WPD INNOVATION
Transforming the electricity network

OHL Power Pointer - Report on Method 2

Method 2: Directional Power Flow State Estimation

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1. Executive Summary

In our RIIO-ED1 business plan and DSO Transition Strategy, WPD has made the commitment to improve visibility of distribution network power flows.

Ofgem's RIIO-ED2 methodology draws on the principle of a smart and flexibly energy system. Ofgem is clear that the use of data lies at the heart of the energy system transition, and that a shared understanding of what is happening to power flows and the status of network infrastructure will be key enablers for creative solutions to future challenges.

WPD's Distribution System Operability Framework identified the main drivers for increased monitoring and control:

- Making informed decisions about switching and network operation;
- Ratings of transformers, as they are dependent on power-flow direction;
- Running real-time analysis like Active Network Management (ANM) will necessitate this level of detail to ensure the control systems can represent the network accurately; and
- Enabling the network to be correctly represented in power system software as this is used to determine reinforcement requirements and network constraints.

OHL (Overhead Line) Power Pointer is a project which is funded through Ofgem's Network Innovation Allowance (NIA) mechanism, it has trialled a device that is capable of self-powering operation and provides real-time voltage, current, directional power flow and conductor temperature information. This information has been used to more accurately assess network operation, such as latent generation output and directional fault detection to more quickly identify the location of faults. The project was registered in January 2019 and completed in May 2022.

This report has been prepared following the completion of the field trials and presents the findings of Method 2: Directional Power Flow State Estimation.

Directional power flow state estimation is a key enabler for the control room, where it can assist with decision-making in the day-to-day configuration of the network and in automated algorithms, to manage power flows around the network, particularly where there are high levels of intermittent low-carbon technologies connected. State estimation addresses the challenge of combining (existing) substation sensory monitoring with modelling techniques to deliver a low-cost solution for maximum network observability. For example, in a high-voltage feeder with a teed connection to a generator, it could be possible to infer the direction of power flow through branches with non-directional sensors (such as Ampere measurements), considering the available directional measurements (such as MW sensors) across the wider network, by modelling the overall state of the network.

The Shrewsbury 33kV network was selected as the trial area network for the assessment of the state estimation solution. The Shrewsbury 33kV network comprises several primary substations connected in a loop arrangement supplied from Shrewsbury BSP. Two large photovoltaic solar and a conventional thermal generation plant are connected to the 33kV network. The network is instrumented with a combination of modern directional and older non-directional sensors, relative to the respective age of primary substations.

A Power Network Analyser (PNA) feature has been developed and deployed to the iHost online monitoring platform. The PNA integrates the open source pandapower power systems analysis package into iHost which includes a module for performing state estimation on pandapower networks, and load flow analysis. The PNA module supports the read/write interface of SCADA measurements to pandapower networks, which are impedance models derived (and verified) from multiple internal data systems, including EMU and IPSA+.

Real-time SCADA measurements are captured from an Inter-Control Centre Communications Protocol (ICCP) link established between the West Midlands iHost server and ADMS. iHost generates full time-series datasets (in script format) to enable the retrospective simulation of the network events using an ICCP simulator connected to the project partner's external iHost server. The datasets incorporate over 400 binary and analogue datapoints, and capture over 1 million events on the trial area network over a typical 24-hour period.

Extensive testing of the pandapower state estimation module was carried out using 24-hour time-series datasets capturing seasonal changes in power injections, and normal and abnormal network running arrangements.

Case studies capturing different network configurations are presented in this report. The studies have proven that typical data (captured within ADMS) from sensory equipment installed across 33kV networks is sufficient provide visibility of directional power flows through feeders. The results of the state estimation solution have been evaluated for accuracy and compared against the input data using root mean squared error (RMSE) methods. Moreover, the results of directional power flow have been independently validated using data from Smart Navigator 2.0 sensors installed on OHLs at ten site locations across the trial area network.

It has been concluded that the state estimation solution could be a powerful tool to support the visibility of directional power flows through distribution networks. Prior to the method being adopted as business-as-usual any anomalous results should be investigated and further testing should be carried out to determine the suitability and applicability to alternative trial areas.

2. Project Background

OHL (Overhead Line) Power Pointer is funded through Ofgem's Network Innovation Allowance (NIA). The project was registered in January 2019 and completed in May 2022.

OHL Power Pointer has trialled a device that is capable of self-powering operation and provides real-time voltage, current, directional power flow and conductor temperature information. This information has been used to more accurately assess network operation, such as latent generation output and directional fault detection to more quickly identify the location of faults.

OHL Power Pointer has deployed Smart Navigator 2.0 sensors onto WPD's networks to monitor directional power flows and address the "Network Monitoring and Visibility" challenge within the "Assets" section of WPD's "Distribution System Operability Framework".

Smart Navigator 2.0 sensors clip onto overhead lines (operating at voltages from 11kV to 132kV) and sample the voltage and current waveforms (multiple times per cycle) to determine the real-time power flow direction at that point in the network. The devices weigh less than 1kg, harvest power from the overhead line for self-sustaining operation and can be readily ported between sites for redeployment. Using encrypted DNP3 communications over mobile networks, the devices transmit power flow data from remote sites to a central system (for example, iHost or PowerOn). The sensors support over-the-air upgrades, which means their functionality can be reconfigured remotely without the need for multiple site visits.

A rendered illustration of a set of Smart Navigator 2.0 sensors installed on a three-phase overhead line is presented in Figure 2-1.

Figure 2-1: Rendered Illustration of a set of Smart Navigator 2.0 sensors

WPD is the first UK DNO to use Nortech's technology in these DSO applications.

Over 100 sets of Smart Navigators have been trialled in this project, covering the various Methods and nominal voltage levels of overhead lines in the South West (132kV circuits) and West Midlands (66KV, 33kV and 11kV circuits) licence areas.

3. Scope and Objectives

3.1. Scope

The project has been delivered over the course of three years, in three overlapping phases, as summarised below.

- Phase 1: Design and Build (January 2019 – April 2020)
  In this phase, the functionality of the OHL Power Pointer solution was defined for each of the five Methods (directional power flow monitoring, directional power flow estimation, auto-recloser operation detection, directional fault passage indication (FPI) and post-fault rating of overhead lines). The software was designed and implemented. Network locations were identified, and equipment installation locations were selected. In addition, the trials of the various methods were designed.
- Phase 2: Install and trial (September 2019 – February 2022)
  In this phase, the Smart Navigator 2.0 equipment (for directional power flow monitoring, auto-recloser detection, directional fault passage indication and post-fault rating determination) was installed and trialled. Initially, 50 sets of devices were installed to cover the trials of the various Methods. These devices communicated to Nortech's iHost system for rapid prototyping of the software and support with the solution design. As part of the main trials, an additional 50 sets of devices were installed, communicating to WPD's iHost system and the 50 sets installed as part of the initial trials were transitioned across to WPD's iHost system.
- Phase 3: Analysis and Reporting (January 2019 – May 2022)
  In this phase, the results from the trials were analysed and a report on the learning resulting from each of the Methods was prepared. Results and key learning outputs were disseminated and policies were written to facilitate the wider adoption of the OHL Power Pointer solution WPD's business should WPD proceed with Business as Usual (BaU) roll-out

3.2. Objectives

This section outlines the project objectives, more detail is provided later in the report.

Table 3-1: Project objectives

Objective
Create policies for equipment installation and location
Carry out assessments of the accuracy and consistency of determining power flow directions within WPD's distribution network
Provide recommendations on the number and location of devices needed for full visibility of power flow direction
Quantify the savings gained by using the Smart Navigator to detect and communicate auto-recloser operations (rather than using visual inspections of AR equipment)

Quantify the savings made to Customers Minutes Lost (CMLs) through the use of OHL directional FPIs
Provide the control room with visibility of overhead line real-time post-fault ratings

4. Success Criteria

This section indicates the success criteria of the project, more detail is provided later in the report.

Table 4-1: Project success criteria

Success Criteria
Power flow direction determined correctly at a minimum of 10 sites across 11kV and 33kV networks
Power flow direction estimated correctly at a minimum of 10 sites across 11kV and 33kV networks
Correct detection of a minimum of 5 auto-recloser operations during the project lifetime (recognising this is dependent on faults occurring)
Direction of passage of fault current determined at a minimum of 5 sites during the project lifetime (recognising this is dependent on faults occurring)
Post-fault ratings determined for at least one circuit at or above 33kV during the project lifetime
Completion of trials of the five different Methods, with a report on each Method detailing the learning and updated business case for wider business adoption
Development of policies to facilitate the wider business adoption of the technology at the end of the project should WPD decide for BaU adoption

5. Details of the Work Carried Out

This project has delivered a solution for the real-time directional power flow state estimation of the distribution network. The method utilises impedance models and available system measurements to estimate voltage angles and magnitudes at each busbar in the network. The solution has been tested using a live network topology and data from the SCADA system to evaluate the accuracy and effectiveness in networks with limited visibility of directional power flows over the SCADA system.

Smart Navigator 2.0 devices have been deployed on each OHL circuit on the live network to provide a source of independent validation for the direction of power flow through the circuits.

5.1. The Network Visibility Problem

It is not cost effective to blanket the entire network with monitoring equipment. Judicious deployment of sensing infrastructure is needed, and a balance needs to be struck between the amount of sensing equipment deployed and the visibility required.

State estimation is a technique which is used to derive a state of the system from sensory data gathered from an instrumented network, whereby erroneous and missing data can be solved to form an estimated holistic state of the system. Except for previous innovation trials, state estimation has generally been limited to the transmission system where nodes and circuits are often well instrumented, and often have high frequency sampling rates and can maintain synchronisation between sensors.

OHL Power Pointer has assessed state estimation on less heavily instrumented 33kV distribution networks. The candidate network for this method was a group of primary substations supplied by Shrewsbury BSP, in the county of Shropshire.

This method investigated whether the quality of the data delivered from the sensory infrastructure on the distribution network can provide a reliable estimate of the state of the network the control room. It was found that quality of data may be affected in the following ways:

- accuracy - due to equipment limitations (e.g., old technology, poor calibration), or varying configurations (e.g., deadbanding);
- polarity – incorrect orientation of sensors resulting in power flow direction recorded opposite to the true direction;
- frequency – poor synchronism of measurements with other instruments on the network, slow sampling rate resulting in out-of-date information;
- latency – poor communications, distortion of analogue signals, communications failure or sensor malfunction.

An assessment of the trial data has been carried out to attempt to evaluate and quantify these issues.

5.2. Theory of State Estimation

State estimation offers a holistic solution to the problem of inaccurate or erroneous measurement data in electricity networks, or indeed other similar dynamic systems.

State estimation is the process of estimating the voltage magnitudes and angles at each node in a network, based on measurement data. Measurements (V, I, P, Q) are recorded around the network and reported to the Control room over the SCADA system. The measurements are not reflective of the true (exact) state of the network, each measurement device operates within a set of tolerances, which inherently leads to an inaccuracy in the received value. The SCADA system transfers analogue, binary and counter data points, analogue measurements can be distorted with noise, binary inputs can fail through poor contacts, through transmission data can be delayed (or lost) over the communications medium. The state estimation method accounts for these errors, it processes all available measurements and using mathematical regression techniques to determine the likely true state of the electrical network.

In transmission networks, the asset base is small and risk to supply is significant, therefore high-accuracy (and synchronised) recording equipment, such as phasor measurement units (PMUs) are more widely available. This greatly reduces the error in measurements and provides a reliable basis for state estimation, enabling the Control room to make informed decisions. In distribution networks where the asset base is much larger it is more often not cost-effective to integrate (or maintain) similar equipment, therefore measurements are inherently more coarse.

The result of state estimation in electrical networks is therefore a set of voltage magnitudes and voltage angles for all nodes (busbars) present in the network, from which estimated power flows through circuits can be derived. In order to solve the state estimation problem an impedance model is required (representative of the network topology) and a number of sensor measurements from around the network.

5.2.1. Mathematics

The weighted least squares (WLS) regression method was selected as it is a widely used solution for state estimation, with considerable supporting literature and test cases. An implementation of the method is also readily available in the open-source Pandapower python package.

The least squares principle is that best estimates of the state variables are chosen as those which minimise the weighted sum of the squares of the measurement errors, in this case SCADA measurement errors.

Mathematically the formulation of the problem is expressed as follows:

$$Z = h(x) + e$$

Z = measurement vector (SCADA measurement set)

h = system impedance model relating the state vector to the measurement set

x = state vector (voltage magnitudes and angles at each node)

e = error vector associated with the SCADA measurement set

5.2.2. Measurement Set

State estimation depends on a level of observability. A system is fully observable if voltage phasors at all nodes can be uniquely estimated using the available measurements. The voltage phasors are the state variables, *v* and *va*, present at each node. Assuming the system contains *n* nodes (buses) then the network can be described as *2n* state variables, *n* voltage magnitudes *v*, and *n* voltage angles *va*. A slack bus provides the reference in the model and the voltage angle at this node is set to zero. Therefore, the state estimation should find *2n-k* variables, where *k* is the number of defined slack buses in the model. The minimum number of measurements considered for performing the state estimate is therefore *2n-k*, however, to perform well, the number of redundant measurements should be higher. A value of *4n* is often considered reasonable for practical purposes.

Measurements can be line measurements, or bus injections, or transformer measurements.

Measurements can be real, or they can be predicted based on historical data, the accuracy of the estimate will only be as reliable as the measurement data that is provided.

Real measurements are measurements derived from transducers across the network, for example V, I, P, Q measurements at substations. In a perfect system samples would be taken in synchronism across the network, however typical distribution measurements are not sampled in synchronism, but by excursion events (above or below tolerance thresholds), to conserve communications bandwidth.

Virtual measurements are measurements where an expected quantity is known with some certainty, for example a node without any bus power injections (loads, shunts or generators), can be assigned bus injection P, Q values of zero, to constrain the model where appropriate and improve the estimate.

Pseudo measurements are measurements that can be applied to unobservable elements in the model, for example distribution transformers can be assumed to deliver a load profile according to a typical daily demand curve, with a peak approximately at half rated capacity. Pseudo measurements could also be load forecasts or scheduled generation.

Measurements are given a standard deviation which provides weighting in the regression model.

5.2.3. Accuracy of the Estimate

The individual residuals between the observed (SCADA) values and the estimated (state estimate) values are derived in the model. Residuals are a measure of how far from the regression line the data points are; root mean squared error (RMSE) is a measure of how concentrated the data is around the line of best fit.

The individual measurement errors have been weighted according to the quantity (V, I, P, Q) prior to the RMSE calculation.

RMSE is calculated according to **Equation *1***.

$$RMSE = \sqrt{\frac{\sum_{i=1}^{n}(estimate - observed)^2}{n}}$$

Equation 1: Root mean squared error (RMSE)

Where, *n* is the number of measurements.

5.3. The Trial Area Network

5.3.1. Selection of Trial Network

The Shrewsbury primary network was selected for trials of the state estimation method as it features the following characteristics:

- The 33kV **distribution voltage** provides a suitable balance between the availability of existing sensor infrastructure at primary substation, and the availability of outages for the installation of Smart Navigator 2.0 equipment (for power flow direction validation). If the method is proven to be successful, it is anticipated that the state estimation solution could be applied to other 11kV, 33kV, 66kV and 132kV networks.
- The network comprises large (15 MW and 17 MW) solar photovoltaic (PV) **embedded generation** connections, and a 9.8 MW conventional thermal energy-from-waste generation plant.
- The network is normally operated in a **closed ring configuration**. More frequent observations of bi-directional power flows are likely in looped circuits rather than radial circuits, as the load fluctuates at substations throughout the day.
- Opportunity to **integrate with wider WPD systems**, the Shrewsbury network was endorsed by the Primary System Design team as it had been selected for the introduction of an Active Network Management scheme. Data from Smart Navigator 2.0 equipment, installed under the OHL Power Pointer project, could be used to augment future ANM schemes by providing enhanced network visibility in real-time.

5.3.2. Network Schematic & Monitoring Locations

A schematic of the network of interest for these studies is presented in **Figure 2-1**. The installations of Smart Navigator 2.0 sensors are denoted with a site location number, the corresponding key for the direction of power flow at each site is denoted with green and red arrows, as is reported to the central monitoring platform.

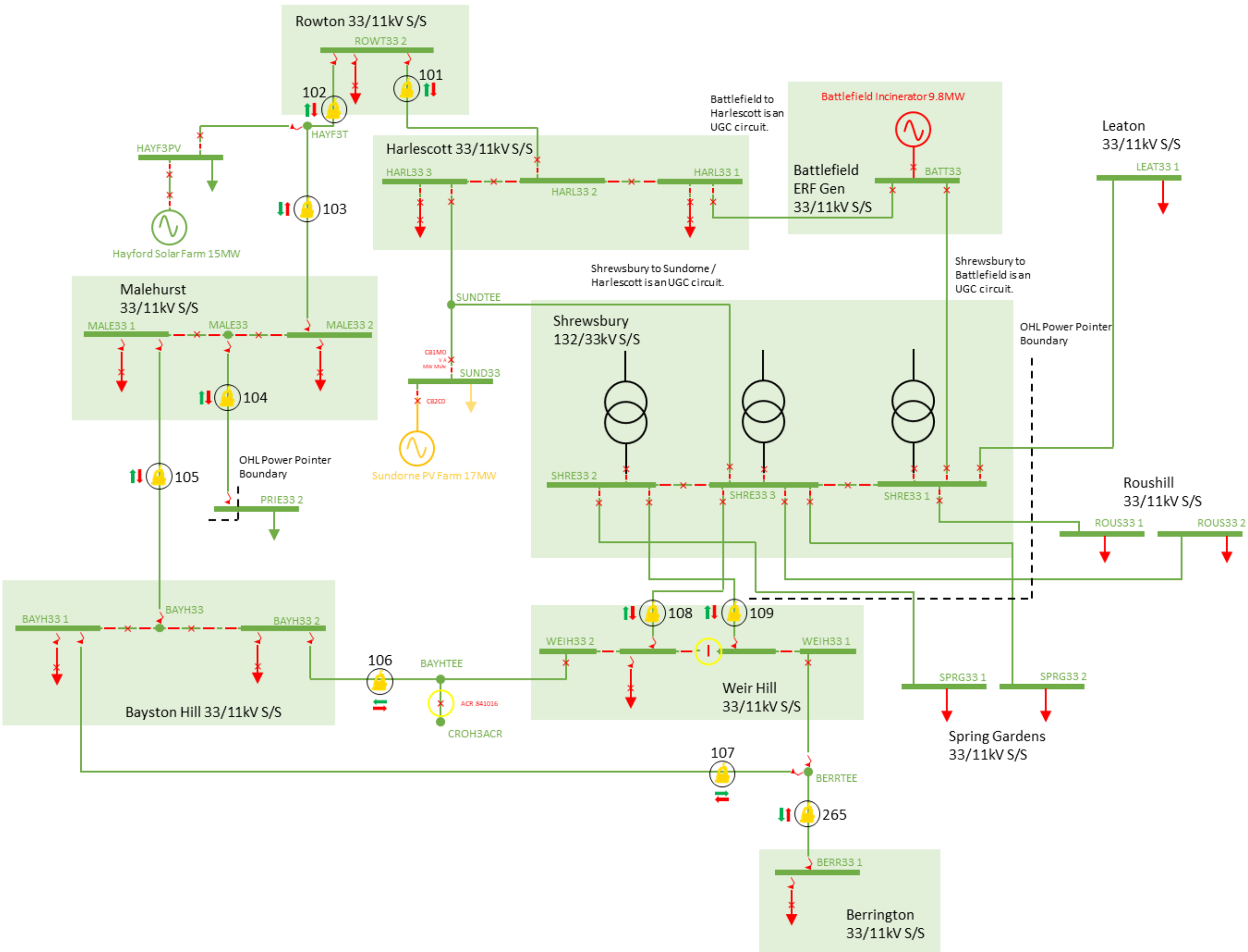

Figure 5-1: Schematic of the 33kV Shrewsbury trial network

5.4. Review of Available SCADA Measurements

The Distribution Network Management System (ADMS) is a central platform that provides the Control team with tools to manage the operation of the distribution system.

Sensors installed on circuits and at substations routinely report data into the ADMS over the SCADA system, providing visibility of real-time electrical measurements (V, I, P, Q) and other important information (transformer tap position, winding temperature, circuit breaker status).

With the boundaries of the trial area network established, the Control team prepared a script to trace the available data points (measurements, etc.) from the SCADA system. The data points have been overlayed on the schematic, note the positions of the points across the 33kV system and at the 11kV bus of the primary transformers at each substation.

The Control team was able to extract a time-series dataset of six hours duration from the traced data points using the ADMS historian. The dataset was subsequently analysed to assess the quality of measurements, the findings of this exercise are documented in a separate report[1].

The examples in the following subsections are intended to provide context for subsequent sections.

5.4.1. Example of a Strong Measurement

Figure 5-2 illustrates the data that was collected over 6 hours from transducers located on the 11kV side Malehurst primary transformer T1. Note the negative values of active and reactive power, indicating power flowing from HV to LV through the transformer, according with the power flow direction convention given in TP6F[2]. There are two noticeable step changes in voltage and reactive power, this is the result of a tap change event at T1 and subsequently at T2 (transformers in parallel sharing common 11kV busbar). Also note the reactive power profile is indicative of asynchronous tap changer behaviour in paralleled transformers, causing circulating currents and consequently excessive electrical losses.

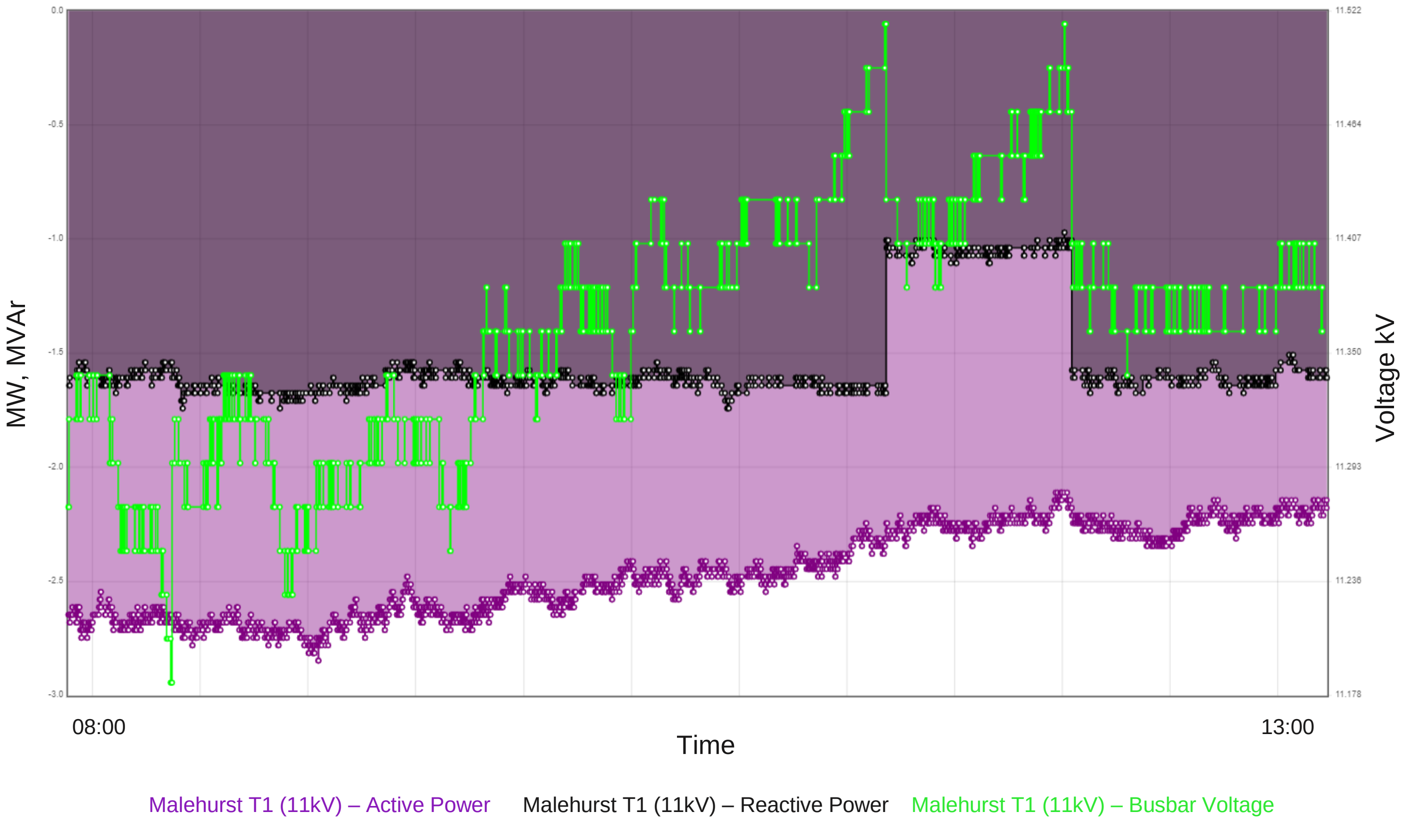

Figure 5-2: Plot of data from Malehurst Primary Transformer T1 (11kV Winding)

Table 5-1 presents the analysis of data reported over the SCADA system for primary transformer T1 at Malehurst substation.

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[1] Title: 'OHL Power Pointer: SCADA TSDS Report', Doc Ref: D_003386, Version: 1.1

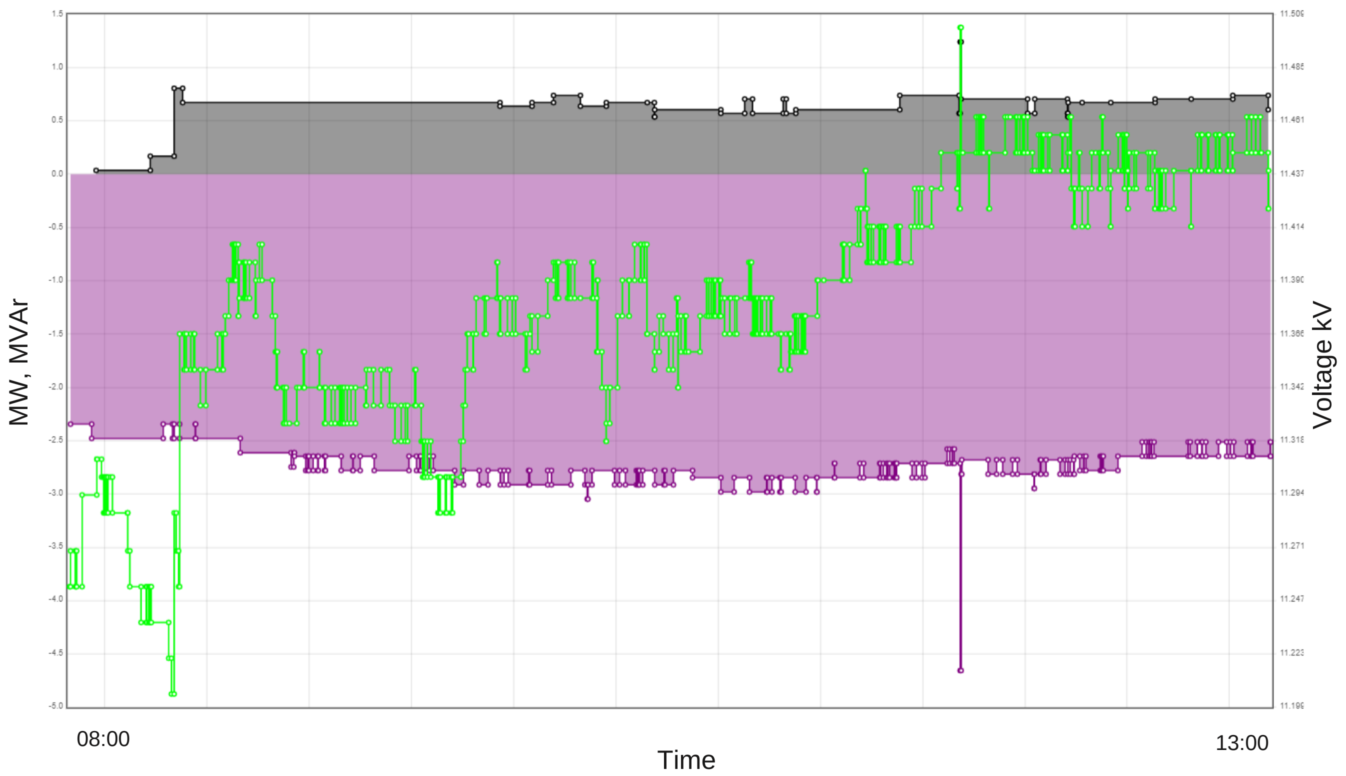
[2] Title: 'WPD Standard Technique: TP6F - Power Measurement Conventions', Date: 5th February 2016

Table 5-1: Analysis of measurement reporting from Malehurst Primary Transformer T1 (11kV Winding)

Data Point	Sample Interval	Deadband
Active Power (MW)	Once per 12.52 seconds (average over 6 hours)	0.033 MW
Reactive Power (MVAr)	Once per 24.18 seconds (average over 6 hours)	0.033 MVAr
Busbar Voltage (kV)	Once per 32.98 seconds (average over 6 hours)	0.022 kV
Current Magnitude (A)	Once per 13.92 seconds (average over 6 hours)	1.758 A

5.4.2. Example of a Weak Measurement

Figure 5-3 illustrates the data that was collected over 6 hours from transducers located on the 11kV side Harlescott primary transformer T2. Note the large intervals between reactive power events, this could either be due to negligible change in the electrical quantity (and therefore no excursion outside of the deadband zone to trigger an event), poor communications from the transducer, or issues with the configuration of the transducer. It would normally be expected that a maximum suppression period is configured, where a data point is reported at fixed intervals if there is no event, to ensure the integrity of the data. The longest period observed without capturing an event was 1 hour and 32 minutes.



Harlescott T2 (11kV) – Active Power   Harlescott T2 (11kV) – Reactive Power   Harlescott T2 (11kV) – Busbar Voltage

Figure 5-3: Plot of data from Harlescott Primary Transformer T2 (11kV Winding)

Table 5-2 presents the analysis of data reported over the SCADA system for primary transformer T2 at Malehurst substation.

Table 5-2: Analysis of measurement reporting from Harlescott Primary Transformer T2 (11kV Winding)

Data Point	Sample Interval	Deadband
Active Power (MW)	Once per 2 minutes 25 seconds (average over 6 hours)	0.033 MW
Reactive Power (MVAr)	Once per 7 minutes 22 seconds (average over 6 hours)	0.033 MVAr
Busbar Voltage (kV)	Once per 45.11 seconds (average over 6 hours)	0.008 kV
Current Magnitude (A)	Once per 3 minutes 51 seconds (average over 6 hours)	1.758 A

5.4.3. Observations

The review of the SCADA data provided valuable learning ahead of the implementation of the state estimation method:

- Confirmation of the circuits and transformers where directional power flow measurements are recorded by existing sensory infrastructure, and confirmation of where non-directional measurements remain the primary source of network visibility.
- The tap changer operation was assessed at each primary transformer, of the 9 primary transformers in the trial network, 7 were found to have been assigned SCADA data points, the exceptions being Weir Hill T2 and Berrington T1. Tap position appears to be reported by exception (on tap position change). There were tap change events recorded for 5 of the 7 transformers over the six-hour period, the exceptions being Bayston Hill T2 and T3, where it is assumed that there was no physical tap change during the period and that the datapoints are functioning correctly.
- The orientation of the transducers monitoring the Shrewsbury BSP grid transformers (33kV winding), and several 33kV circuits was not consistent with the practice given in TPF6. The orientation shall be corrected in value scaling for the state estimation method.
- Site surveys should be undertaken to confirm consistency between tap changer position recorded at primary substations and tap positions displayed in the Control Room.
- The assessment of the deadbanding of transducers has been used to assign accuracy tolerances to the input values in the state estimation models.

5.5. State Estimation Package

Pandapower[3] was selected for the implementation of the state estimation method. Pandapower is an open-source Python package published under the 3-clause BSD licence. The core mathematical functions are based on the PYPOWER solver, which is a port of the well-established MATPOWER (Matlab-language) package for electric power system simulation and optimisation. Pandapower offers power flow, optimal power-flow, short-circuit and state estimation modules for performing power system studies. Data exchange with the core pandapower modules is with DataFrame objects, which are fundamental data structures of the pandas Python package. Pandas is developed for data analysis and therefore facilitates an array of options for assessment and presentation of the state estimation results.

5.6. Building the Impedance Model

The impedance model was derived from multiple sources of data and refined and validated using site records and historical data.

An overview is presented in the chart in **Figure 5-4**.

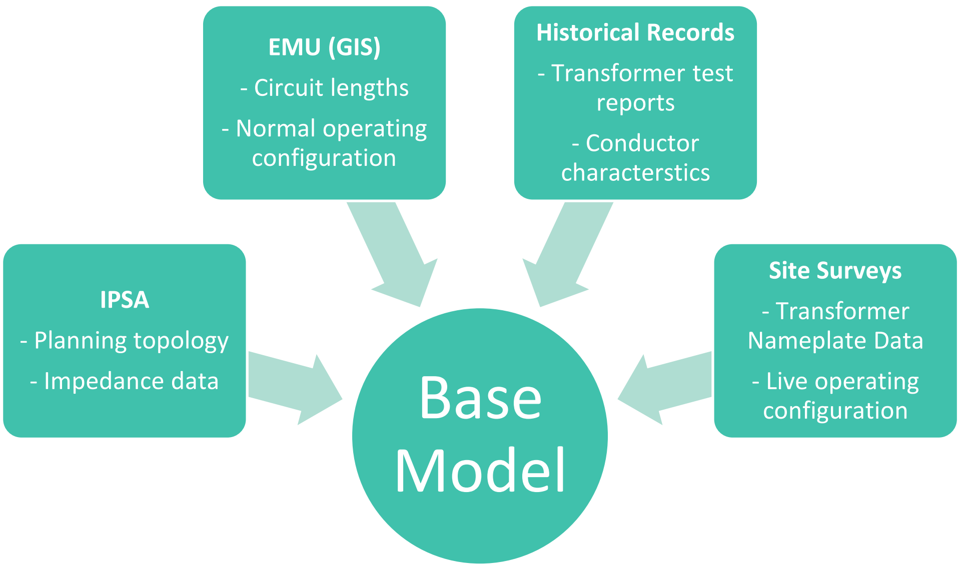


Figure 5-4: Multiple data sources used to establish an accurate base model

5.6.1. West Midlands IPSA Model Data

The IPSA power system models for the West Midlands network were provided by Primary System Design (PSD). The line impedances were converted from per unit format to ohms, suitable for use in pandapower. Similarly, transformer impedances and voltage control mechanisms were translated to a common format for comparison with alternative records.

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[3] L. Thurner, A. Scheidler, F. Schäfer et al, pandapower - an Open-Source Python Tool for Convenient Modeling, Analysis and Optimization of Electric Power Systems, in IEEE Transactions on Power Systems, vol. 33, no. 6, pp. 6510-6521, Nov. 2018

5.6.2. EMU (GIS) Records

The Shrewsbury network topology was extracted in a geographical format from EMU (GIS system), electrical parameters were assigned to the circuits based on conductor types for individual line sections. Conductor characteristics were obtained from PSD design manuals and supplemented with typical data where appropriate.

A comparison was undertaken for the circuits to compare the impedance parameters from the two systems, the results are presented in **Table 5-3**.

Table 5-3: Comparison of IPSA data with records derived from EMU (GIS data)

	Comparison (Absolute)			Error (%)		
Circuit (IPSA ID)	**R (Ohm)**	**X (Ohm)**	**C (nF)**	**R**	**X**	**C**
WEIH33 1 to BERRTEE	0.000055	0.002057	10.413642	0.02%	0.31%	0.50%
BERRTEE to BAYH33 1	0.005678	0.023697	0.052603	0.71%	1.32%	0.02%
BAYH33 to MALE33 1	0.006620	0.061880	1.005332	0.37%	1.47%	0.71%
MALE33 to PRIE33 2	0.021784	0.072850	2.528623	1.01%	1.64%	1.63%
MALE33 2 to HAYF3T	0.017826	0.001500	0.211630	2.59%	0.11%	0.43%
HAYF3T to ROWT33 2	0.002225	0.012234	0.350541	0.72%	1.93%	1.58%
ROWT33 2 to HARL33 2	0.063321	0.060988	1.716070	2.30%	1.10%	0.32%
HARL33 3 to SUNDTEE	0.015455	0.000939	27.930849	9.99%	0.29%	3.76%
HARL33 1 to BATT33	0.003472	0.000210	6.186796	9.99%	0.29%	3.71%
BATT33 to SHRE33 1	0.051236	0.041138	44.082451	15.68%	6.05%	2.81%
SHRE33 3 to WEIH33 2	0.006078	0.006848	72.026573	4.55%	1.19%	31.23%
WEIH33 2 to BAYHTEE	0.003085	0.012717	10.666853	0.68%	1.46%	1.13%
BAYHTEE to BAYH33 2	0.012126	0.009257	0.470396	1.44%	0.54%	0.78%
SUNDTEE to SHRE33 3	0.017354	0.001145	31.545166	9.97%	0.32%	3.77%
SUNDTEE to SUND33	0.001144	0.000024	0.159092	21.89%	0.49%	1.51%
HAYF3PV to HAYF3T	0.058869	0.023942	11.073501	100.27%	34.90%	8.83%
SHRE33 2 to WEIH33 1	0.003240	0.004606	50.162389	2.37%	0.77%	27.15%
BERR33 1 to BERRTEE	0.000137	0.000142	0.122905	2.36%	1.05%	21.02%
BAYHTEE to CROH3ACR	0.000051	0.001852	0.007629	0.15%	2.99%	0.37%

For the purposes of modelling, the EMU data was selected as the primary source as the records were timestamped, thereby providing an auditable method to ensure the data was most up to date and accurate.

The EMU system also provided the basis for the inclusion of all switches on the network. These are generally minimised for efficiency in the IPSA model (as considered of limited relevance for network planning), but essential to implement fully in the state estimation model since the status of each switch impacts on the true configuration of the system. For example, the two 33kV busbars are not physically connected in the IPSA model, whereas the true topology in EMU indicates that the buses are connected, but with an open switch. It was essential to translate the topology fully in order to produce a valid model suitable for real-time simulations.

The EMU system does not present detailed electrical parameters of transformers using the online portal; therefore, no comparison could be undertaken with IPSA transformer data.

5.6.3. Site Surveys & Central Data Records

Several transformer factory acceptance test records were obtained by PSD from the central records repository. A comparison with IPSA transformer data highlighted notable differences between tap control configurations. The differences were due to limitations of modelling in IPSA, whereby the voltage ratings of two-winding transformer are adopted from the respective nominal voltages of HV and LV connected buses. This can invalidate the winding ratios for common primary transformer where winding is rated 33/11.5kV. To accurately model these in IPSA, with a nominal LV bus voltage of 11kV, it is understood that the adjusted ratio is compensated for in each transformer impedance and tap control mechanism in the IPSA model.

Site surveys were carried out and nameplate data obtained for all primary and grid transformers in the model. Transformers were remodelled from the nameplate data and factory acceptance test records where available to ensure accuracy of the model.

5.6.4. Base Power System Model

The following element types are included in the model:

- Slack bus (132kV)
- Busbars (11kV, 33kV, 132kV)
- Lines (33kV)
- Power transformers (33/11kV, 132/33kV)
- Switches (11kV, 33kV, 132kV)
- Measurements (11kV, 33kV)

The ADMS data point identifier was captured in switches (status), power transformers (tap position) and measurements (V, I, P, Q as bus, line and transformer power injections).

There are a total of 67 busbars (including intermediary nodes where SN2.0 sensors are installed), 24 line-sections and 12 power transformers.

A total of 69 **real measurements** were included which are representative of observable points on the SCADA system, 92 **virtual measurements** (zero injection constraints) were included at busbars where there was known to be no load or generation connected, and 2 **pseudo measurements** were included to profile the PQ load at Berrington substation where there are observable SCADA points.

The 11kV bus ties between parallel transformers at each primary substation were not included in the SCADA trace. Each bus tie was observed to be operated in a normally closed state during site visits. In order to ensure that the voltage transformer (VT) measurements were representative of the nodal voltage on the secondary side of the transformer, the bus tie was opened during each transformer outage.

The plot in **Figure 5-5** presents a results file from the pandapower package which shows the topology of the Shrewsbury system.

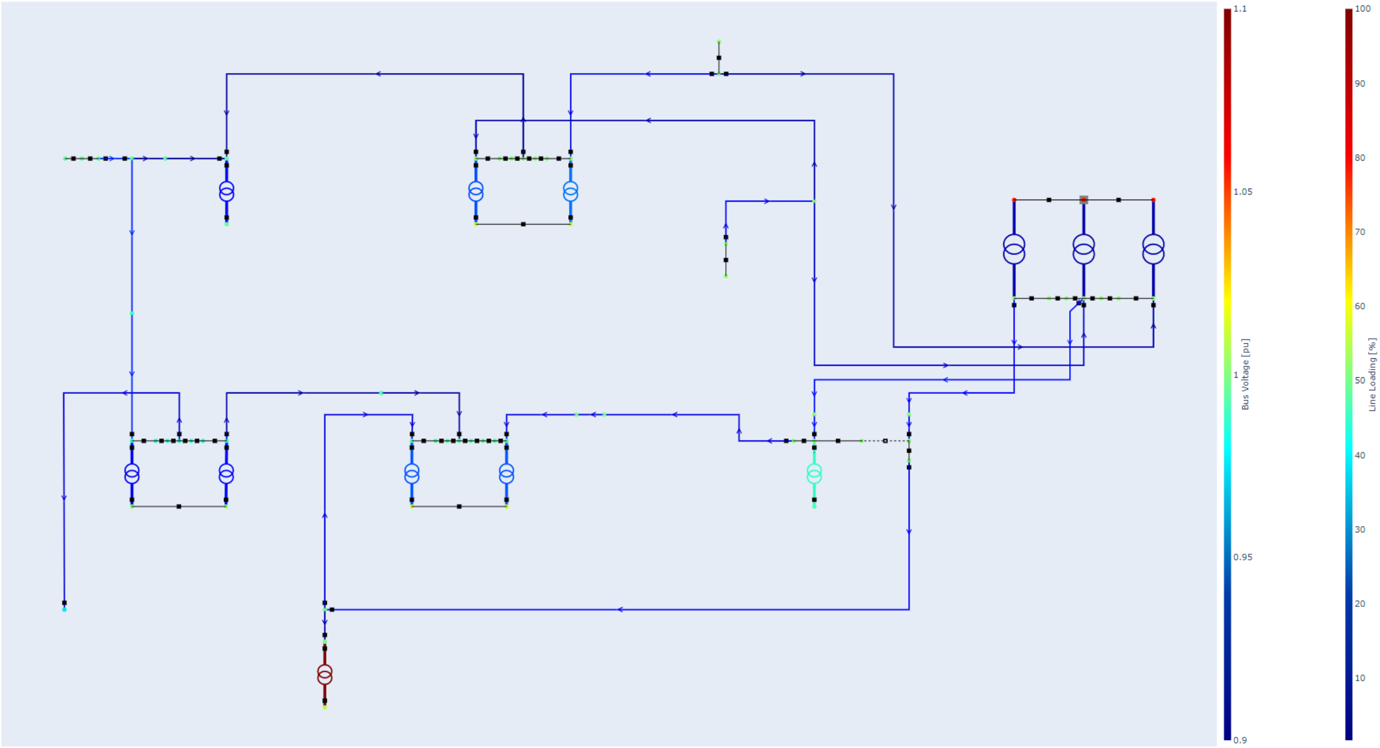

Figure 5-5: Plot of the power system impedance model

5.7. Testing the Effectiveness of the State Estimation Solution

5.7.1. Testing the Prototype Model

The base power system model was further refined offline in Python, standard deviations of measurements were adjusted to achieve convergence. Estimates of the state of the system were performed at intervals over a six-hour period, by replicating the behaviour of the SCADA system using a python script to feed data into the model.

The root mean squared error (RMSE) method was employed to provide a high-level indication of the goodness of fit of the measurement set to the state estimate.

5.7.2. Testing the Performance of the Module in iHost

iHost is Nortech's online software platform, it is widely used by UK DSOs for monitoring and control applications. iHost acts as a central data historian, allowing users to visualise data and manage, remotely, the configuration of a large population of field devices. iHost also includes powerful software engines to operate ANM schemes and other bespoke control modules. There is support for a wide variety of industry standard communications protocols, including Inter-Control Centre Communications Protocol (ICCP).

An ICCP link was established between the ADMS and iHost, within WPDs corporate IT environment, to provide real-time data from the selected group of measurements in the Shrewsbury network to iHost. This exercise was to prove that the concept of online state estimation using live network data. The testing was successfully completed after the main project trials had completed.

The prototype state estimation solution, developed in Python, was integrated into a Power Network Analyser (PNA) module for the iHost platform. This is a powerful new feature which combines power system analysis and impedance models with real-time data over the ICCP link from the ADMS. The state estimation package in the PNA was tested using the impedance model of the Shrewsbury primary network and historical time-series data from the ADMS was 'replayed' through an ICCP simulator to demonstrate the performance of the module in an offline environment.

5.7.3. Validating the Results using Smart Navigator 2.0 Data

The Smart Navigator 2.0 sensors were installed on the network to provide an independent method of validation of estimated power flow directions through circuits.

5.7.4. Stress Testing the Impedance Model with Network Reconfigurations

The model was developed using an extensive set of test data however, the data was limited to the normal running arrangement of the network. This produced expected outcomes in terms of power flows through circuits. In order to observe the performance of the model when switches were opened and power flows were reduced to zero, for example, the models were stress tested using network configurations with circuits and transformers temporarily out of service.

5.8. Results

The main project trials took place between 10th February 2021 and 8th February 2022, with the objective of testing the OHL Power Pointer solution.

5.8.1. Snapshot Simulation - Errors Across the Range of SCADA Measurements in the Model

The errors between SCADA measurements and the results of the state estimation simulation were quantified and evaluated at stages during the main trial period. The following observations were made following a simulation of the state of the network at 11:00am on 14th August 2021, when the network was operating in the normal running arrangement, except for Shrewsbury GT1 which was out-of-service. This is a "snapshot" of the system at a point in time.

Significant error between the active power values of the parallel Harlescott transformers was observed. This could indicate an error in the modelling of the impedance of the transformers, causing load to be shared between the transformers differently to the actual observed values over SCADA. All transformers were modelled using data obtained from the manufacturer's nameplate where available, however the nameplate for Harlescott T1 was not present in the substation during the site visits, therefore this transformer was modelled using impedance values from the IPSA model.

There is also a significant error between the reactive power values of the parallel Malehurst transformers and the estimated values. Both transformers were modelled using manufacturers nameplate data. During a site visit to Malehurst substation the Control room confirmed a discrepancy between the value of T1 tap position reported to PowerOn (tap position 3) and value observed locally at the tap changer (tap position 4), this is documented in more detail in the Shrewsbury site visits report[4]. A mismatch in tap position across parallel transformers would ordinarily

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[4] Title: 'OHL Power Pointer: Site Visits Report', Doc Ref: D_003939, Version: 1.0

cause issues with voltage regulation and consequently circulating reactive power flows. This is demonstrated and discussed in more detail in the report on SCADA data[5].

Both of the above cases demonstrate the effectiveness of modelling with SCADA data to validate the performance of the network and detect errors in the accuracy of transducer information and impedance data which drives the tools for planning and investment across the business.

5.8.2. 24-Hour Time-Series Simulations - Normal Network Configuration – 14th August 2021

Timeseries data captured between 11:00 14th August 2021 and 11:00 15th August 2021 was replayed through the power network analyser, state estimation simulations were performed every 120 seconds. There were no significant changes to the network configuration during this period, except for Shrewsbury GT1 which was out-of-service.

The RMSE value of the weighted error between SCADA measurements and state estimate results is presented in **Figure *5-6*** the brief peak at 19:15 on 14th August 2021 was the result of a tap step on T1 which caused a significant increase in error between the reactive power measurements recorded by SCADA and the state estimate results at both Harlescott T1 and T2. It is possible that the modelling of the impedance, or the tap changer ratio is inaccurate, which could result contradictory reactive power flows. After further investigation, records showed that the tap changing mechanism at Harlescott had been replaced in August 2021. It is plausible that the ratio changed which would have affected the model and the magnitude of reactive power flows through the parallel transformers.

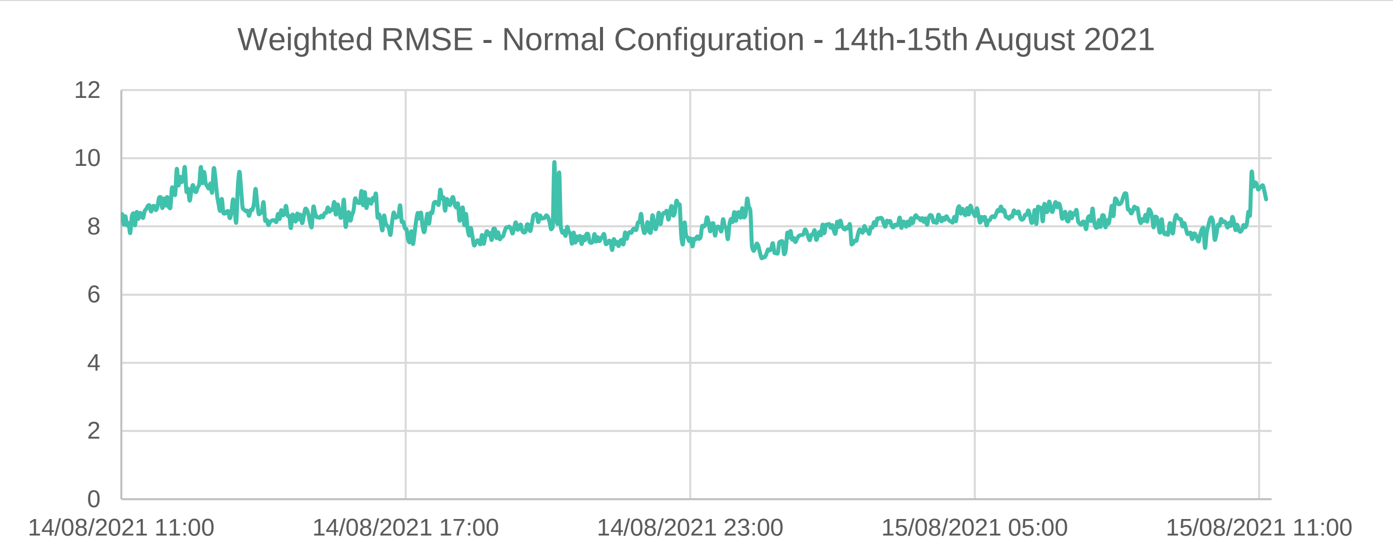

Figure 5-6: RMSE – Normal Network Configuration

The RMSE value remains relatively constant through the 24-hour period, during which over 700 simulations were performed.

The estimated power flow direction through the OHLs was compared against independent data recorded by the Smart Navigator 2.0 sensors. It was found that the power flow direction was estimated correctly at each of the ten trial

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[5] Title: 'OHL Power Pointer: SCADA TSDS Report', Doc Ref: D_003386, Version: 1.1

locations through the 24 hours period. The power flow direction derived from the state estimate results is presented in **Figure *5-7***.

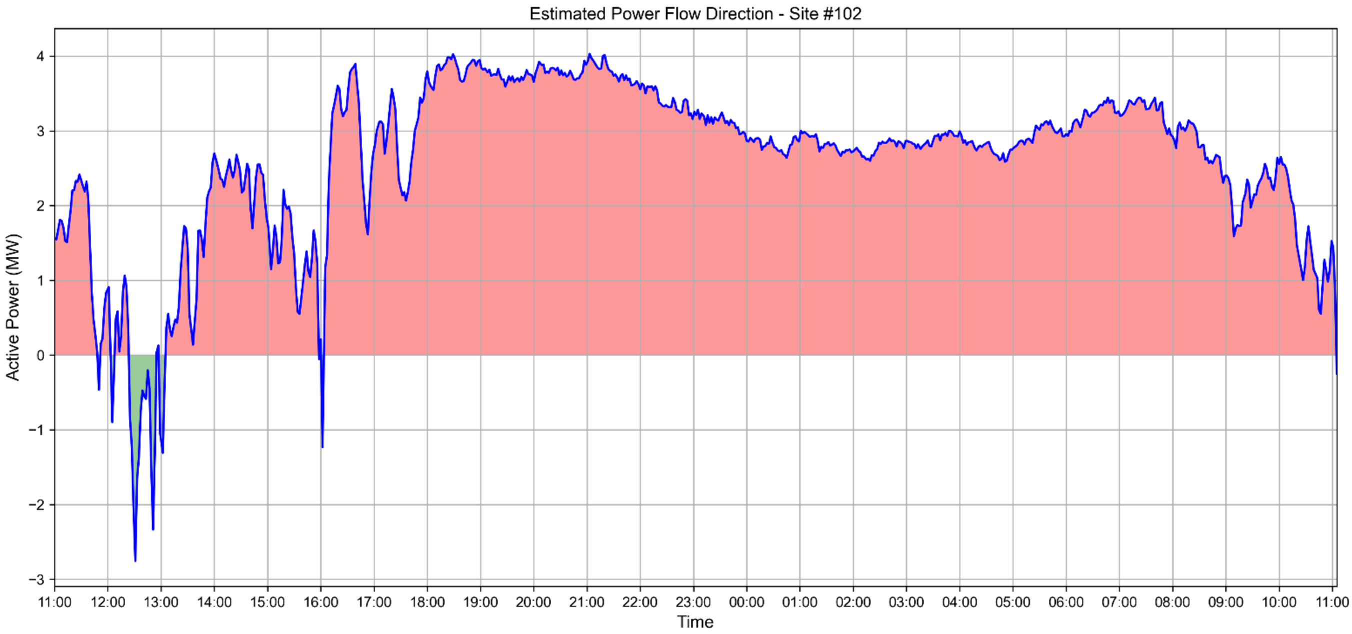

Figure 5-7: Estimated Power Flow Direction – Site #102

The power flow direction derived from the Smart Navigator 2.0 data is presented in **Figure *5-8***. There is a strong correlation between the data, with the green shaded areas indicating periods of power flowing in the reverse direction. The Smart Navigator 2.0 was configured to sample routine load data every 15 minutes, and report changes in power flow direction by exception.

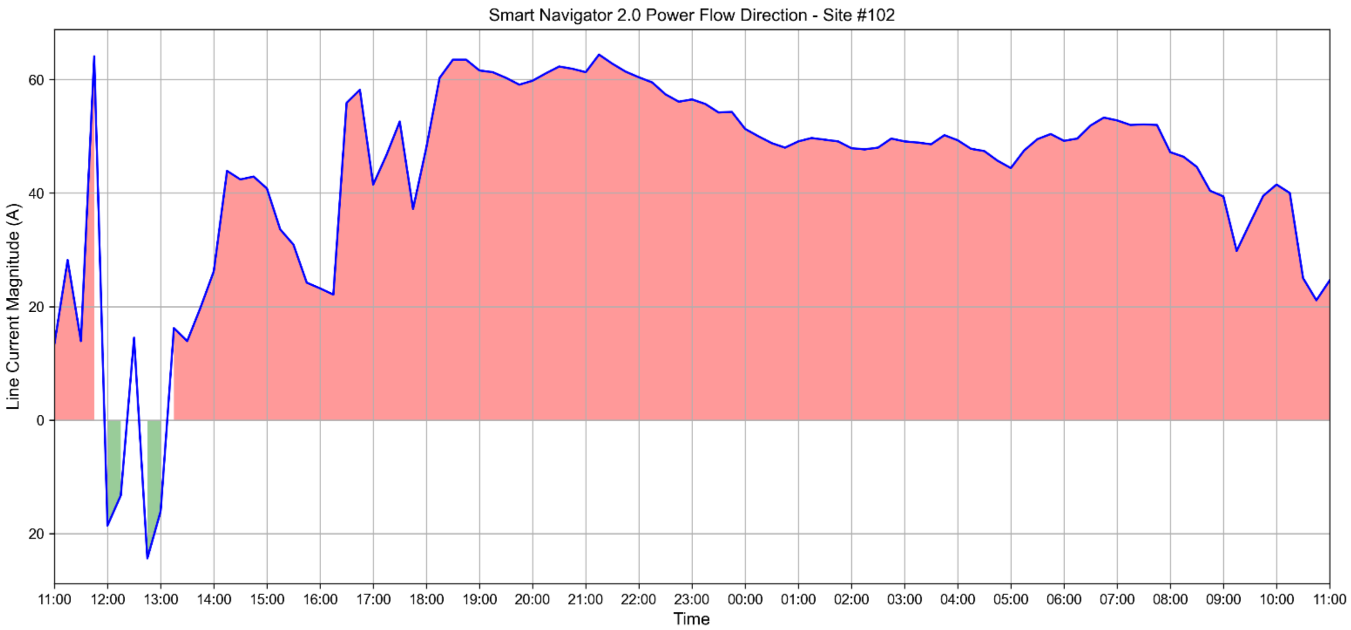

Figure 5-8: Smart Navigator 2.0 Power Flow Direction – Site #102

5.8.3. 24-Hour Time-Series Simulation - Abnormal Network Configuration – 28th September 2021

Timeseries data captured between 11:00 28th September 2021 and 11:00 29th September 2021 was selected to stress-test the model, to evaluate the response to abnormal network running arrangements.

Table 5-4 lists several major changes to the primary network configuration during the evaluation period.

Table 5-4: Abnormal Network Configuration – Switching Events

Network Reconfiguration	Time
Bayston Hill Bus Section 2	Open for duration of period
Weir Hill – Bayston Hill (Longwood) circuit	Open at the beginning of period
Bayston Hill T2	Out-of-service at the beginning of period
Weir Hill – Bayston Hill (Longwood) circuit	Returned to service at 10:03:48
Bayston Hill T2	Returned to service at 10:04:41
Bayston Hill T3	Switched out-of-service at 10:08:52
Berrington T1*	Switched out-of-service between 10:12:43 and 10:38:51
Weir Hill – Berrington circuit & Bayston Hill – Malehurst circuit & Bayston Hill Bus Section 1	Switched out-out-service at 10:16:29
Bayston Hill – Berrington circuit	Switched out-out-service at 10:27:23
Weir Hill – Berrington circuit	Returned to service at 10:30:14

* Note 11kV load transfer to Weir Hill Substation

Figure *5-9* presents the RMSE value of the errors between the SCADA measurements and the corresponding state estimate results over the period of 24 hours. The RMSE value remains relatively constant through the period, until approximately 10:00 when the switching events listed in **Table 5-4** occur. These events are evaluated below.

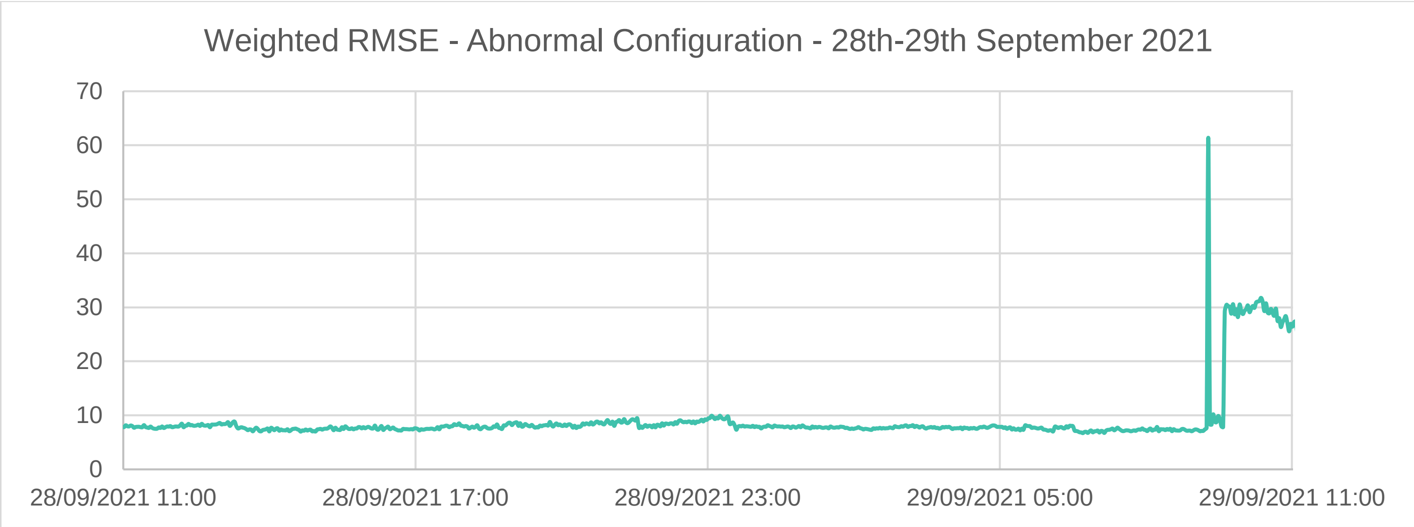

Figure 5-9: RMSE – Abnormal Network Configuration

To test the effectiveness of the model, a short time delay (> 60 seconds) was introduced to the opening of the 11kV circuit breaker at Bayston Hill T3, enabling a state estimate simulation to be performed with a conflict between measurements and network configuration. The result of this can be seen over the period of interest in chart **Figure *5-10*** as an anomalous spike in the overall RMSE value of 61.39.

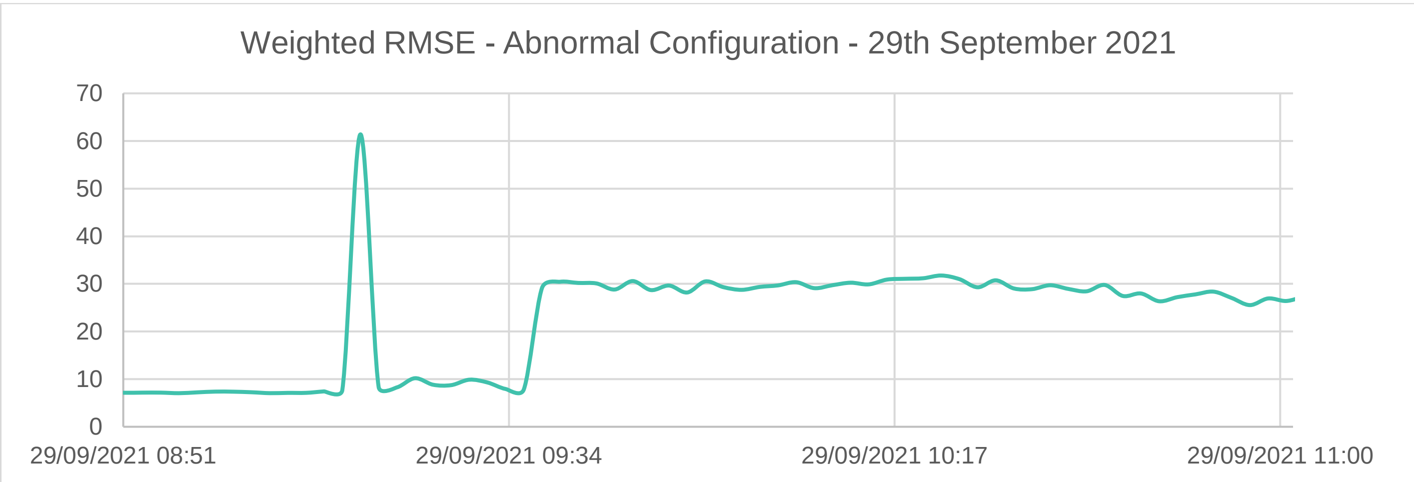

Figure 5-10: RMSE – Abnormal Network Configuration – Period of Anomaly

The individual measurement errors were examined to determine the most significant contributors (weighted error > 100) to the RMSE value, these measurements are listed in **Table 5-5**:

Table 5-5: Abnormal Network Configuration – Individual Measurement Errors

Equipment	SCADA Value	Estimated Value	Weighted Error
Shrewsbury 33kV > Weir Hill No2 > Load	173.2 A	104.7 A	-195.92
Bayston Hill 11kV > T2 > Active	-7.79 MW	-3.42 MW	218.91

Bayston Hill 11kV > T2 > Load	384.5 A	176.7 A	-198.03
Bayston Hill 11kV > T3 > Active	0 MW	-3.74 MW	-187.17
Bayston Hill 11kV > T3 > Load	0 A	193.5 A	184.34
Weir Hill 33kV > Bayston Hill/Berrington > Load	7.6 A	67.4 A	170.92
Weir Hill 33kV > Bayston Hill/Longwood > Load	128.8 A	60.2 A	-195.85

After the short time delay expires and the switch is closed, eliminating the conflict between the measurements and network topology, the model recovers and the RMSE value returns to < 9 for a short period. The RMSE error then increased to circa 30 for the remaining period. The measurement errors were re-evaluated to determine the cause of the increase in RMSE value. The following measurement is the most significant contributor (weighted error > 100) to the RMSE value:

Table 5-6: Abnormal Network Configuration – Weighted Error

Equipment	SCADA Value	Estimated Value	Weighted Error
Weir Hill 33kV > Bayston Hill/Berrington > Load	11.7 A	93.5 A	233.77

The error was caused during the first state estimate simulation after the Weir Hill – Berrington circuit had been returned to service, this caused power flows to be observed, incorrectly, through the Bayston Hill – Berrington circuit, which was out-of-service at the time. The cause of the issue is unknown. Further investigation within the conversion process to a PYPOWER model would be required. Simulations on the affected model were reperformed with switches on both sides of the branch open. This resulted in zero power flow through the affected branch and the RMSE value returned to < 10, indicating estimated results were within a satisfactory range.

5.9. iHost User-Interface

A user interface has been developed to present the results of the state estimation solution, validation data from Smart Navigator 2.0 sensors, and the SCADA measurement data into one dynamic space, to facilitate cross-comparison of results, in real-time. The user interface utilises the interactive single line diagrams feature in the iHost monitoring platform.

The user interface presents a single line diagram of the Shrewsbury primary network with power flow direction and current magnitude displayed at each key SCADA measurement location on the network. An overview of the network is presented in **Figure *5-11***.

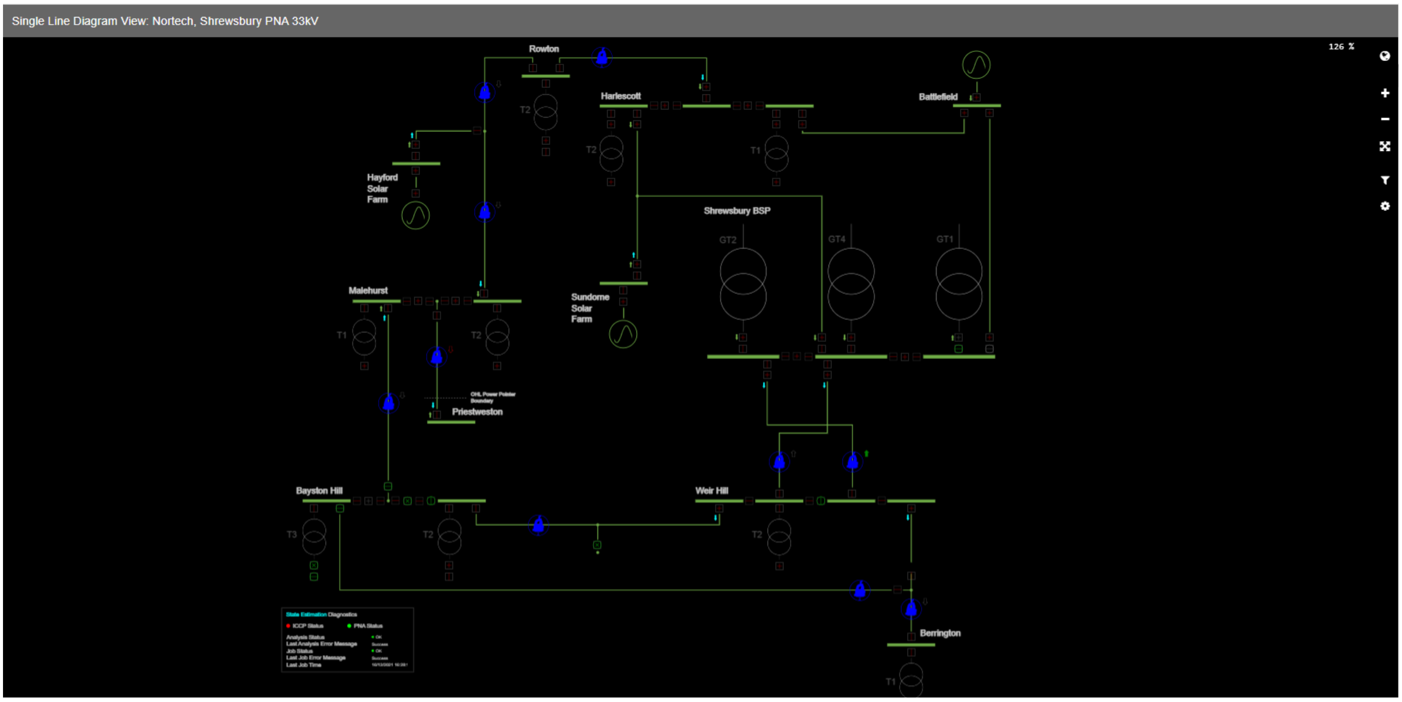

Figure 5-11: iHost User Interface – Single Line Diagram - Overview

Isolators and circuit breakers in an open state are indicated in green, those in a closed state are indicated in red. Switch symbols are dynamic and respond to changes in state in real time, as could be observed on live control room diagrams. Diagrams can be imported from common CAD format, with customised interactive symbols placed on the diagram to represent RTUs and individual analogue and binary datapoints, as presented in **Figure *5-12***.

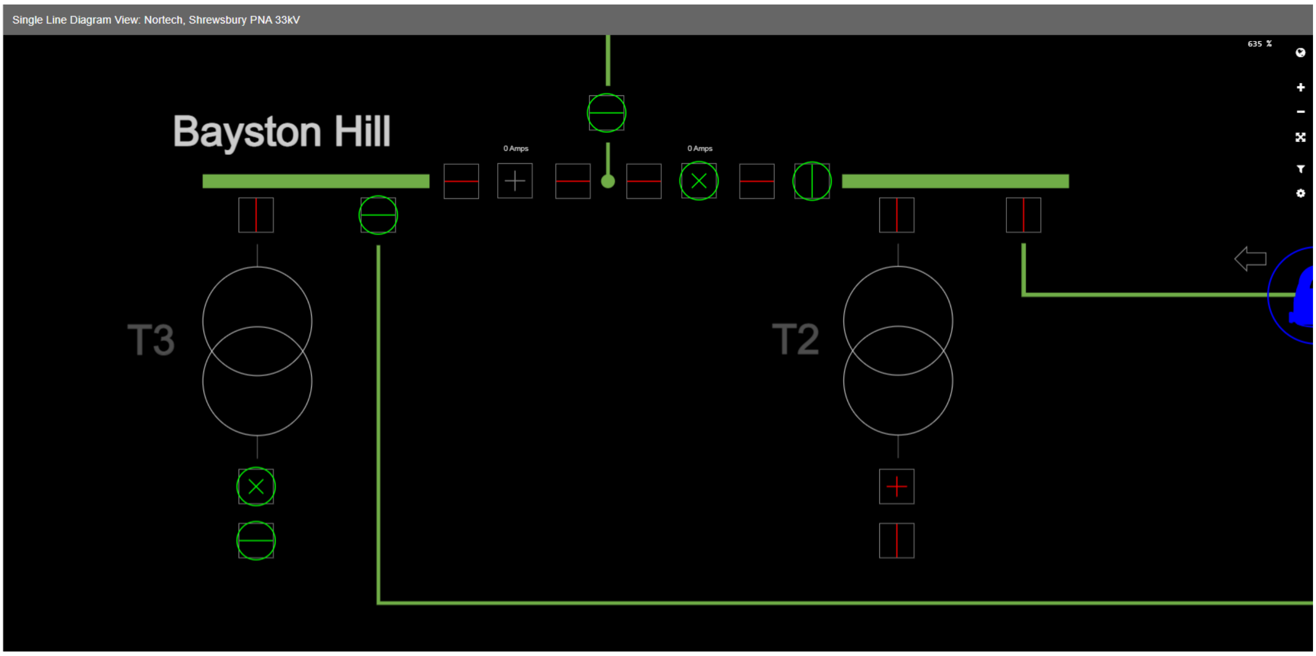

Figure 5-12: iHost User Interface – Single Line Diagram – Interactive Switches

Power flow direction along feeders is derived from active power measurements recorded at each substation and reported over SCADA, these are displayed as green arrows next to the feeder switch in **Figure *5-13***. Similarly, the analogue current magnitude measurement is displayed next to the switch. The corresponding branch results from each state estimate simulation are displayed with a cyan arrow and cyan text, beyond the feeder switch. This enables direct comparison of the results.

The blue symbol is a set of Smart Navigator 2.0 sensors installed on the OHL. The power flow direction and current magnitude analogue can be displayed to provide validation of the branch currents, independently of the measurements reported over SCADA.

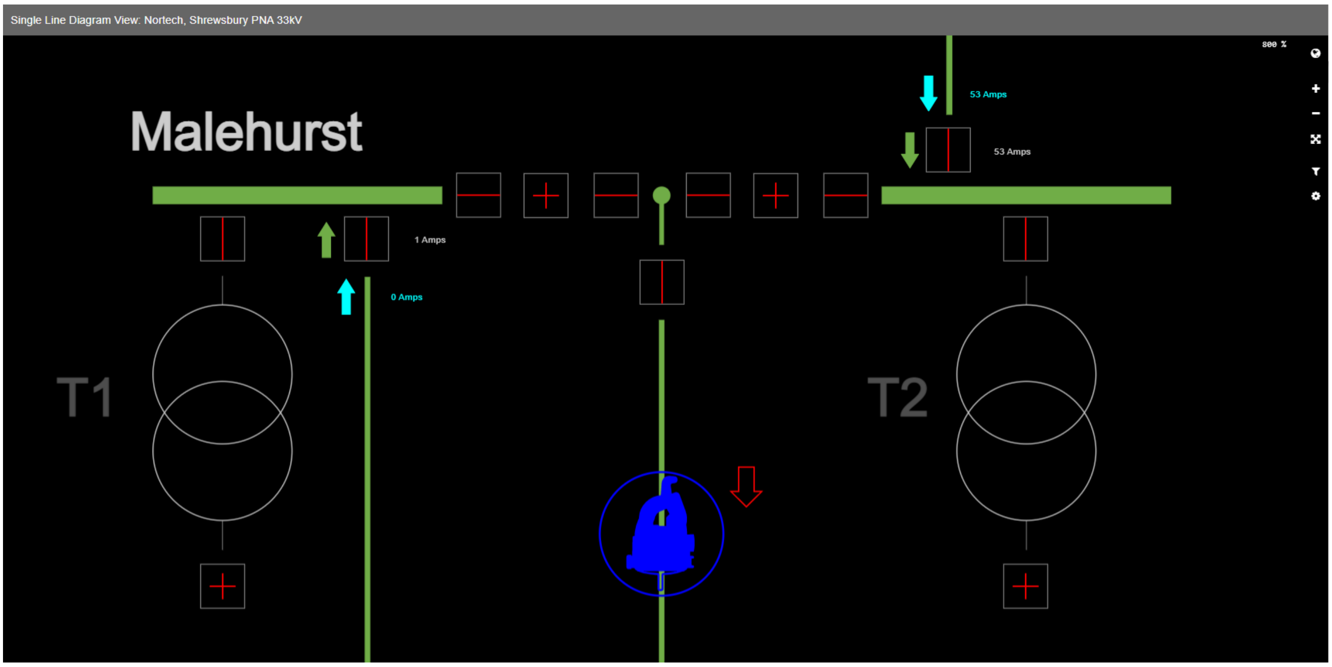

Figure 5-13: iHost User Interface – Single Line Diagram – State Estimate Results

ICCP and DNP3 simulator scripts capturing network activity can be “replayed” through the power network analyser to simulate the behaviour of the network and the state estimator retrospectively.

6. Performance Compared to Original Aims, Objectives and Success Criteria of the Method

The OHL Power Pointer project has successfully delivered and trialled a solution for real-time estimation of power flow direction through primary distribution networks.

The solution has been prototyped, developed and tested to deliver the aims of the project for UK distribution networks. The main trials have demonstrated that the solution can improve visibility of directional power flows across high-voltage distribution networks. The performance of the solution has been scrutinised with seasonal data and various network configurations, sub-reports have been prepared to document the review of the SCADA measurement data and the observations from site visits to each primary substation in the trial area network.

The online platform for obtaining real-time data from ADMS over an ICCP link was proven to be successful. The power network analyser transformed the data retuned from the ICCP link into suitable measurement inputs for the impedance model. State estimation simulations have been executed on the trial area network at 60 second intervals, over a complete 24-hour period of time-series data. If the solution were to be integrated into the control room, an assessment would need to be made to determine the performance requirements of the server to deliver state estimation for all high voltage networks, at 33kV and above. The computational performance requirements may be significant.

The case studies of normal and abnormal network configurations presented in the report have proven that the typical sensory data captured within ADMS from a 33kV network is sufficient provide visibility of directional power flows through feeders. The results of the state estimation solution have been evaluated for accuracy and compared against the input data using root mean squared error (RMSE) methods. Moreover, the results of directional power flow have been independently validated using data from Smart Navigator 2.0 sensors installed on OHLs at ten site locations across the trial area network.

A significant RMSE error was observed towards the end of the time-series simulation during an abnormal network running arrangement, this was evaluated and found to be an error with out-of-service status of a line in the impedance model. This anomaly would require deeper investigation prior to adoption of the solution.

The limited observability of the distribution network is a barrier for deployment of the solution at lower voltage levels, such as 11kV systems. Most 11kV systems are insufficiently instrumented to deliver a converging solution within the models. At higher distribution voltages, where feeders are more widely instrumented with a combination of directional and non-directional sensors, state estimation offers an opportunity to provide improved network visibility.

The analysis undertaken for this method has been completed offline, using datasets captured historically and then ‘replayed’ through an ICCP simulator to evaluate the performance of the solution. The computational performance of a system should be considered before deployment of any solution to a control room environment.

In accordance with the success criteria, directional power flow state estimation has been determined correctly at ten sites across the 33kV network.

7. Potential for New Learning

The solution has been trialled in an offline environment, using data captured from the live operational network. Significant learning has been obtained through the project:

1. Distribution system state estimation has been demonstrated using data from the live ADMS system to deliver representation of power flow direction through feeders equipped with non-directional sensors.
2. A dashboard has been developed and deployed to the iHost system which provides a real-time view of directional power flows through feeders derived from the results of state estimation. The dashboard presents indication of success of the simulation, and comparison against original SCADA measurements where available.
3. Detailed analysis into measurement data recoded by substation transducers and reported over SCADA from across the primary network has been completed, this has provided valuable learning into the application of directional power flow convention in TP6F/1. Learning has also been delivered on the range of configurations applied locally at transducers, with a review of deadbanding of data and frequency of reporting delivered.
4. An ICCP link between ADMS and iHost has been established, facilitating the transfer of live analogue and binary data to iHost to enable state estimation simulations to be performed.
5. A review of the frequency and granularity of time-series SCADA data recorded at primary substations has been undertaken, with recommendations given on the findings in a separate report.
6. Smart Navigator 2.0 sensors installed on OHLs in the trial area have delivered directional power flow information to independently validate the estimated power flow direction through feeders.

The following opportunities for new learning could be considered:

1. In an ideal system 100% observability of the network would be achieved, providing the state variables (voltage magnitudes and angles) at each node, synchronised and in real-time to input into the regression model. This approach can be likened to the transmission network with the use of phasor measurement units (PMUs). Whilst the installation of PMUs on the distribution would likely be cost-prohibitive, in an isolated study it could expose the weaknesses in present levels of observability and guide DSOs on optimal sensor placement and sensor configuration to balance and optimise observability against cost for the purposes of distribution system state estimation.
2. The impedance models could be derived from the Integrated Network Model (INM), this would reduce the steps required to condition the data to establish a network model, which is often derived from multiple data sources and requires resources of multiple departments within the business. It would also enable any changes in the topology of the network to be updated frequently, improving maintainability.
3. Different trial areas could be considered to test the effectiveness of the state estimation method in networks where the penetration of modern directional transducers in substations is lower.
4. The solution could be deployed to West Midlands iHost system under a live trail period, should the solution be adopted as business-as-usual.

8. Conclusions of the Method

In our RIIO-ED1 business plan and DSO Transition Strategy, WPD has made the commitment to improve visibility of distribution network power flows.

Ofgem's RIIO-ED2 methodology draws on the principle of a smart and flexibly energy system. Ofgem is clear that the use of data lies at the heart of the energy system transition, and that a shared understanding of what is happening to power flows and the status of network infrastructure will be key enablers for creative solutions to future challenges.

WPD's Distribution System Operability Framework identified the main drivers for increased monitoring and control:

- Making informed decisions about switching and network operation;
- Ratings of transformers, as they are dependent on power-flow direction;
- Running real-time analysis like Active Network Management (ANM) will necessitate this level of detail to ensure the control systems can represent the network accurately; and
- Enabling the network to be correctly represented in power system software as this is used to determine reinforcement requirements and network constraints.

The directional power flow state estimation method directly responds to these challenges by combining monitoring and modelling into a low-cost solution for real-time power flow direction visibility. Extensive analysis and evaluation of the network modelling data and the operational data reported over SCADA has been undertaken to ensure that the network is correctly represented in the power system software. These recommendations are made in supplementary reports.

The Power Network Analyser (PNA) has been developed and deployed as a new feature of the iHost monitoring platform. The PNA integrates the open-source pandapower power systems analysis package into iHost and supports the read/write interface of SCADA measurements to high-accuracy impedance models, which have been derived and verified from multiple data sources. Pandapower comprises a module for performing state estimation simulations on the impedance model. The PNA extracts the results from the models and presents the data on single line diagrams, a snapshot of the power system model in pandapower schematic format is captured for each simulation for offline analysis.

State estimation simulations were performed for several snapshots of the system state, and the individual errors between the SCADA measurements and the results of the state estimate solution were assessed. This study indicated weaknesses in the state estimation solution, where large sections of the network were instrumented with non-directional sensors. The study also revealed issues with the reactive power flows through Malehurst substation transformers, caused by the inaccuracy of the reported tap position over SCADA.

An Inter-Control Centre Communications Protocol (ICCP) link was established between the live ADMS and the iHost monitoring platform (within the corporate IT environment) to capture routine datasets for testing the models through various network configurations. The datasets contained over 400 binary and analogue datapoints and captured over 1 million events on the trial area network during each 24-hour period.

Extensive testing was carried out using the time-series datasets over several 24-hour periods to evaluate the overall root mean squared error (RMSE) between the SCADA measurements and the estimated system state. Simulations were performed at 2-minute intervals through the period and the RMSE was calculated from the individual errors. The error was consistent across the period when the network remained configured in the normal running arrangement.

The time-series datasets were examined to obtain a period where the control room had undertaken significant network reconfiguration through the switching of transformers and primary circuits. Simulations were performed on the selected dataset to stress-test the models by observing the response to routine outages of primary equipment. The model responded satisfactorily to the initial reconfiguration of the network, and subsequent switching events, the RMSE remained consistent with the normal running arrangement, however the switching of a particular circuit caused power flows to be observed in an out-of-service circuit. The reason for this anomaly could not be identified but was indicated by a significant increase in the RMSE value.

An attempt was made to disrupt the model by inserting an artificial delay in the switching of a circuit breaker to demonstrate how the model would respond to a conflict between the network topology and analogue measurements. The RMSE of the measurements significantly increased, a review of the individual measurement errors guided the user to the area of the error in the network topology.

Independent validation of the direction of power flows through OHL circuits was performed by Smart Navigator 2.0 sensors which were installed on each OHL circuit on the Shrewsbury 33kV primary network under the main field trials.

On 26th November 2021 the topology of the network changed, to include an additional 50A of unidentified load on the system at Weir Hill primary substation, this caused expected disruption to the model. It is recommended that due consideration is given to the significant effort and resource required to prepare the models and maintain the models. It is likely that once a holistic modelling solution becomes available, such as the Integrated Network Model, which may combine impedance data, network topology and SCADA measurement identifiers into one distributable model, the directional power flow state estimation model could become a low-cost solution for network observability

Therefore, before considering the deployment of the state estimation solution to the high voltage network, the following key points should be considered with respect to the observability of the distribution system:

1. A systematic review of conventional measurements at substations should be undertaken to ensure polarity of directional transducers is correct in accordance with WPD Standard Technique: TP6F.
2. Policies or technical guidance should be updated to define minimum electrical parameters for analogue transducers installed on the network, this should include (but not limited to) the following:
    a. Defined minimum deadband tolerances for efficient use of communication bandwidth,
    b. Defined minimum sampling frequency to ensure time-bound integrity of data,
    c. Defined maximum suppression period, to ensure integrity of the transducer where no deadband excursions are reported for an extended duration.
3. Sensors should be checked periodically to ensure that the quantity or state recorded locally at the sensor is communicated accurately over the SCADA system to ADMS.

It is concluded that the state estimation solution could be a powerful tool to support the visibility of directional power flows through distribution networks. Prior to the method being adopted as business-as-usual any anomalous results should be investigated and further testing should be carried out to determine the suitability and applicability to alternative trial areas.

Glossary

Abbreviation	Term
ADMS	Advanced Distribution Management System
APN	Access Point Name
ANM	Active network Management
CI	Customer Interruptions
CML	Customer Minutes Lost
DNO	Distribution Network Operator
DSO	Distribution System Operator
FPI	Fault Passage Indicator
HV	High Voltage
ICCP	Inter-Control Centre Protocol
MW	Megawatt
MVAr	Mega volt-ampere
NIA	Network Innovation Allowance
OHL	Overhead Line
SCADA	Supervisory Control and Data Acquisition
SN2.0	Smart Navigator 2.0
RTU	Remote Telemetry Unit
TSDS	Time Series Data Store
WPD	Western Power Distribution

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