WESTERN POWER DISTRIBUTION

INNOVATION

NEXT GENERATION NETWORKS

LOSSES INVESTIGATION

WPD_NIA_005

NIA MAJOR PROJECT PROGRESS REPORT

REPORTING PERIOD:

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Contents

1 Executive Summary

Losses Investigation is funded through Ofgem's Network Innovation Allowance (NIA). Losses Investigation was registered in April 2015 and will be complete by July 2018, reporting October 2018.

Losses Investigation aims to quantify technical losses on the LV and HV network, and determine the minimum information required to accurately predict network losses.

This report details progress of the project, from April 2018 to the end of September 2018.

1.1 Business Case

This project will provide information that should allow us in subsequent work to accurately target the most economically viable mitigation techniques, allowing us to reduce losses where action presents a net benefit.

From the Digest of UK Energy Statistics 2014 (DUKES) the final electricity consumption across the UK was 317TWh in 2013. Of this approximately 25.2% or 83.7TWh is consumed within WPDs network. With the conservative figure of 5.8% losses in the distribution network this means that 4.64TWh is lost on WPDs network, of this approximately 3.34TWh (72%) is lost after transformation down to HV. Using the Ofgem value of £48.42/MWh this is worth £161.9 million directly with a further contribution of £103 million from the value of the carbon emitted generating it (figures of 524.62 TCO2/GWh and £59/TCO2 was used from the NIA benefits guide).

Estimated cost of HV and LV losses on WPD network = £161.9m + £103.5m = £265m per year.

If we can target losses and reduce 10% of the technical losses on the LV and HV networks by 10% then the method cost would be £2.65 million a year.

1.2 Project Progress

This is the fourth six month progress report. It covers progress from April 2018 to the end of September 2018. Activities and progress included:

- Completion of the development of HV feeder loss estimation processes and the production of 2130 feeder-specific annual feeder loss estimates for feeders in the East Midlands region of WPD.
- Completion of the initial development of LV feeder loss estimation processes and the production of feeder-specific annual loss estimates for 254 feeders in the Milton Keynes area. These LV feeders are associated with the HV feeders that have monitoring installed as part of the Losses Investigation project; this monitoring allows comparison of the LV feeder load models with actual feeder load data. These initial estimates are based on based on approximated LV network models provided by the WPD Electric Nation project, and simplified half-hour load models.
- Ongoing receipt and processing of monitoring data from all 11 HV and 11 LV trial feeders, with the preparation of loss assessments on all feeders. This has included ongoing refinement of loss assessment calculations for LV feeders, improving the handling of reverse power flows at LV points of connection due to embedded generation.

Focus over the next reporting period will be on concluding LV feeder estimation work, plus project final report preparation and dissemination of learning.

During this period the project end date has been reviewed and revised to January 2019 (reporting by April 2019). A revised project registration document has been agreed.

1.3 Project Delivery Structure

1.3.1 Project Review Group

The Losses Investigation Project Review Group meets on a bi-annual basis. The role of the Project Review Group is to:

- Ensure the project is aligned with organisational strategy;
- Ensure the project makes good use of assets;
- Assist with resolving strategic level issues and risks;
- Approve or reject changes to the project with a high impact on timelines and budget;
- Assess project progress and report on project to senior management and higher authorities;
- Provide advice and guidance on business issues facing the project;
- Use influence and authority to assist the project in achieving its outcomes;
- Review and approve final project deliverables; and
- Perform reviews at agreed stage boundaries.

1.3.2 Project Resource

WPD are providing full-time project management resource, plus project oversight and direction.

Academic, loss assessment design, and analytical support is being provided by Loughborough University.

Planning and implementation of HV feeder monitoring is provided by ex-WPD staff through agencies. This work is being undertaken in close collaboration with the local WPD Network Services staff.

Lucy Electric Gridkey have provided substation monitoring equipment and is also providing ongoing data collection services for all the HV feeder monitoring equipment and the LV substation monitoring equipment.

Manx Utilities (MUA) is providing planning, implementation and data provision services for the LV feeder monitoring.

WPD has provided EDMI[1] meters from its metering operation. The project has made use of EDMI's technical support under the WPD umbrella.

1.4 Procurement

The following table details the current status of procurement for this project.

Table 1 Procurement Details

Provider	Services/goods	Area of project applicable to	Anticipated Delivery Dates
Loughborough University	Services (academic, loss assessment design, and analytical support)	• HV & LV feeder loss assessment on monitored feeders • Design and development of loss estimation methods for non-monitored HV & LV feeders	Ongoing until the end of the project
Lucy Electric Gridkey	Goods (supply of established MCU520 LV substation monitoring equipment)	• HV & LV feeder loss assessment on monitored feeders	Complete June 2017.
Lucy Electric Gridkey	Goods (design, development and supply of monitoring at HV supply points, based on MCU520	• HV feeder loss assessment on monitored feeders	Complete Feb 2017.

[1] Meter design and manufacturing company

Provider	Services/goods	Area of project applicable to	Anticipated Delivery Dates
	equipment)		
Lucy Electric Gridkey	Services (data collection for deployed MCU520 equipment)	• HV & LV feeder loss assessment on monitored feeders	Ongoing until the end of the project
MUA	Services (planning, implementation and data provision services)	• LV feeder loss assessment on monitored feeders	Ongoing until the end of the project

1.5 Project Risks

A proactive role in ensuring effective risk management for Losses Investigation is taken. This ensures that processes have been put in place to review whether risks still exist, whether new risks have arisen, whether the likelihood and impact of risks have changed, reporting of significant changes that will affect risk priorities and deliver assurance of the effectiveness of control.

Section 7.1 of this report shows the current top risks associated with successfully delivering Losses Investigation as captured in our Risk Register.

1.6 Project Learning and Dissemination

Project lessons learned and what worked well are captured throughout the project lifecycle. These are captured through a series of on-going reviews with stakeholders and project team members, and will be shared in lessons learned workshops at the end of the project. These are reported in Section 5 of this report.

2 Project Manager's Report

2.1 Project Background

Distribution Network Operators have an obligation to operate efficient and economic networks. As such the effective management of distribution losses is paramount. Current estimates put the technical losses at between 5.8% and 6.6% of electricity delivered ("Management of Electricity Distribution Network Losses" IFI report) worth approximately £900 million across the UK. Approximately £640 million of these losses occur after transformation down to 11kV.

Some improvements with clear cost benefits across the network are being rolled out, as outlined in WPDs Losses Strategy; however these have limits due to a lack of detailed understanding in the variation of losses across our network. As such, reductions in losses on existing network cannot be targeted on a feeder specific basis and the network cannot be fully optimised.

The Losses Investigation NIA project aims to:

- Quantify technical losses on samples of LV and HV network through the application of load monitoring equipment; and
- Establish loss estimation approaches, using a minimum necessary additional information set, which can be widely applied to HV and LV networks.

The project started in April 2015, and was originally due to be complete by December 2017, reporting March 2018. It is now due for completion January 2019, reporting April 2019.

Key phases to the project are:

- Project mobilisation, partner selection and establishment of appropriate project agreements;
- Initial laboratory testing of proposed load monitoring equipment, and establishment of loss assessment methodologies and calculations;
- Field testing of proposed equipment, installation, data collection, and assessment methods for one pilot HV network, and one pilot LV feeder;
- Installation of monitoring to selected HV and LV feeders;
- Assessment of Losses on monitored HV and LV feeders;
- Development of loss estimation methods for HV and LV feeders, using minimum additional information sets.

2.2 Project Progress Overview

Project activity over this six month period has been focused on:

- Concluding development of loss estimation processes for HV feeders and internal review of estimated loss results for the East Midlands area of WPD;
- Detailed development of loss estimation processes for LV feeders, aiming for losses to be estimated on a large scale using business-as-usual data; and
- Ongoing receipt and processing of monitoring data from all 11 HV and 11 LV trial feeders, with the preparation of loss assessments on all feeders.

As a result:

- Estimates of feeder-specific annual feeder losses have been produced for 2130 HV feeders in the East Midlands region of WPD, based on processes developed within the project that use business-as-usual data sources;
- Initial estimates of feeder-specific annual feeder losses have been produced for 254 LV feeders in the Milton Keynes area. These LV feeders are associated with the HV feeders that have monitoring installed as part of the Losses Investigation project; this monitoring allows comparison of the LV feeder load models with actual data. These initial estimates are based on based on approximated LV network models provided by the WPD Electric Nation project, and simplified half-hour based load models; and
- Loss assessments (based on the installed instrumentation on 11 HV feeders and 11 LV feeders) have continued to be produced, providing further and longer term data showing seasonal variations in feeder technical losses. This data is being used for comparison with loss estimation method results and summary charts are contained in Appendix A.

Progress against each of the project phases is summarised in **Error! Reference source not found.**.

Details of the completion of the HV feeder estimation work are summarised in Section 2.3.

Details of the development of initial LV feeder loss estimates are summarised in Section 2.4.

During this period the project end date has been review and revised to January 2019 (reporting by April 2019). A revised project registration document has been agreed.

Table 2 Summary of project progress against project phases

Project Phase	Progress
Project mobilisation, partner selection and establishment of appropriate project agreements	**Complete** (reported in March 2017 Six Monthly Report) - The project has selected Loughborough University as its academic and analytical partner, and has confirmed Manx Utilities (Isle of Man) as its partner for investigating losses on LV networks. Collaboration Agreements have been established with both.
Initial laboratory testing of proposed load monitoring equipment, and establishment of loss assessment methodologies and calculations	**Complete** (reported in March 2017 Six Monthly Report) – Loughborough University successfully completed initial laboratory testing of the proposed monitoring and measurement arrangements.
Field testing of proposed equipment, installation, data collection, and assessment methods for one pilot HV network, and one pilot LV feeder	**Complete** (reported in March 2017 Six Monthly Report) – Installation of required monitoring equipment on one HV and one LV feeder was completed in 2016, with successful modelling and loss measurement and assessment being demonstrated.
Installation of monitoring to selected HV and LV feeders	Complete (reported in September 2017 Six Monthly Report) - The installation of the required monitoring equipment has been completed on all the 11 selected HV and 11 selected LV feeders. An overview of the monitored feeders is contained in Appendix A.
Assessment of Losses on monitored HV and LV feeders	**Ongoing** (during this period) – • Data now regularly being collected from 346 meters and 196 Gridkey devices; • Loss assessment models/engines have been refined to improve the handling of reverse power flows at LV points of connection due to embedded generation; • Ongoing loss assessments are produced for all HV and LV feeders.
Development of loss estimation methods for: • HV feeders; and	**Complete** (during this period) –Development of HV feeder loss estimation processes and the production of 2130 feeder-specific annual feeder loss estimates for feeders in the East Midlands region of WPD to demonstrate the working processes.
• LV feeders	**Ongoing** (during this period) – Initial development of LV feeder loss estimation processes and the production of feeder-specific annual loss estimates for 254 feeders in the Milton Keynes area.

2.3 Completion of Loss Estimation for HV Feeders

This element of the project has set out to develop methods to estimate losses on HV electricity distribution feeders, from outgoing breaker of a primary substation, to the LV side of distribution substation transformers. Development of a method to achieve this has now been completed, and has been demonstrated by estimating feeder-specific losses on HV feeders in the East Midlands region of WPD. The following sections:

- Describe the method;
- Introduce the structure of results;
- Provide an overview of the results for the East Midlands;
- Test the credibility of outlier results;
- Use results to identify a group of high cost feeders; and
- Recognise potential causes of inaccuracy in the estimates.

2.3.1 Overview of HV feeder annual loss estimation method

An outline of the finalised estimation method is shown in Figure 1 where inputs to the process are shown in blue and the output (estimated losses) in green. Bold lines indicate time-series data for the demand and loss analysis which has a half-hourly time resolution.

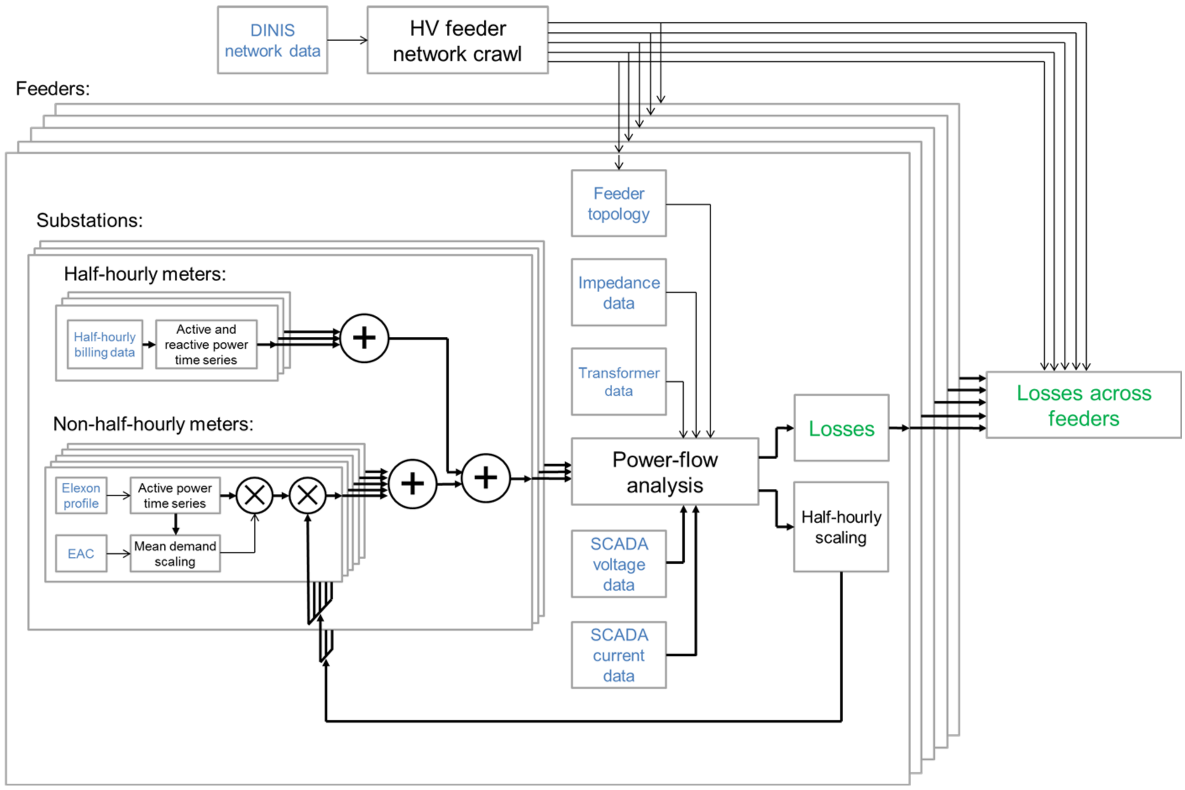


Figure 1 Outline of HV feeder loss estimation method.

In summary, for each HV feeder, the loss estimation method combines network topology data with demand data in order to run a power-flow analysis from which the individual feeder losses are calculated. These individual feeder results are then collated so that loss characteristics of the overall HV feeder set can be examined and identified.

A network data file for the East Midlands region is analysed, and individual HV feeders are identified.

The demand data is based on a time-series with half-hour periods; using known meter data where this is available (for half-hourly meters), and using estimated demands for the non-half-hourly meters. The estimated non-half-hourly demand is based on Elexon profile, selected according to the profile class for each customer, and scaled according to the estimated annual consumption (EAC).

The power-flow analysis gives an initial estimate of the losses and of the total current, aggregated from all of the distribution substations that would be expected at the primary substation. This estimated primary substation current is compared to the measured data that is available from the SCADA current monitoring at the primary. For any individual half-hour period, this will differ from the initial demand estimate based on the scaled Elexon profiles. This is expected as the demands for individual customers will differ from the Elexon profiles that are averaged over many customers and for the half-hour period on many days. In order to allow for this variation, the non-half-hourly demands are scaled for each half-hour period such that the total predicted current at the primary agrees with the measured data. There is no information here to determine which particular customers have a demand that is above or below the average profile and so a common scaling factor is applied to all of the non-half-hourly demands. The total non-half-hourly demand therefore retains an appropriate proportion at each substation (according to the number of customers, their EACs and their profile class), but is also scaled such that the combined demand at the primary substation from the power-flow analysis is consistent with the SCADA monitoring.

The power-flow analysis uses a modified forward/backward sweep algorithm that accommodates the requirement for the predicted primary current to match with the measurements, and also takes into account the additional power imported into the network to allow for the losses. The sum of the half-hourly demand, the estimated non-half-hourly demand, and the losses, are then consistent with the measured demand at the primary substation.

Although the process described above would ideally be applied for all feeders, it has been found that there are a number of cases where the SCADA data appears unreliable. In this case, the half-hourly scaling cannot be applied and the non-half-hourly demand is based simply on the Elexon profiles.

As described above, the loss estimates are based on a half-hour load model. It is recognised that losses calculated with half-hourly demand data will be systematically lower than loss calculations with a higher time resolution. However, the error has been found to be minimal for HV feeders where there is a significant level of demand aggregation. For the pilot trial feeder (940037-0002), the difference was found to be only 1%.

The phase assignments for single-phase customers are not known and so the loss estimation method makes an assumption that the demand of three-phase substations is balanced. However, the power-flow performs a full unbalanced analysis to allow for single-phase HV branches where the demand is assumed to be connected between the red and blue phases. This approach has been adopted as comparisons for the project HV trials showed minimal differences if the losses were calculated with balanced demands rather than unbalanced demands. It is recognised that the use of balanced demands will tend to under-represent losses but the impact appears low relative to the much more dominant factors relating to the level of demand, the location of the demand along the feeder, and the lengths and impedances of the cables.

Further details on specific aspects of data used and the method employed are contained in:

- Appendix C.1 - Network topology data
- Appendix C.2 - Cable Impedance Data
- 0 -

- Meter assignment to **substations**
- Appendix C.4 - Half-hourly meters
- Appendix C.5 - Non-half-hourly meters
- 0 -

- Transformer **Data**
- 0 -

- Current and voltage **data**
- Appendix C.8 - SCADA channel mapping
- 0 -

- Scaling of Non-Half-Hourly **Demand**
- Appendix C.10 - Power Flow Analysis
- Appendix C.11 - Selecting to Use Non-Half-Hourly Scaling

2.3.2 Structure of HV feeder loss estimate data

Detailed results for each feeder are written to HTML pages and can be accessed using a web browser. The pages consist of:

- Overall results are accessed via a top level listing of analysed HV feeders;
- A summary page for each HV feeder provides details of the feeder (e.g. feeder topology, details of the substations and distribution transformers, and also the numbers of customer meters connected at each substation); and
- Losses results pages for each feeder (both scaled and unscaled) can be accessed from the HV feeder summary page.

Figure 2 shows the hierarchy of the html results pages.

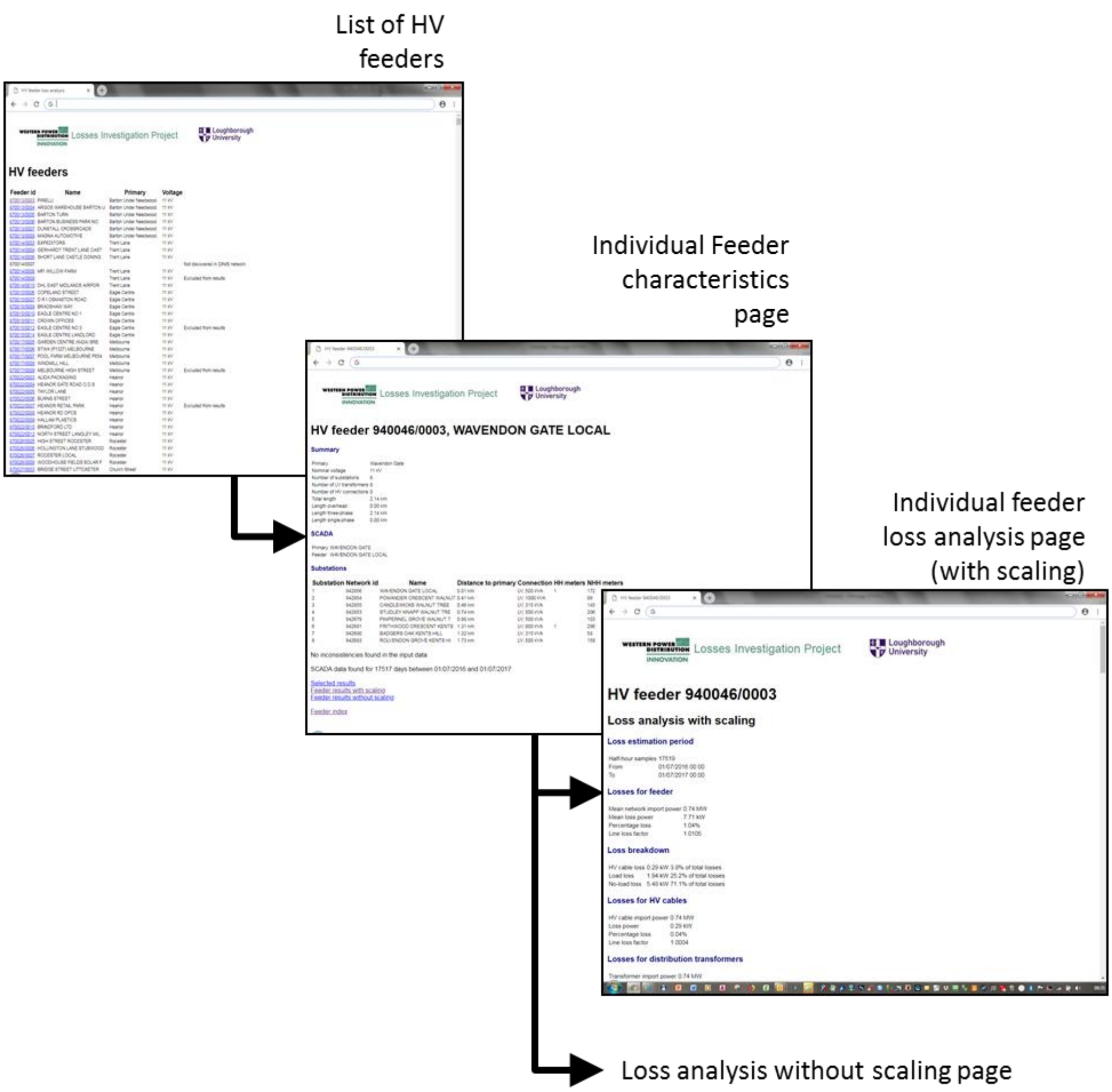
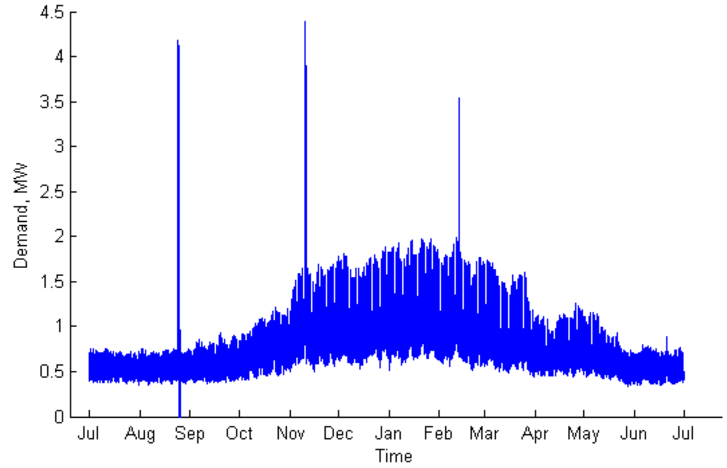
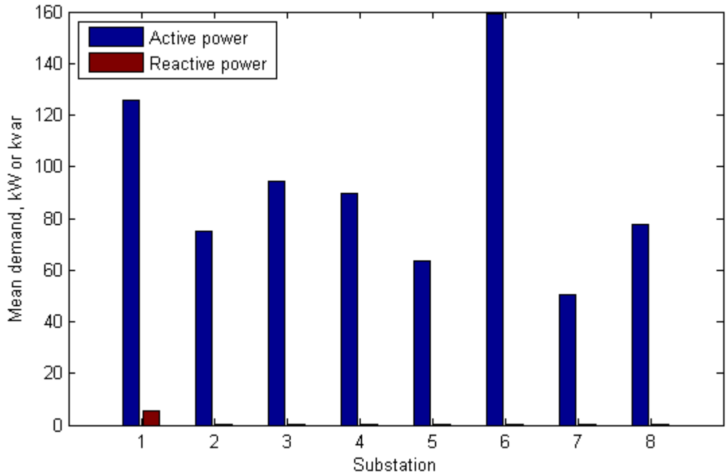


Figure 2 Example of feeder summary HTML page.

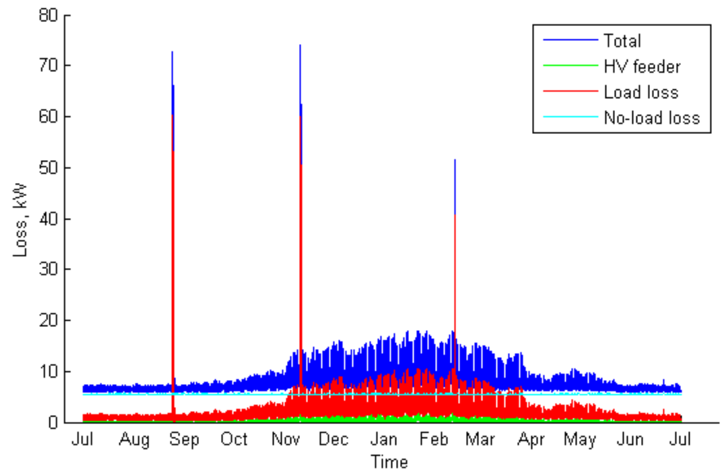
The individual feeder loss analysis pages contain summary data and a number of graphics, examples of which are shown in Figure 3. A full range of the graphics available for each feeder is shown in Appendix D.



HV feeder demand. Spikes illustrate temporary changes in feeder configuration.



Mean distribution substation loads for substations supplied by the HV feeder.



HV feeder Losses, with breakdown of losses between HV line, transformer no-load losses and transformer load losses.

Figure 3 Examples of loss analysis graphics available in html results pages.

The results from the loss analysis are also stored as a table of losses, also showing the breakdown of losses between HV cables and transformer load-losses and no-load losses. This also includes the cost of losses based on the value of lost energy of £48.42/MWh (Ofgem). This table is the principal data source for analysis of the overall result set (see examples of analysis in Section 2.3.3)

An extract of the data in this table is stored as a separate "high loss" feeder table, allowing investigation and (where appropriate) investment action to be targeted towards feeders that give the greatest potential reductions in losses and costs.

The HV cable losses are generally greatest in the first branch connected to the primary substation as this carries the aggregated current from all of the distribution substations. The results therefore also give a list of the first branches with the highest losses, separated into different categories according to the resistance of the cable or overhead line. This list may be used to consider conductor replacements for these branches.

2.3.3 Overview of HV feeder loss estimate results

This section presents examples of the analysis that is possible on the loss estimate results set. The purpose of this section is to demonstrate the range and depth of analysis that can be undertaken using the method that has been developed under this project.

Total loss power vs load

One of the fundamental means of showing the overall HV feeder loss estimation result set is to project the results on a scatter plot of mean total loss power versus feeder mean power. An example of this is shown in Figure 4. Each point on the chart represents one of a set of 2138 HV feeders for which the network and demand data has been found to be consistent (76% of the HV feeder population in the East Midlands region).

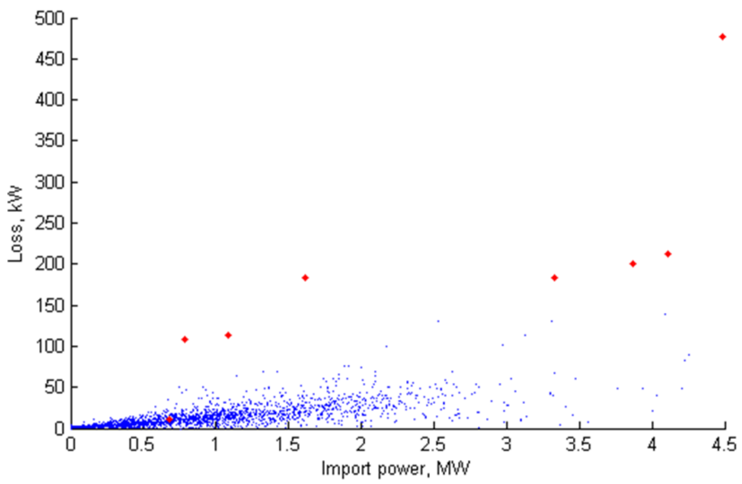


Figure 4 Scatter plot of mean loss power versus feeder mean power for HV feeders.

An early review of these results identified a number of feeders where the results were unduly affected by misallocation of load to individual substations (see 2.3.6- Customer meter assignments and 0). These feeders are shown as red points in Figure 4. A further processing of the data with corrected MPAN-substation allocations will be considered as part of the final stages of the project.

As a result, these feeders were removed from further analysis of the overall result set, and a revised scatter plot generated, this is shown in Figure 5.

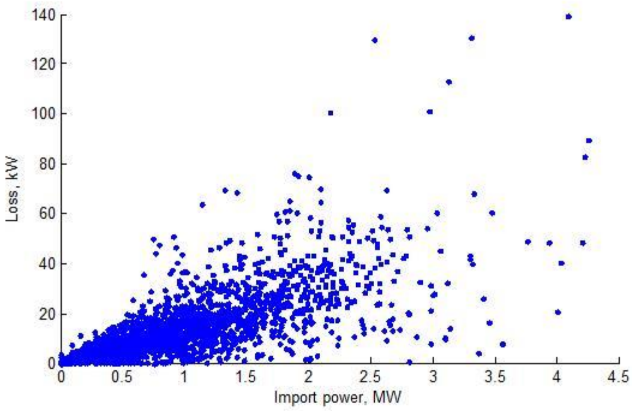


Figure 5 Revised losses scatter plot excluding feeders with erroneous MPAN allocations affecting loss estimates.

As would be expected, feeder losses generally rise with feeder load, though a significant variation in the level of loss can be seen for feeders of similar mean power (e.g. 1.5MW). This variation is driven by an individual feeder’s: length; conductor size; number of transformers; distribution of load along the feeder; and how that load distribution varies over time.

Cost of losses and feeder load

A variation on the fundamental scatter plot of mean total loss power versus feeder mean power is to convert the loss power to annual cost of the losses. This has been done on the basis of the loss being valued at 48.42/MWh (Ofgem). The resulting plot, Figure 6, is identical to Figure 5 except for the re-scaled vertical axis.

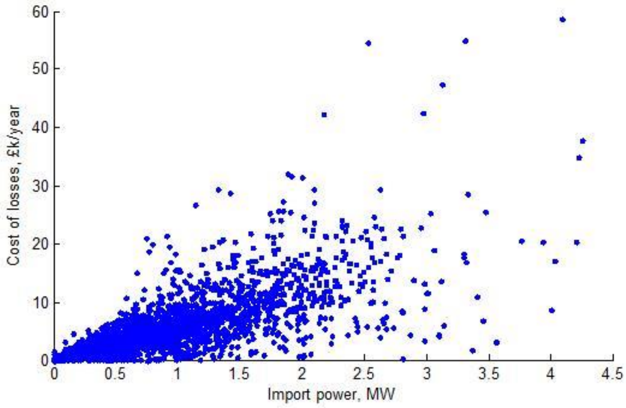


Figure 6 Cost of feeder losses vs. feeder load.

The plot of cost of losses versus feeder load has been used as the basis for result validation (see Section 2.3.4) and for one high-loss-network targeting approach (see Section 0).

Breakdown of where HV feeder losses occur

To assess the broad picture of loss breakdown (by HV conductors, transformer no-load losses and transformer load losses), losses for all feeders were aggregated. The results are presented in Figure 7.

Aggregating the losses for all of the feeders with accepted results, there is a total mean loss power for the East Midlands region of 30.4 MW.

By proportion, this consists of:

- HV cable losses of 11.3 MW, 37% of the total mean losses
- Transformer load losses of 4.9 MW, 16% of the total mean losses
- Transformer no-load losses of 14.1 MW, 47% of the total mean losses

The total mean demand at primary substations is estimated as 1.93 GW, with a total network import power of 2.06 GW allowing for embedded generation. This suggests a mean percentage loss for the HV feeders of 1.57% of the demand delivered from primary substations, or 1.47% of the network import power.

Figure 7 Breakdown of aggregate loss results

Correlation between transformer no-load losses and feeder load

Further analysis of the impact of transformer no-load losses on feeder losses can be seen in Figure 8.

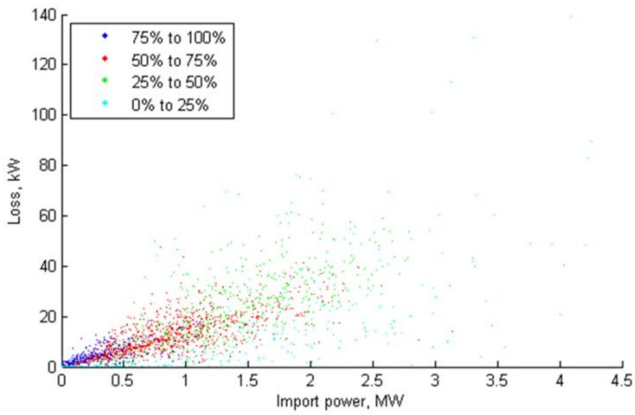


Figure 8 Loss vs. network import power coloured for proportion of losses due to transformer no-load losses.

Figure 8 suggests that losses for feeders with low import power are dominated more by the no-load losses. As the network load increases, no-load losses become a less significant factor. As a consequence, loss mitigation on lower loaded feeders is potentially achieved through changes of transformers (to low loss types).

There is no clearly visible equivalent trend for transformer load-losses. Feeders with low transformer load-losses cover the whole range of the points in such a plot; therefore this plot is not shown in this report.

Correlation between HV line losses and feeder load

The extent to which feeders with higher HV line losses correlate with higher loss feeders is examined in Figure 9.

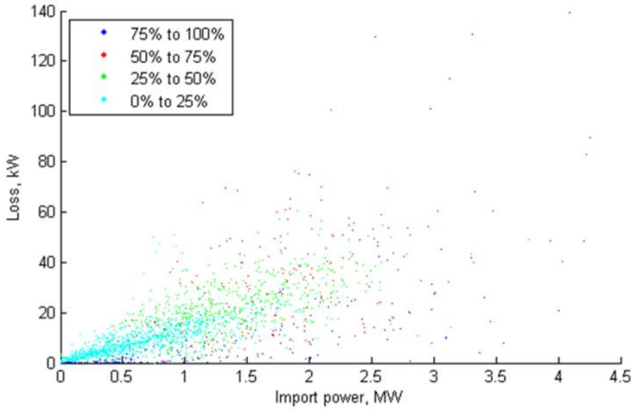


Figure 9 Loss vs. network import power coloured for proportion of losses due to HV cable load losses.

In general this suggests that higher loss feeders (say feeders with losses greater than 40kW) are predominately made up of feeders where the HV line losses are greater than 50% of the total losses. Hence higher loss feeders are generally characterised by high HV line loss.

Correlation between feeder loss and feeder type (urban, semi-urban, semi-rural and rural)

The extent to which feeder loss is correlated with feeder type is explored in Figure 10.

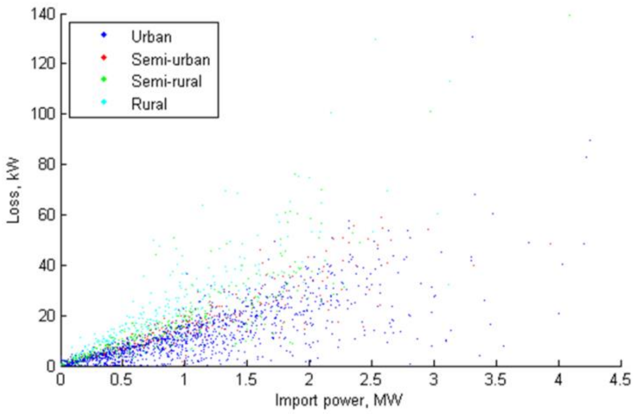


Figure 10 Loss vs. network import power coloured for feeder type.

The HV feeders are characterised into types according to criteria set out in Figure 11.

Urban:	no overhead lines
Semi-urban:	Proportion overhead is > 0% and <= 20% of the feeder
Semi-rural:	Proportion overhead is > 20% and <= 50% of the feeder, or > 50% and <= 80% and with total feeder length < 19 km
Rural:	Proportion overhead is > 50% and <= 80% and with total feeder length >= 19 km, or proportion overhead is >= 80%

Figure 11 Criteria for categorisation of HV feeders within this analysis.

As might be expected, when considering feeders of similar mean load up to around 2.5MW mean load, higher loss feeders are generally of rural type. Feeders with higher mean loads than this are generally not of rural type.

Correlation between feeder loss HV voltages (11kv vs 6.6kV)

Analysis of the HV feeder population included both 11kV and 6.6kV feeders. A loss scatter plot that identifies 6.6kV feeders as red coloured points is shown in Figure 12.

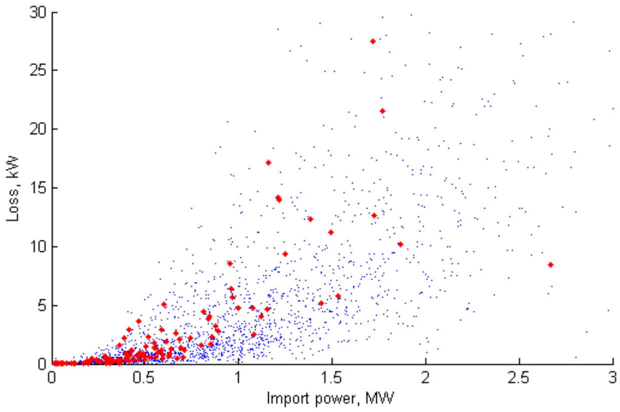


Figure 12 Line loss vs. network import power coloured for voltage (blue: 11 kV, red 6.6 kV).

All of the 6.6 kV feeders have loads below 3 MW and so the axes have been reduced here, allowing the comparison to be seen more clearly. For feeder loads above 1 MW, this shows that 6.6 kV feeders typically have slightly higher losses than the average of similarly loaded 11 kV feeders. However, the differences are minimal and not apparent for feeders with less than 1 MW load. This result should not be taken to imply that changing a particular feeder from 6.6 kV to 11 kV would not reduce losses. However, it does show that the design of existing 6.6 kV feeders is such that they do not have significantly higher losses than 11 kV feeders operating with the same level of load.

Presentation of losses as percentages versus feeder power

An alternative representation of the HV feeder loss data set is as a scatter plot of percentage loss (loss power divided by feeder import power) versus feeder mean power. This is shown in Figure 13. To some extent this normalises loss with respect to power; however, at low feeder loads, high loss percentages are generated where loss powers are low and the monetary value of losses are correspondingly low. This representation of losses has not been used extensively in this analysis.

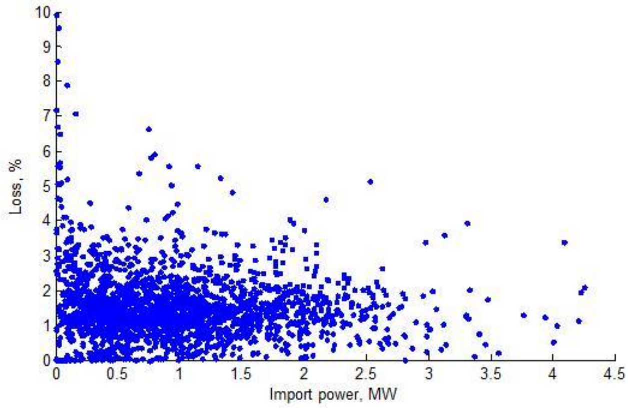


Figure 13 Revised losses scatter plot showing percentage loss versus feeder mean power.

2.3.4 Review of outlier results

In addition to overall method validation (testing estimation results against monitored feeders, previously reported), a number of outlying results have been reviewed. Figure 14 shows the scatter plot of the cost of losses versus feeder load, with 15 boundary and other feeders highlighted and listed.

1. 900021/0005
2. 930057/0008
3. 930073/0006
4. 890058/0004
5. 870047/0007
6. 900013/0010
7. 910055/0008
8. 940043/0009
9. 940022/0004
10. 890068/0002
11. 880022/0005
12. 940046/0008
13. 874558/0036
14. 920059/0004
15. 910018/0008

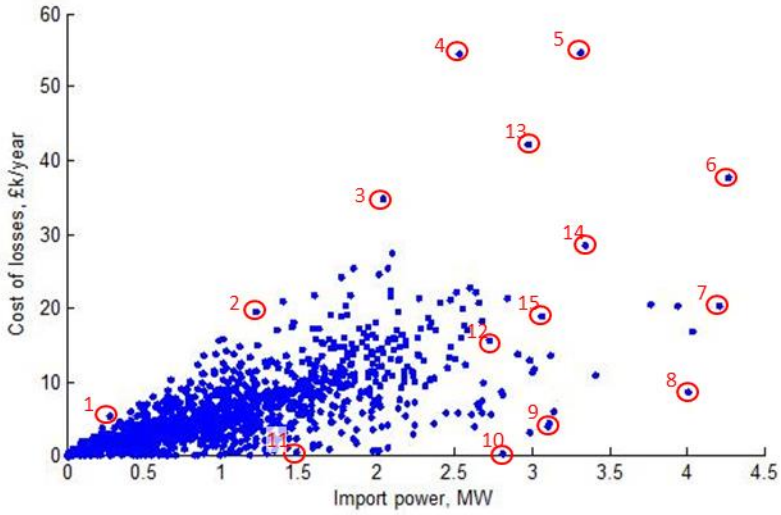


Figure 14 Revised losses scatter plot showing percentage loss versus feeder mean power.

The review of each feeder included a range of considerations. Feeder topology was reviewed to provide overall context, together with broad characterising metrics. An example of this is shown in Figure 15. In these plots, the HV network is simplified as straight line branch sections using start and end x,y coordinates.

- Wood End primary
- Rural feeder (45km total length; 63% OH; 82 substations / 78 Transformers)
- Feeder is on the boundary of EM licence area

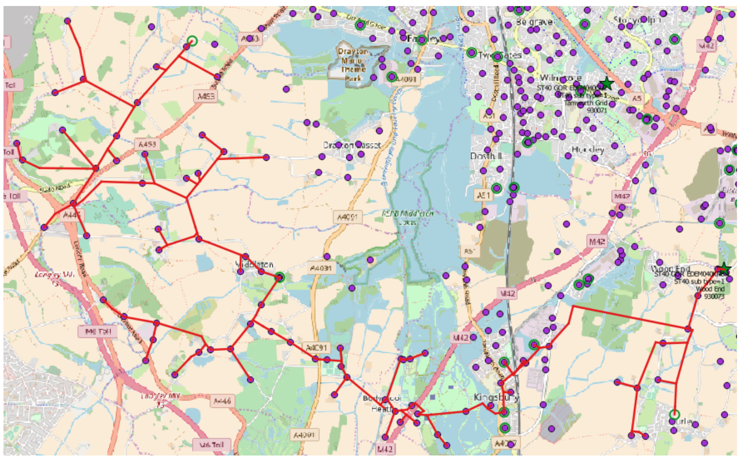
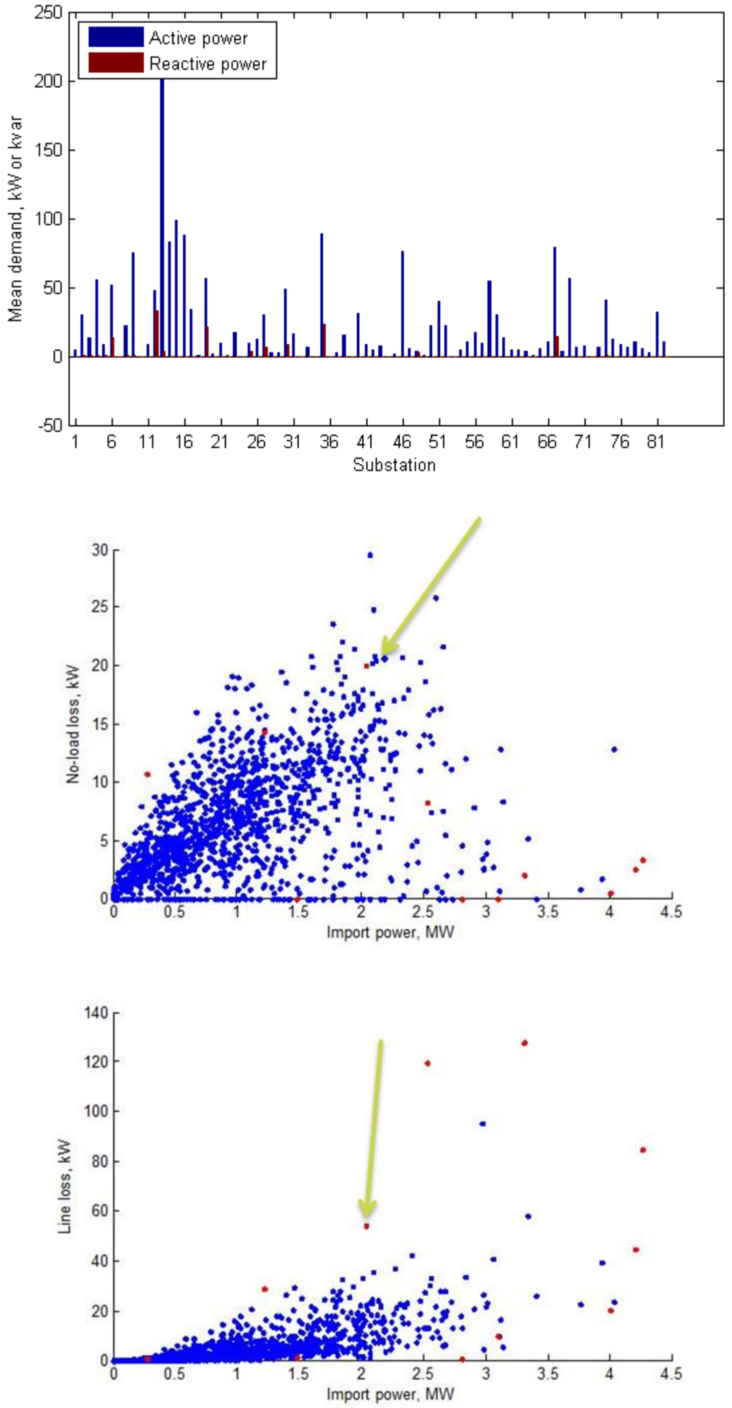


Figure 15 Example of network topology and broad feeder characteristics.

Drivers of the level of loss were considered for each feeder. Typically this included the distribution of substation loads along the HV feeder; and depending on the specific feeder, additional pieces of analysis. An example of this is shown in Figure 16.



Mean distribution substation loads for substations supplied by the HV feeder. In this case emphasising the high number of connected transformers.

Scatter plot of HV feeder transformer no-load losses, showing that this feeder has one of the highest levels of aggregate transformer no-load loss

HV feeder Losses, with breakdown of losses between HV line, transformer no-load losses and transformer load losses.

Figure 16 Examples of analysis used to consider what was driving losses for an individual HV feeder.

Potential means of mitigating losses were considered to a very basic extent, to test the capability of the analysis to support mitigation investigation work. An example of considering the position of open points and the possibility of changing the position of the open points is shown in Figure 17. An alternative or possibly addition means of mitigation in this case might be the consideration of low loss transformers.

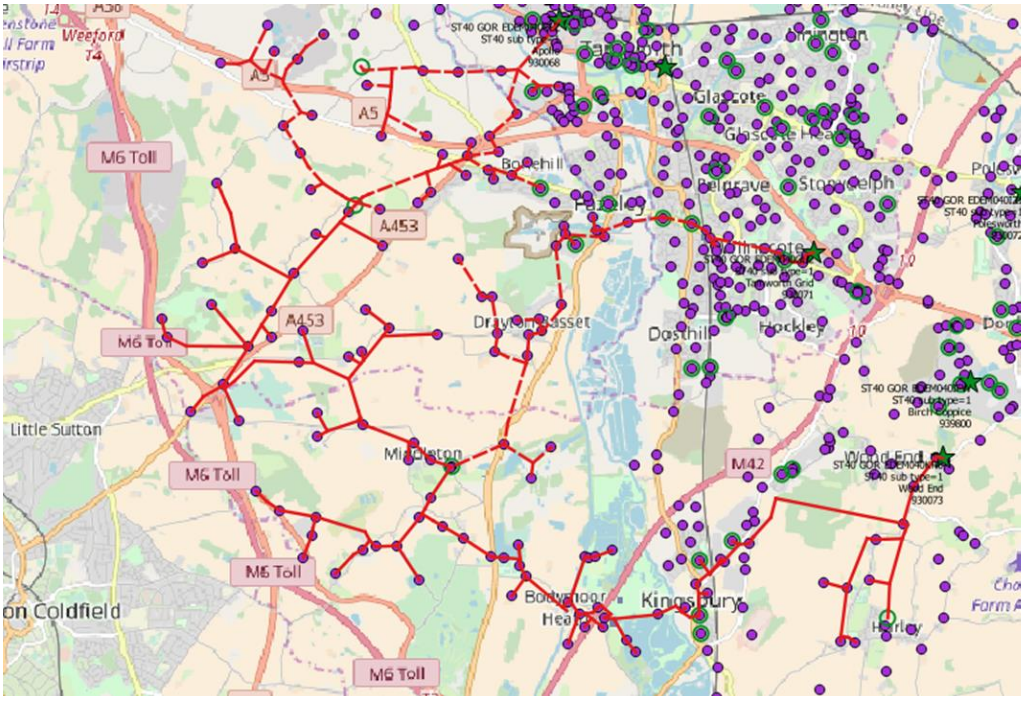


Figure 17 Feeder under review (shown with solid lines) and adjacent HV feeders (shown with dashed lines).

In the example above, the level of loss estimated for the HV feeder appears reasonable given the length of the feeder (leading to relatively high HV line losses) and the number of connected transformers (leading to relatively high transformer no-load losses).

In all 15 cases reviewed, the estimated level of loss could be linked to characteristics of the network (e.g. length, cross-sectional areas number of connected transformers), and the load (e.g. how the load is distributed across connected substations, and the location of dominate loads on the HV feeder).

2.3.5 Targeting of High Loss HV Feeders

Results data from the HV feeder loss estimation process have been used to identify network that might deliver a nominal annual loss cost saving target as set out in the project's NIA project registration document. The nominal target is £0.25 million for HV feeders in the East Midlands region. The basis for this figure is set out in Appendix E.

Such a cost saving might most easily be achieved by addressing the highest loss feeders. A histogram of the cost of losses for each of the 2130 feeders, ranging from near zero up to approximately £60k per year is shown in Figure 18.

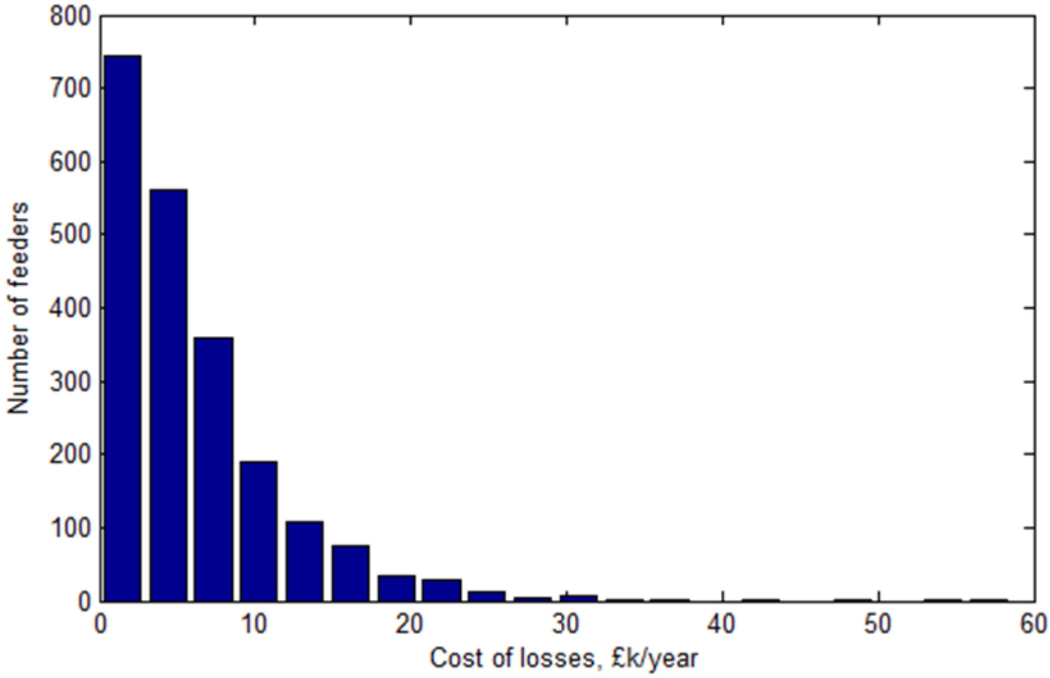


Figure 18 Cost of losses for feeders with accepted results, based on £48/MWh.

If the 10% loss reduction could be applied to the feeders with highest losses, then mitigation action on 110 feeders might contribute an annual saving of £0.25 million. Feeders with an annual cost of ~£17 thousand or more form the target group. Figure 19 shows this group on the histogram, and Figure 20 shows the potential target group on the cost of losses scatter plot.

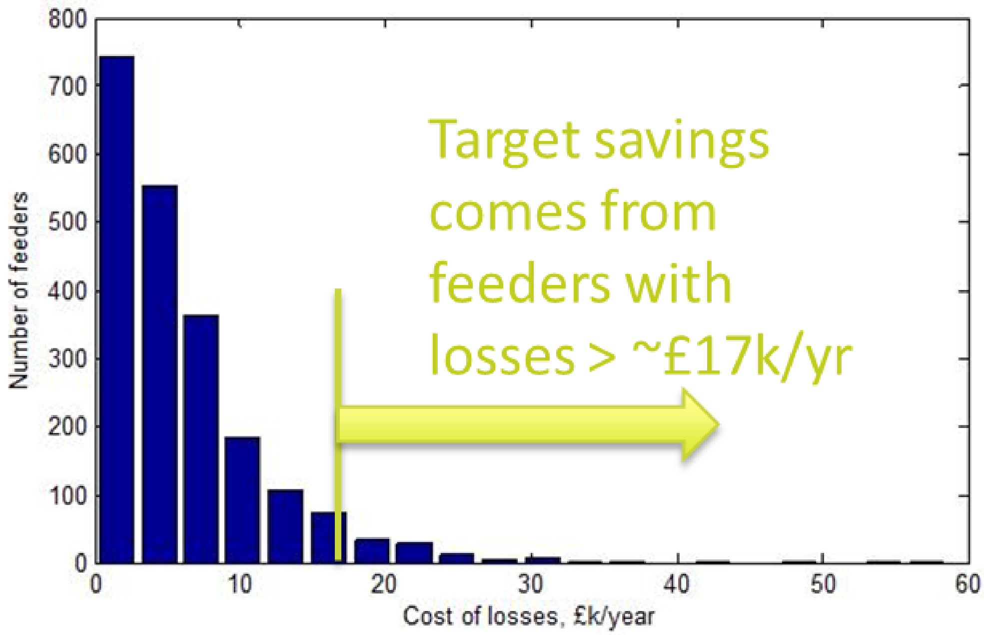


Figure 19 Cost of feeder losses histogram showing £17k/yr. threshold.

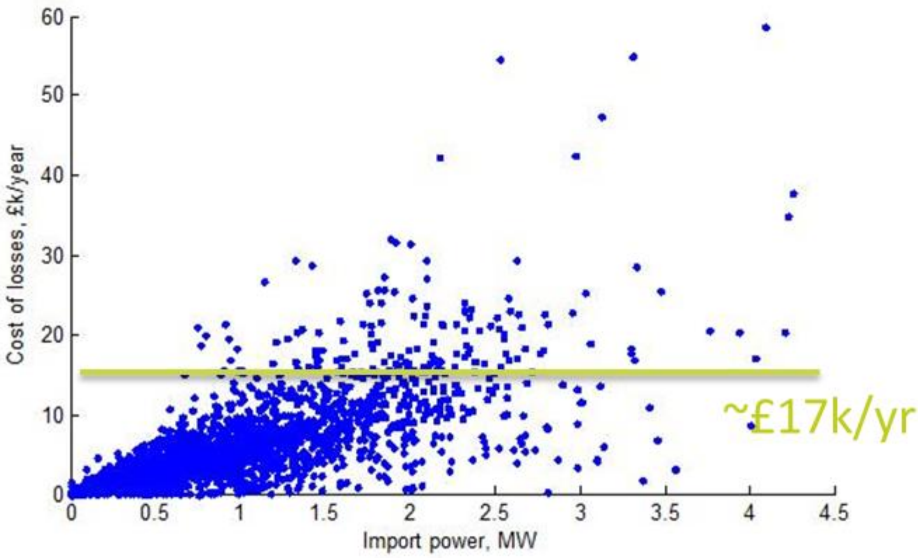


Figure 20 Cost of feeder losses scatter plot showing £17k/yr. threshold.

2.3.6 Potential causes of estimation inaccuracy

This section describes a number of potential causes of inaccuracy in the loss estimates.

Network changes

The loss estimation for the East Midlands region uses a DINIS file exported in November 2017. Clearly, there will be network changes since this time, and there would also have been changes in the network configuration over the 1-year period for which the losses were estimated. The loss estimation results are therefore recommended as an indicator of feeders with high losses. The network configuration for these high loss feeders can then be re-checked when evaluating possible loss mitigation actions.
It is also possible that there are errors in the network data. However, the loss estimation method carries out a number of consistency tests to ensure that the identified HV feeders are consistent with the geographic feeder data in the EMU database.

Customer meter assignments

It has been found that some of the database records for customer meters show that they are connected to either the incorrect substation or HV feeder. Eight high loss feeders have been excluded from the analysis for this reason but it is likely that there are other cases where this has not been detected. Undetected meter assignment errors are likely to cause load losses to be incorrectly recorded, with some transformers having additional load and others having an under-estimated load. Provided that the meters are recorded on the correct HV feeder, an error in the substation assignment has less of an impact on the HV cable loss calculation as the highest losses occur where the full feeder current is aggregated together.

Missing cable data records

Some of the branches in the DINIS network file are defined with a default cable type that has an impedance value of zero. In most cases these branches are short jumper cables at substations, but there are a few with much longer sections of cable having zero impedance.

Independent DNO demand data

Substations for independent DNOs (IDNOs) are increasingly being connected to HV feeders. In many cases the IDNO is responsible for the distribution transformer and for the downstream network to the customers. WPD generally does not have load data or customer EACs for these MPANs (organised by distribution substation) and so these MPANs are omitted from the demand model.

There is no impact to the transformer loss metrics for the IDNO transformer itself as these losses are not within scope of the losses managed by WPD. However, there are other impacts to the loss estimation, depending on whether the SCADA measurements are used for scaling the non-half-hourly demand. If so, then the load losses on other distribution transformers will be over-estimated as the non-half-hourly demand at the other substations will be scaled up so that the total current matches the measurement at the primary. The HV cable loss estimate will also be affected, although the aggregated current in the branch nearest at the substation, typically with the highest losses, will be effectively unchanged. If the non-half-hourly demand is not scaled, then the IDNO substation demand is simply omitted and the HV cable losses will be under-estimated.

SCADA current measurement accuracy

Where SCADA data is used to scale the non-half-hourly demand, the results are clearly sensitive to the accuracy of the SCADA current readings. These may be specified as class 5 accuracy (±5%) although comparisons with separate measurements using GridKey loggers on the project HV trial feeders have generally shown much closer agreement.
If all of the demand is non-half-hourly metered then a 5% error in the current reading would give approximately 10% error in the loss power.

Missing transformer records

The loss estimation software assigns a distribution transformer to a substation if a record can be found in the list of transformers exported from the CROWN database. If a substation has no transformer listed in this data, then it is assumed to be an HV customer connection point and so there is a risk that transformer losses will be under-estimated if transformer records are missing. The loss estimation software therefore excludes any feeders with a substation that has a non-zero load rating specified in the DINIS file, but for which no transformer can be identified. Other differences between the transformer rated power and the DINIS file load rating are ignored as the CROWN transformer database has been treated as more reliable than the load ratings in the DINIS file.
It is possible that further missing transformers have not been detected, particularly as there are some substations with non-half-hourly customers connected, assumed to be at LV, but where there are no records for the distribution transformer in DINIS or CROWN. Although this causes the transformer losses to be under-estimated, there is negligible impact to the HV cable losses.

2.4 Development of Initial Loss Estimates for LV Feeders in Milton Keynes area

During this reporting period, methods and processes of estimating LV feeder losses have been developed, and loss estimates for 254 LV feeders established. These LV feeders are associated with distribution substations in the Milton Keynes area that are monitored as part of the HV feeder losses part of the project.

The following sections describe:

- Key background for LV feeder loss estimation;
- The LV feeder loss estimation method, as currently developed

2.4.1 Key background for LV feeder loss estimation

As with loss estimation for HV feeders, the preferred project approach for LV feeders is to undertake load flow analysis for each considered feeder, using best available network and load information.

In comparison to HV feeders, the key issue is the widespread relative unavailability of established data describing the network topology and load connectivity in a format that can directly be used in load flow analysis.

Key issues with data used to prepare network and load models for the purpose of estimating LV feeder losses are:

- The identification of which LV cables constitute the topological feeders from a distribution substation. For example, it may be known that a group of customers are on LV feeder 3, but it is not clear from LV cable meta-data which set of cable routes constitute this feeder;
- The existence of open points between LV feeders, in the form of data tables, with appropriate referencing to LV feeders. Inaccurate knowledge of the connectivity at link boxes can cause uncertainty in establishing the end of a particular feeder; and
- The connection points for loads along the LV feeders (particularly larger commercial and industrial loads).

The Electric Nation project has demonstrated methods that provide estimates of: LV networks emanating from distribution substations; the association of connected customers to particular estimated feeders; and a nominal connection point onto the feeder main for each identified customer. This network model is used in their Network Assessment Tool (EATL NAT).

The working approach for the Losses Investigation project is therefore to build on the available network/load connection data available from the EATL NAT, to add in further elements of the network model necessary for loss assessment (e.g. services), and further develop the load model, including key considerations of load diversity and phase balance.

During this reporting period, methods of estimating LV feeder losses have been developed, and loss estimates for 254 LV feeders established. These LV feeders are associated with distribution substations in the Milton Keynes area that are monitored as part of the HV feeder losses part of the project.

The following sections describe progress made.

2.4.2 Overview of LV feeder loss estimation method

Methods and associated processing software have been developed to undertake large-scale LV feeder loss estimation as illustrated in Figure 21.

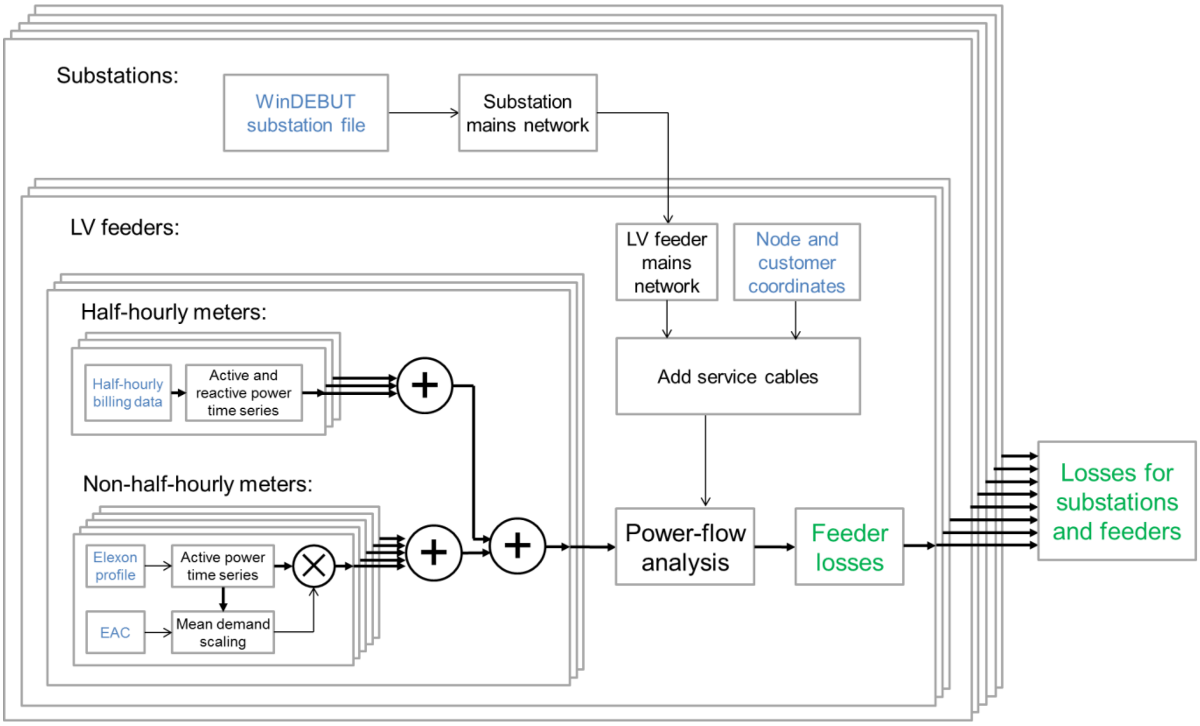


Figure 21 Outline of the LV feeder loss estimation method.

As with the HV feeder process, the loss estimation method combines network topology data with time-series demand data in order to run a power-flow analysis from which the individual LV feeder losses are calculated. These individual feeder results are then collated so that loss characteristics of the overall LV feeder set can be validated.

As discussed in Section 2.4.1, approximated LV mains data from the EATL NAT is being used as the basic backbone of the LV network. Cable types and cross-sectional areas (CSA) are established from this data. Services are then modelled as straight line connections from each recorded customer location to a notional mains-service joint position. At present, the start/end nodes of the EATL NAT data act as potential main-service joint positions and the closest potential main-service joint positions is identified for each customer location. A modelled service is then established on this basis for all single customer locations. There are instances where multiple customers are nominally located at the same spatial position, or are in very close proximity (e.g. within 3 metres). In these instances, a shared service is established for the customer group (where customers have a profile class of 1-4). At present, services are sized by selecting a cable CSA according to the modelled peak load before diversity. Service cables are assumed to Wavecon 35 (single- or three-phase), or larger sizes of three-phase Wavecon cables if required according to the aggregated peak current. Currently, single phase connections are allocated to a phase on a running cylindrical basis (L1, L2, L3, L1, L2, L3 etc.), with imbalance being introduced through the differing quantities of power drawn by different customers. Three phase connections are currently modelled on a balanced load basis; this will be reviewed with variations on this introduced at a later development stage based on observed demand statistics, such as from the Isle of Man monitored feeder data.

At this point in development, the time series demand data is based on half-hour periods. Although this provides a close approximation for HV feeders, it is recognised that significantly more time diversity may be required to accurately represent the feeder losses for LV feeders. This is one of the next method/process development steps. The current load model is based on HH meter data, where available, plus EAC-scaled HH profile data for NHH metered connections. If EAC data is not available, load is included provided profile class is known, effectively with average consumption data for the profile class of connected customer. At present there is no scaling of NHH load (as is done for HV feeder loss assessment).

2.4.3 Overview of processing to date

The EATL NAT model provides data for 133 of the 154 distribution substations with LV network[2] (86%), and provides data for 278 of the actual 311 LV feeders (89%).

From the 278 EATL NAT identified feeders, the power-flow analysis converged for 254 feeders and there were 24 feeders for which the solution did not converge, mostly due to the meter locations requiring an unrealistically long service cable.

This gives results for an overall total of 254 solved feeders, 82% of the 311 feeders. The loss power versus feeder load scatter plot for these 254 feeders is shown in Figure 21.

[2] Distribution substations providing an HV connection obviously have no associated LV network, and would therefore not be included in the EATL NAT model.

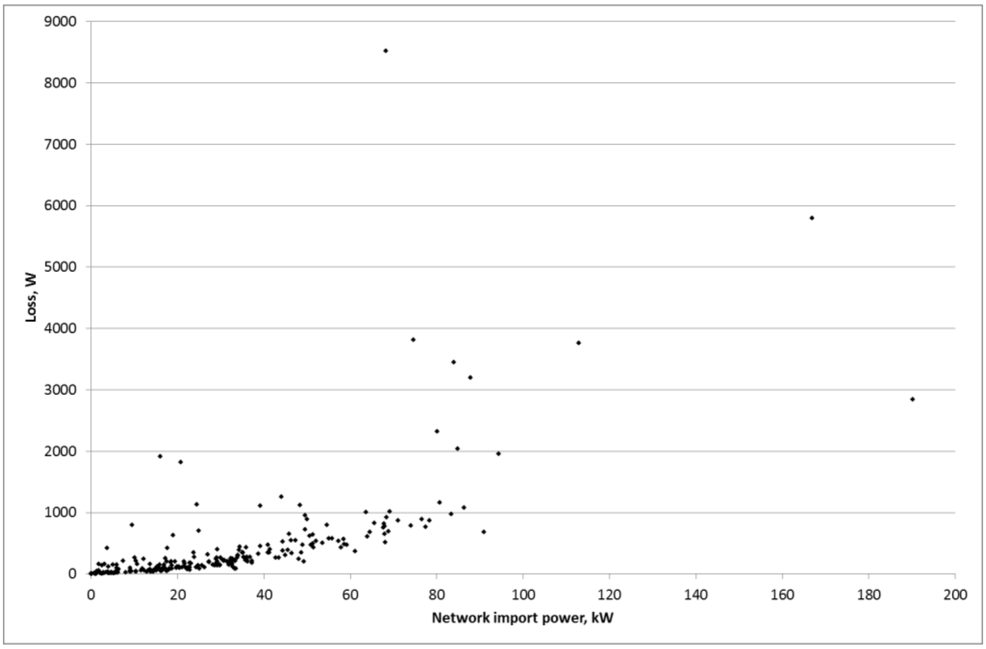


Figure 22 Loss power versus load scatter plot for all 254 processed LV feeders.

Initial review of outliers on this plot identified instances of network topology issues where:

- WPD customer/Point of Connection location records appear inaccurate and are leading to:
    - exceptionally long modelled service cables (e.g. 887m for the highest loss feeder in Figure 21) causing exaggerated loss estimates;
    - over association of loads to a particular feeder within the EATL NAT model (e.g. 945226 F2, second highest loss feeder in Figure 22) causing exaggerated loss estimates;
- The EATL NAT model creation processes had not been able to accurately capture the actual network topology, leading to inaccurate loss estimates.

As a result, work is ongoing to establish reliable methods of identifying loss estimates that are affected by unreliable input data. To date, length of modelled service and minimum modelled voltage are being considered. This might lead to an initial “working” set of loss estimates as shown in Figure 26 (note the smaller Y-axis compared to Figure 22).

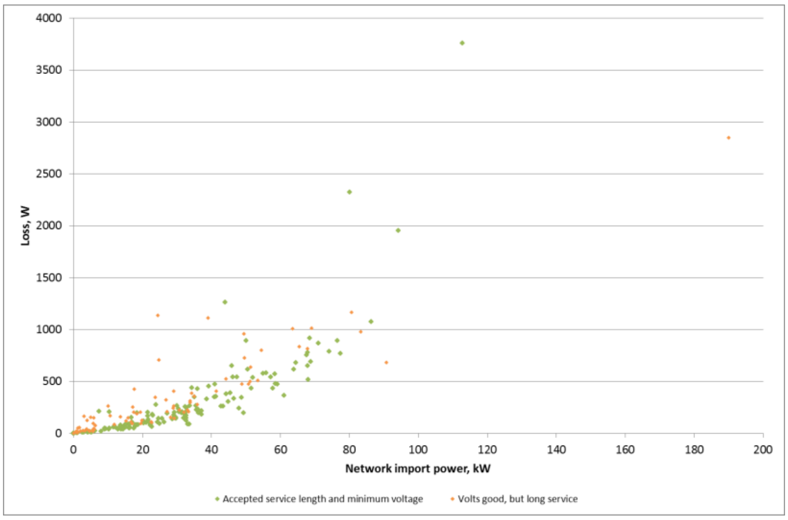


Figure 23 Loss power versus load scatter plot for “working” set of LV feeders.

In this result set, estimates with less than maximum service length and more than minimum voltages are initially accepted. In addition, results with acceptable minimum modelled voltages, but where the modelled cable length is higher than expected in reality, are also included (separately marked). This is intended to maximise the working set, without compromising the results with unreliable results. This initial working set is also shown as percentage loss versus feeder load in Figure 24. All results lie in a credible range.

This initial screening of all results leads to a working result set of containing 232 feeders, 75% of the actual 311 feeders.

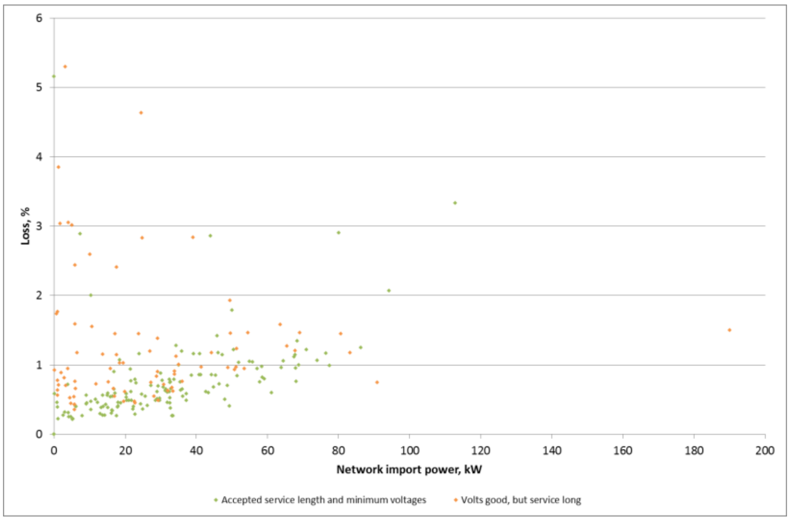


Figure 24 Loss percentage versus load scatter plot for “working” set of LV feeders.

2.4.4 Next steps

Next steps in the development of the LV feeder loss estimates include:

- Further investigation of methods to isolate and remove unreliable loss estimates (due to unreliable input data);
- Further validation of the estimation method using results from the LV monitored feeders;
- Extension of the processing scale to enable assessment of tens of thousands of feeders; and
- Refinement of the load model and nominal phase connection methodologies to account for sub half-hour load diversity and LV phase imbalance.

3 Progress against Budget

3.1 Overview of Progress against Budget

Table 3 Progress Against Budget

Spend Area	Budget (£k)	Expected Spend to Date (£k)	Actual Spend to Date (£k)	Variance to Expected (£k)	Variance to Expected %
HV Feeder Monitoring	£1,007	£808	£795	£13	2%
LV Feeder monitoring	£496	£233	£226	£7	3%
Analysis	£425	£390	£390	£0	0%
Design & Project Management	£417	£341	£352	-£11	-3%
Contingency	£235	£0	£0	£0	0%
Total	£2,580	£1,772	£1,763	£9	1%

3.2 Comments around variance

None.

4 Progress towards Success Criteria

At inception, the project identified five success criteria. These criteria are listed in **Error! Reference source not found.** with commentary on progress towards completion.

Table 4: Progress towards project Success Criteria

Project Success criteria	Commentary on progress
1) Construction of fully monitored HV and LV networks	**Construction is now complete.** All required monitoring is now installed on the 11 HV feeders. This includes monitoring at 7 primary substations, 58 pole-mounted transformers 18 HV-customer supply substations and 116 ground-mounted transformer distribution substations. All required monitoring is now installed on the 11 LV feeders. This includes 288 single phase meters, 47 three-phase meters, 13 ground-mounted LV feeder monitors and 2 pole-mounted LV feeder monitors.
2) Measurement of network losses on monitored feeders	**Ongoing loss assessments based on full monitoring data are now available for all HV and LV feeders**. A snapshot of the Loss assessments for these feeders is shown in Appendix A.
3) Accurate modelling of losses with full information	
4) Several models with limited data sets created and tested	**The development and demonstration of method and processes to estimate HV feeder losses has been completed.** Various approaches to estimating feeder specific losses have been considered and tested. For HV feeders, a finalised approach has been developed that delivers high degrees of agreement to monitored feeders. This method has been demonstrated on 2130 HV feeders in the East Midlands region. Details of the method and the loss estimation results are described in Section 2.3 of this report. **Initial methods and processes to estimated LV feeder losses have been developed, and demonstrated on a selection of LV feeders in the Milton Keynes area**. Work continues on an LV approach, and progress with development is described in Section 2.4 of this report.
5) Conclusion on level of information needed to accurately predict losses	Conclusions on the level of information required for HV feeders (based on the completed method, processes and demonstrated results) will be included in the final project report and dissemination. Conclusions on LV feeder specific loss estimation will follow ongoing development work.

5 Learning Outcomes

The development of the HV loss estimation method has been completed within this last six month period. The learning outcomes below therefore bring together the learning on this topic over the full duration of the project.

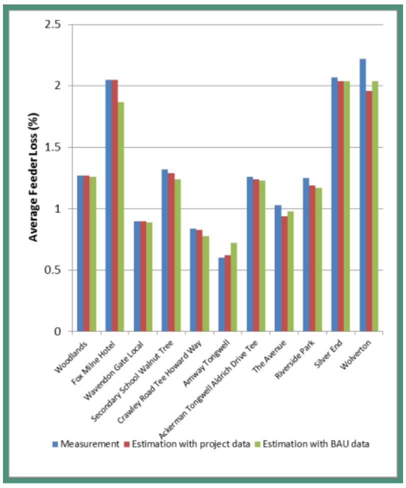
Table 5: Illustrative and key learning

Area of Learning	Learning
HV loss estimation results	• Losses can be estimated for individual HV feeders using BAU data sources and without requiring additional monitoring equipment. The loss estimation method is based on a power-flow analysis using imported network and demand data. • From a total of 2832 HV feeders in the East Midlands license area, loss estimates have been calculated for 2130 feeders, approximately 75% of the feeders in the license area. Feeders have been excluded from the loss estimation results where the input network or demand data has been found to have issues sufficient to invalidate a loss estimate. • Overall, the HV feeder losses (including the feeder cable losses and the LV transformers) for the East Midlands licence area are estimated to be 30.4 MW. This equates to 1.57% of the 1.93 GW power delivered from the primary substations, and 1.47% of the 2.06 GW power to the HV network from primary substations plus embedded generation. This loss figure is likely to be lower than for other regions with more rural feeders or older transformers. • Within the mean 30.4 MW of loss power, approximately two thirds of the overall feeder loss power (63%) occurs in distribution transformers and approximately one third (37%) occurs in the HV feeder cables. • Within the distribution transformers, 75% of the losses are no-load loss (iron losses) with only 25% due to the load losses (copper losses) • Replacement of transformers by newer designs with lower no-load losses may therefore be a possible means of mitigating a significant proportion of the total HV feeder losses. The results therefore provide a list of substations for which the age and rated power of the transformer indicate that the no-load losses may be higher than average, and where the benefits from replacement may be greatest.

Area of Learning	Learning
	• HV cable losses are also a significant portion (37%) of the total HV feeder losses. There is also a wide variation in the losses per feeder, ranging from near zero for feeders with minimal load, to a worst-case feeder with around 140 kW of total losses at an associated cost of £60k/year. A key output of the loss estimation method is therefore a candidate list of feeders which have the highest losses, such that any investment decisions or mitigation actions can be targeted towards the feeders with higher losses. • For a nominal saving target of £0.25million in the cost of losses, and assuming a saving of 10% per feeder, then 411 feeders would need to be addressed if these were selected at random. However, by using the losses estimation method to select the candidate feeders with high losses, the number of feeders is reduced to only 110. • The list of feeders with high losses is proposed on the basis that the feeders will then be reviewed in greater detail to determine whether the network model is representative of the current operational state of the feeder or whether there any significant changes or errors in the load model (e.g. due to incorrect assignments of meter MPANs). • A number of case studies have been developed showing examples where the HV cable losses could possibly be reduced by a change in the network configuration, such as by moving an open point. In some cases there may be a greater potential to mitigate losses by encouraging generation to be sited at specific points in the network, or by adopting a mesh topology. • Transformer load losses are the lowest contributor (16%) to the total HV feeder losses. However, some transformers are associated with losses that are much higher than the average losses and these may merit further investigation to review whether asset replacement may be appropriate. The loss estimation results therefore also provide a list of transformers with high losses, categorised by rated power.

<table>
<tr><th>Area of Learning</th><th>Learning</th></tr>
<tr><td></td><td></td></tr>
<tr><td>Comparisons between estimated and measured loss for monitored HV feeders</td><td>

11 HV feeders were fitted with extensive (but reasonably practicable) instrumentation to provide high time-resolution voltage and current monitoring data from which an assessment of feeder losses could be made. These “measured” losses were successfully used as to assess the accuracy of loss estimation methodologies. Further detailed points of learning have previously been reported associated with: the use of a pilot approach to the fitting of instrumentation; the instrumentation fitted; and calculation methods used for the assessment of losses from measurements.
Reasonable to very good agreement was found between the finalised estimated losses and “measured” losses.
The estimated losses were in most cases within 10% of the losses calculated from measurement data, and in one case within 20%.
Where larger deviations occur, the differences are typically caused by data errors in the load assignment.



The ranking of the feeders using BAU data estimation is not materially different to the ranking according to measured data.

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<tr><td>NOP position and potential reductions in HV feeder loss</td><td>

Losses on HV feeders can be reduced by changes in the NOP location. Three inter-connected project-monitored HV feeders have been studied, demonstrating scope to reduce the combined losses of the paired feeders by 14.7%, 15.9% and 3.9%. This corresponds to an annual cost saving of £405, £2892, and £599 for the three feeders.
Nearly all of the potential benefit is realised by a one-off movement of the NOP location, with little further reduction in losses if the NOP location were to be optimised on a half-hourly basis.
In two of the studied NOP position cases the majority of the loss reductions could be achieved using an NOP location on substations near to the optimal network node. This provides some degree of flexibility if the optimal location cannot be selected for operational reasons.

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Area of Learning	Learning
Input Network Data	• The loss estimation method uses network data exported from a BAU HV power flow tool (DINIS). Routines to import this proprietary-format data were successfully established. • Reviews of examples of feeder loss estimates (testing results) identified that the BAU DINIS data contains network simplifications at some substations which may create topology inaccuracies. These may be identified as network loops that do not actually exist, or through inconsistencies between the resulting electrical network and the underlying branch metadata (e.g. sudden changes in feeder references in apparently continuous branches). Tests of network data integrity have been found to be essential in establishing a level of confidence in the loss estimation, and feeders with uncertain topologies have been excluded from the set of results. • A consequence of adopting these consistency tests is that networks which genuinely have a meshed topology are excluded from the analysis. • In some cases there are feeders that are known to have a meshed topology but the mesh inter-connections are not represented in the analysed network data. The estimation results for these feeders therefore indicate the (higher) losses that would apply for a radial configuration, rather than actual case. • The cable resistances used by the DINIS software tool are around 5% lower than those estimated using for the project using finite element analysis. This difference is likely to be due to the omission of AC resistance effects in the DINIS cable definitions data. There are many different cable types used across the WPD networks and it has not been possible to develop finite element models for each variation. • An approximation method has therefore been used to correct the input DINIS cable data and allow for the AC resistance effects. Although the results vary for different cable types, a reasonable approximation is given by applying a correction that is proportional to the phase conductor cross-sectional area, giving an 11% increase in the resistance for 300 mm^2 conductors. • Omitting the cable admittances has a negligible impact on the estimated loss values.

Area of Learning	Learning
Input Demand Data	• A demand model has been constructed for each feeder based on the combined demands of each of the recorded customer meters, connected either at LV or as an HV customer connection. This approach gives loss results that are specific to each feeder and represent the best estimate of the actual distributed energy. • For the trials feeders, this approach has generally been found to give good agreement to the substation demand measured using the GridKey monitoring instrumentation. • However, in some cases, there are errors in the MPAN-feeder allocation. This affects the estimated losses, particularly where these are more heavily loaded half-hourly metered connections. In one of the HV trials feeders, differences between the BAU meter data and the project meter data accounted for a change in the estimated losses of 15%. More generally, minor differences in recorded MPAN-feeder allocation data caused a much lower impact. • The demand model for non-half-hourly metered connection points is based on the averaged Elexon profiles and so does not represent variations from the average demand for individual customers or for each half-hour period. The half-hourly SCADA data measured at the primary has therefore been used to introduce a representation of this variation into the model. A scaling factor is applied to the non-half-hourly demand such that the primary substation current predicted by the power-flow analysis is consistent with the SCADA measurement data. • Although the actual variations in the non-half-hourly demand will vary between customers, a common scaling factor has been applied throughout. HV cable losses are greatest in the branches near to the primary, where the half-hourly current is measured. Although variations in the demand that occur further downstream are less well represented, their impact on the total losses is also much lower. • If the demand model is correct, then it would be expected that the long-term mean of the current primary substation demand predicted by the power-flow analysis would be equal to the measured demand from the SCADA data. This allows significant errors in the estimated demand due to inaccurate locations and assignments of customer connections to be detected

Area of Learning	Learning
	• However, the use of the SCADA data to provide a scaling factor also means that the results are dependent on the accuracy of the SCADA measurements. The agreement between the predicted and measured demand is dependent on the measurement tolerances of the current sensors and of the current transformers used in the primary substation protection equipment installation. It has been assumed that the scaling factors derived from the SCADA data are invalid if the mean demand correction is more than 20% of the uncorrected demand. • The SCADA data provides only the magnitude of the current and so an algorithm has been developed that allows for the case where there is a net export from the feeder. The scaling factor for the non-half-hourly demand assumes either net import or net export, with the value selected such that the correction to the demand is minimised. • It has also been found that there are some feeders for which the SCADA data frequently has zero values or does not follow an expected demand profile. These cases are detected as noted above. • Where the SCADA data has been found to be unreliable, the loss estimates use the non-half-hourly demand without applying further scaling factors. The losses for these feeders have a lower level of certainty (as there is no verification of the mean demand against the SCADA data), but are included as the best available estimate. • The SCADA measurements are also affected by network reconfigurations, such as where open points are moved and the substations supplied by the HV feeders are not as indicated by the network model. These network reconfigurations are mostly of short duration and so have a low impact on the estimated losses, but longer-term changes can be detected as described above. • The use of SCADA data to scale the non-half-hourly demand is helpful in correcting errors where customers are assigned to the incorrect substation. If too many customers are included, then the demand is scaled down according to the measured SCADA data. However, the impact on individual substations is not corrected by this process and so a further consistency check has been applied to ensure that the mean demand for any LV substation is not greater than 25% above the rated power for the transformer.

Area of Learning	Learning
	• A practical difficulty has been found in using the SCADA measurements data as the logged data is not always identified using the same naming as has been adopted for the feeder. Measurement logging can also be enabled for multiple sensors (when new circuit breaker boards are installed), or changed as the network configuration is updated. • The demand model uses a half-hourly time resolution. For the HV feeders, the use of half-hourly data was found to have a minimal impact on the losses which are under-estimated by less than 5% compared to calculations with the full 1-minute measurement resolution. • Detailed phase allocation data for single-phase loads is not available but analysis of the trials feeders has also shown that there is minimal impact on the loss estimates if the demand is assumed to be balanced. • The unbalance due to single-phase branches of the HV feeder network or from single-phase transformers does have an impact and has been taken into account in the modelling. The BAU data does not generally indicate which phases are used in connecting single-phase transformers or branches and so a worst-case assumption has been adopted that all are connected between the red and blue phases. • Loss estimates for individual substations are more highly dependent on the accuracy of the customer assignments than loss estimates for the combined HV feeder. The loss results have been used to compile a list of transformers with higher-than-average losses, but it is recognised that some of these examples will be cases where the load model is incorrect. • The HV loss estimation could be improved if more detailed data were to be available relating to the load supplied to IDNO connections. This would resolve an inconsistency in the power balance which arises when the total power supplied to the feeder at the primary is not equal to the sum of the delivered power and losses, due to the unknown demand supplied to individual IDNO connections.

Area of Learning	Learning
HV loss estimation transformer models	• The estimated losses for the distribution transformers use input data specifying the rated copper losses and iron losses. These parameters are not available from BAU data for most transformers and so values have been approximated using averaged data from transformers elsewhere on the network with the same rated power, number of phases and, where possible, for the same decade of manufacture. For configurations where there are no suitable transformers to act as a reference, values for the next available higher rated power are adopted. • There are minor impacts on the estimated transformer load losses if the tap settings are not accurately known. Typically the transformers are assumed to be on a tap setting of 2, as has been found to be the case for most of the transformers on the HV trial, but the transformer load losses would be under-estimated if transformers were actually on tap 1 or over-estimated if a higher tap setting were used. • The model assumes constant power loads, and also assumes a constant voltage and current at the primary, and so inaccurate tap setting data causes no error to the estimated HV cable losses or to the transformer no-load losses. • The estimation method would also be unaffected if single-phase transformers were to be modelled as three-phase transformers. This data is mostly available and so for most feeders this concern does not arise in practice.

6 Intellectual Property Rights

A complete list of all background IPR from all project partners has been compiled. The IP register is reviewed on a quarterly basis.

7 Risk Management

Our risk management objectives are to:

- Ensure that risk management is clearly and consistently integrated into the project management activities and evidenced through the project documentation;
- Comply with WPDs risk management processes and any governance requirements as specified by Ofgem; and
- Anticipate and respond to changing project requirements.

These objectives will be achieved by:

- ✓ Defining the roles, responsibilities and reporting lines within the Project Delivery Team for risk management;
- ✓ Including risk management issues when writing reports and considering decisions;
- ✓ Maintaining a risk register;
- ✓ Communicating risks and ensuring suitable training and supervision is provided;
- ✓ Preparing mitigation action plans;
- ✓ Preparing contingency action plans; and
- ✓ Monitoring and updating of risks and the risk controls.

7.1 Current Risks

The Losses Investigation Risk Register is a live document and is updated regularly. There are currently eight live project related risks. Mitigation action plans are identified when raising a risk and the appropriate steps then taken to ensure risks do not become issues where reasonably possible. **Error! Reference source not found.** provides details of the project's top five current risks. For each of these risks, a mitigation action plan has been identified and the progress of these are tracked and reported.

Table 6 Top five current risks (by rating)

Details of the Risk	Risk Rating	Mitigation Action Plan	Progress
Overall losses assessment methodology has uncertainties that are too large for the intended purpose. Now applicable to LV only	15	• Adoption of Pilot approach. • Retention of both power difference and I^2R calculation methods. • Review of differences between the loss assessment of the two calculation methods	• Credible explanations of differences between calculation methods are within instrument tolerances. • Final checks on uncertainty in the overall methodology will be made once estimates of loss have been made for a wide range of feeders.
Time synchronisation of data available from different field devices is not adequate.	9	• Adoption of Pilot approach. • Ongoing review of accumulated data.	• Time synchronisation of data sources is probably only to ±5 seconds. This does cause some noise in current balance and power diff loss assessments, but does not affect the average loss values being arrived at. • Is being reviewed on an ongoing basis
Accuracy/detailed operation of measurement devices proves inadequate for the intended purpose. Now applicable to LV only	9	• Adoption of Pilot approach. • Review of differences between the loss assessment of the two calculation methods	• Probable causes of differences between the loss assessment methods are due to apparent data inaccuracies in the meter load survey logging. • Correction factors have been drawn up and are in use.
Captured EDMI meter data cannot be adequately transmitted to a central data store for required roll out	6	• Project plan always included the implementation of a volume meter data collection system. • Collaborative testing of the proposed system.	• Volume data collection system is providing data • Some manual intervention is necessary, and being undertaken as required.
Unavailability of Distribution Transformer parameters /insufficiency of type values for loss assessment.	6	• Estimate unavailable parameters based on available transformer details (significant for SW and S Wales)	• Estimates of unavailable transformer parameters established based on rating, number of phases and decade of manufacture • Comments will be sought during dissemination and final reporting period on estimates and validation work undertaken

Figure 25 provides a snapshot of the risk register, detailed graphically, to provide an on-going understanding of the projects' risks.

Likelihood = Probability x Proximity						
	Certain/Imminent (21-25)	0	0	0	0	0
	More likely to occur than not/Likely to be near future (16-20)	0	0	0	0	0
	50/50 chance of occuring/ Mid to short term (11-15)	0	0	0	0	0
	Less likely to occur/Mid to long term (6-10)	0	1	0	0	0
	Very unlikely to occur/Far in the future (1-5)	0	4	2	0	1
		1. Insignificant changes, re-planning may be required	2. Small Delay, small increased cost but absorbable	3. Delay, increased cost in excess of tolerance	4. Substantial Delay, key deliverables not met, significant increase in time/cost	5. Inability to deliver, business case/objective not viable
		Impact				

	Minor	Moderate	Major	Severe	
Legend	7	1	0	0	**No of instances**
Total	8				No of live risks

Figure 25 Snapshot of Risk Register

Figure 26 provides an overview of the risks by category, minor, moderate, major and severe. This information is used to understand the complete risk level of the project.

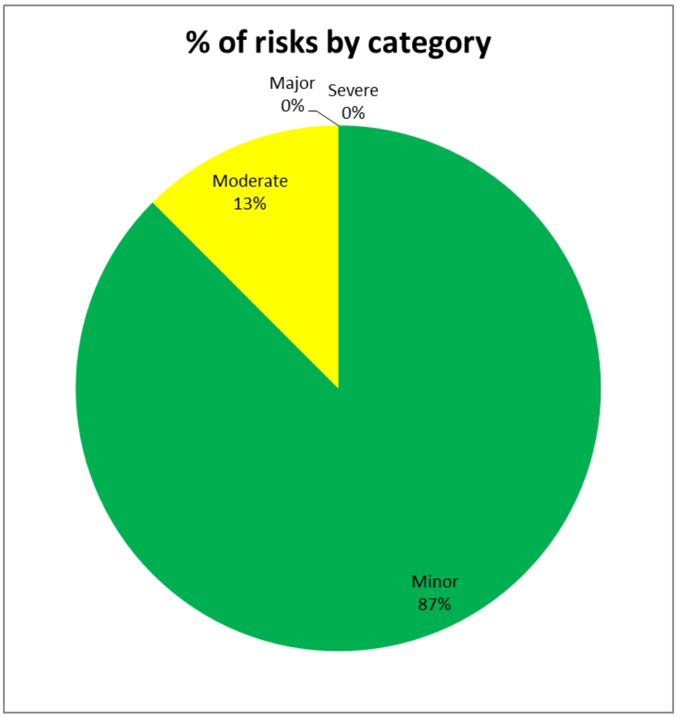


Figure 26 Graphical view of Risk Register by Risk Category

8 Consistency with Project Registration Document

During this period the project end date has been review and revised to January 2019 (reporting by April 2019). A revised project registration document has been agreed.

The scale, cost and timeframe of the project is consistent with the current registration document >>following this link[3]<<.

9 Accuracy Assurance Statement

This report has been prepared by the Losses Investigation Project Manager (Chris Harrap), reviewed and approved by the Future Networks Manager (Roger Hey).

All efforts have been made to ensure that the information contained within this report is accurate. WPD confirms that this report has been produced, reviewed and approved following our quality assurance process for external documents and reports.

[3] http://www.smarternetworks.org/project/nia_wpd_005

Glossary

Term	Definition
BaU	Business as usual
CSA	Cross sectional area
DG	Distributed Generation
DNO	Distribution Network Operator
DUKES	Digest of UK Energy Statistics
EATL NAT	EA Technology's Network Assessment Tool, produced as part of the Electric Nation project.
EDMI	Meter design and manufacturing company.
Elexon	The not-for-profit company fulfilling the role of the Balancing and Settlement Company within the UK wholesale electricity market
GB	Great Britain
GIS	Geographic information system
GPRS	General Packet Radio Service, the mobile data service on 2G and 3G cellular communications systems.
GWh	Gigawatt hour
HH	Half Hourly
HV	High Voltage
I^2R	Loss assessment approach based on I^2R
IPR	Intellectual Property Register
LCT	Low Carbon Technologies
LLF	Line Loss Factor: means the multiplier which, when applied to generation or demand on the distribution system, converts the data to an equivalent value at the transmission system boundary inclusive of distribution system losses
LV	Low Voltage
MPAN	Meter Point Administration Number
NHH	Non Half Hourly
NIA	Network Innovation Allowance
PICAS	Paper insulated corrugated aluminium sheath cable
PILCSWA	Paper insulated lead covered steel wire armoured cable
MUA	Manx Utilities (Manx Utilities Authority)
RMS	Root mean square
SCADA	Supervisor Control and Data Acquisition
Var	Volt-ampere reactive
WPD	Western Power Distribution
XLPE	Cross-linked polyethylene cable

Appendix A Overview of monitored feeders

Appendix A 1 Overview of HV monitored feeders

Feeder	Overview	Detailed Feasibility	Primary Sub work	Secondary Sub work	Data Available
Pilot feeder *- 940037-02 (Marlborough Street: The Woodlands)*	*UG2A, 4.8km.* *11 GM Subs.*	*Complete*	*Complete*	*Complete.*	*Yes*
940043-03 (Fox Milne: Fox Milne Hotel)	UG2B, 13.3km. 16 GM Subs.	Complete	Complete	Complete.	*Yes*
940046-03 (Wavendon Gate: Wavendon Gate Local)	UG1B, 2.1km. 8 GM Subs.	Complete	Complete	Complete.	*Yes*
940046-08 (Wavendon Gate: Secondary School Walnut Tree)	UG2A, 8.5km. 13 GM Subs, 2 HV sites.	Complete	Complete	Complete.	*Yes*
940041-10 (Newport Pagnell: Howard Way Tee Crawley Road)	UG1A, 3.8km. 3 GM Subs, 3 HV sites.	Complete	Complete	Complete.	*Yes*
940041-08 (Newport Pagnell: Amway Tongwell)	MA1A, 19% OH, 2.4km. 4 GM Subs, 7 HV sites.	Complete	Complete	Complete.	*Yes*
940041-09 (Newport Pagnell: Ackerman Tongwell Tee Aldrich Drive)	MB1A, 29% OH, 8.3km. 7 GM Subs, 4 PM sites.	Complete	Complete	Complete.	*Yes*
940041-04 (Newport Pagnell: Riverside Park)	MA2A, 10% OH, 8.6km. 12 GM Subs, 2 HV sites, 7 PM sites.	Complete	Complete	Complete.	*Yes*
940046-02 (Wavendon Gate: The Avenue)	MB2A, 37% OH, 12.0km. 8 GM Subs, 2 HV sites, 11 PM sites.	Complete	Complete	Complete.	*Yes*
940036-11 (Wolverton: Energy from Waste RMU C))	MC1B, 76% OH, 15.7km. 7 GM Subs, 1 HV site 14 PM sites.	Complete	Complete	Complete.	*Yes*
940045-04 (Olney: Silver End Olney)	OH1B, 87% OH, 23.9km. 8 GM Subs, 22 PM sites.	Complete	Complete	Complete.	*Yes*

Table 7 Overview of HV monitored feeders

Appendix A 2 Overview of LV monitored feeders

Feeder	Overview	Feasibility & Modelling Info	Secondary Sub work	Meter work	Data Available
Pilot feeder – around Douglas	*277m u/g mains cable* *187m u/g service cable* *13 – 1ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*
Dom#1 – Laxey	770m u/g mains cables 1054m u/g service cables 57 - *1ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*
Dom#2 - Ramsey	431m u/g mains cables 742m u/g service cables 53 - *1ϕ + 1 – 3 ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*
Dom#3 – Tromode	794m u/g mains cables 885m u/g service cables 56 - *1ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*
I&C#1 – Peel Feeder A	383m u/g mains cables 159m u/g service cables 9 - *3ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*
I&C#1 – Peel Feeder B	408m u/g mains cables 189m u/g service cables 8 - *3ϕ* + 12 - 1ϕ	*Complete*	*Complete*	*Complete.*	*Yes*
I&C#2 – Ballasalla	426m u/g mains cables 357m u/g service cables 6 - *1ϕ + 11 - 3ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*
I&C#3 – Braddon	484m u/g mains cables 118m u/g service cables 8 - *1ϕ +11 - 3ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*
OH#1 – Santon o/h	89m u/g mains, 289m OW mains 183m u/g, 114m o/h services 16 – *1ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*
OH#2 – Abbeylands	368m u/g mains, 546m ABC, 173m OW mains 488m services 26 - *1ϕ + 4 - 3ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*
OH#3 – Ramsey OH	337m u/g mains, 393m OW mains 882m services 48 - *1ϕ* + 1 - *3ϕ*	*Complete*	*Complete*	*Complete.*	*Yes*

Table 8 Overview of LV monitored feeders

Appendix B Ongoing Loss Assessments

Appendix B 1 HV feeders

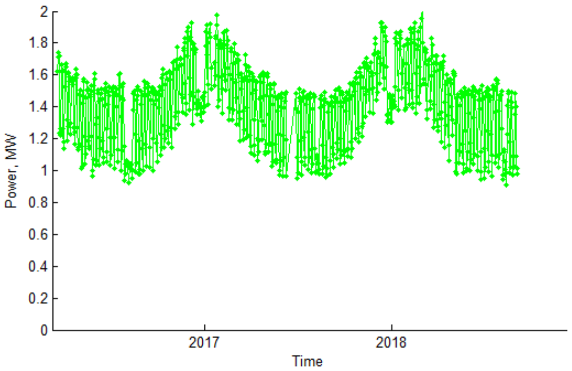


Figure 27 Long term mean daily feeder demand (Woodlands HV feeder)

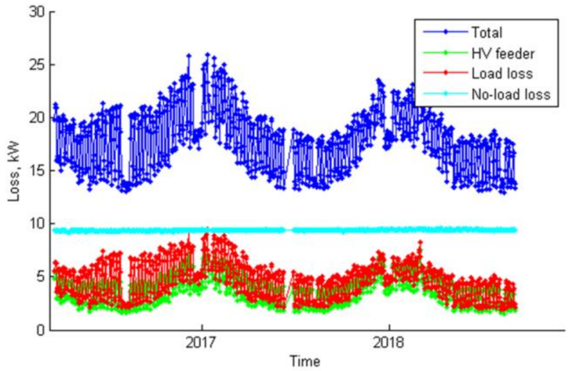


Figure 28 Long term mean daily (I^2R) loss (Woodlands HV feeder)

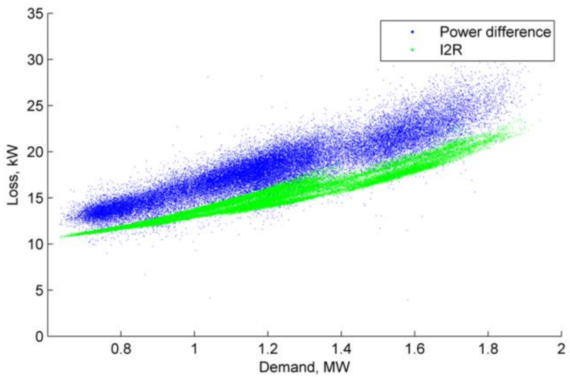


Figure 29 Aug 2018 Loss, kW vs demand (Woodlands HV feeder)

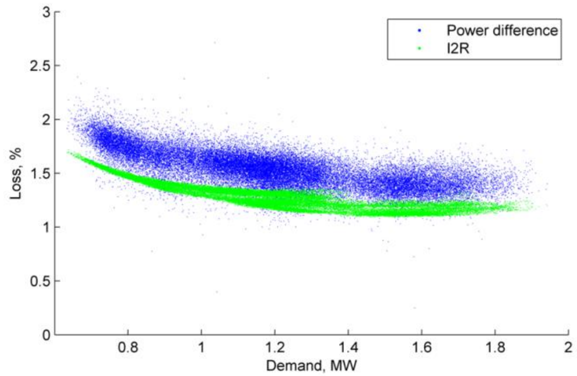


Figure 30 Aug 2018 Loss, % vs demand (Woodlands HV feeder)

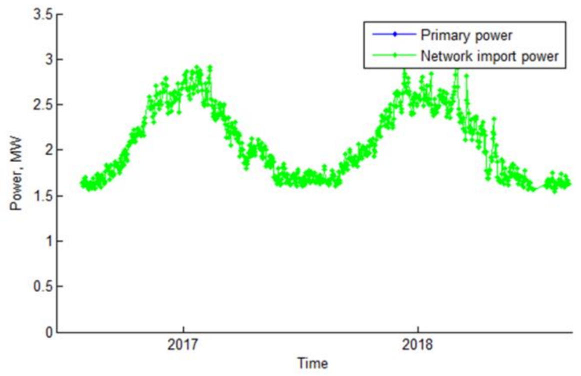


Figure 31 Long term mean daily feeder demand (Fox Milne Hotel HV feeder)

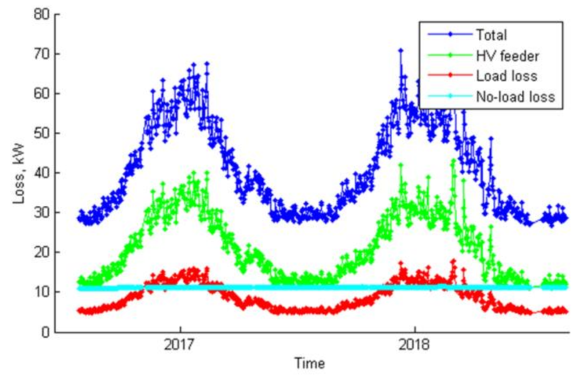


Figure 32 Long term mean daily (I^2R) loss (Fox Milne Hotel HV feeder)

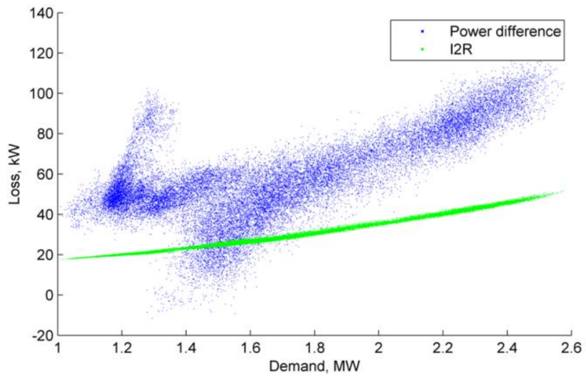


Figure 33 Aug 2018 Loss, kW vs demand (Fox Milne Hotel HV feeder)

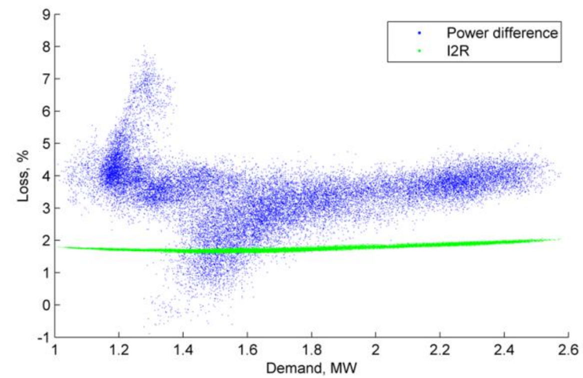


Figure 34 Aug 2018 Loss, % vs demand (Fox Milne Hotel HV feeder)

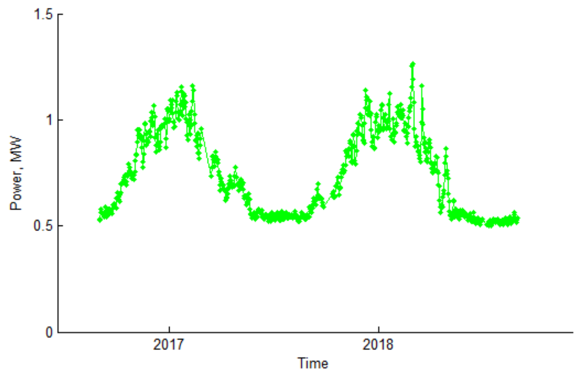


Figure 35 Long term mean daily feeder demand (Wavendon Gate Local HV feeder)

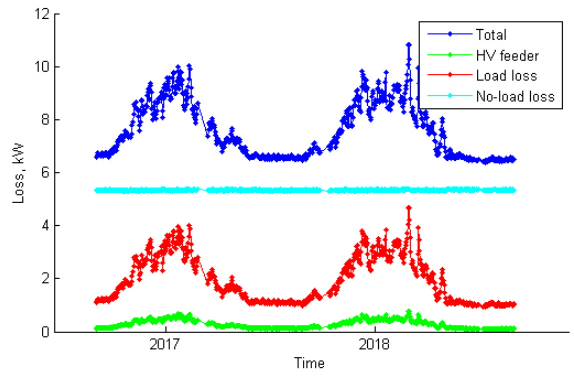


Figure 36 Long term mean daily (I^2R) loss (Wavendon Gate Local HV feeder)

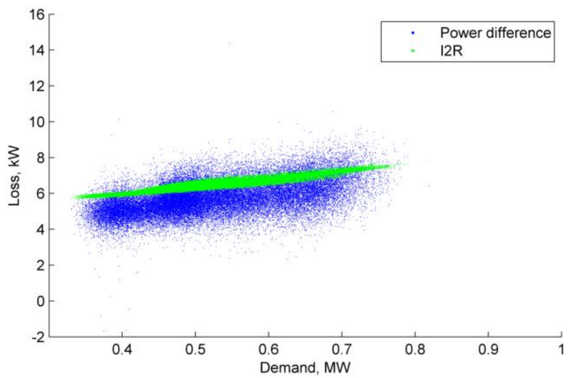


Figure 37 Aug 2018 Loss, kW vs demand (Wavendon Gate Local HV feeder)

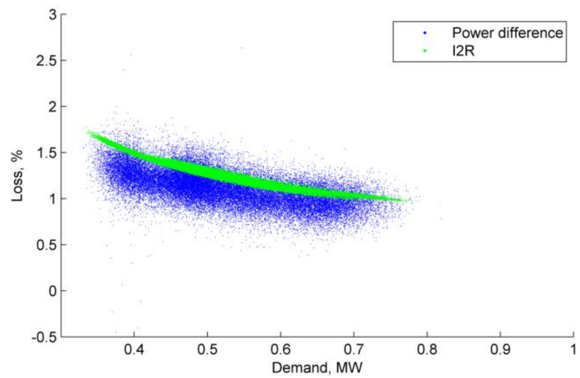


Figure 38 Aug 2018 Loss, % vs demand (Wavendon Gate Local HV feeder)

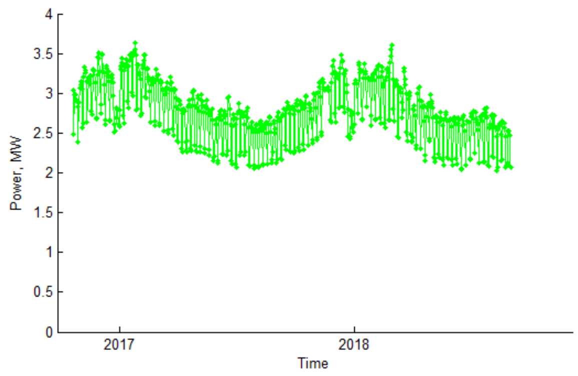


Figure 39 Long term mean daily feeder demand (Secondary School Walnut Tree HV feeder)

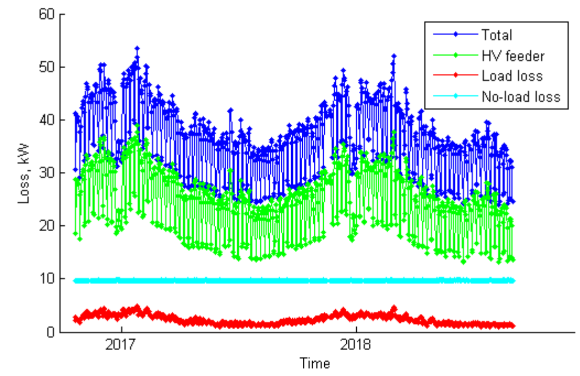


Figure 40 Long term mean daily (I^2R) loss (Secondary School Walnut Tree HV feeder)

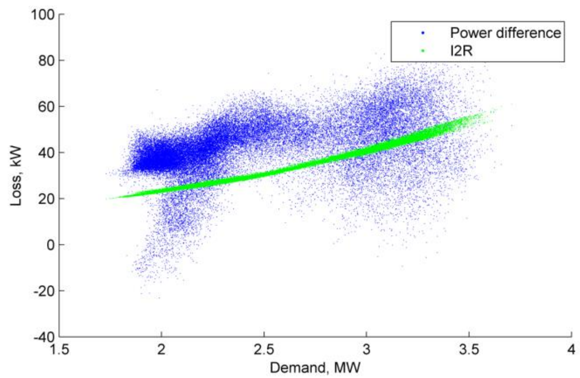


Figure 41 Aug 2018 Loss, kW vs demand (Secondary School Walnut Tree HV feeder)

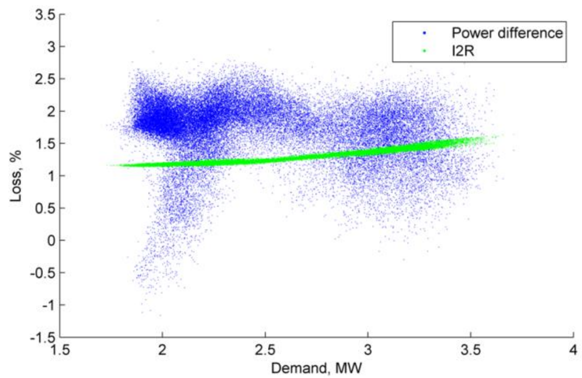


Figure 42 Aug 2018 Loss, % vs demand (Secondary School Walnut Tree HV feeder)

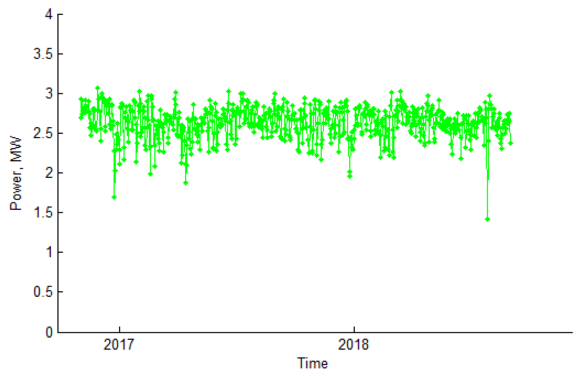


Figure 43 Long term mean daily feeder demand (Crawley Road Tee Howard Way HV feeder)

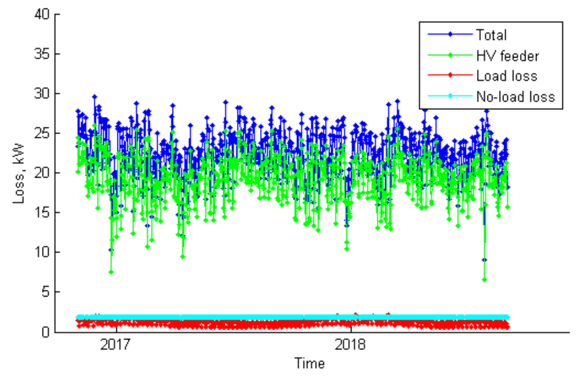


Figure 44 Long term mean daily (I^2R) loss (Crawley Road Tee Howard Way HV feeder)

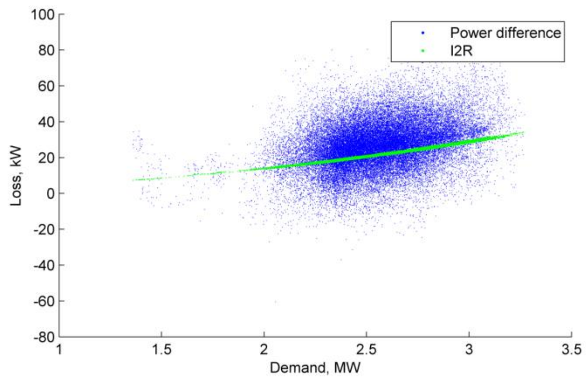


Figure 45 Aug 2018 Loss, kW vs demand (Crawley Road Tee Howard Way HV feeder)

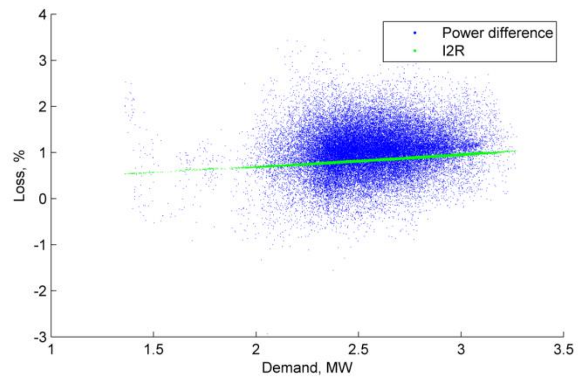


Figure 46 Aug 2018 Loss, % vs demand (Crawley Road Tee Howard Way HV feeder)

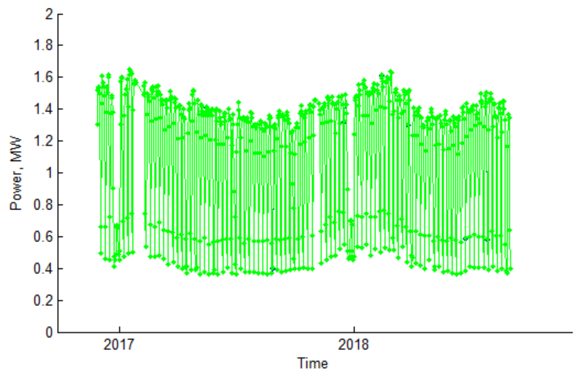


Figure 47 Long term mean daily feeder demand (Amway Tongwell HV feeder)

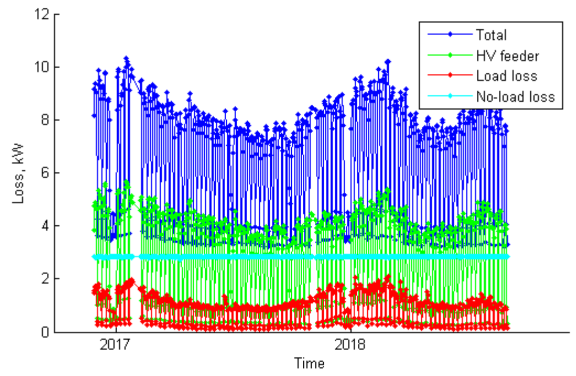


Figure 48 Long term mean daily (I^2R) loss (Amway Tongwell HV feeder)

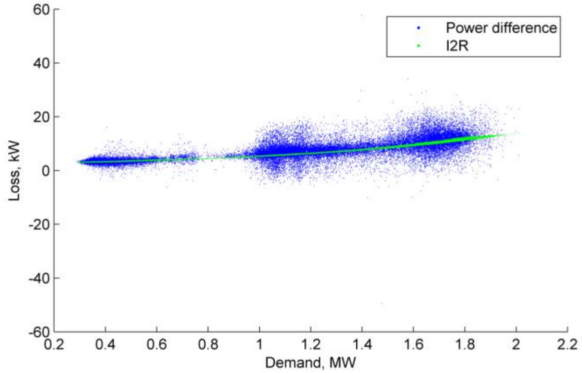


Figure 49 Aug 2018 Loss, kW vs demand (Amway Tongwell HV feeder)

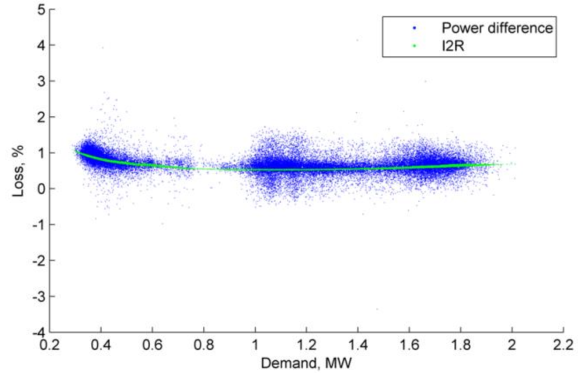


Figure 50 Aug 2018 Loss, % vs demand (Amway Tongwell HV feeder)

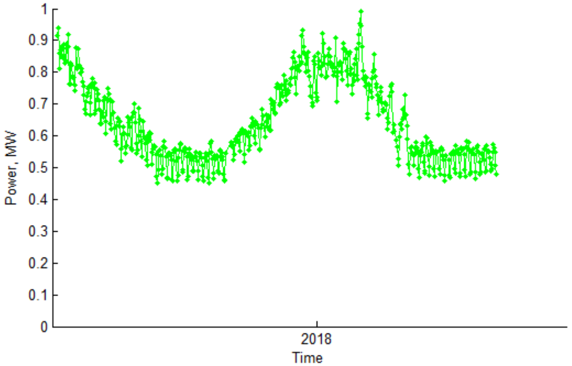


Figure 51 Long term mean daily feeder demand (Ackerman Tongwell Aldrich Drive Tee HV feeder)

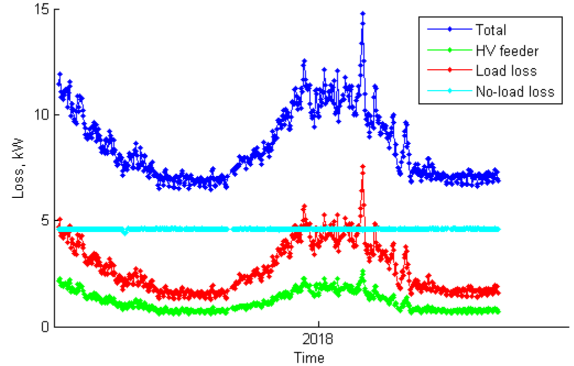


Figure 52 Long term mean daily (I^2R) loss (Ackerman Tongwell Aldrich Drive Tee HV feeder)

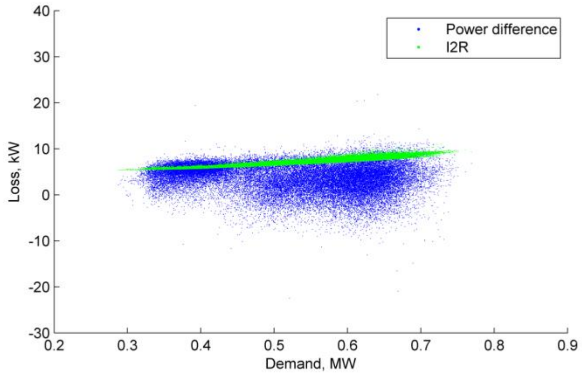


Figure 53 Aug 2018 Loss, kW vs demand (Ackerman Tongwell Aldrich Drive Tee HV feeder)

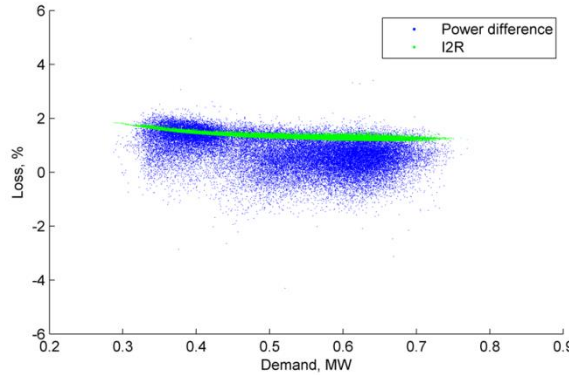


Figure 54 Aug 2018 Loss, % vs demand (Ackerman Tongwell Aldrich Drive Tee HV feeder)

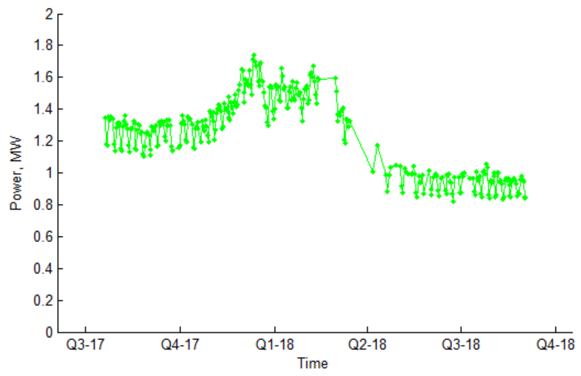


Figure 55 Long term mean daily feeder demand (The Avenue HV feeder)

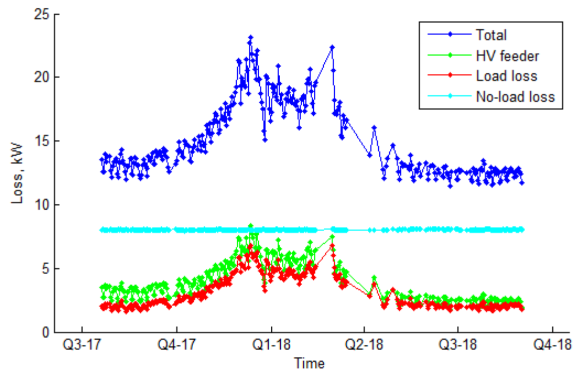


Figure 56 Long term mean daily (I^2R) loss (The Avenue HV feeder)

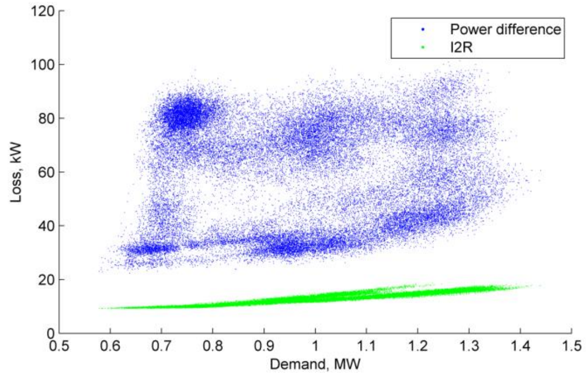


Figure 57 Aug 2018 Loss, kW vs demand (The Avenue HV feeder)

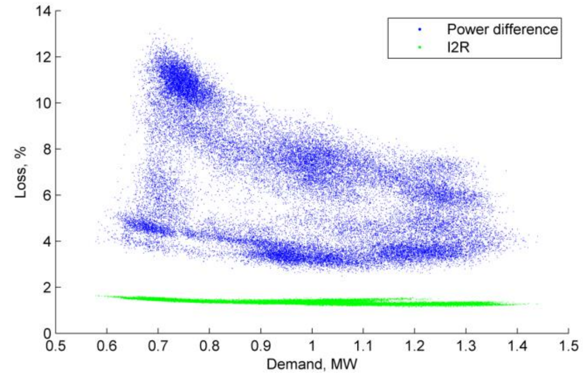


Figure 58 Aug 2018 Loss, % vs demand (The Avenue HV feeder)

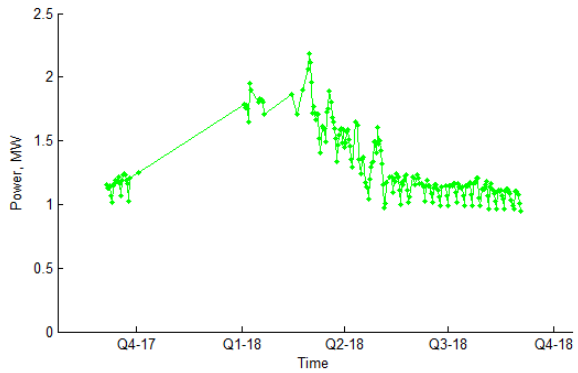


Figure 59 Long term mean daily feeder demand (Riverside Park HV feeder)

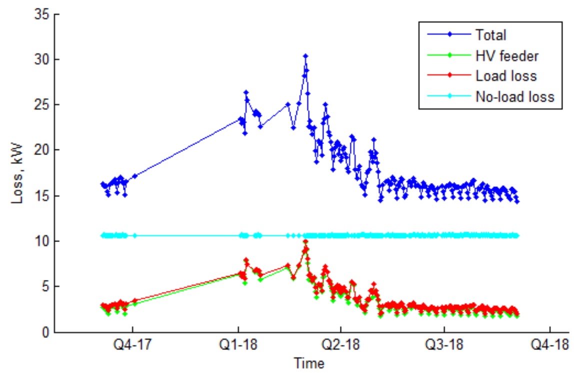


Figure 60 Long term mean daily (I^2R) loss (Riverside Park HV feeder)

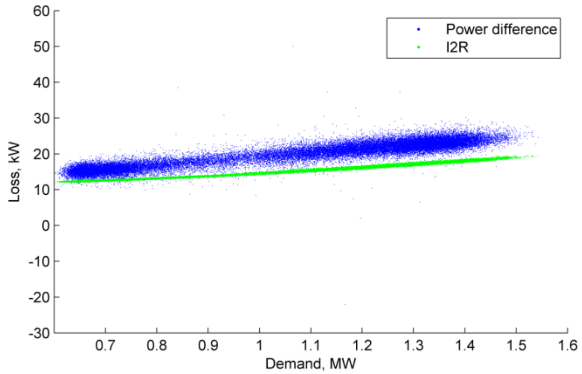


Figure 61 Aug 2018 Loss, kW vs demand (Riverside Park HV feeder)

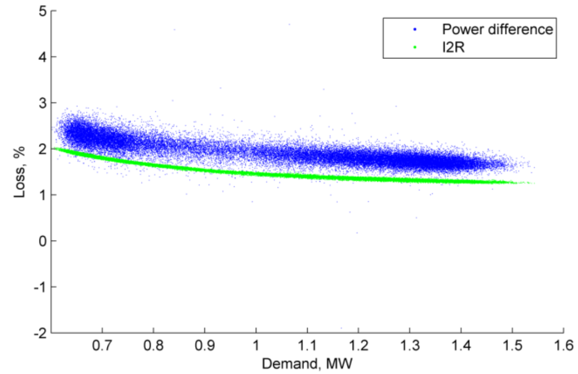


Figure 62 Aug 2018 Loss, % vs demand (Riverside Park HV feeder)

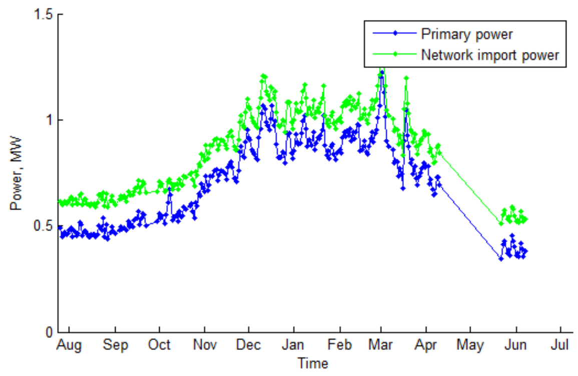


Figure 63 Long term mean daily feeder demand (Silver End HV feeder)

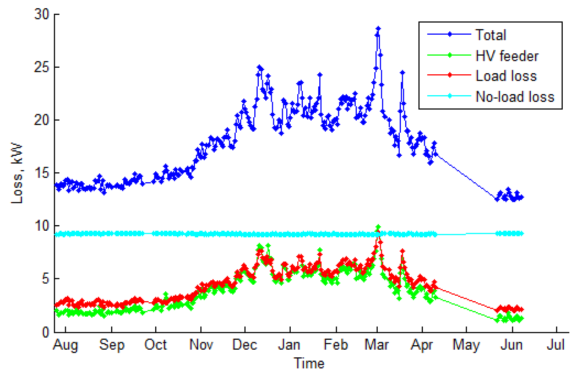


Figure 64 Long term mean daily (I^2R) loss (Silver End HV feeder)

n/a

Figure 65 Aug 2018 Loss, kW vs demand (Silver End HV feeder)

n/a

Figure 66 Aug 2018 Loss, % vs demand (Silver End HV feeder)

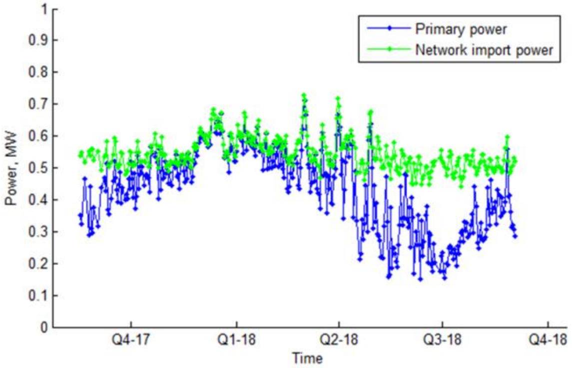


Figure 67 Long term mean daily feeder demand (Wolverton HV feeder)

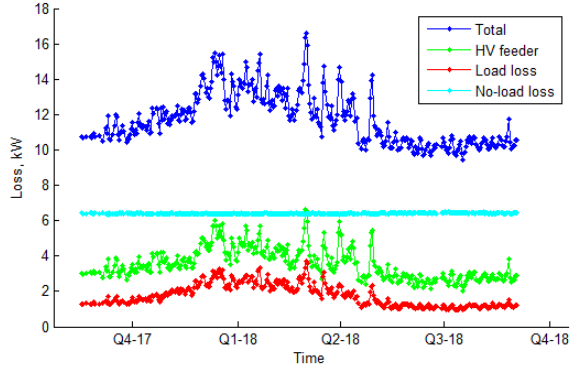


Figure 68 Long term mean daily (I^2R) loss (Wolverton HV feeder)

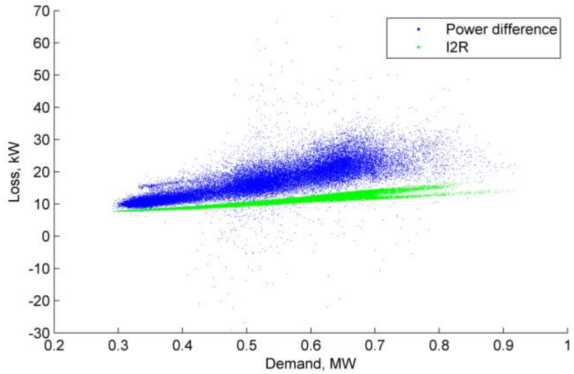


Figure 69 Aug 2018 Loss, kW vs demand (Wolverton HV feeder)

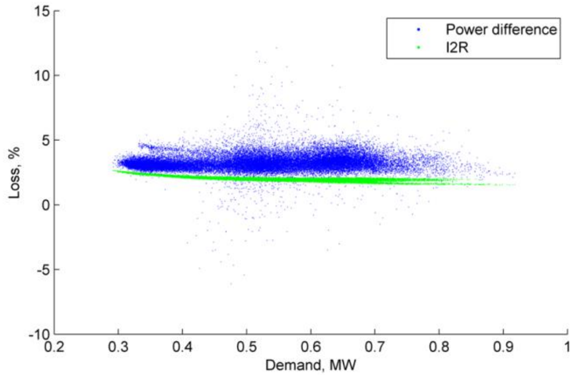


Figure 70 Aug 2018 Loss, % vs demand (Wolverton HV feeder)

Appendix B 2 LV feeders

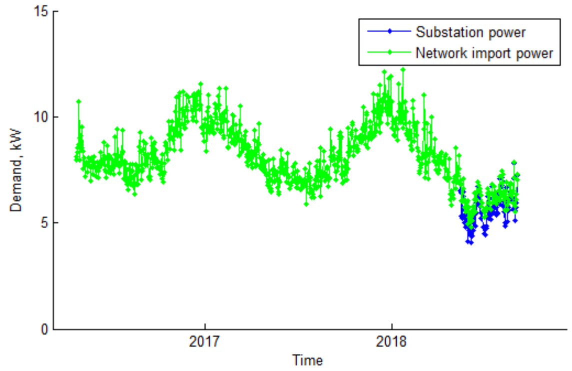


Figure 71 Long term mean daily feeder demand (Domestic Pilot LV feeder)

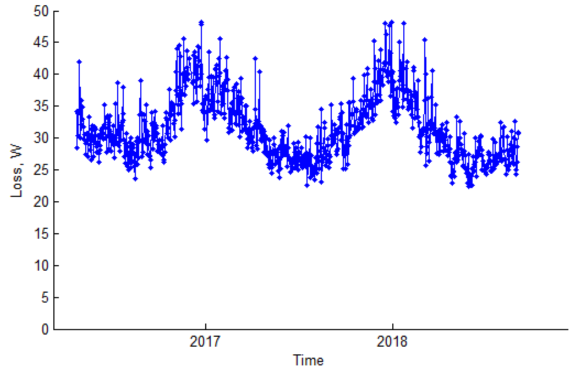


Figure 72 Long term mean daily (I^2R) loss (Domestic Pilot LV feeder)

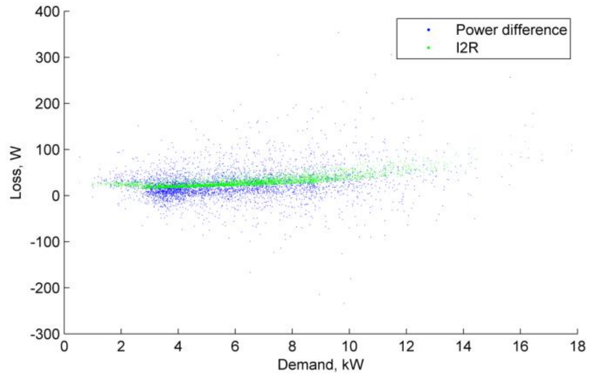


Figure 73 Aug 2018 Loss, kW vs demand, 10 min. av. (Dom. Pilot LV feeder)

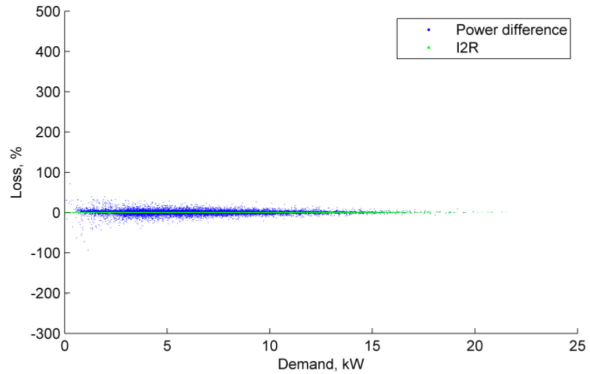


Figure 74 Aug 2018 2017 Loss, % vs demand, 1 min. av. (Dom. Pilot LV feeder)

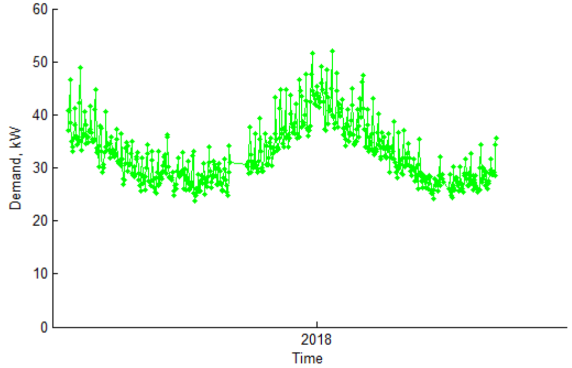


Figure 75 Long term mean daily feeder demand (Laxey Dom. LV feeder)

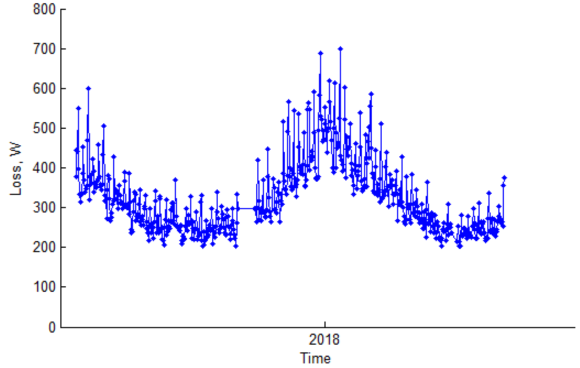


Figure 76 Long term mean daily (I^2R) loss (Laxey Dom. LV feeder)

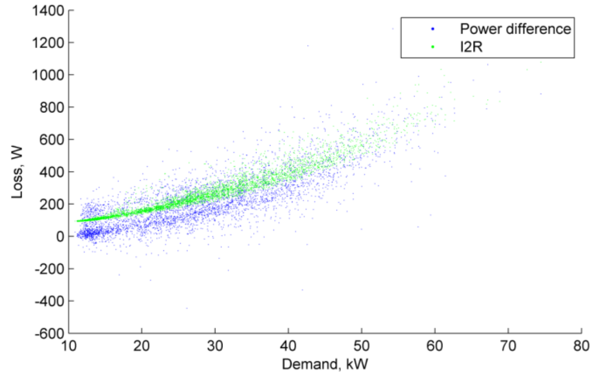


Figure 77 Aug 2018 Loss, kW vs demand, 10 min. av. (Laxey Dom. LV feeder)

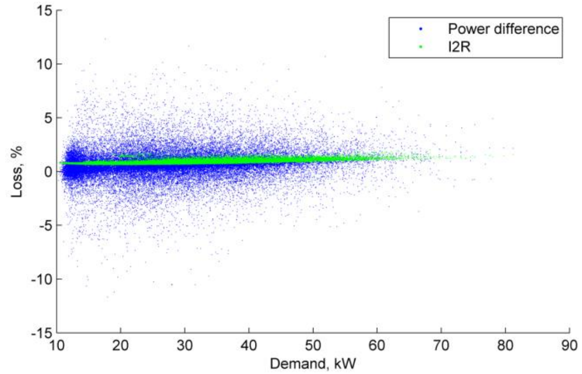


Figure 78 Aug 2018 Loss, % vs demand, 1 min. av. (Laxey Dom. LV feeder)

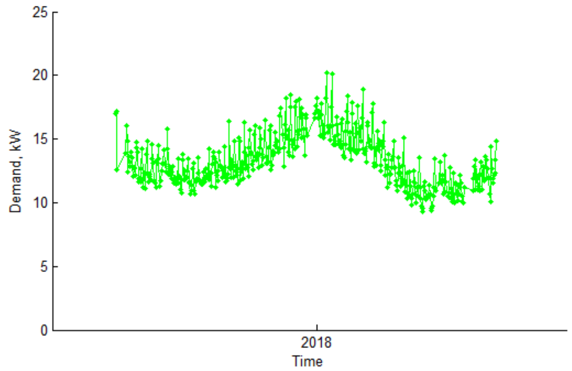


Figure 79 Long term mean daily feeder demand (Ramsey Dom. LV feeder)

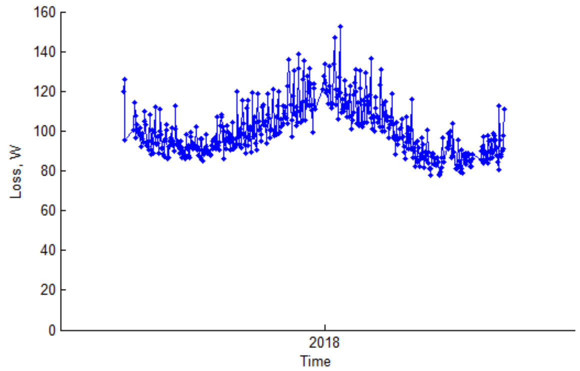


Figure 80 Long term mean daily (I^2R) loss (Ramsey Dom. LV feeder)

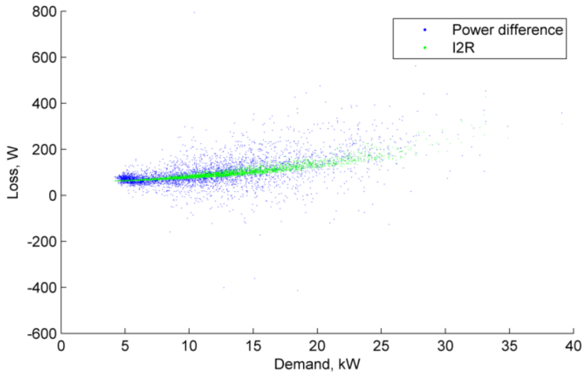


Figure 81 Aug 2018 Loss, kW vs demand, 10 min. av. (Ramsey Dom. LV feeder)

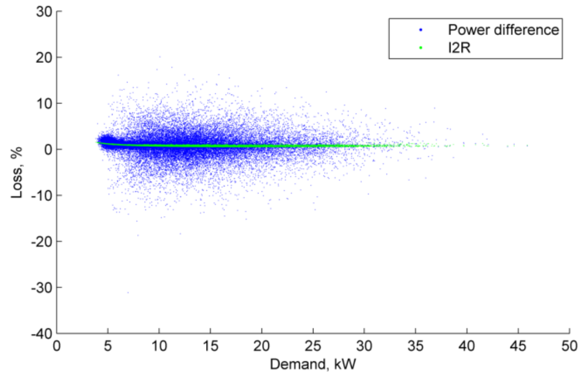


Figure 82 Aug 2018 Loss, % vs demand, 1 min. av. (Ramsey Dom. LV feeder)

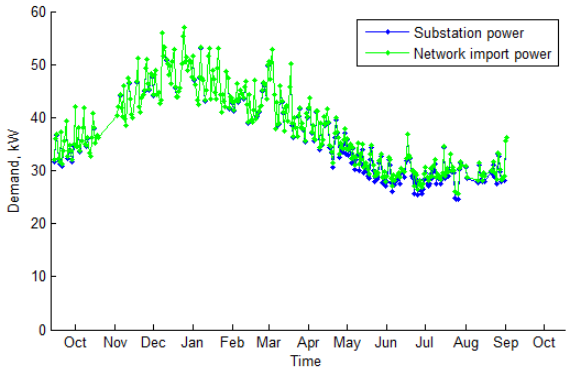


Figure 83 Long term mean daily feeder demand (Tromode Dom. LV feeder)

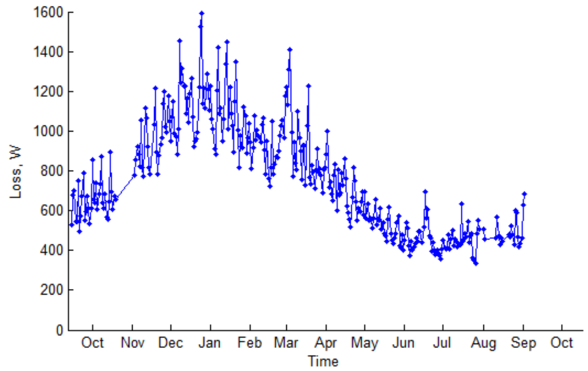


Figure 84 Long term mean daily (I^2R) loss (Tromode Dom. LV feeder)

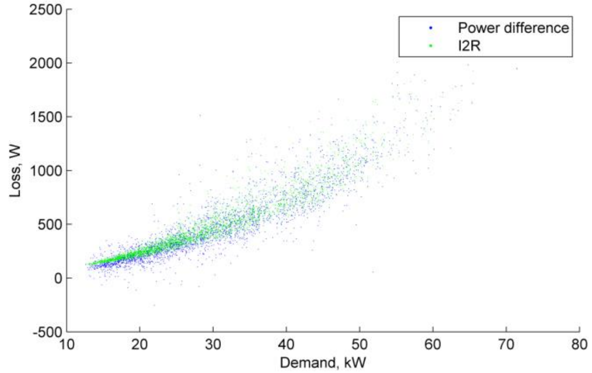


Figure 85 Aug 2018 Loss, kW vs demand, 10 min. av. (Tromode Dom. LV feeder)

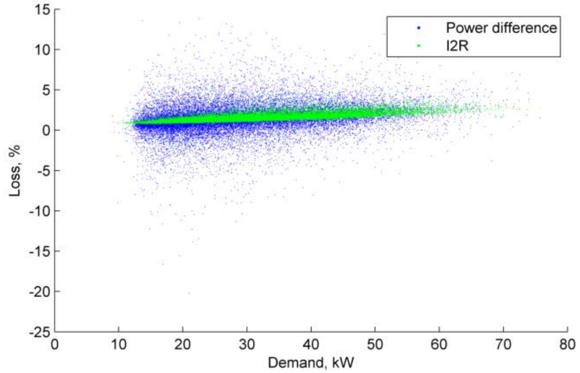


Figure 86 Aug 2018 Loss, % vs demand, 1 min. av. (Tromode Dom. LV feeder)

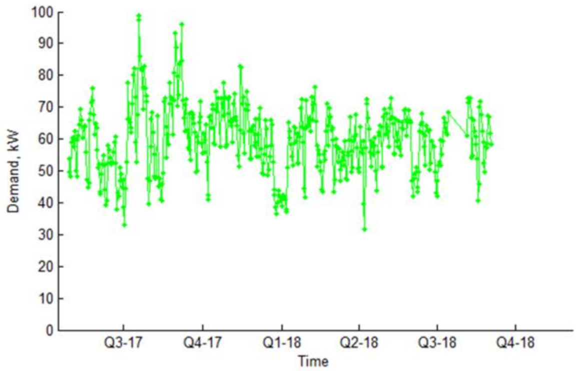


Figure 87 Long term mean daily feeder demand (Peel A I&C LV feeder)

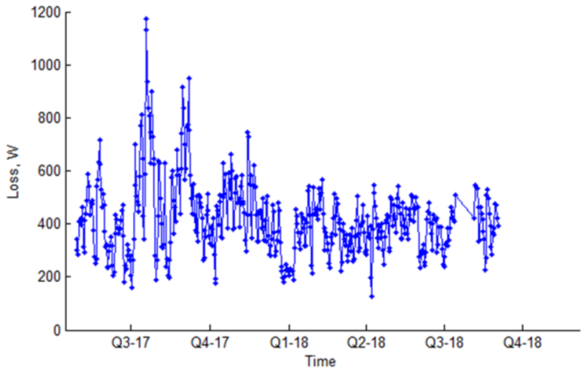


Figure 88 Long term mean daily (I^2R) loss (Peel A I&C LV feeder)

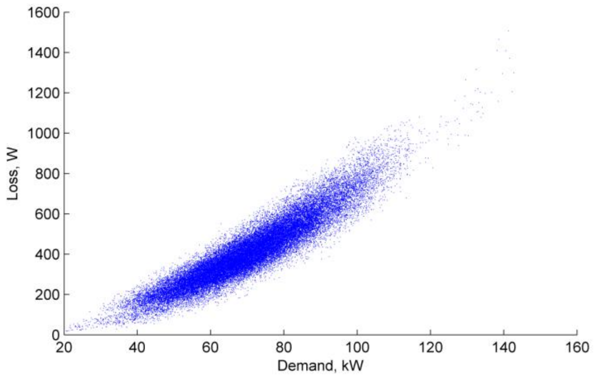


Figure 89 Aug 2018 2017 Loss, kW vs demand, 10 min. av. (Peel A I&C LV feeder)

n/a

Figure 90 Aug 2018 Loss, % vs demand, 1 min. av. (Peel A I&C LV feeder)

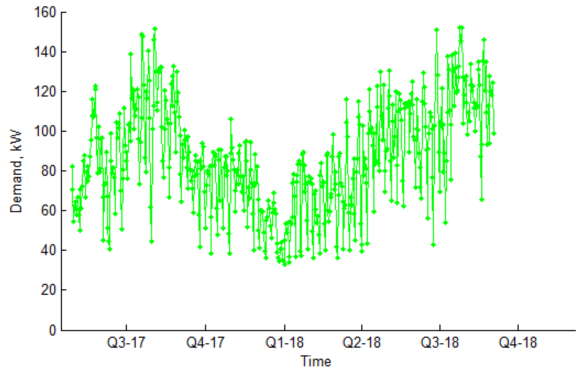


Figure 91 Long term mean daily feeder demand (Peel B I&C LV feeder)

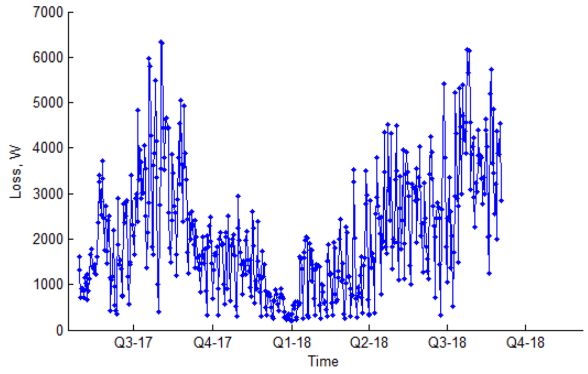


Figure 92 Long term mean daily (I^2R) loss (Peel B I&C LV feeder)

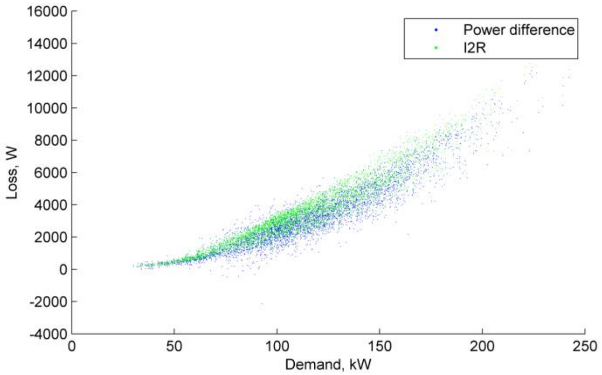


Figure 93 Aug 2018 Loss, kW vs demand, 10 min. av. (Peel B I&C LV feeder)

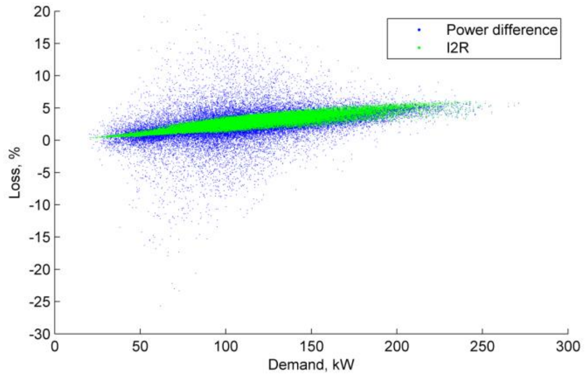


Figure 94 Aug 2018 Loss, % vs demand, 1 min. av. (Peel B I&C LV feeder)

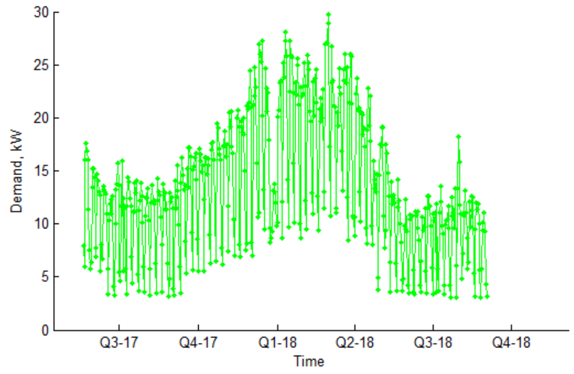


Figure 95 Long term mean daily feeder demand (Ballasalla I&C LV feeder)

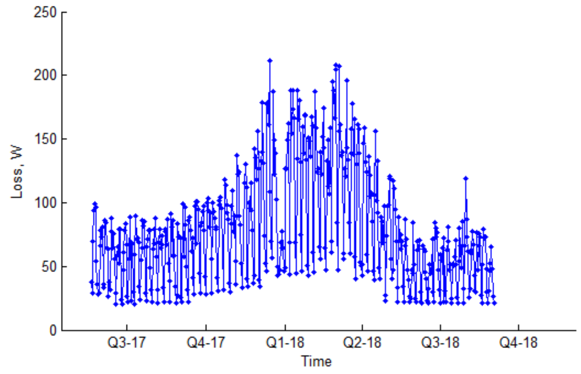


Figure 96 Long term mean daily (I^2R) loss (Ballasalla I&C LV feeder)

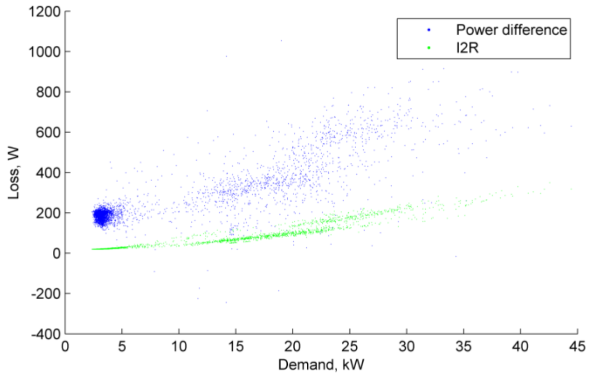


Figure 97 Aug 2018 Loss, kW vs demand, 10 min. av. (Ballasalla I&C LV feeder)

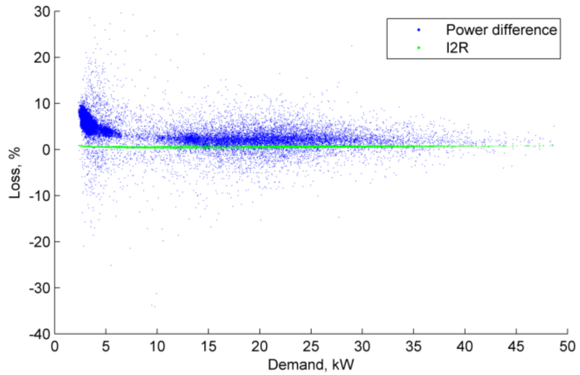


Figure 98 Aug 2018 Loss, % vs demand, 1 min. av. (Ballasalla I&C LV feeder)

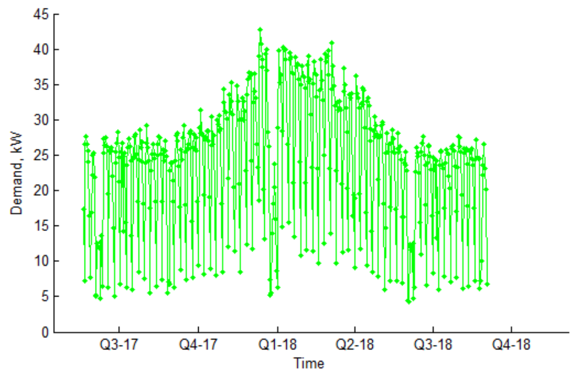


Figure 99 Long term mean daily feeder demand (Braddan I&C LV feeder)

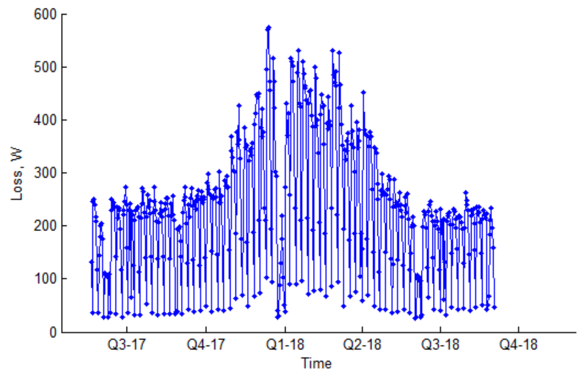


Figure 100 Long term mean daily (I^2R) loss (Braddan I&C LV feeder)

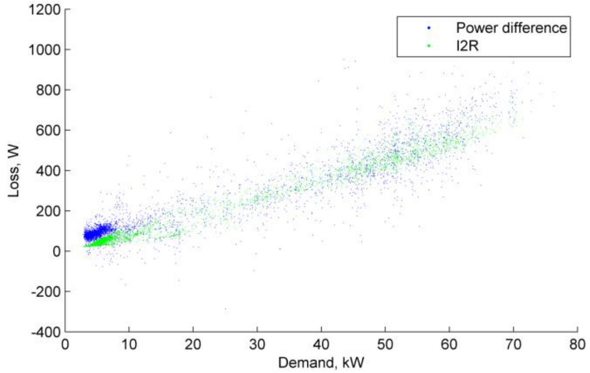


Figure 101 Aug 2018 Loss, kW vs demand, 10 min. av. (Braddan I&C LV feeder)

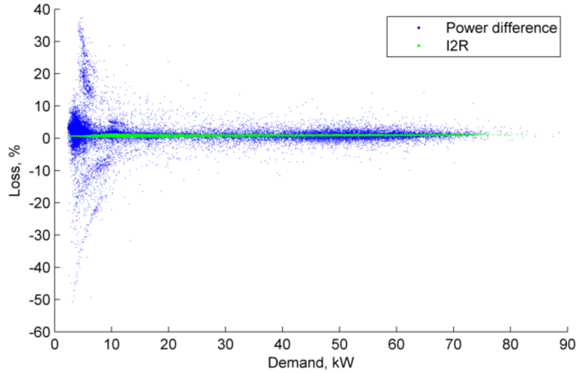


Figure 102 Aug 2018 Loss, % vs demand, 1 min. av. (Braddan I&C LV feeder)

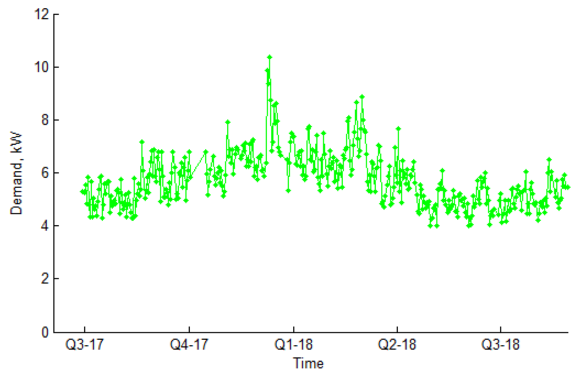


Figure 103 Long term mean daily feeder demand (Santon OH LV feeder)

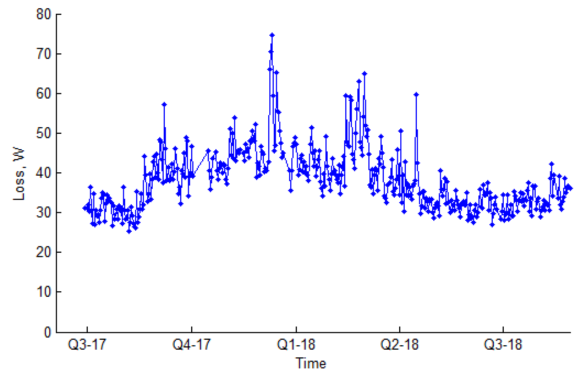


Figure 104 Long term mean daily (I^2R) loss (Santon OH LV feeder)

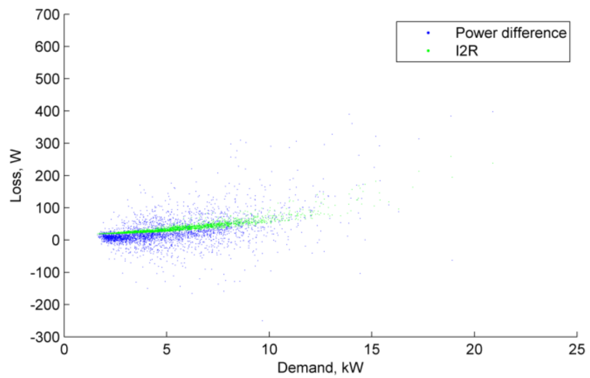


Figure 105 Aug 2018 Loss, kW vs demand, 10 min. av. (Santon OH LV feeder)

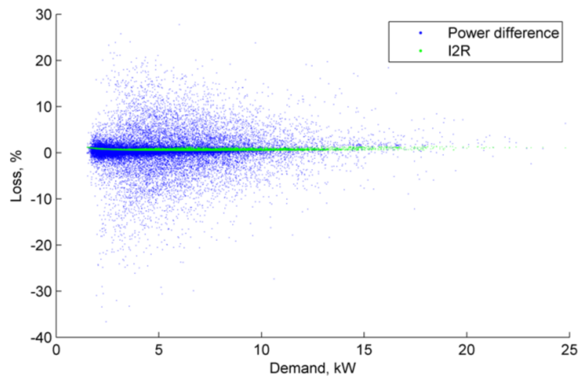


Figure 106 Aug 2018 Loss, % vs demand, 1 min. av. (Santon OH LV feeder)

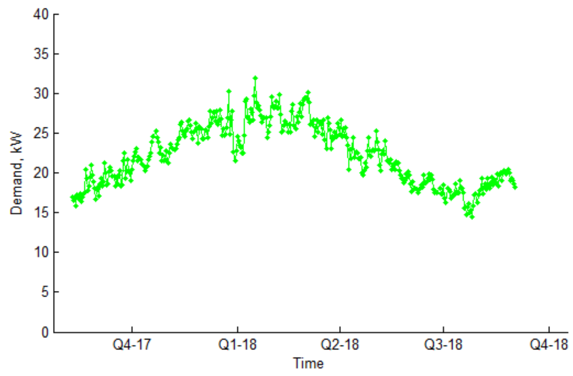


Figure 107 Long term mean daily feeder demand (Abbeylands OH LV feeder)

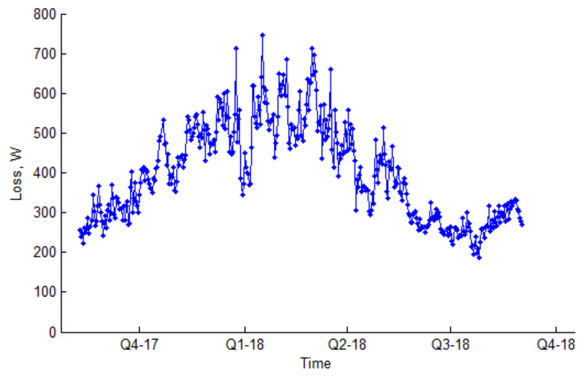


Figure 108 Long term mean daily (I^2R) loss (Abbeylands OH LV feeder)

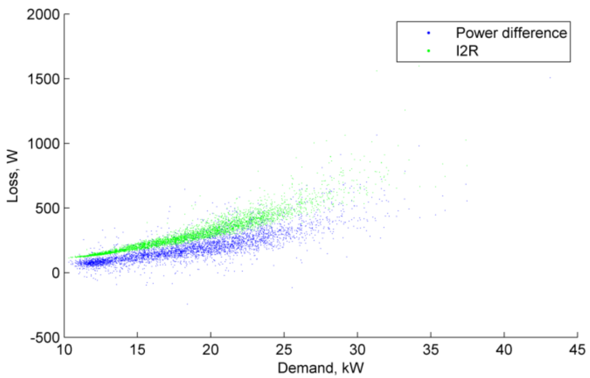


Figure 109 Aug 2018 Loss, kW vs demand, 10 min. av. (Abbeylands OH LV feeder)

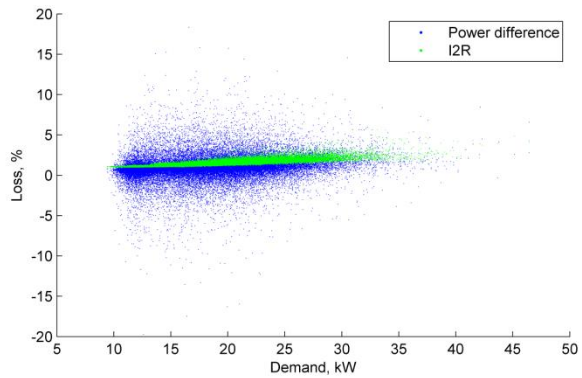


Figure 110 Aug 2018 Loss, % vs demand, 1 min. av. (Abbeylands OH LV feeder)

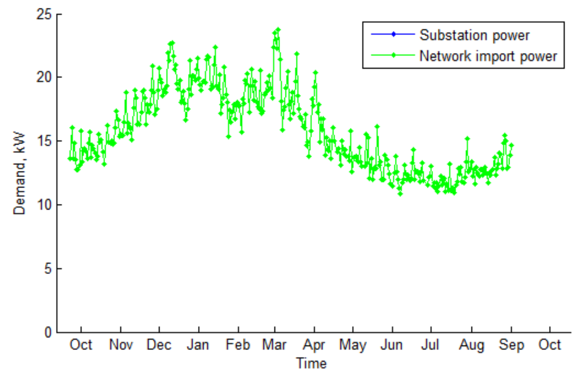


Figure 111 Long term mean daily feeder demand (Ramsey OH LV feeder)

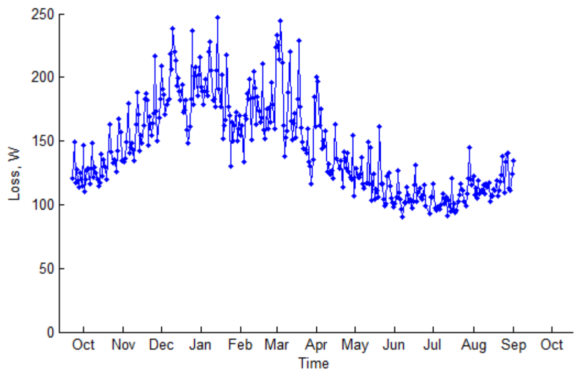


Figure 112 Long term mean daily (I^2R) loss (Ramsey OH LV feeder)

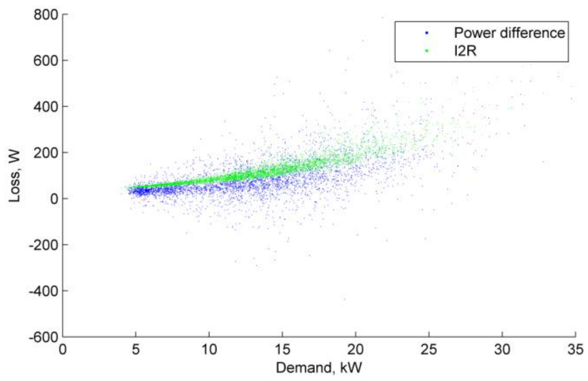


Figure 113 Mar & Apr 2018 Loss, kW vs demand, 10 min. av. (Ramsey OH LV feeder)

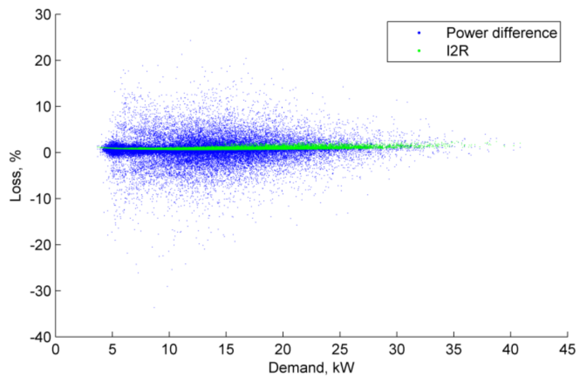


Figure 114 Mar & Apr 2018 Loss, % vs demand, 1 min. av. (Ramsey OH LV feeder)

Appendix C Further details on HV feeder loss estimation method and input data

Appendix C.1 Network topology data

The loss estimation software uses a network data file exported from the DINIS network planning tool. This file contains all of the HV feeders in the East Midlands region.

The input data to DINIS originates from data in the WPD EMU database. The EMU data provides a geographic representation of the feeders and is formed into an electrical model when the DINIS input file is created. The creation of this electrical model involves a number of assumptions being made, for example that cables are considered to be electrically connected when their end points are located a fixed proximity. There are a number of scenarios when this automated process omits some level of detail in the connectivity and so the data provided in DINIS must be considered to be an approximation to the actual network topology. The network data exported from DINIS, as used for the loss estimation, contains these approximations.

The loss estimation software builds a representation of the network from the nodes and branches described in the DINIS export file. Nodes that act as primary substations are identified. For each primary, the software then 'crawls' through the network of nodes and branches to identify the HV feeders, terminating either when the tree structure of branches has no further connections, or when the end nodes act as normal open points to feeders served from other primaries.

A key requirement is that the identified feeders must be radial. Although there are a few scenarios where feeders are actually operated in a mesh topology, it has been found that loops in the identified feeders generally occur when the underlying data in DINIS does not adequately interpret the geographic data. Feeders with loops are therefore excluded from the loss analysis as the results would be unreliable. Feeders are also excluded from the analysis if the feeder identifiers attached to each branch (derived from the original geographic data) are not consistent with the structure identified by crawling through the node and branch topology.

The loss estimation software supports the analysis of feeders at 11 kV or 6.6 kV. A small number of feeders with interposing transformers and therefore mixed voltages are excluded.

The data file is not populated with information to indicate how single-phase network branches are connected and so it is assumed that these always connected between the red and blue phases. This represents the most onerous loss case.

The network branches listed in the DINIS file refer to a library of cable types that are defined in a separate line code file named 'TlTab.Type'. These line codes include the cable impedance, admittance, number of phases, and nominal voltage.

Appendix C.2 Cable Impedance Data

The impedances for the cables used in the project HV trial feeders have also been calculated using a finite element model (FEM) simulation so as to take account of AC resistance effects, as described in [3]. This more detailed impedance data is not used in the loss estimation analysis, such that the process can be applied using only BAU data, and also as there are many cable types and sizes, each of which would require the construction of a bespoke model.

The resistances of underground cables from the FEM simulations are typically higher than the values specified in the DINIS line code file. It has therefore been assumed that the DINIS file contains DC resistance values rather than AC resistances at 50 Hz. The resistances are compared in Figure 115 which shows the ratio between the positive sequence resistance from the FEM modelling and the positive sequence resistance specified in the DINIS line code file (after conversion from per unit values). The plot also shows an approximation function that gives a close match to the observed points, given by:

$$\mathrm{r_{ac}} = \mathrm{r_{dc}} \times \left(1 + \frac{0.11}{300} \cdot \mathrm{A_{Cu}}\right)$$

where $\mathrm{r_{ac}}$ and $\mathrm{r_{dc}}$ are the AC and DC resistances and $\mathrm{A_{Cu}}$ is the equivalent copper cross-sectional area of the conductor in mm^2. For copper conductors this is the actual cross-section, whereas for aluminium conductors the conductor area is divided by a factor of 1.6.

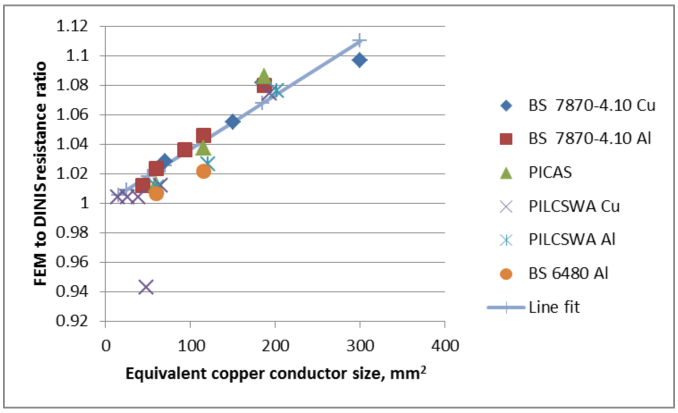


Figure 115 AC resistance scaling for underground cables.

Therefore, the positive sequence resistance values from the TITab.Type file have been uplifted to better reflect AC resistances at 50Hz.

Appendix C.3 Meter assignment to substations

The list of customer connections associated with each substation is specified in a data file extracted from WPD's asset record system CROWN. For each MPAN, this data provides the normally supplying distribution substation reference number and also gives the Elexon profile class and EAC for non-half-hourly metered customers.

This data file also specifies the normally supplying primary substation and HV feeder to which the distribution substation is connected. It has been found that these fields do not always coincide with the primary and HV feeder numbers for the network topology originating from the EMU database (as used to obtain the DINIS network data file). Where inconsistencies have been investigated, it appears that the EMU database is more current and so disparities between the network data and the primary and HV feeder numbers from the CROWN database have been ignored.

Appendix C.4 Half-hourly meters

Half-hourly data has also been obtained from BAU data for MPANs in the East Midlands region over a 1-year period from 1st July 2016 to 1st July 2017. This provides four-quadrant power data and so gives a time series of the net active and reactive power demand. The demand is assumed to be zero if readings are absent for some of the period (e.g. at the beginning or end of the period).

Some MPANs with half-hourly data also have a defined profile class and/or EAC. The loss estimation software treats these MPANs as half-hourly throughout. MPANs no half-hourly data and with either the profile class or EAC undefined are omitted.

Appendix C.5 Non-half-hourly meters

The demand for non-half-hourly meter is formed by constructing a time series from the appropriate Elexon profile over the 1-year period defined above, and then re-scaling this for each meter according to the customer EAC. The reactive power is set to zero (for unity power factor), based on project experience with the LV feeder trials in the Isle of Man where a number of domestic customers were found to have both imported and exported reactive power.

Appendix C.6 Transformer Data

The power-flow analysis for the HV loss estimation uses input data for each distribution transformer to specify the rated power, number of phases, percentage impedance, and the copper and iron losses. The asset data available from WPD's CROWN system generally only provides the rated power and the number of phases, but impedance and loss data is available only for some transformers, most of which are located in the South West or South Wales regions. Averaged loss and impedance values from these transformers have therefore been used as approximated figures for the majority of transformers for which data is not available.

Separate average values have been formed according to the rated power, number of phases, and decade of manufacture, although an average of all manufacture years is used when no data is available for a particular decade. There are also a number of transformer ratings for which there is no data in any year and so losses for these transformers are taken from the nearest higher transformer rating with a valid average figure. An impedance of 4.73% has been used as a default where no transformer data was available for the required rating or phase type.

There are also some transformers for which the records of the number of phases is unclear and so it has been assumed that transformers are three-phase if the rated power is 30 kVA or above. In a few cases the number of phases is known but not the rated power. In this case, a rating of 500 kVA is assumed for three-phase transformers and 16 kVA for single-phase transformers.

The loss calculations are relatively insensitive to differences in the assumed transformer tap settings. Actual tap positions are not available from asset data and so a default of tap 2 (+2.5%) has been assumed, based on experience from the project trial substations in the Milton Keynes area, giving a transformer ratio of 11275V to 433V.

There is also no information to determine the phase connections of single-phase transformers. A worst-case option is therefore assumed where all single-phase transformers are connected between the red and blue phases.

Appendix C.7 Current and voltage data

The SCADA monitoring at the primary substation provides half-hourly measurements of voltage and of the current on each of the HV feeders.

The current data includes only the amplitude of the current, with no phase information, and so there is an ambiguity whether a feeder has imported or exported power. The measurement is made on only the yellow phase and so there is also no information to indicate the level of unbalance.

The data generally includes multiple voltage measurements for each primary. Typically, in normal operation, these might be from a pair of transformers and the two sets of values appear to differ only due to measurement noise. However, in some cases, one of the values may be zero or other values that are clearly out of the accepted operating range. This could occur for short periods if one of the transformers has been switched out for maintenance, or if there are longer-term changes to the switch-boards at the primary. To resolve this, the loss estimation software makes a selection on a half-hourly basis of whichever voltage measurement is nearest to the nominal voltage for the feeder. If none of the measured voltages are within 10% of the nominal voltage then the half-hour period is marked as invalid and not included in the loss estimation calculations.

Appendix C.8 SCADA channel mapping

In order to use the SCADA data, the loss analysis software needs to be provided with the name of the primary and HV feeder, as used in the SCADA records, and corresponding to the reference number of the primary and feeder in the DINIS data. The names used in the SCADA system frequently differ slightly from the names used in the EMU database (and therefore by DINIS) and so this name mapping is not always obvious or easily resolved by the loss analysis software. A data file has therefore been established to act as a lookup such that the software can find feeder data in the SCADA system. There are primaries for which the naming has changed at some point within the 1-year period used for the loss estimation. In this case the loss analysis results are omitted for the period when no valid SCADA data can be found.

Appendix C.9 Scaling of Non-Half-Hourly Demand

Provided that the SCADA measurement data appears to be valid, these measurements are used to scale the non-half-hourly demand applied at each of the distribution substations such that the total demand from each HV feeder is consistent with the measurement at the primary, as shown in Figure 1.

If the demand on the feeder is dominated by non-half-hourly customers then it is assumed that the feeder imports power from the primary substation (since the Elexon profiles contain no generation). If the feeder is dominated by half-hourly meters then the current magnitude should be closely consistent with the magnitude of the net complex power supplied to the feeder, with the feeder either importing or exporting in accordance with the half-hourly demands.

The algorithm used to find the non-half-hourly demand scaling also allows for the more general case where there is a mixture of both half-hourly and non-half-hourly meters. It is also necessary to allow for either the half-hourly or non-half-hourly customers to have embedded generation, and also for the case where the assumed power factor for the non-half-hourly demand may not be consistent with the measurement data.

The scaling algorithm proceeds as follows. The power-flow analysis calculates separate complex phasors for the estimated current at the primary substation due to the half-hourly and the non-half-hourly demand. The method then uses two different approaches, depending on whether the estimated primary current amplitude due to the half-hourly demand alone is greater or less than the measured current amplitude.

Two examples of the case where the amplitude of the primary substation current from half-hourly (HH) demand is less than the measured current at the primary are shown in Figure 116 and Figure 117.

The most typical example is shown in Figure 116 where the current phasors for both the half-hourly and the non-half-hourly current contributions represent active power being imported into the feeder. In this example the non-half-hourly (NHH) current contribution requires scaling up such that the amplitude of the total current phasor will be consistent with the measured amplitude. The difference between the scaled and un-scaled NHH current is illustrated in red as the 'correction' current.

Figure 117 shows an example where the half-hourly current contribution represents generation and power is exported from the feeder. The Elexon profiles do not include generation and so the NHH current contribution opposes the HH current. Although it would be possible to apply a substantial positive scaling to the NHH current, it is also possible that some of the substations have embedded generation, giving a negative NHH current. The algorithm selects whichever scaling factor is closest to unity.

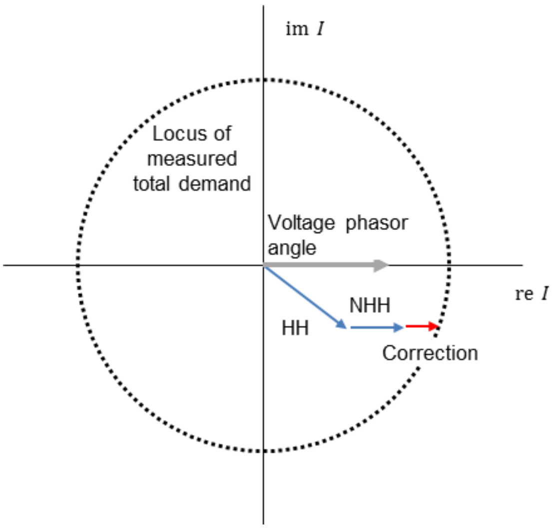


Figure 116 Corrections applied to non-half-hourly demand where the amplitude of the primary substation current due to half-hourly demand is less than the measured current at the primary, and with half-hourly, with non-half-hourly demand as loads.

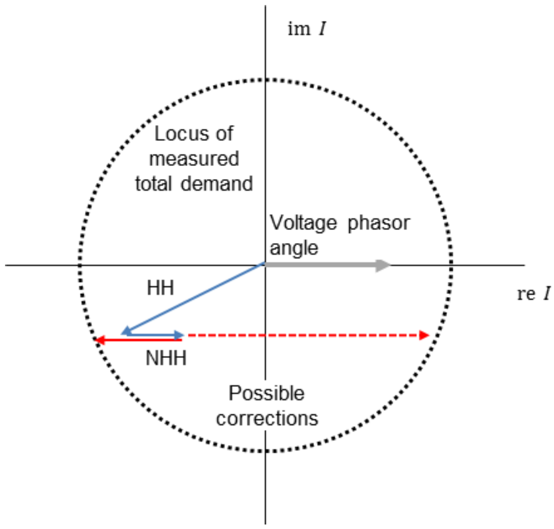


Figure 117 Corrections applied to non-half-hourly demand where the amplitude of the primary substation current due to half-hourly demand is less than the measured current at the primary, with half-hourly demand as generation.

A different approach is needed where the amplitude of the primary substation current from half-hourly (HH) demand is greater than the measured current at the primary. This case is shown in Figure 118 where there is no real-value scaling for the NHH current that will give a total current with an amplitude that lies on the same circle as defined by the current measurement. The algorithm therefore selects a scaling such that the total current will have the same phase angle as the HH current contribution alone. This gives a complex-valued scaling factor with both amplitude and phase.

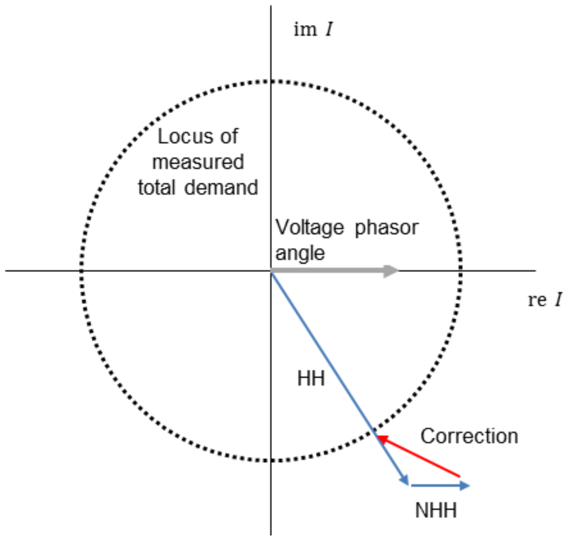


Figure 118 Corrections applied to non-half-hourly demand where the amplitude of the primary substation current due to half-hourly demand is greater than the measured current at the primary.

The use of these two approaches allows for a consistent scaling factor to be found in all cases, including the case where the assumption that the non-half-hourly demand has a un does not allow for a consistent solution, and also allows for the possibility that either the HH or NHH current contributions could include generation.

Appendix C.10 Power Flow Analysis

A power-flow analysis is used to calculate the losses for the given network and demand data. This analysis runs with half-hourly resolution for 1-year period from 1st July 2016 to 1st July 2017, with each half-hour included provided that the SCADA data is available. The power-flow analysis uses a forward-backward sweep method, based on the technique described in [4], and modified so as to allow for the inclusion of the scaling factors, as described above.

Conventionally, the forward-backward sweep algorithm uses input data to determine the current at each load (in accordance with the node voltage and the assumed load model) and the voltage at the upstream node (in this case the primary substation). Initially, all of the currents are assumed to be zero and so the voltage at the loads is equal to the primary substation voltage. The current at the upstream node is then calculated, and then the branch currents are used to calculate a revised estimate of the voltage at each load. This process continues iteratively until the change in node voltages falls below a defined threshold.

For the loss estimation method, the total load current is given by the super-position of the current for the half-hourly meters and the current for the non-half-hourly meters. The current for the half-hourly meters can be calculated from the load demand and from the load voltage, but the currents for the non-half-hourly meters are subject to a scaling factor which is not yet known. However, the modified backward sweep differs from the conventional method in that the SCADA monitoring provides the primary substation current as input data, rather than this being an output from the calculations. This additional data can be used to linearly scale the currents for non-half-hourly demand so as to match the required primary substation current. The forward sweep then follows the conventional method and uses the branch currents to calculate the voltages at each node.

Once the forward-backward sweeps have converged, the losses in each branch and the load losses in the transformers are determined using an $\mathrm{I}^2\mathrm{R}$ calculation. No-load losses for the transformers (dependent on the load voltages) are also calculated. For the power-flow analysis, the sum of these losses is also consistent with the difference between the power input to the network at the primary substation and the power output at each of the loads. (This is not the case for the measurement data analysis, where a method using the $\mathrm{I}^2\mathrm{R}$ calculation plus estimated transformer no-load losses has been found to be more reliable than a power difference method.)

Appendix C.11 Selecting to Use Non-Half-Hourly Scaling

Loss estimations using the process described above have been found to be relatively tolerant to errors in the incorrect assignment of customer meters to substations on the same HV feeder. Provided that the total demand is scaled correctly, the demand from a meter assigned to the wrong substation on a feeder will still be represented in the branches near to the primary where most of the cable losses occur, and errors in the transformer load losses generally have a less impact.

Ideally, if the customer EAC data is accurate and in the absence of measurement errors, then the mean of the demand correction power summed over the 1-year period will be zero. In practice, this is never the case as the EAC is only an estimate, and the time period for which it applies is not aligned with the 1-year period used in the loss estimation.

Measurement errors also affect the results. If the SCADA current monitoring has a 5% accuracy class (allowing for both the sensors and for current transformers), then the overall demand may be scaled higher or lower than would be expected based on the EAC values.

Despite these risks, good agreement has been found between the estimated and measured losses for the feeders in the HV losses trials in Milton Keynes. However, if the SCADA data itself is invalid, then using this to create the scaling factors introduces errors into the loss estimation. Most of the HV feeders have short periods for which the open points have been reconfigured, either for maintenance or in the case of a fault. There are then likely to be either more (or fewer) substations on the feeder than are normally connected and the current measured at the primary substation will not be consistent with the demand for the substation connections recorded in the network data. In this case the SCADA current measurement is not at fault, but the modelling is subject to a limitation that short-term re-configurations are not included.

If the network is re-configured to include additional substations, then the SCADA current data will be higher than would be expected for the substations that are normally connected. The scaling algorithm will then scale any non-half-hourly demand from the normally connected substations, so as to match the measured current. Both the cable losses and the transformer load losses may exceed their normal expected ranges. However, the periods with network re-configurations are usually relatively short and so the erroneous values have a low impact on the overall loss assessment.

There are also HV feeders for which the SCADA data appears to contain errors. This might be found where the current is either permanently or intermittently stuck at a zero value, or where the current sensors has not been appropriately configured, giving either incorrectly scaled readings, or in some cases readings with a non-linear operating range. If these errors persist throughout the 1-year loss estimation period then the impact on the results can be significant. In this case, it is likely that a better loss estimate would be provided by using the Elexon profiles without scaling the demand to match the SCADA data (although still scaling the demand for each customer according to their EAC).

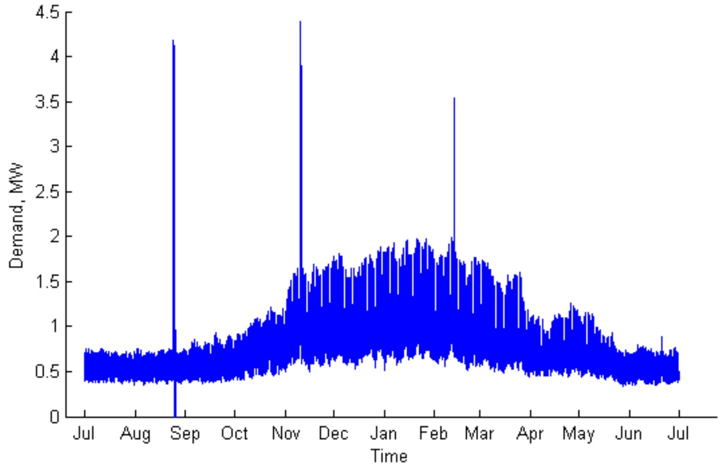
The loss estimation software runs the analysis both with and without the scaling process. The results with scaling are used by default, but the results without scaling are used if:

- Any of the distribution substations on an HV feeder has a mean loading that is more than 25% above the rated power for the transformer
- The SCADA data is zero for more than 5% of the 1-year period.
- The demand correction power is more than ±20% of the power imported into the network (where the power imported into the network is calculated with no scaling applied).

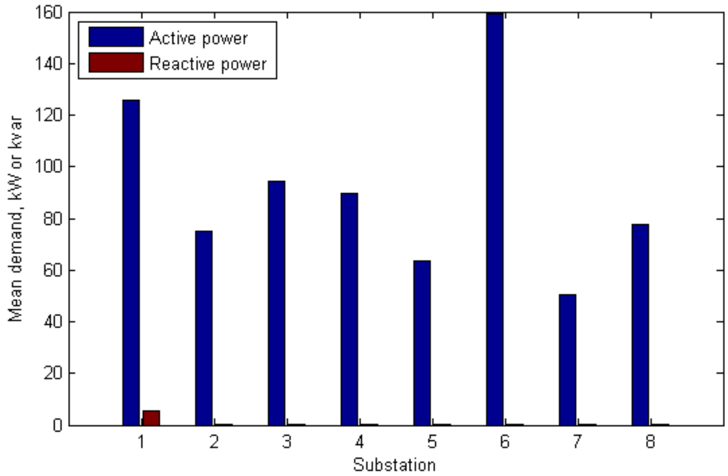
If the feeder has no non-half-hourly meters then no scaling factor is required.

Appendix D Examples of Individual HV Feeder Loss Analysis Graphics

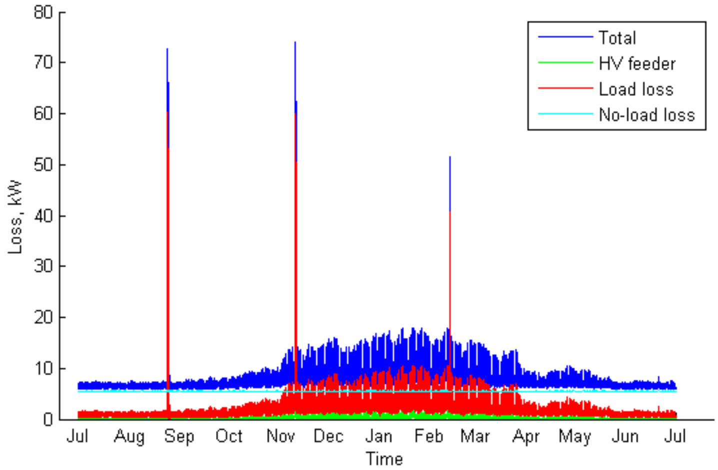
As discussed in Section 2.3.2, the loss analysis html pages contain a ranger of analysis graphics. Examples of these are shown in Figure 119 below.



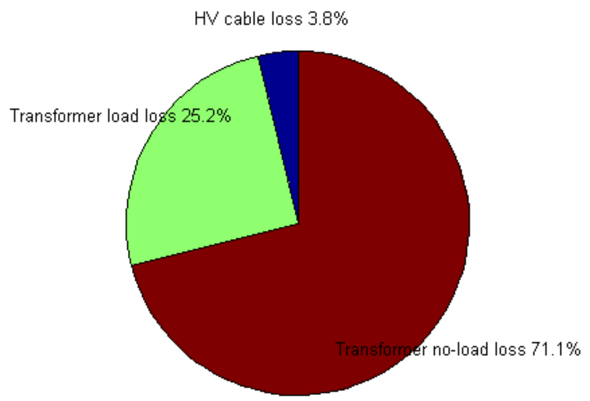
HV feeder demand. Spikes illustrate temporary changes in feeder configuration.



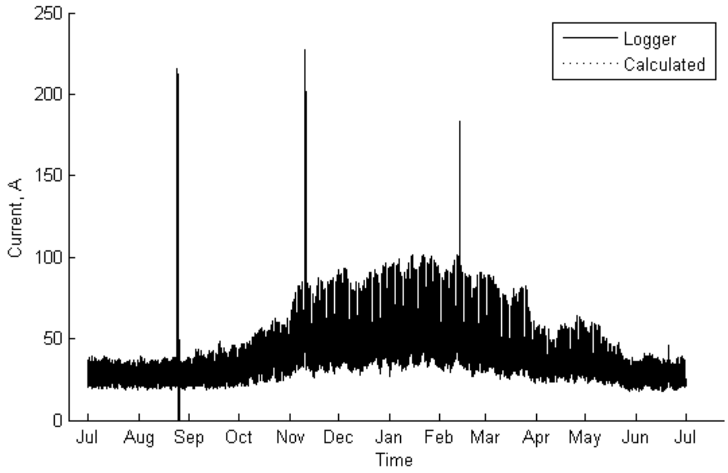
Mean distribution substation loads for substations supplied by the HV feeder.



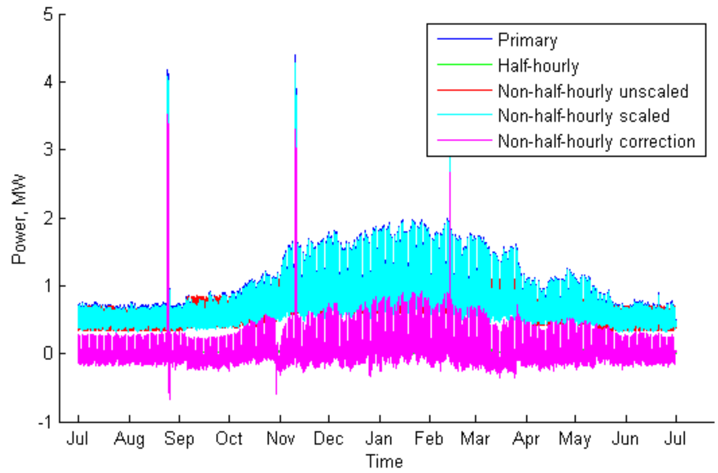
HV feeder Losses, with breakdown of losses between HV line, transformer no-load losses and transformer load losses.



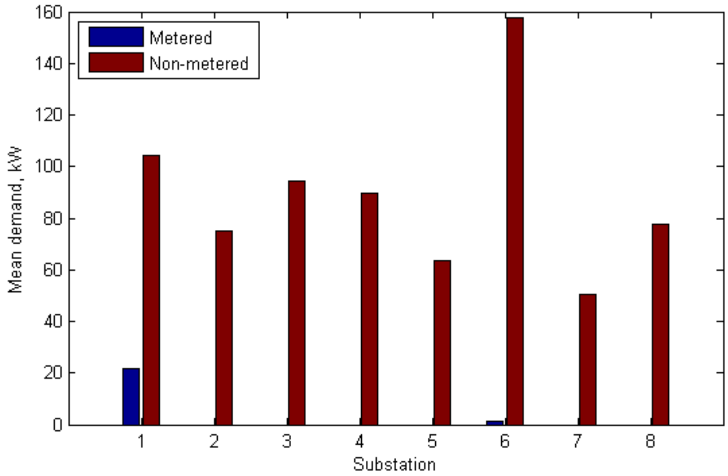
Breakdown of HV feeder mean annual losses between HV line, transformer no-load losses and transformer load losses



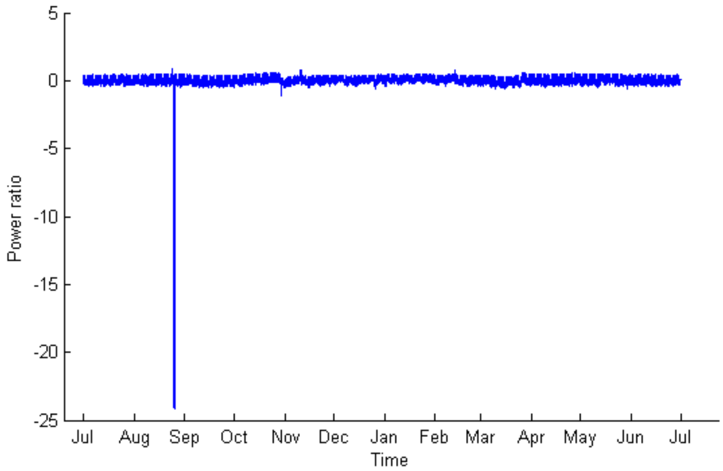
Primary current from SCADA.



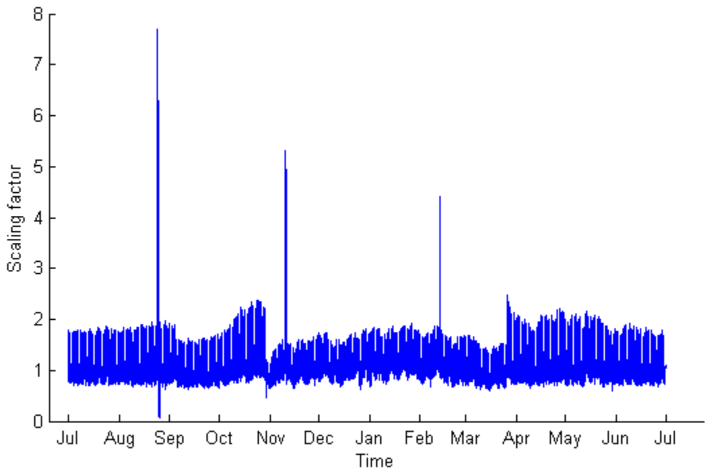
Scaled and unscaled modelled substation load.



Mean HH versus NHH demand by substation.



Ratio of scaling factor for NHH demand to network import power.



NHH demand scaling factor to match profile load estimate to SCADA current data.

Figure 119 Examples of loss analysis graphics available in html results pages.

Appendix E Nominal loss cost savings target for estimation methods to support

The NIA project registration document includes an example target for cost savings achieved through a reduction in losses. This is based on a total UK electricity consumption of 317 TWh, of which 25.2%, or 79.9 TWh, is supplied by WPD. An overall distribution network loss of 5.8% is assumed, and 72% of this applies for distribution at HV and below. The losses for WPD at HV and LV are therefore approximated as 3.34 TWh.

The cost of these losses is calculated using the OFGEM cost of losses of £48.42/MWh, and also allowing a carbon intensity of 524.62 TonneCO2/GWh and carbon cost of £59/TonneCO2, giving an additional cost of carbon of £30.95/MWh. This gives a total cost of losses of £79.37/MWh.

Combining these two figures gives a total annual cost of losses for the WPD HV and LV feeders of £265 million. It is then assumed that a 10% loss reduction could be achieved on 10% of feeders, giving a total annual saving of £2.65 million.

It could be assumed that approximately half of these losses are at HV and half at LV, and that the East Midlands region has one quarter of the feeders. Scaling also for the proportion of feeders with accepted results, the figures in the project registration document suggest an annual cost of losses of £25 million, and the same 10% loss reduction on 10% of feeders would give a saving of £0.25 million.

These figures can now be compared against the results from the estimation method. The total mean estimated losses for the accepted HV feeders are 30.4 MW for a total mean power supplied by primary substations of 1.93 GW, equivalent to an annual energy demand of 16.9 TWh. This appears reasonable if the demand for the East Midlands region is roughly 25% of the total for WPD, and for 75.2% of the feeders having accepted results, which would give an expected total of 15.0 TWh.

The mean losses from the estimation results are 30.4 MW for the 2130 accepted HV feeders; giving an annual energy loss of 0.27 TWh. Using the same cost basis as above, this has an annual cost of £21.1 million. This is slightly less than the approximate cost of losses based on the NIA project registration figures of £24.9 million, although the results are still reasonably consistent given the uncertainty in the simple scaling ratios applied. It is also highly likely that other regions with more rural feeders will have higher losses than in the more densely populated East Midlands region.

As the estimated losses for the accepted feeders are slightly lower than assumed in the project registration document, the contribution from HV feeders in the East Midlands would need slightly more than 10% of feeders, around 250 of the 2130 feeders with accepted results.

More conservatively, if the cost savings were to be based on only the OFGEM cost of losses of £48.42/MWh, then the initial target total savings of £2.65 million would require a contribution from 411 of the 2130 East Midlands HV feeders with accepted results.

However, the losses vary widely and so the same cost saving could be achieved from fewer feeders if loss reduction measures could be directed at those with the greatest losses. Figure 120 presents a histogram of the cost of losses for each of the 2130 feeders, ranging from near zero up to approximately £60k per year. If the 10% loss reduction could be applied to the feeders with highest losses, then only 110 feeders would need to be considered.

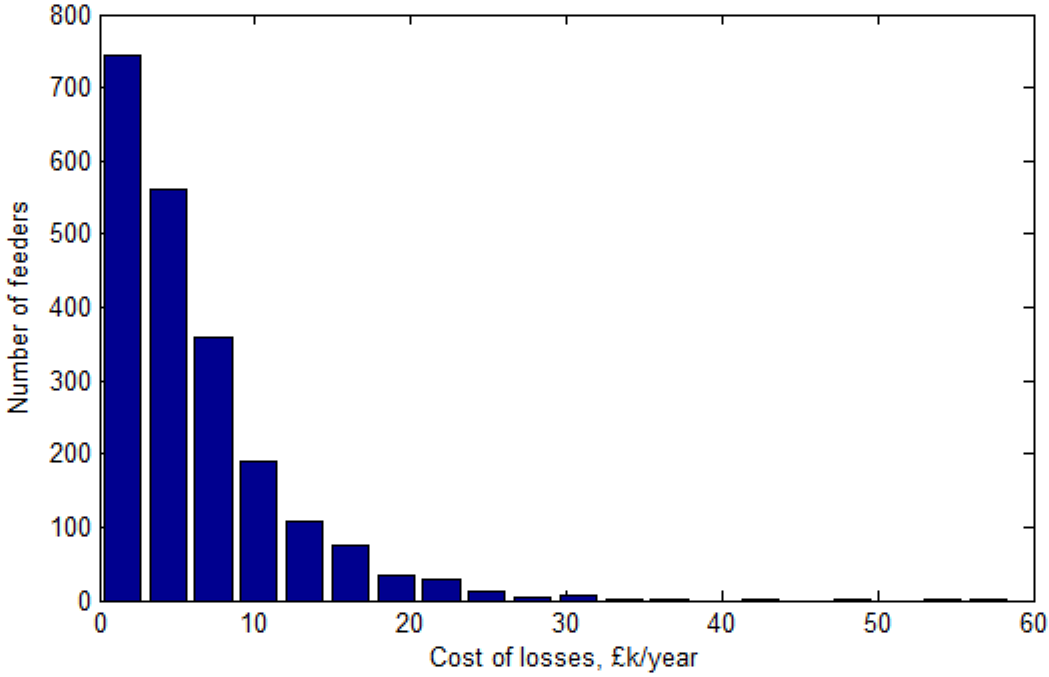


Figure 120 Cost of losses for feeders with accepted results, based on £48/MWh