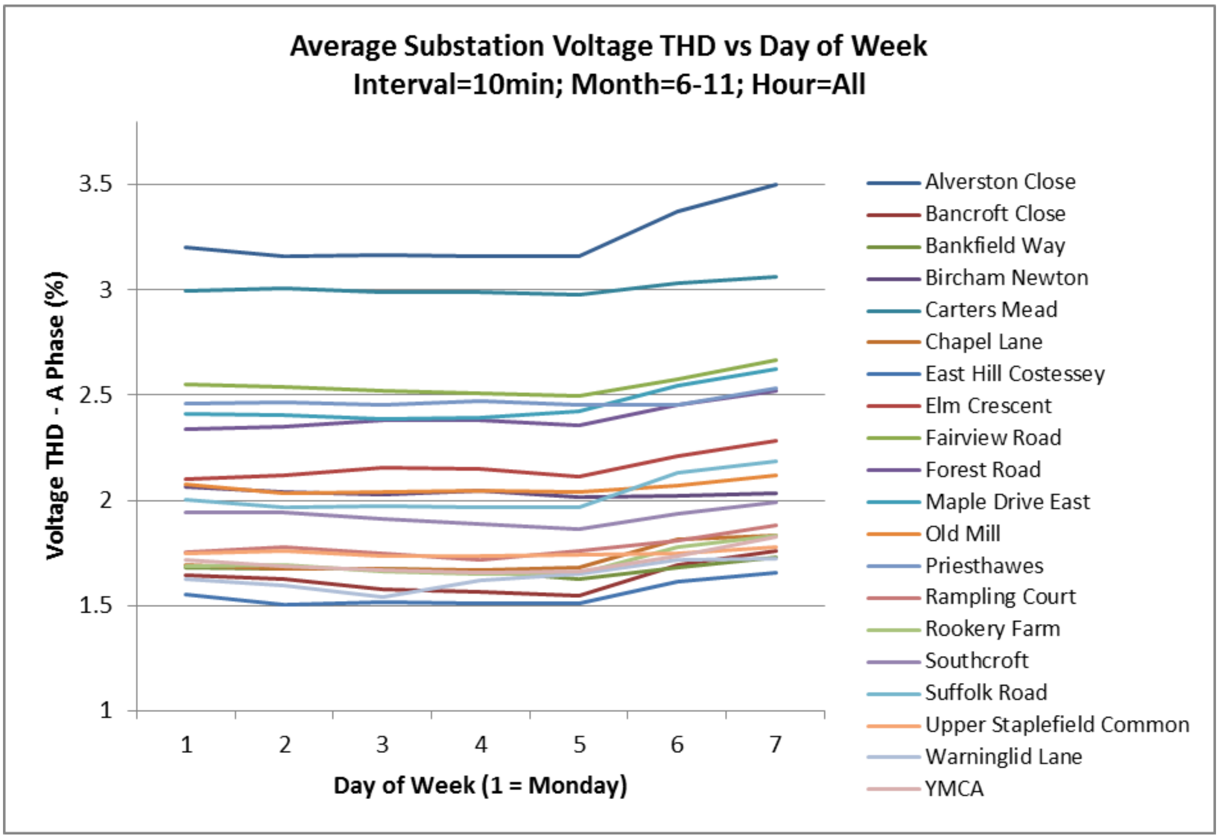


Figure 31 – Average substation voltage THD vs day of week

Figure 32 shows that **most PV inverters' harmonic emissions were highest when operating at less than 10% output**, and harmonic emissions did not increase significantly between 10% and 100%. (NB Alverstone Close is shown on a different scale.)

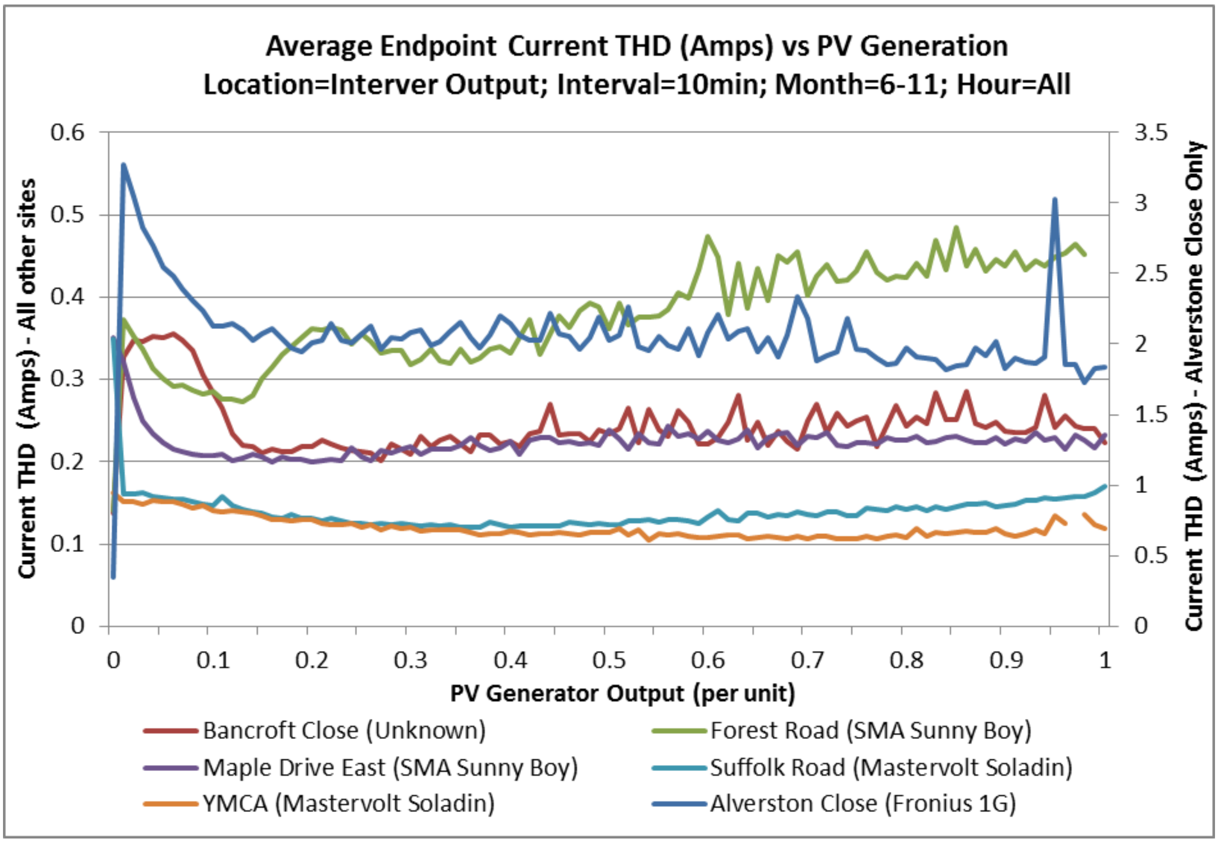


Figure 32 – Endpoint current THD (measured at inverter output) vs PV Generation

4.4.5 Voltage imbalance

Result:	• PV generation did not cause any increase in average substation voltage imbalance.

PV generators may cause more voltage imbalance if they are installed on the less-loaded phases, or may mitigate voltage imbalance if they are installed on the more-loaded phases.

Figure 33 shows that **PV generation did not cause any increase in average substation voltage imbalance**. At Maple Drive East, increased PV generation coincided with a decrease in voltage imbalance, perhaps indicating that more PV generation was installed on the most heavily loaded phase. Voltage imbalance at Alverstone Close was particularly high, which may limit this substation's headroom for PV generation and other low-carbon technologies.

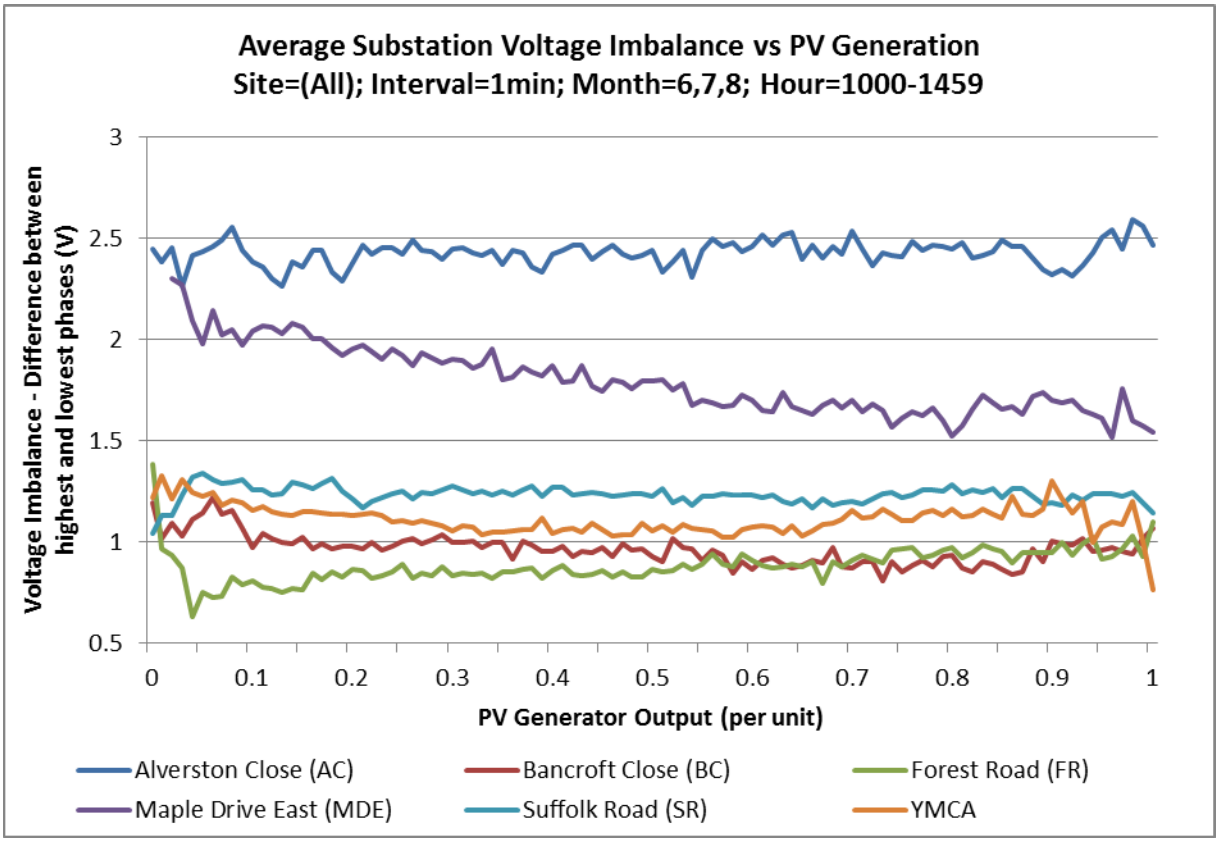


Figure 33 – Average Substation Voltage Imbalance vs PV Generation

4.5 Trial Method 4: Understand solutions available to address network constraints

Result:	• There are many voltage control solutions available in GB. Some require further innovation trials, and some are ready for business-as-usual deployment. Different scenarios call for different solutions: ○ For a small group of affected customers, where the voltage rise is mainly on the LV network: pole-mounted or ground-mounted voltage regulators; ○ For larger groups of affected customers, where there is also significant voltage rise on the HV network: distribution transformer with OLTC, or wide-area voltage control; ○ To address existing or predicted saturation: export limiters or reactive power control on PV inverters; or ○ Where there are also thermal constraints: network meshing, demand side management, or distributed storage.

Trial Method 3 found that PV generation's main impact on the LV network was to raise voltages, indicating that as the uptake of PV generation continues, new voltage control solutions will be needed to mitigate issues in areas of unusually high PV penetration. On average, the endpoint voltage rise due to PV occurred 60% on the LV feeder, and 40% on the HV network and distribution transformer, indicating that solutions to mitigate voltage rise should also address voltage regulation on the high voltage network.

Traditional solutions to voltage complaints involve overlaying cables, or installing a new substation closer to the customer. The latter is often severely delayed, due to difficulties in obtaining wayleaves and planning permission.

Table 15 summarises the LV voltage control solutions currently available in GB. UK Power Networks is investigating several of these technologies for further innovation trials or BAU deployment.

Table 15 – Comparison of available voltage control solutions

Scenario	Recommended Solutions	Advantages	Disadvantages	Maturity	Estimated Cost
When a small group of customers are affected, typically **at the end of a LV feeder**	**Pole-mounted voltage regulators** Power electronic device that regulates voltage to a small group of customers	Can target individual customers Quick to deploy	Only suitable for overhead LV networks Most currently-available products cannot handle reverse power flow	Several products commercially available BaU in Australia	About £2k for a single-phase device

Scenario	Recommended Solutions	Advantages	Disadvantages	Maturity	Estimated Cost
When many customers **on the same LV feeder** are affected	**Ground-mounted voltage regulators** Power electronic device that regulates voltage on individual feeders	As per distribution transformer with OLTC, but can target individual feeders, and balance voltages	Requires a large amount of space in the substation Prototypes' typical dimensions are 1.0 x 0.8 x 0.3m, i.e. about the size of an LV switchboard.	Under development	About £8k for a 200-250kVA unit
When many customers **on the same distribution substation** are affected, especially where **PV is causing significant voltage rise on the HV network**	**Distribution transformer with on-load tap changer (OLTC)** Regulates voltage at the LV busbar	Completely mitigates upstream (HV network) voltage regulation	High Cost Requires existing transformer to be replaced	Several products commercially available GB – ENWL and NPG are trialling BaU in Germany	About £30k per transformer
	Wide area voltage control of primary transformers Lower 11kV target voltage during peak generation times	Low cost Mitigates voltage regulation on the HV network over large areas	May increase OLTC operations (increased wear) Requires LV network monitoring (or smart meter data) to ensure compliance with statutory voltage limits	GB – UK Power Networks trial being considered Trialled in Germany	£35k per primary substation
To allow a new PV generator to connect to an already-saturated network	**Export limiters** Devices that reduce inverter output to prevent them from exporting more than a set limit, or at all May operate in conjunction with an electrical or thermal energy (e.g. hot water) storage system	Low cost May suit industrial and commercial customers who aim to offset on-site demand rather than export Allows additional PV generators to connect when there is no available headroom	May reduce domestic customers' FiT or export income unless they have high daytime consumption, or an energy storage system May requires change to ENA standards	BaU in Australia	TBC (customers may need additional equipment)

Scenario	Recommended Solutions	Advantages	Disadvantages	Maturity	Estimated Cost
As a proactive measure to delay PV saturation	**Reactive power control on PV inverters** Typically implemented as a fixed leading power factor (i.e. import reactive power when exporting real power)	Low cost	May increase network losses Effectiveness limited to size of PV inverters May require changes to ENA standards May reduce domestic customers' FiT or export income	BaU in Australia and Germany	Nil (assuming customers' inverters already have this capability)
Where the feeder or substation also has **thermal constraints** that need to be addressed	**Network meshing** Interconnection of existing LV networks using power electronics to redistribute load and PV generation	Also mitigates thermal constraints	Unsuitable for rural networks, which is where PV generation is most likely to cause constraints	GB – UK Power Networks and ENWL are trialling	TBC
	Demand side management Incentivise energy consumption or storage during peak generation times to reduce reverse power flows	Also mitigates thermal constraints	In residential areas, relies on customer behaviour	GB – several DNOs have trialled BaU in Germany	TBC
	Distributed energy storage Store energy during peak generation times to reduce reverse power flows	Also mitigates thermal constraints	High cost Needs to be installed at feeder mid-points or in customers' homes for maximum benefit	Several domestic products commercially available GB – ENWL has simulated	TBC
Not suitable for voltage issues caused by PV	**Reactive power compensation (STATCOMs or capacitors)** Use reactive power flows to regulate voltage	Quick response	High cost Needs to be installed at feeder mid-points for maximum benefit Capacitors can only boost voltage	GB – ENWL are trialling	About £15k per device (TBC)

4.6 Trial Method 5: Understand how information available to PV installers could be used by DNOs

Result:	• Information from PV installers will not reduce DNOs' need to deploy their own LV network monitoring schemes, where network data is needed, but smart meter data is not yet available.

UK Power Networks identified and approached three PV installers to obtain operational data that they had collected from their PV installations. The project obtained and reviewed data provided by two installers, and assessed whether it (or similar data) could be useful to DNOs, and/or reduce the need for DNOs to deploy their own LV network monitoring schemes.

Unfortunately, it was found that the data only comprised energy (kWh) measurements, which might at best help DNOs to understand the actual peak export of PV installations in a cluster. However, energy measurements alone are of little help in identifying network constraints or estimating headroom for additional installations, which depend on, and require measurements of, voltage, current, and power. Therefore, it was concluded that information from PV installers will not reduce DNOs' need to deploy their own LV network monitoring schemes, where network data is needed, but smart meter data is not yet available.

Figure 34 shows an example of the data that was obtained.

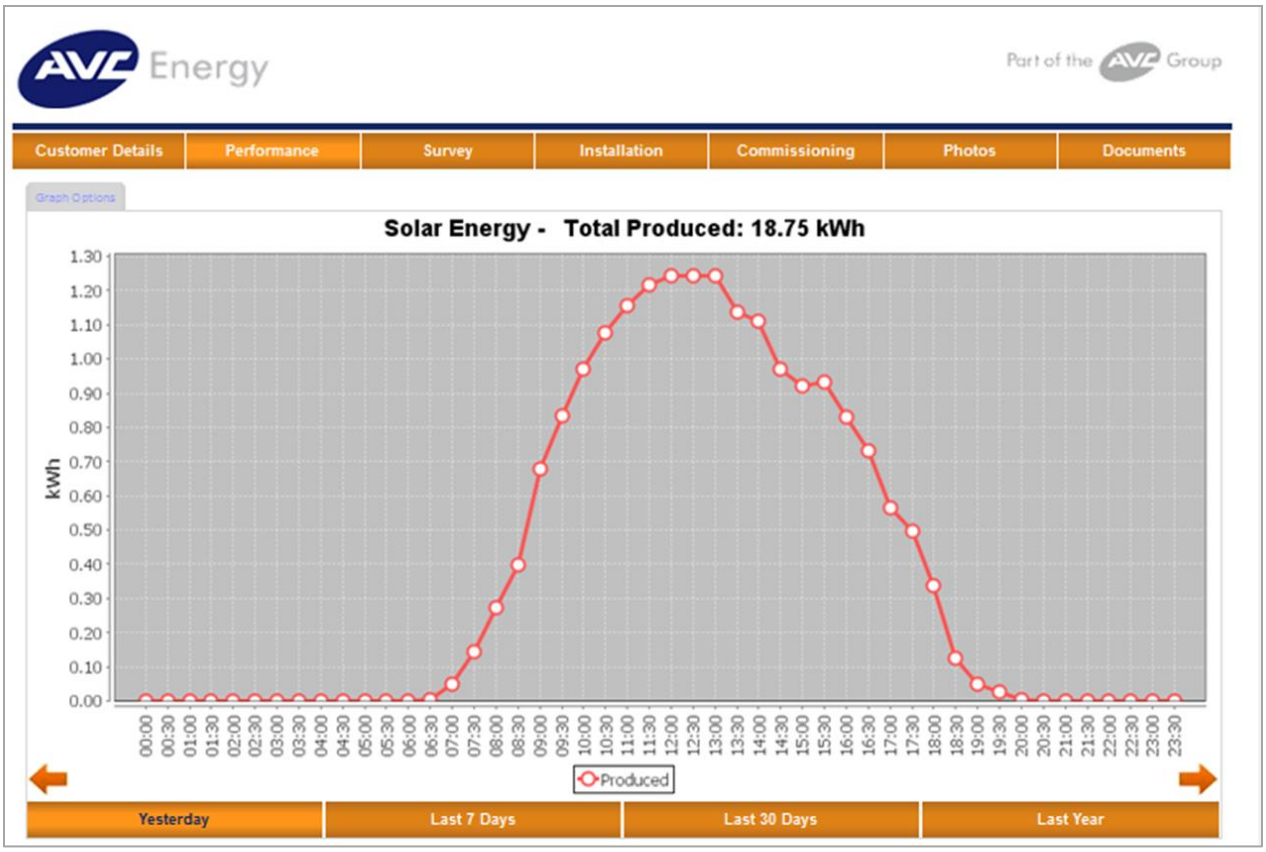


Figure 34 – Typical data available from PV installers

5. PERFORMANCE COMPARED WITH PROJECT AIMS, OBJECTIVES AND SUCCESS CRITERIA

Key message	
	• The project satisfied all its aims and objectives. • The project satisfied all but one of its success criteria, but this did not have any impact on the project's overall success.

5.1 Introduction

The project delivered new learning that will be disseminated to other DNOs, including:

- A validated and pragmatic connection assessment approach;
- Confirmation that EPN and SPN networks are performing well with current PV penetration levels, and most LV feeders will continue to perform well in a low-carbon future, where more renewable energy is connected;
- Insights into PV generation's most likely impacts on LV networks;
- A review of suitable solutions, and when each should be used; and
- Confirmation that information from PV installers will not reduce DNOs' need to deploy their own LV network monitoring schemes, where network data is needed, but smart meter data is not yet available.

5.2 Performance compared with project aims and objectives

Table 16 – Project aims and objectives

Objectives	Satisfied	Details
Validate UKPN's guidelines for assessing PV connection requests and develop a formal policy.	✓	The project delivered **a validated and pragmatic connection assessment approach**, comprising a formal design procedure and an improved tool, that UK Power Networks will adopt into business as usual and share with other GB DNOs during 2015**.**
Develop a better understanding of the impact (including weather related behaviour) that PV clusters would have on the LV network by monitoring 20 secondary substations and 10 PV connection points.	✓	The project delivered **key learning about PV generators' behaviour and impacts on the LV network** in terms of diversity, voltage rise, reverse power flow, harmonics, and voltage imbalance; based on 25,775 days of data gathered from 20 secondary substations and 10 PV connection points.
Understand how information available to PV installers could be used by DNOs.	✓	The project found that information from PV installers will not reduce DNOs' need to deploy their own LV network monitoring schemes, where network data is needed, but smart meter data is not yet available.

Objectives	Satisfied	Details
Gain a better understanding of the solutions available to address network constraints.	✓	The project delivered a **review of voltage control solutions** that could be trialled or adopted in GB, including recommendations of which solutions best suit likely constraint scenarios.

5.3 Performance compared with project success criteria

Table 17 – Original project success criteria compared with results

Success criteria	Satisfied	Details
Guidance and methodologies for assessing PV connection requests have been validated and developed into a formal policy.	✓	The project delivered **a validated and pragmatic connection assessment approach**, comprising a formal design procedure and an improved tool, that UK Power Networks will adopt into business as usual and share with other GB DNOs during 2015**.**
Successful 24 months of data gathering at 30 locations.	*Partially satisfied*	**The project delivered a rich dataset** spanning 16 months (480 days) and 30 locations, comprising 25,775 days of valid data, and over 171 million individual measurements, despite unexpected challenges in the customer recruitment and installation phases. **This reduced monitoring period did not affect the project's overall success**: the actual requirement was 12 months (one full summer), and the planned period of 24 months (two full summers) was intended to provide data redundancy.
Generation diversity along a feeder is understood.	✓	The project found that variations in panel orientation do not necessarily create diversity in the output of PV clusters, if they include undersized inverters.
The impact of PV on different types of LV network is understood and documented.	✓	The project found that PV generation may pose a greater risk of overvoltages on small transformers (<200kVA), which are more common on rural/overhead networks.
Data from a PV installer is available for UK Power Networks to view and assess.	✓	The project obtained and reviewed information from two PV installers.
An understanding of how network constraints can be mitigated has been developed.	✓	The project delivered a **review of voltage control solutions** that could be trialled or adopted in GB, including recommendations of which solutions best suit likely constraint scenarios.

6. REQUIRED MODIFICATIONS TO THE PLANNED APPROACH DURING THE PROJECT

Key messages	
	• The project needed to modify its approach to the amount of data to be collected, and the location of some monitoring equipment. • Despite these modifications, the project was an overall success.

6.1 Introduction

This section details two challenges encountered during the course of the project, and how they were mitigated to ensure that the project was still a success. Section 8 discusses these challenges and the lessons learnt in further detail.

6.2 Modification to the 24 months of data gathering

Situation	Revised Approach	Impact
It was originally planned to gather data over 24 months, two full summers, to ensure that at least one full summer of data would be gathered in case of unexpected delays. All monitoring equipment was expected to be in place by November 2012, however this was delayed by approximately 12 months by a combination of unexpected challenges: • Developing and obtaining approval for the customer engagement plan took much longer than planned; • Recruiting customers and identifying suitable premises took much longer than planned because of low response rates, difficulty in identifying and getting permission from stakeholders, and lack of suitable premises; and • Installation works were delayed because field staff frequently had to attend to higher-priority work, such as restoring supply to customers affected by faults. Ofgem was notified of these issues and the resulting delay in March 2014.	The data analysis was completed using approximately 16 months of data.	This reduced monitoring period did not affect the project's overall success: the actual requirement was 12 months (one full summer), and the planned period of 24 months (two full summers) was intended to provide data redundancy.

6.3 Monitoring PV installations from outside the customers' premises

Situation	Revised Approach	Impact
It was originally planned to monitor 10 PV installations by installing monitoring equipment inside customers' homes. However, due to low response rates, and 70% of inspected homes being unsuitable, it was only possible to install monitoring equipment inside six customers' homes.	The remaining four PV installations were monitored by installing monitoring equipment on the overhead network just outside the customers' premises.	The trial was able to measure voltage and harmonics at all 10 PV installations, and confirm that PV was not causing any issues. At the six PV installations with monitors inside the customers' premises, the trial was also able to measure PV generator output, and determine to what extent PV was causing changes in voltage and harmonics.

7. SIGNIFICANT VARIANCE IN EXPECTED COSTS AND BENEFITS

Key messages	

Key messages	• The total project cost was £417,704.
	• The project will deliver many benefits for customers and DNOs, including:
	  ○ Reduced processing time for PV connection applications;
	  ○ More-accurate assessments of PV generators' impact on the network; and
	  ○ Cheaper and more-effective alternatives to traditional network reinforcement.

7.1 Project cost and variance

Table 18 summarises the project's estimated vs actual expenditure.

Table 18 – Project expenditure by funding source

Funding Source	Estimated (£)	Actual (£)	Variance (£)	Variance (%)
Allowable First Tier Project Expenditure (funded by LCNF)	366,945	375,934	8,989	2.4%
Funded by UK Power Networks	40,772	41,770	999	2.4%
Eligible First Tier Project Expenditure	**407,717**	**417,704**	**9,987**	**2.4%**

Table 19 breaks down the variance for each phase of the project.

Table 19 – Project expenditure by project phases

Project Phase	Estimated (£)	Actual (£)	Variance (£)	Variance (%)
Site selection and customer engagement	22,000	21,590	-410	-1.9%
Data gathering *(procurement, installation, maintenance, and removal of monitoring equipment)*	247,837	283,566	35,729	14%
Data analysis	57,800	59,154	1,354	2.3%
Project management and reporting	50,080	53,394	3,314	6.6%
Contingency	30,000	*N/A*	*N/A*	*N/A*
Total Expenditure	**407,717**	**417,704**	**9,987**	**2.4%**

The site selection and customer engagement activities were delivered on budget, despite being delayed. This is discussed further in chapter 8. The 14% variance in the cost of the data-gathering phase is largely due to unplanned additional site visits, which were required to troubleshoot or replace faulty equipment, or when previous site visits had to be cancelled because of unsafe weather conditions.

The budget contingency was appropriate for the project overall, but future projects should specifically consider how to mitigate unplanned equipment installation and maintenance costs. Future projects should also consider additional schedule contingency to allow for delays in customer engagement and equipment installation.

7.2 Project benefits

Table 20 summarises the project's planned benefits, and how they will translate to actual benefits for customers and DNOs. These benefits will become increasingly important as the uptake of small-scale PV generation continues.

Table 20 – Planned and actual project benefits

Planned Benefits	Delivered	Actual Benefits for Customers and DNOs
A validated and pragmatic connection assessment approach, based on a better understanding of PV's impacts on the LV network	✓	Reduced processing time for PV connection applications, resulting in: • Improved customer satisfaction; and • Reduced processing costs. More-accurate assessments of PV generators' impact on the network, resulting in: • Customers able to connect more PV without having to pay for network reinforcement; • Customers less likely to be impacted by voltage issues; and • DNOs spending less on resolving voltage complaints.
Understand solutions to mitigate PV's impacts on the LV network	✓	Cheaper and more-effective alternatives to traditional network reinforcement, resulting in: • DNOs able resolve voltage complaints more cheaply and quickly; and • New PV schemes that would traditionally require network reinforcement are more likely to be feasible.
Understand whether information from PV installers could be useful to DNOs	✓	It was hoped that the data obtained from PV installers could help reduce DNOs' need to deploy their own LV network monitoring schemes. Unfortunately, the data was found to be inadequate for this purpose.

8. LESSONS LEARNT FOR FUTURE PROJECTS

Key messages	• UK Power Networks now better understands the challenges of DNOs recruiting trial participants directly, such as data protection, incentive payments, low response rates, complex stakeholder relationships, and rarity of suitable customer premises. • When deploying LV network monitoring schemes in future innovation projects, DNOs need to consider issues such as availability of field staff, reliability of mobile communications, equipment failure, and data archiving. • G83 notifications are not accurate, and DNOs need access to better information about the existing PV generation connected to their networks.

8.1 Acquired project experience

This section discusses the lessons learnt throughout each phase of the project.

8.1.1 Trial design

Lesson learnt	Details
G83 notifications are not accurate, and DNOs need access to better information about the existing PV generation connected to their networks.	The trial design had assumed that PV customers could be located using G83 notification data. However, it was discovered that many registered PV installations appeared to not actually exist, and many existing PV installations were not registered. For this project, the presence of PV installations was verified using public-domain aerial photography (e.g. Google Maps) and site visits, which delayed the site selection and customer recruitment phases of the project. In the long term, **DNOs will need to collaborate with other organisations who hold data about PV installations, (e.g. Ofgem, DECC, suppliers, the smart metering DCC)** to ensure that accurate information is available for use in connection assessments and strategic planning. This lesson should also be applied to managing notifications of heat pump and electric vehicle installations.

8.1.2 Customer engagement

Lesson learnt	Details
UK Power Networks gained a better understanding of the requirements for directly engaging customers in trials.	Direct engagement with customers was relatively new territory for DNOs, and a number of iterations were necessary to have the customer engagement and data protection plans approved. This process took seven months but was a valuable exercise for future projects that include customer engagement. UK Power Networks now have a good Customer Engagement Plan that has been used to inform other projects, including "Vulnerable Customers and Energy Efficiency".
When directly recruiting customers for trials, DNOs should expect a lower response rate and allow for a longer recruitment period accordingly.	The customer response rate was lower than expected, because: • UK Power Networks did not have an existing relationship with most of the customers it attempted to recruit; • UK Power Networks did not know the customers' names, so letters had to be addressed to "the occupant", and hence were likely to be ignored as junk mail; and • Optimal incentive payment amounts had to be determined by trial and error. A second round of recruitment was needed to find enough suitable customers for the trial. This was not planned for, and contributed to a 3.5 month delay in the customer recruitment phase.
When directly recruiting customers for trials, DNOs should anticipate that multiple stakeholders may also need to agree to the trial.	At many potential trial premises, the occupant, landlord, and PV owner were all separate parties, and all had to consent to the trial. Additional time was needed to identify and negotiate with these parties, especially where the landlord was a social housing provider. This was not planned for, and contributed to a 3.5 month delay in the customer recruitment phase. Future trials should aim to identify all stakeholders early in the recruitment process, and where a stakeholder is an organisation, identify who within the organisation has the authority to consent to the trial. For the LCNF Tier 2 project "Vulnerable Customers and Energy Efficiency", this issue was mitigated by involving landlords as full project partners.
When planning to install equipment inside customers' homes, DNOs should expect 70% of homes to be unsuitable, and increase recruitment quotas accordingly.	The trial design expected that the monitoring equipment could be safely installed in about 50% of customers' homes. In practice, only about 30% of homes inspected were found to be suitable. Issues included lack of a safe mounting location, and lack of spare capacity on distribution boards. These issues contributed to a 3.5 month delay in the customer recruitment phase, and in the end required four PV installations to be monitored from the LV network just outside the customers' premises.

8.1.3 Equipment installation

Lesson learnt	Details
When using their own field staff in trials, DNOs should mobilise a small specialised team, ring-fenced to perform the installations within a defined period.	The project had planned to use UK Power Networks' field staff to perform the monitoring equipment installations at substations as part of their normal day-to-day activities. In practice, the project work was repeatedly rescheduled when higher-priority work, such as restoring supply to customers affected by faults, took precedence. The project had planned three months to install the 20 substation monitors, but in practice it took nine months.
Monitoring equipment and installation instructions should be made as user-friendly as possible for the installers.	Several unplanned site visits were required to rectify equipment installation defects, e.g. current sensors installed with incorrect polarity or plugged into the wrong sockets on the data logger, etc. These defects, and the unplanned site visits, could have been reduced by making the equipment more user-friendly, e.g. colour coding the sensors, plugs, and sockets; or labelling them more clearly.

8.1.4 Data gathering and archiving

Lesson learnt	Details
Future trials should include strategies to minimise the impacts of equipment failure, such as holding spare equipment.	The project did not include a budget for spare equipment, so when a monitoring unit failed, it had to be retrieved from site and shipped back to the factory in the US for repair. This resulted in an outage whilst the equipment was repaired, and a second site visit and associated costs to reinstall it at site. The outage and second site visit could both have been avoided by holding spare equipment, so that the faulty equipment could be replaced at the first site visit.
At rural trial sites, mobile signal strength should be checked to determine if alternative communications equipment or methods are required.	Some monitoring locations suffered from unreliable mobile data communications due to poor signal strength, or mobile network outages. In most cases, the issue was resolved by retrofitting high-gain antennae to the monitoring equipment. A mobile signal strength survey could have identified where high-gain antennae were needed from the start of the project, or where fixed communication methods may have been more appropriate.

Lesson learnt	Details
The design of LV monitoring projects should include a data archiving specification that meets the project's requirements.	The trial was designed to gather measurements at 10-minute intervals; however, constraints in the data archiving system meant that all measurements taken before 10 June 2014 were aggregated to hourly minima and maxima. This is in part because the requirement to archive 24 months of 10-minute measurements was not specified at the start of the project. The analysis needed all data from all devices be exported into a single file, however the data archiving system was only able to export one file per month per device, and each file had to be exported manually. This caused delays in the data analysis phase.

8.2 Potential for large scale application

The design procedure and tool that this project developed are applicable to the entire GB DNO community.

8.3 Recommendation for future projects

8.3.1 Accuracy of DG notifications and registers

As discussed previously, this project found that UK Power Networks DG registers were often not accurate due to incorrect (or missing) notifications from PV installers.

UK Power Networks plans to investigate opportunities to improve the quality of this data, which may include:

- Collaborating with other organisations who hold DG/FiT data e.g. Ofgem, DECC, suppliers, the smart metering DCC;
- Aerial or satellite photography; and/or
- Smart meter data.

It is expected that this work will also help DNOs collect and maintain accurate information about electric vehicle and heat pump installations as their uptakes increase.

8.3.2 Improvement of substation busbar voltage and phase imbalance assumptions

This trial did not identify any correlations that would allow substation busbar voltage to be predicted without a site visit, requiring a single conservative assumption that will be an overestimate in most cases.

The trial identified that phase imbalance is higher on rural feeders than urban feeders, and recommended different assumptions for each. However, these are still conservative, and will be an overestimate in most cases.

As PV penetration increases, DNOs will need new methods to determine more-accurate, less-conservative assumptions on a site-by-site basis, without a site visit. This will further improve connection application processing times for customers, and reduce DNOs' costs for site visits.

8.3.3 **Probabilistic headroom estimation methods**

It may be possible to estimate headroom for additional PV generation using probabilistic methods, such as Imperial College's fractal-based LRE (load-related expenditure) model. Such a method could provide a risk-based PV/DG headroom estimate for every feeder on the network, without requiring accurate information about substation busbar voltages, or phase connection of existing generators. Such a method would complement the existing connection assessment approach.

8.3.4 **Smart solutions**

Further work is needed to enable adoption of smart solutions into business as usual. Some solutions, such as pole-mounted voltage regulators, are commercially available and only require routine approval to enable their use, whereas others, such as wide-area voltage control, require large-scale demonstration to prove their effectiveness.

9. PLANNED IMPLEMENTATION

Key messages	• UK Power Networks will adopt a new engineering design procedure and improved voltage rise assessment tool into BAU during 2015. • Further work is needed to provide more-accurate input information for generation connection assessments.

9.1 LV network monitoring

In the long term, the GB smart meter rollout is expected to obviate the need for DNOs to deploy LV network monitoring schemes. However, in the meantime, UK Power Networks plans to deploy LV network monitoring where network data is needed for innovation trials or business-as-usual implementations of smart solutions.

The monitoring equipment procured for this project has been re-used to support UK Power Networks' "Flexible Urban Networks – Low Voltage" project, which is trialling the use of power electronics devices to interconnect and release capacity on urban LV feeders.

9.2 Generation connection assessment procedure

UK Power Networks has a formal generation connection assessment procedure that prescribes a voltage rise assessment as part of the overall process, but does not provide any guidance on <u>how</u> to complete the voltage rise assessment.

The project has developed an engineering design procedure that provides guidance on how to complete voltage rise assessments, including:

- The design assumptions recommended in section 4.3;
- Other relevant learning from this project;
- Guidance on how to apply relevant spreadsheet calculation tools as a first-stage assessment; and
- Guidance on what to do if the first-stage assessment is inconclusive.

UK Power Networks will adopt this procedure into business as usual during 2015.

9.3 Improved voltage rise assessment tool

UK Power Networks will adopt the improved tool into business as usual during 2015.

Initially, the improved tool's worst-case calculation will be used as a direct replacement for the existing tool, to eliminate the existing tool's risk of underestimating voltage rise where existing PV generation is highly imbalanced.

In future, as PV penetration increases and headroom is reduced, the improved tool's realistic-case calculations will become more relevant and necessary to minimise connection application processing times. However, as previously discussed, this will require further work to ensure that accurate input data is available.

10. FACILITATE REPLICATION

Key messages	
	• The LV network monitoring scheme used commercially available products. • A copy of the design procedure and tool is available to other GB DNOs on request.

10.1 LV network monitoring

10.1.1 **Components**

All of the hardware and software used in the LV network monitoring scheme were commercially available products provided by Ormazabal.

Table 21 – Monitoring equipment details

Components	Model	Qty
Current sensors	Current 9650 flex sensor Part #: 210-0484-0001	80
	Current 9603 small 45mm sensor Part #: 210-0471-0001	280
Network data loggers	*Indoor substations with multiple ways:* Current 6-slot CCE (Communications & Connectivity Engine) with 4x LVA (Low Voltage Analytics) cards Firmware specially upgraded to support THD measurements up to the 50th harmonic Part #: 210-0450-0027	16
	Pole-mounted substations and endpoints, and customer premises: Current 9749 MPA (Multi-Purpose Appliance) with 1x LVA (Low Voltage Analytics) card Part #: 210-0459-0029	14
Network data analytics and archiving	Current OpenGrid Software – provided as a hosted service.	24 months
Weather data collection	Davis Vantage Pro 2 ISS with WeatherLink serial data logger and solar radiation sensor	10

10.1.2 **Knowledge**

Ormazabal provided all of the training and technical support required to deploy the scheme.

The project also learnt many lessons that would be invaluable to any similar trials – see Chapter 8 for details.

10.2 Generation connection assessment procedure

The project's design procedure and findings are generally applicable to all GB DNOs, and could be used to validate or inform an update to their respective generation connection assessment procedures.

A copy of the design procedure is available to GB DNOs on request.

10.3 Voltage rise assessment tools

The voltage rise assessment tool is a Microsoft Excel spreadsheet, and does not require any other software or licences to run.

A copy of the spreadsheet is available to GB DNOs on request.

Appendix A: Description of the Tools

The existing tool

UK Power Networks developed this tool to cope with the unprecedented influx of PV connection applications at the time. It sped up connection assessments, by reducing the need for detailed power system modelling (e.g. in WinDEBUT) to calculate voltage rise.

Table 22 – Comparison of UK Power Networks' existing tool to commercial power system modelling software

	UK Power Networks' existing tool	**Commercial power system modelling software** *e.g. DigSILENT PowerFactory / WinDEBUT*
Scope	**Specialised:** Spreadsheet-based tool developed by UK Power Networks' engineering teams. Calculates voltage rise using a simple lumped-impedance model.	**Broad:** Designed to cover all aspects of power system design and planning. Able to build detailed models and run several types of simulations, including voltage rise.
Effort	**Low:** Easy to use, requires minimal training, minimal input data, and minimal time to produce a result.	**High:** Requires specially trained staff, detailed input data, and significant time to build suitable models.
Accuracy	**Low, but conservative:** makes conservative assumptions to simplify the calculation and limit the input data needed.	**High:** Able to build highly detailed and accurate models – if accurate input data is available.
Intended Use	**As a first-stage assessment:** In most cases, the tool returned an acceptable result, confirming that reinforcement was not needed. When the tool returned an unacceptable result, this indicated that further assessment (e.g. in WinDEBUT) was needed to confirm whether reinforcement was needed.	**As a second-stage assessment:** WinDEBUT required more effort, and was only used when simpler methods (e.g. a spreadsheet tool) were unable to confirm that reinforcement was not needed.

	UK Power Networks' existing tool	Commercial power system modelling software *e.g. DigSILENT PowerFactory / WinDEBUT*
Amount of input data required	**Low:** Type, size, and length of every cable segment comprising the feeder branch under consideration. Total kW of existing and proposed generation.	**High:** Full feeder topology, including status of link boxes and other operational open points. Type, size, and length of every cable segment for every feeder branch. Location, size, and phase of every existing and proposed load and generator.
Assumptions and Limitations	• Feeder cable modelled as a single lumped impedance. • All power flows are assumed to be three-phase balanced. • Does not allow for load. • All generators are assumed to be at the end of the feeder, which exaggerates the voltage rise. • Unable to model feeders with multiple branches/termini.	• Limited by the availability and accuracy of input data. • Unfortunately, much of the required input data either does not exist or is known to be inaccurate, especially the quantity, locations, sizes, and connected phases of existing generators. • Not able to plot phase-neutral voltage profiles (can only plot phase-ground voltage profiles).
Cost	**Free:** Requires Microsoft Excel, which is already available to all office-based staff.	**High:** Most software packages require purchase of a perpetual 12-month licence for each simultaneous user. DNOs typically only have a limited number of licences.

Figure 35 shows an example calculation using the existing tool.

Generator voltage rise

	Gen			
Generator Rating	20.25	Three Phase kW		
Voltage	429.55	Line Volts	248	Phase Volts
FLC	27.2216	Phase Amps		

REMARKS cable rating	**CABLE Size**	**Cond (al/cu)**	**Length (m)**	**Type ug/oh**	**Volt (kV)**	**Impedance R/km**	**X/km**	**R**	**X**	**Z**
	185.00	wave	100.00	ug	0.4	0.164	0.074	0.01640	0.00740	0.02
	120.00	wave	100.00	ug	0.4	0.253	0.073	0.02530	0.00730	0.03
	70.00	wave	100.00	ug	0.4	0.443	0.0755	0.04430	0.00755	0.04
	35.00	wave	100.00	ug	0.4	0.868	0.0775	0.08680	0.00775	0.09
	-		-		0					
	-		-		0					
	-		-		0					
	-		-		0					
	-		-		0					
	-		-		0					
	35.00	wave	-	UG	0.40					
			400					**0.173**	**0.030**	0.175385

	Phase		Line
voltage rise	4.77	V	8.27
New Voltage at POCC	252.77	V	437.82
voltage rise	1.93	%	1.93

Figure 35 – Screenshot of the existing tool

The improved tool

The project also developed and validated an improved tool that calculates voltage rise in three steps: the first step provides a worst-case result using minimal inputs, and if required, subsequent steps provide more-accurate results, using more-detailed inputs.

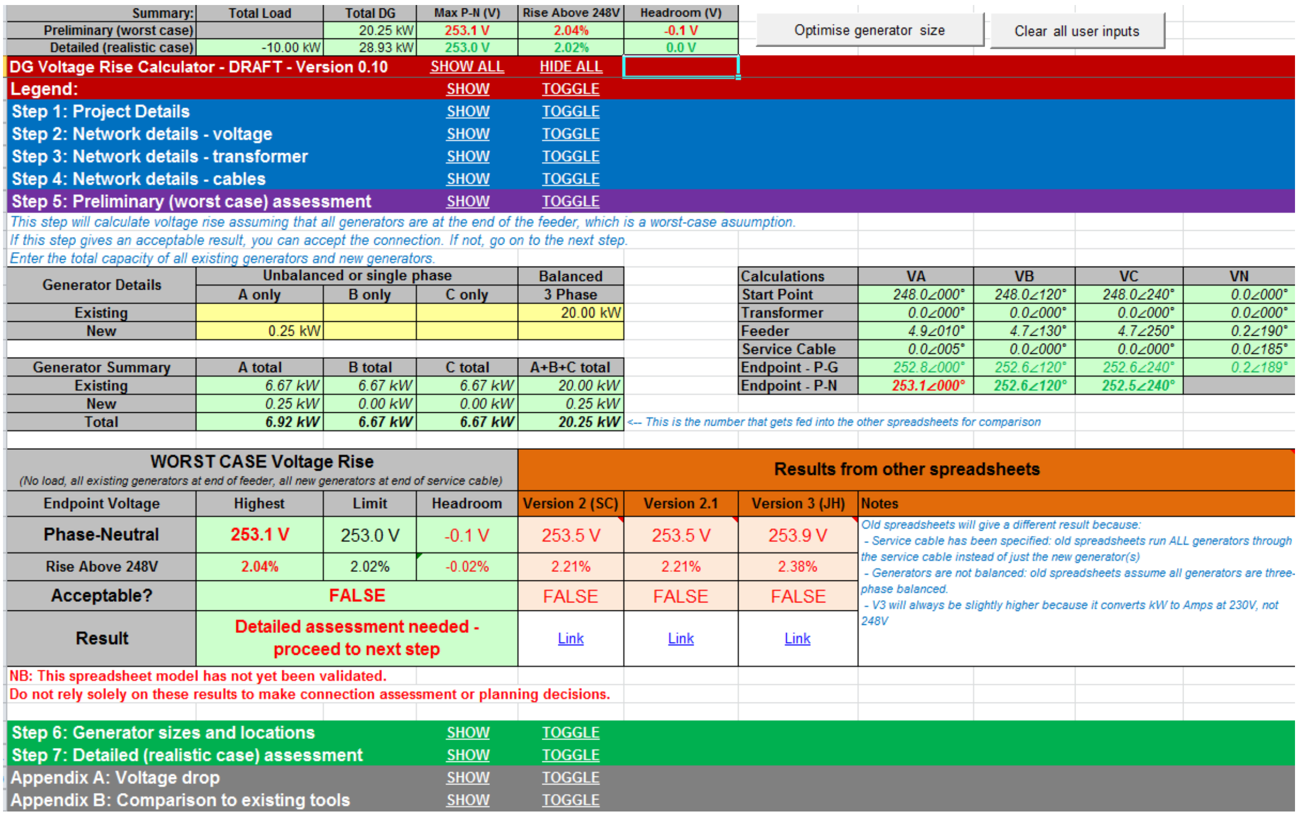
Table 23 – Improvements in the improved tool

	Existing Tool	Improved Tool
Impedance Model	Feeder cable modelled as a single lumped impedance.	Feeder cable modelled as up to 200 individual segments.
Phases	All power flows are assumed to be three-phase balanced.	Power flows, currents, and voltages are calculated separately for each phase conductor and neutral. Allows for phase imbalance. Generators and loads can be assigned to specific phases if known.
Generators & Loads	Does not allow for load. All generators are assumed to be at the end of the feeder, which exaggerates the voltage rise.	Allows for loads. The location of each generator and load can be specified separately, if known. (Defaults to end of the feeder for the worst-case scenario, or if not known).
Generator Data Needed	Total kW of existing and proposed generation.	Locations and sizes of existing and proposed generators.

The improved tool makes a number of assumptions about neutral voltage displacement:

- It assumes that all imbalance current returns via the neutral conductor. In reality, some imbalance current will return via PME systems, causing less neutral voltage displacement than predicted.
- It assumes that neutral conductors have the same impedance as phase conductors (i.e. $Z_0 = 4Z_{1)}$. In reality, neutral conductors are often undersized, causing more neutral voltage displacement than predicted.

Figure 36 and Figure 37 show an example calculation using the improved tool.



Summary:	Total Load	Total DG	Max P-N (V)	Rise Above 248V	Headroom (V)
Preliminary (worst case)		20.25 kW	253.1 V	2.04%	-0.1 V
Detailed (realistic case)	-10.00 kW	28.93 kW	253.0 V	2.02%	0.0 V

Optimise generator size | Clear all user inputs

DG Voltage Rise Calculator - DRAFT - Version 0.10	SHOW ALL	HIDE ALL
Legend:	SHOW	TOGGLE
Step 1: Project Details	SHOW	TOGGLE
Step 2: Network details - voltage	SHOW	TOGGLE
Step 3: Network details - transformer	SHOW	TOGGLE
Step 4: Network details - cables	SHOW	TOGGLE
Step 5: Preliminary (worst case) assessment	SHOW	TOGGLE

This step will calculate voltage rise assuming that all generators are at the end of the feeder, which is a worst-case asuumption.
If this step gives an acceptable result, you can accept the connection. If not, go on to the next step.
Enter the total capacity of all existing generators and new generators.

Generator Details	Unbalanced or single phase			Balanced
	A only	B only	C only	3 Phase
Existing				20.00 kW
New	0.25 kW			

Generator Summary	A total	B total	C total	A+B+C total
Existing	6.67 kW	6.67 kW	6.67 kW	20.00 kW
New	0.25 kW	0.00 kW	0.00 kW	0.25 kW
Total	6.92 kW	6.67 kW	6.67 kW	20.25 kW

<-- This is the number that gets fed into the other spreadsheets for comparison

Calculations	VA	VB	VC	VN
Start Point	248.0∠000°	248.0∠120°	248.0∠240°	0.0∠000°
Transformer	0.0∠000°	0.0∠000°	0.0∠000°	0.0∠000°
Feeder	4.9∠010°	4.7∠130°	4.7∠250°	0.2∠190°
Service Cable	0.0∠005°	0.0∠000°	0.0∠000°	0.0∠185°
Endpoint - P-G	252.8∠000°	252.6∠120°	252.6∠240°	0.2∠189°
Endpoint - P-N	253.1∠000°	252.6∠120°	252.5∠240°	

WORST CASE Voltage Rise (No load, all existing generators at end of feeder, all new generators at end of service cable)				Results from other spreadsheets			
Endpoint Voltage	Highest	Limit	Headroom	Version 2 (SC)	Version 2.1	Version 3 (JH)	Notes
Phase-Neutral	253.1 V	253.0 V	-0.1 V	253.5 V	253.5 V	253.9 V	*Old spreadsheets will give a different result because: - Service cable has been specified: old spreadsheets run ALL generators through the service cable instead of just the new generator(s) - Generators are not balanced: old spreadsheets assume all generators are three-phase balanced. - V3 will always be slightly higher because it converts kW to Amps at 230V, not 248V*
Rise Above 248V	2.04%	2.02%	-0.02%	2.21%	2.21%	2.38%	
Acceptable?	FALSE			FALSE	FALSE	FALSE	
Result	Detailed assessment needed - proceed to next step			Link	Link	Link	

NB: This spreadsheet model has not yet been validated.
Do not rely solely on these results to make connection assessment or planning decisions.

Step 6: Generator sizes and locations	SHOW	TOGGLE
Step 7: Detailed (realistic case) assessment	SHOW	TOGGLE
Appendix A: Voltage drop	SHOW	TOGGLE
Appendix B: Comparison to existing tools	SHOW	TOGGLE

Figure 36 – Screenshot of the improved tool – worst-case results

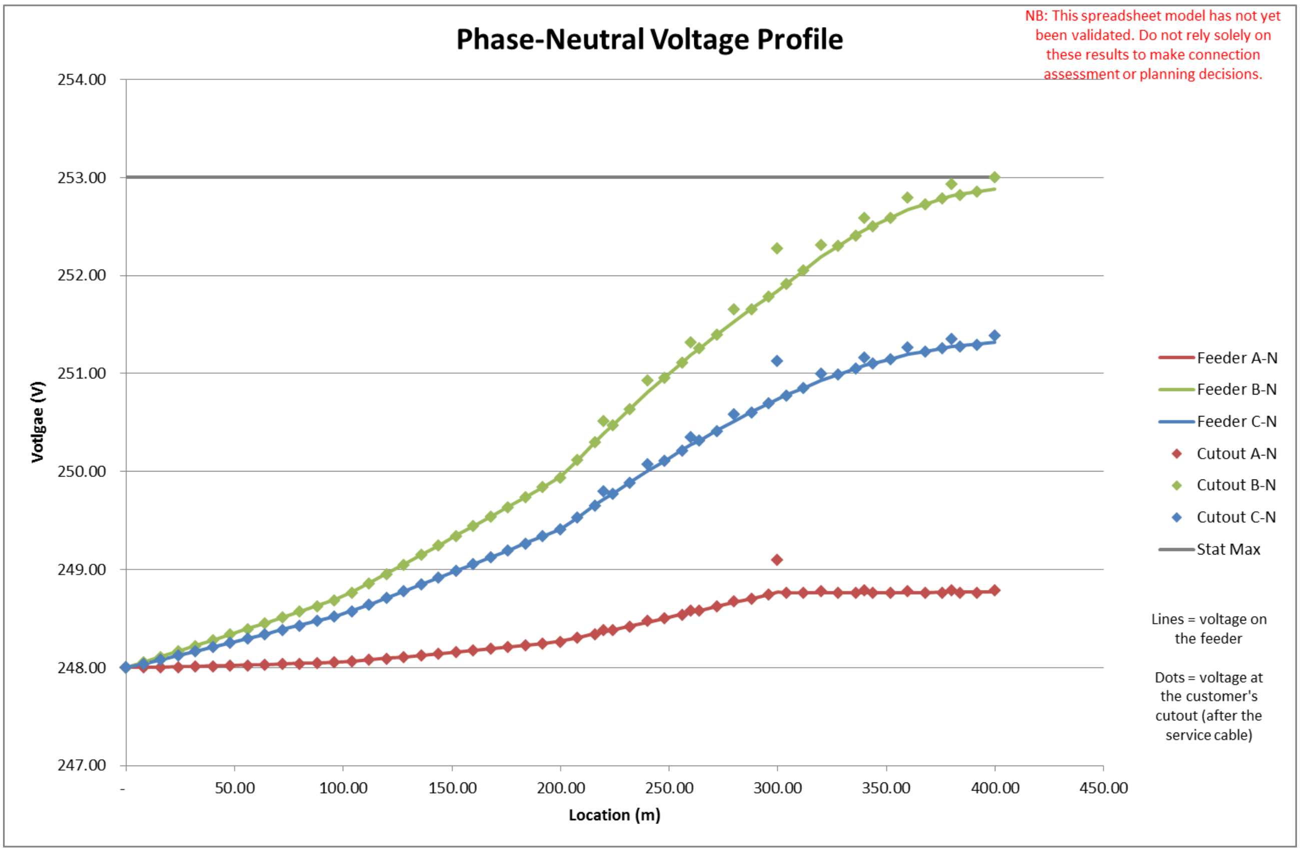


Figure 37 – Screenshot of the improved tool – realistic-case results

Appendix B: EXAMPLE CUSTOMER ENERGY REPORT

Understanding PV
your energy report

June 2014 - August 2014

Thank you for your continued support in helping us to understand the impact that small-scale photovoltaic (PV) installations have on the electricity distribution network.

We are pleased to share with you the fourth energy report for your property which shows the data collected by our monitoring equipment between June 2014 and August 2014.

Reading your energy report

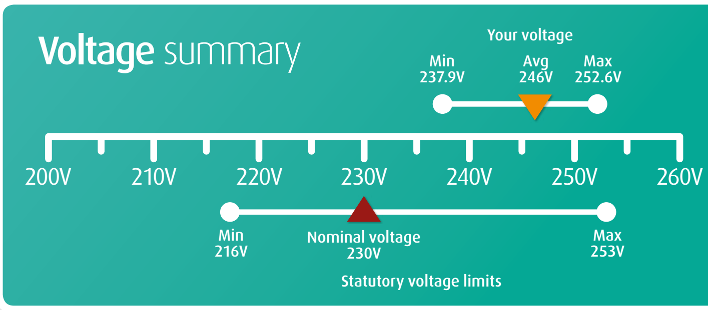
kWh	The unit for measuring electrical energy i.e. generating or using 1kW for one hour = 1kWh
Energy generated	The amount of electricity generated by your PV panels
Energy exported	The amount of electricity generated but not consumed at the time of generation
Energy imported	The amount of electricity taken from the network
Statutory voltage limits	The minimum and maximum voltage levels UK Power Networks is legally required to supply
Nominal voltage	The level at which electrical devices are designed to operate

Energy import/export summary*

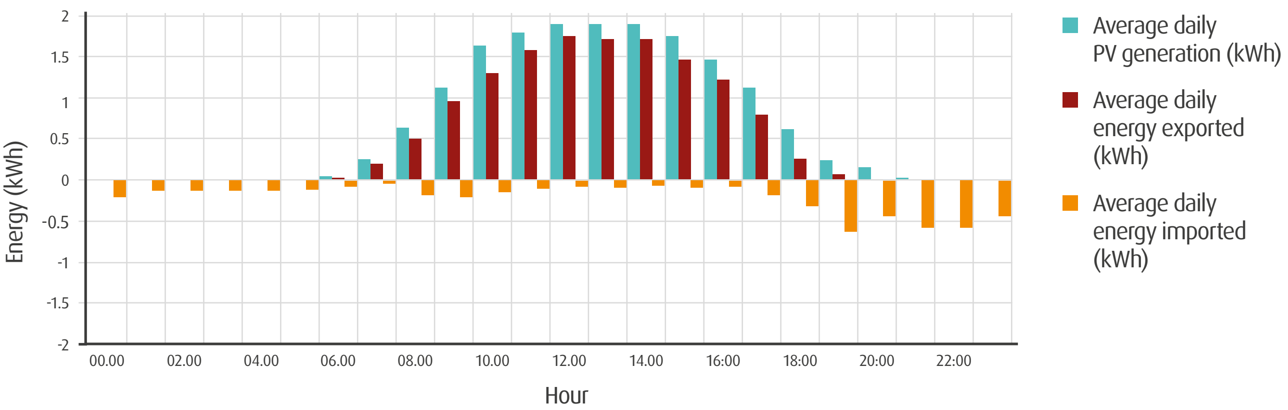
Energy imported:	**4456 kWh**
Energy exported:	**11197 kWh**
Energy generated:	**1490 kWh**

*All figures represent data collected by our monitoring equipment and may not correspond exactly to billing information you receive from your energy supplier.

Voltage summary

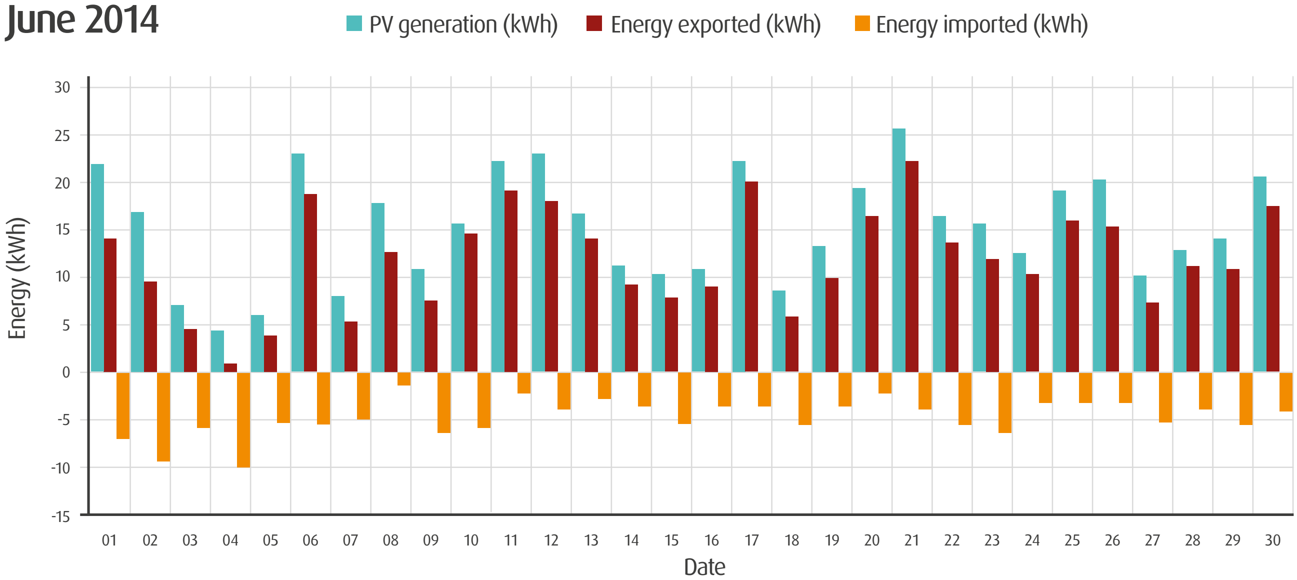


Average daily energy generation and import/export

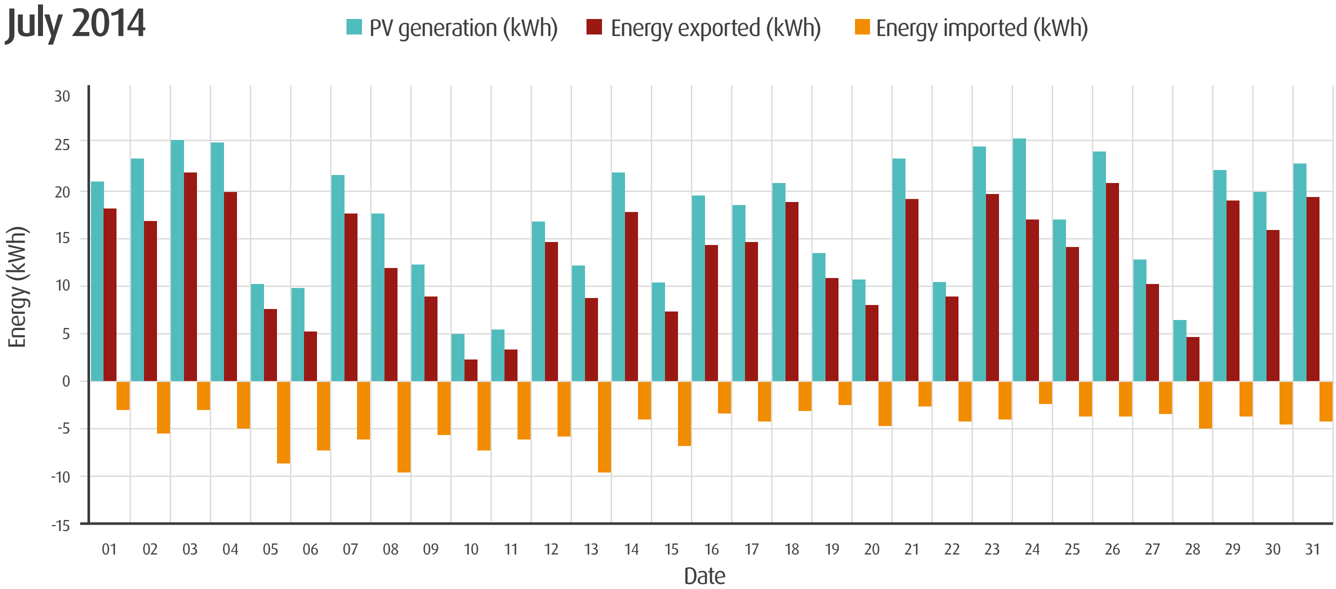


Monthly energy generation and energy import/export

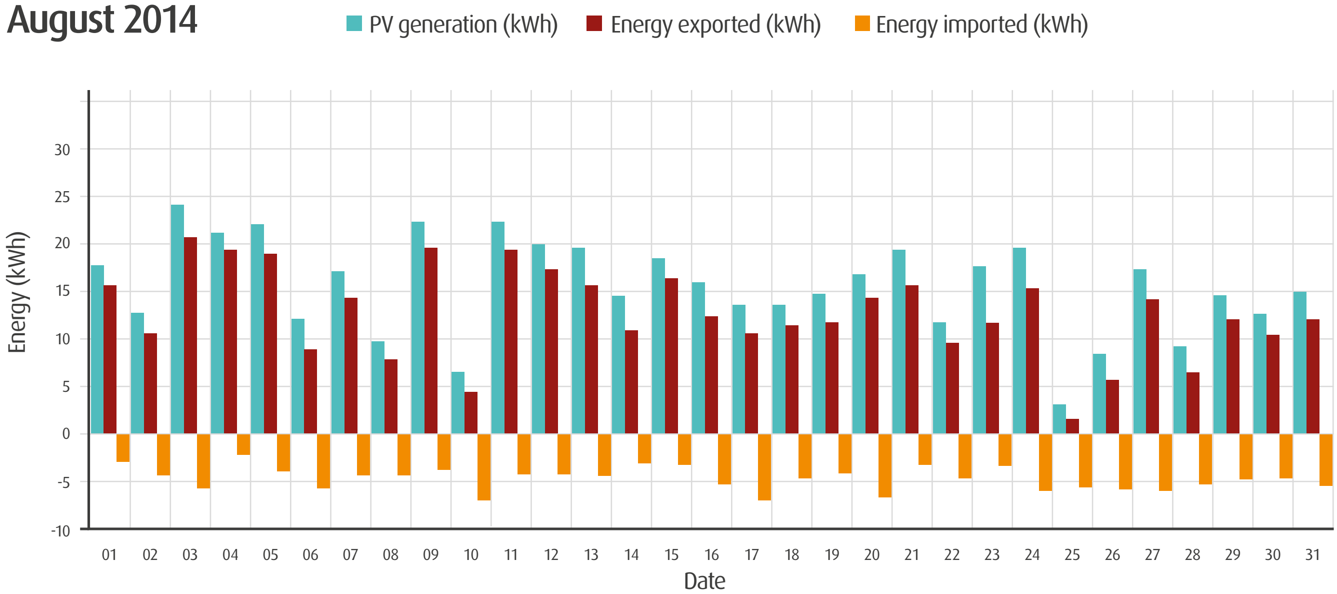
June 2014



July 2014



August 2014



If you have any queries please contact the Future Networks project team on **0800 169 0247** or at **understandingPV@ukpowernetworks.co.uk**

More information about the project can be found on our website **ukpowernetworks.co.uk/innovation** where the project is called 'Validation of PV connection assessment tool'.

Appendix C: CUSTOMERS' RESPONSES TO END-OF-PROJECT SURVEY

Question	Customer	Response
Are you happy with the way that UK Power Networks has communicated with you?	1	Yes – good advance notice when visits needed. Feedback reports helpful in seeing our usage and the times.
	2	Yes – all dates were kept as arranged
	3	Yes *(no further response)*
	4	Yes *(no further response)*
	5	Yes – always communicated to let me know what was happening
	6	Yes *(no further response)*
Are you happy with the way in which our contractor (Cofely) has communicated with you and their work at your premises?	1	Yes – always courteous and right on time for appointments. Explain work and always leave tidy.
	2	Yes – on time, polite and tidy
	3	Yes – arrived when arranged. Pleasant staff
	4	Yes *(no further response)*
	5	Yes – very polite and professional
	6	Yes *(no further response)*
Did you find the quarterly energy reports interesting and easy to understand?	1	Yes – my neighbour has identical solar installation and we have compared monthly meter readings and he has analysed together too.
	2	Yes
	3	Yes – interesting to see how the energy is produced & used
	4	Yes – interesting but I found them hard to understand i.e. how much energy I had saved.
	5	Yes – very interesting to see how the energy produced was being used by myself
	6	Yes *(no further response)*
Please let us have any other comments regarding your experience in the project.	1	It has been helpful to be part of the study and see how the solar panels have produced power – our usage has changed by focusing washing machine and dishwasher use to maximise free power etc.
	2	Would be pleased to help again
	3	Would be happy to participate in future projects.
	4	*(no response)*
	5	Very pleased with the whole experience. Of great benefit to see how to use my electricity more effectively.
	6	Yes *(no further response)*

Appendix D: INDEX OF FIGURES AND TABLES

UK Power Networks (Operations) Limited

Registered office: Newington House, 237 Southwark Bridge Road SE1 6NP
Registered number: 3870728 registered in England and Wales