Project FALCON

Dynamic Asset Rating Distribution Transformers

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FALCON

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Executive Summary

With the growth in all types of low carbon generation, such as wind and solar photovoltaic (PV), and the introduction of new demand technologies such as electric vehicles (EVs) and heat pumps, Western Power Distribution's (WPD) electricity network is expected to see unprecedented swings between peaks and troughs of energy usage in localised areas.

WPD's Project FALCON has examined a range of innovative alternatives to conventional reinforcement that might be used to mitigate the impact of such energy usage. This was undertaken firstly through physically trialling four engineering and two commercial techniques. Secondly, innovative alternatives where examined through building and operating a software tool. This tool: models the real network under a range of energy use scenarios out to 2050; identifies network constraints that arise over time; employs the studied techniques to mitigate constraints; and assesses impact and benefit.

This report is one of a series describing the engineering technique trials, and focuses on Dynamic Asset Rating (DAR) of Distribution transformers within networks. DAR is the process of using prevailing weather conditions to run an asset at a rating potentially higher than its name plate to take advantage of for example, cold temperatures. This has similarities with using seasonal ratings, but DAR is more sophisticated. Within the project, dynamic ratings were considered as an alternative to conventional reinforcement, the traditional engineering remedy to network constraints.

The technique trial involved installation of load and temperature monitoring at 16 Distribution substation sites to provide data to assess Distribution transformer dynamic asset ratings. Provision of dynamic asset ratings requires the formulation of a thermal model of the assets, and a process for assessing current carrying potential within prescribed thermal limits.

The thermal models initially used (populated with common generic parameter values) did not provide a sufficient correlation, on an individual transformer basis, to key measured values. This was due to very significant construction differences across the range of transformers used in the trial.

A novel approach to developing transformer specific thermal model parameter values was developed by the project that led to thermal models with very good correlation to key measured values, across 12 months of monitoring. These thermal models were then used as the basis for projecting "of the moment" dynamic asset ratings.

In addition to assessing "of the moment" dynamic asset ratings, the project also developed an approach to assessing forward dynamic ratings, based on weather forecasts. This addressed the key operational issue of what the rating may be over a forthcoming period.

Key findings from the technique trial are:

- Outdoor transformers ampacity assessments, using predicted weather, result in a gain in peak ampacity of up to ~10% with a mean of up to 5% for a large proportion of the winter months. This compares to peak "of the moment" ampacity gains of up to ~15% based on measured conditions at the time (this because an additional factor to allow for weather predictions is included);
- Well ventilated indoor transformers show calculated ampacity gains in the winter months of up to 3% for around 70% of the time. Indoor transformers with no ventilation may have no benefits at all. From a planning perspective the housing type should be considered within any DAR application; and
- The cyclic rating is based on a fixed percentage of the (sustained) name plate rating. Therefore an increase in the sustained dynamic rating should result in the same percentage increase in cyclic and emergency ratings. However further work is required to prove this.

Recommendations resulting from this report are:

- The technique trial indicates that there is potential benefit from the deployment of Distribution transformer DAR, to reassess thermal capacity on a case by case basis;
- Such potential could be targeted at existing transformers that are approaching thermal/load limits, involve limited installation of temperature & load monitoring, tuning of transformer specific models, and assessment of potential to run at higher than nominal ratings;
- This approach could include addressing the issue of risk management with respect to transformer life. With this method, there will be a small number of days were the ambient temperatures are materially above seasonal averages, and accelerated (vs par) life usage could occur on such days. It is recommended that further work should initially focus on a candidate outdoor secondary transformer to trial actual solution provision; and
- Dynamic asset rating of indoor secondary transformers also appears to offer some potential, though the potential improvements would arise from additional ventilation. Again this potential opportunity could be taken by investigating specific examples of secondary substations approaching thermal/load limits, installing simple monitoring and assessment equipment, and specifically look at improving ventilation as a means of enhancing available capacity.

SECTION 1

Project Introduction[1]

[1] This introduction to Project FALCON (Flexible Approaches for Low Carbon Optimised Networks) is common to all the engineering technique Final Reports.

With the growth in all types of low carbon generation, such as wind and solar photovoltaic (PV), coupled with the introduction of new technologies such as electric vehicles (EVs) and heat pumps, Western Power Distribution's (WPD) electricity network is expected to see unprecedented swings between peaks and troughs of energy usage in localised areas. This expected change in nature of customer demand and electricity generation will have an impact on networks nationwide and globally, and provides a significant challenge to WPD, and all electricity network operators.

Part of WPDs approach to this challenge has been look at new flexible ways to design, optimise and manage the network into the future. Project FALCON (Flexible Approaches for Low Carbon Optimised Networks) is designed to help answer these questions and is focussed on the Milton Keynes area 11kV network.

In the past network operators have used conventional reinforcement to deal with constraints but it can sometimes be over engineered to meet only peak demands; it can also be expensive, disruptive and inefficient. In project FALCON, WPD and its partners are trialling alternative techniques and will assess if they are more flexible, cost effective, quicker to deploy and more effective at managing these new demand requirements than conventional reinforcement. The techniques are:

- Dynamic Asset Ratings – Using prevailing weather conditions to run an asset at a rating potentially higher than its name plate to take advantage of for example, cold temperatures.
- Automatic load transfer – load is redistributed between 11kV feeders.
- Implementation and operation of a meshed (interconnected) 11kV network.
- Deployment of new battery technologies allow the flow of power on the network to be changed as the battery is charged or discharged.
- Demand Response services - the use of localised smaller generation and load reduction services that can be provided in the event of a local constraint.

Central to the project is the Scenario Investment Model (SIM) - a new piece of software being developed to assist long term network planning. The SIM performs load flow analysis for the network for 48 half-hourly periods during the day for different days of the week and different seasons of the year. Predicted load patterns extend as far as 2050. A network planner will operate the SIM to help with planning based on load forecasting. When a network planner is running the SIM and a voltage or thermal problem is found, the SIM will select the techniques that could help resolve the problem and determine how they could be applied to the network. The best solution can be selected using a weighted metric that combines elements such as installation and operating costs, network performance, losses and disruption to customers.

This report presents the work undertaken through project FALCON on the dynamic asset rating of Distribution transformers on the 11kV network.

SECTION 2

Introduction to Technique Trial

2.1 Presentation of Learning

Throughout the document, key learning is presented in a box as follows:

LP #	Brief description of learning.

Each piece of trials feedback is referenced as a Learning Point (LP) with a unique number.

2.2 General Overview of Dynamic Asset Rating Technique

Traditionally overhead lines (OHL), transformers and cables have been assigned capacity ratings intended to ensure operation within safe operating limits, and allow assets to achieve nominal service life. These ratings may be fixed for specific periods of time (e.g. summer and winter ratings of OHLs), or may relate to a load that has a daily cyclic characteristic (e.g. transformer and cables). However, these ratings essentially do not take the current/present environmental conditions into account, nor do they take into account the current/present thermal state of the asset. In this respect, the ratings are regarded as “static” – not responsive to the current thermal or environmental conditions of the asset. These “static” ratings make assumptions about prevailing environmental conditions (air temperature, wind speed and direction etc.) and set a limit on electrical current passing through the asset such that safety and service life of the assets are maintained.

Dynamic Asset Rating (DAR) seeks to allow operation of these assets beyond the static limits, through dynamic assessment of the asset’s actual thermal state (derived from preceding operating circumstances), and the present environmental factors. Whilst seeking to increase capacity, this technique can also identify periods where the dynamic rating is calculated as less than the static rating, thereby potentially reducing the asset’s rating under some circumstances. The dynamic rating is often referred to as ‘ampacity’ – the maximum current that can pass through an asset before the temperature limits are reached. The ampacity may be defined as either ‘sustained’ or ‘cyclic’ where sustained refers to the asset seeing a steady load, whereas as cyclic refers to the asset seeing an ever-changing load following a set pattern.

This technique seeks to properly increase the capacity of assets during peak usage periods to alleviate constraints, whilst maintaining safety and managing impact on asset life. DAR can also constrain use of assets (e.g. generation) when environmental/load conditions are not favourable.

2.3 Overview of Transformer DAR Technique

The practice of using transformer dynamic asset rating is to assess transformer oil and winding temperatures (the prevailing thermal state of the asset) and to estimate the additional load that the transformer could carry and still remain within a stated highest winding temperature (known as the hot-spot), for a given ambient air temperature.

For a given transformer, the temperature of the insulation (limiting factor for operation) is governed by the heating effect of current flowing through the windings, and the cooling of the transformer oil. The temperature of the oil (and cooling effect on the insulation) is governed by the ambient air temperature, the heating from load current, and cooling due the cooling arrangement of the transformer.

It should be noted that the hot-spot temperature exists somewhere around the windings but is difficult to exactly locate. The hot-spot location and temperature is a function of transformer design and cooling functionality, ambient air temperature, oil temperature, and winding losses amongst other parameters. This makes the hot-spot temperature complex to assess with any degree of certainty. Although direct measurement methods do exist, they can only be applied to newly built units, for which the manufacturer can install bespoke technically advanced measuring facilities (for instance sensors with fibre-optic cables). Therefore, the hot-spot temperature may only be computed for most applications.

To establish a dynamic asset rating for a transformer, two elements are necessary:

- A thermal model of the transformer is required to assess prevailing transformer oil and winding temperature given previous load and ambient air temperatures; and
- A process is required that will iteratively increase modelled load current and calculate consequential hot-spot temperature (using the thermal model) until the limiting hot-spot temperature is reached. The load current that results in this limiting hot-spot temperature is the dynamic asset rating, or ampacity of the transformer. This can be either sustained or cyclic.

Fundamental to this assessment of ampacity is the thermal model of the asset. According to industry standards (Section 4.1), the hot-spot temperature is calculated as:

$$\theta_h = \theta_a + \Delta\theta_o + \Delta\theta_h \qquad \text{(Equation 1)}$$

Where:

θ_h is the hot − spot temperature;

θ_a is the ambient air temperature;

$\Delta\theta_o$ is the rise in top − oil temperature above ambient; and

$\Delta\theta_h$ is the rise in hotspot temperature above top − oil temperature.

From Equation 1 it is clear that ambient air temperature is fundamental to hot spot temperature.

An outline of the IEC 60076 calculation of hot-spot temperature is shown in Figure 1. Within this, it can be seen that there are:

- two process inputs - K (the transformer’s per unit load current) and Θ_a (the ambient air temperature)[2]; and

[2] Figure 1 also shows an optional input of a direct input of the transformer top oil temperature Θ_o.

- A number of model parameters (e.g. $\Delta\Theta_{or}$, R, x etc.) that are used within the calculation.

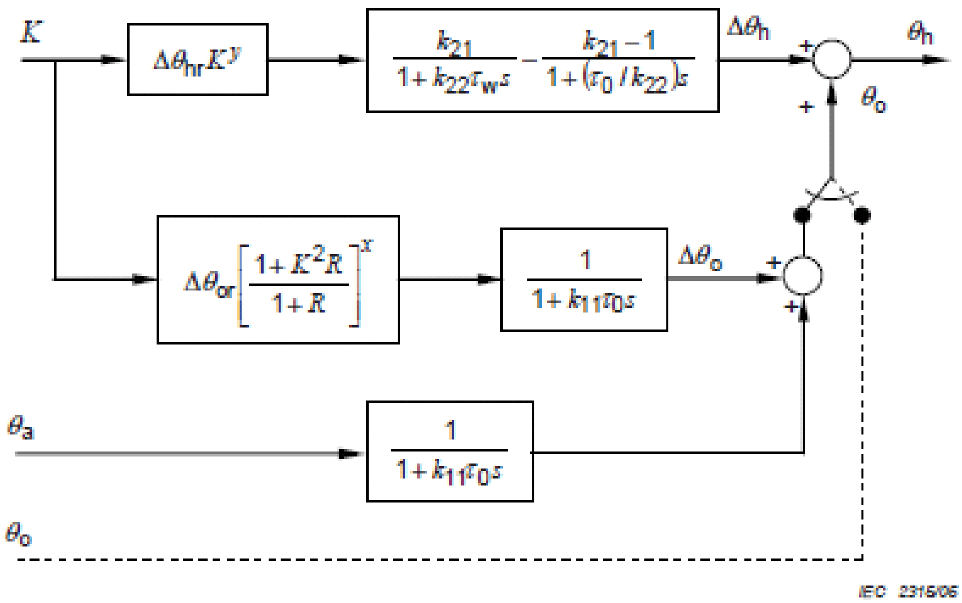


Figure 1: Outline of the IEC 60076 calculation of hot-spot temperature [1]

Further details of the thermal model and the parameter values used within the trial are presented in Section 4.1 and in the FALCON DAR Primary transformer report.

The potential benefits that may be expected when considering dynamic asset rating of transformers within an electricity distribution network include:

- Deferring network reinforcement by allowing more current to pass through the transformer when the weather conditions are favourable to cooling without adversely affecting life;
- Assisting with ratings when highly fluctuating loads are connected (i.e. average rate of loss-of-life of the transformers are still within specified limits even if temporarily the transformer is overloaded compared to nameplate rating).

However, the accuracy of the dynamic asset rating calculation is very dependent on a number of key points:

- The models use mathematical constants within their calculated analysis such as oil and winding thermal time constants, and full load and no load losses. In order to ensure the accuracy of the analysis these constant values need to be confirmed.
- Good operating data (e.g. ambient air temperature, and accurate loading) is key to estimating the hot-spot temperatures. This has two aspects, one is the availability and accuracy of the data and the second is the time periods with which the data is measured.

Appropriate validation needs to occur between what the modelled temperatures and the equivalent measured temperatures, to establish confidence in the modelling fundamental to the technique. As previously discussed, the hot-spot of the transformers within the trial are not directly measurable, therefore confidence in the thermal modelling and estimation of ampacities is dependent on:

- Establishing appropriate modelling parameter values that result in a sufficient coincidence of modelled and measured values of top oil temperature; and
- Robust assumptions about the parameter values used to estimate the rise in hotspot temperature above top-oil temperature.

Minimum basic data requirements to allow a thermal model to be constructed and validated, and for dynamic asset rating values to be estimated are:

- Ambient air temperature (the indoor temperature for housed transformers, external air temperature for outdoor substations)
- Transformer current
- Top oil temperature (for validation)

2.4 Overview of approach to the technique trial

The high-level objectives of the technique trials (the deployment and trialling of techniques) can be generically summarised as to:

- Understand the implementation of the alternative techniques;
- Understand operational capability of the alternative techniques;
- Inform changes to the modelling of the intervention techniques within the SIM;
- Trial an innovative communications network to support the techniques; and
- Capture knowledge and disseminate learning.

Learning Objectives originally associated with this technique are listed in Appendix B.

The overall process approach to the technique trial is shown in Figure 2

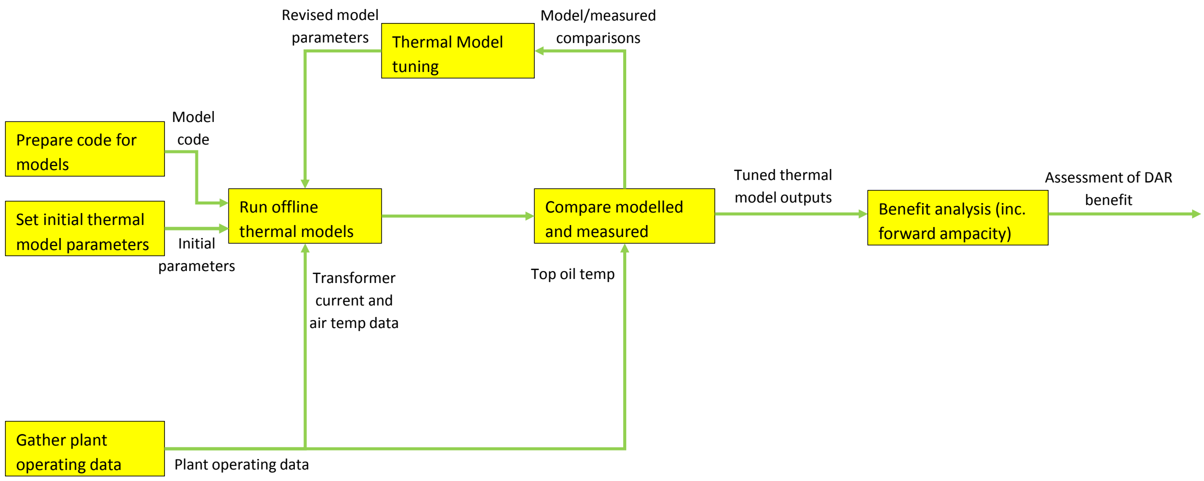


Figure 2: overall process approach to the technique trial

SECTION 3

Design, Construction and Commissioning

This technique trial sought to provide the data outlined in section 2.3 for a range of transformers to allow an offline thermal model to be created and validated, and for transformer dynamic asset rating values to be estimated.

3.1 Overview of selected sites

The initial intentions were to collect data from up to 20 sites, with the recognition that most benefit would be gained from assessing transformers that were operating close to their rated capacity, and that examples were required of:

- Indoor Substations
- Outdoor Substations
- GRP Substations (substations enclosed in Glass Reinforced Plastic housing).

Sites were selected from the 160 Distribution substations in the Milton Keynes area that had been previously identified for load monitoring as part of the FALCON load estimation work package. The selected sites are shown in Table 1.

The sites selected were based on Central Networks load data recorded in 2010/2011, this being best information available at the start of the project. It should be noted that maximum demand (MD) values are calculated from readings of the maximum current for each transformer phase over the 6 months preceding the reading date. The recording devices are thermal maximum demand indicators fitted at each substation and the values recorded for each phase may have occurred at different times or during abnormal feeding conditions. Therefore these calculated values can only be considered as rough guide. An alternative method of assessing transformer loads based on customer meter readings was considered but in the Milton Keynes area the data available was not reliable.

The Transformer cyclic ratings given in figure 1 were those applied by Central Networks in 2010/2011. In general an outdoor transformer was given a cyclic rating of 140% of nameplate rating and an indoor or enclosed transformer a cyclic rating 130% (WPD Standard Technique SD7C). However the individual conditions at separate substations may have resulted in the selection of a different cyclic rating.

Site ref.	Site name	Maximum Demand 3 Phase (kVA)	Rating (KVA)	Transformer Cyclic Rating	Maximum Demand Indicator		Location Brick =B GRP =G OD =O
					%Load	Date	
1	UNIT 32 BLUNDELLS RD BRADVILLE	750	500[3]	700	150	05/08/2010	G
2	GRANVILLS SQUARE	320	315	441	102	06/07/2011	G
3	SHROPSHIRE COURT	325	315	441	103	20/09/2011	B
4	RAINSBOROUGH GIFFARD PARK	563	500	700	113	22/06/2011	G
5	LAKES LANE NEWPORT PAGNELL	375	200	260	188	07/07/2011	G
6	THE LINX BLETCHLEY	475	500	700	95	18/08/2011	O
7	WESTMINSTER DRIVE BLETCHLEY	475	500	700	95	24/08/2011	B
8	COTTINGHAM GROVE BLETCHLEY	488	500	700	98	19/08/2011	O
9	ANGUS DRIVE BLETCHLEY	500	500	700	100	24/08/2011	B
10	GLAZIER DRIVE NEATH HILL	320	315	441	102	14/09/2011	B
11	MIDDLESEX DRIVE BLETCHLEY.	700	500	700	140	24/08/2011	B
12	BUCKINGHAM GATE EAGLESTONE	333	500	441	106	07/10/2011	B
13	BARNFIELD DR. WEST NETHERFIELD	376	315	441	119	10/08/2011	O/G [4]
14	THORNEYCROFT LANE DOWNHEAD PARK	515	500	700	103	14/09/2011	B
15	RICKLEY LANE BLETCHLEY	800	500	700	160	24/08/2011	B
16	PELHAM PLACE DOWNSBARN	745	500	700	149	14/09/2011	O

Table 1: Distribution Transformer monitoring sites

3.2 Overview of as-installed equipment

Each distribution transformer was monitored for load current, ambient air temperature and top oil temperature (to validate the thermal model). Figure 3 provides a schematic overview of the measurement and data collection arrangement.

[3] Subsequently changed to an 800kVA unit before start of trial, and feeding arrangements to the connected customer also changed throughout the trial reducing load through this transformer.

[4] Outdoor transformer with GRP housing

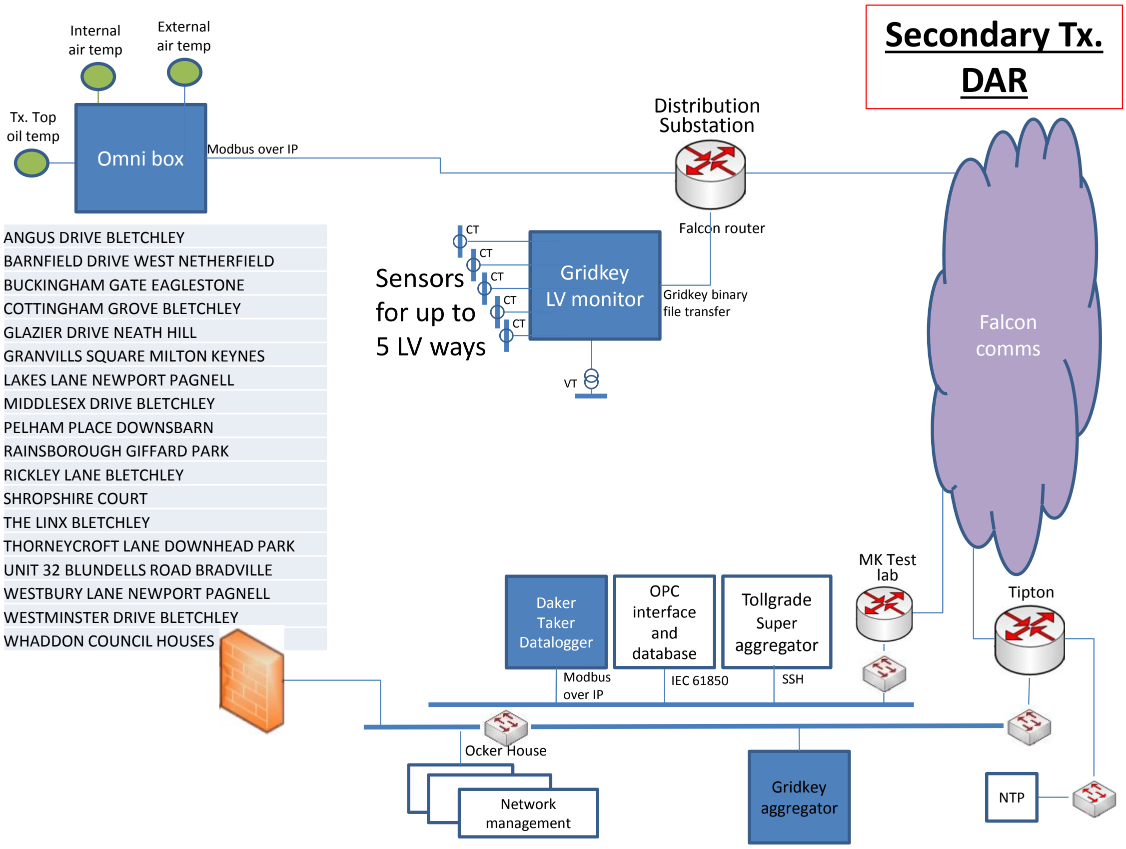


Figure 3 : Schematic of installed Distribution transformer DAR scheme

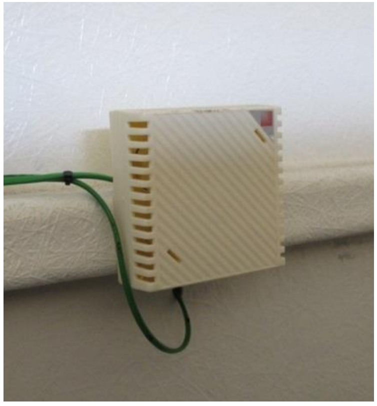
In summary, the installed equipment comprises of:

- Three thermocouples: providing one measurement of indoor air temperature (if applicable); one measurement of external air temperature; and a minimum of one measurement of top oil temperature[5];
- One Exemys RME1-TC (thermocouple to Ethernet) acquisition module – commonly referred to as the "Omni-box", communicating via Modbus over the FALCON IP network with the central dataTaker DT80 data-logger that samples and stores a range of DAR related measurements; and
- One Gridkey LV monitor, communicating with the central Gridkey data aggregator/store over the FALCON IP network;

[5] One site provided two top oil readings

Initial Unshielded outdoor

Shielded outdoor



Indoor

Figure 4 : Illustration of air temperature sensors, and positioning

Placement of the external air temperature sensors was further considered following review of initial data. In general, air temperature sensors were repositioned such that they were out of direct sun, away from air vents and Stevenson Shields were fitted (see Figure 4). At one site (The Linx, Bletchley) an additional external air temperature sensor was installed, allowing differences between shields and unshielded sensors to be illustrated (see Figure 5).

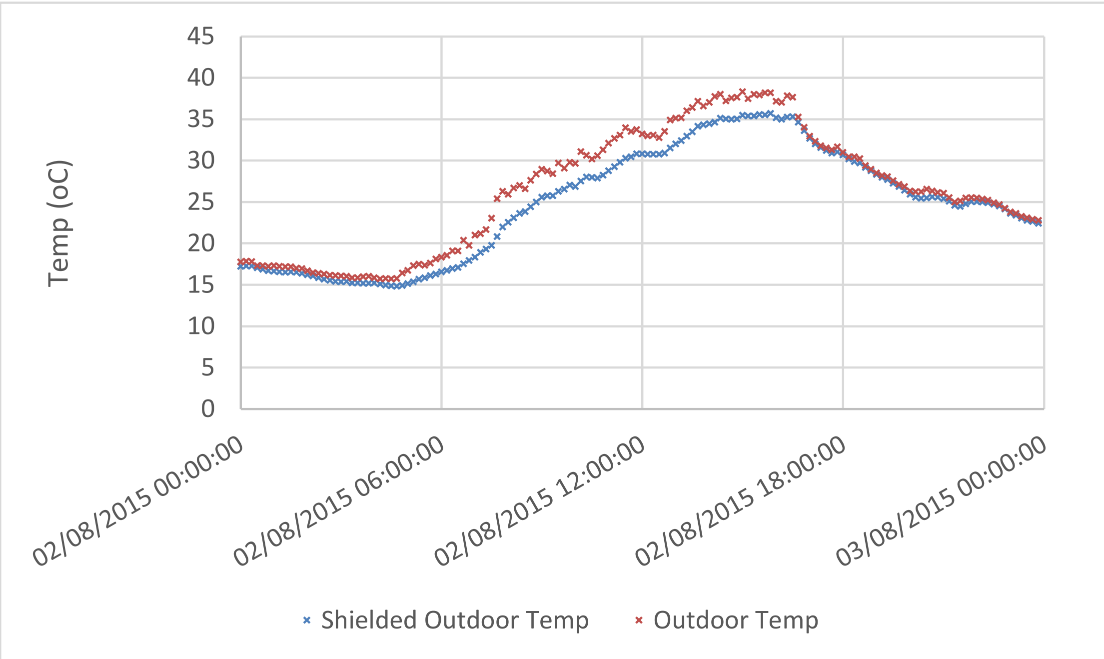


Figure 5 : Difference in measured air temperature with and without a Stevenson Shield – The Linx, Bletchley

The indoor air temperature sensors were mounted in thermostat type housings, which were mounted vertically in substations, again avoiding air vents (see Figure 4).

For top oil temperature measurement (for thermal model validation purposes), the design intent was to fix shim type thermocouples to the side of the tank. However:

Early modelling results showed poor correlation between measured and modelled top oil temperatures, and the measurement arrangements for top oil temperature were reviewed. Initial use of thermocouple shims attached to external tank was revised such that:

- Where fitted, thermometer pockets were used as the measurement location; and
- Where pockets were not fitted to a transformer, the shim position on the tank was adjusted to be just below the top level of the oil, and a secure fixing was ensured.

Comparison of properly positioned tank shim, and shims inserted in the thermometer pocket was carried out at one site, with data being recorded over the trial period (see Figure 6). This comparison showed that well positioned tank shims where a good proxy measurement position for top oil temperature, as measured in manufacturers' thermometer pocket.

Figure 6: Illustration of tank shim temperature measurement, thermometer pocket temperature measurement, and coincidence of measured values from a well-positioned external tank and thermometer pocket measurement positions.

In addition to comparing top oil measurement point data, the absolute values were also validated through the use of a thermal camera. This showed good agreement between the peak temperatures show by the thermal image, and the measured top oil temperature.

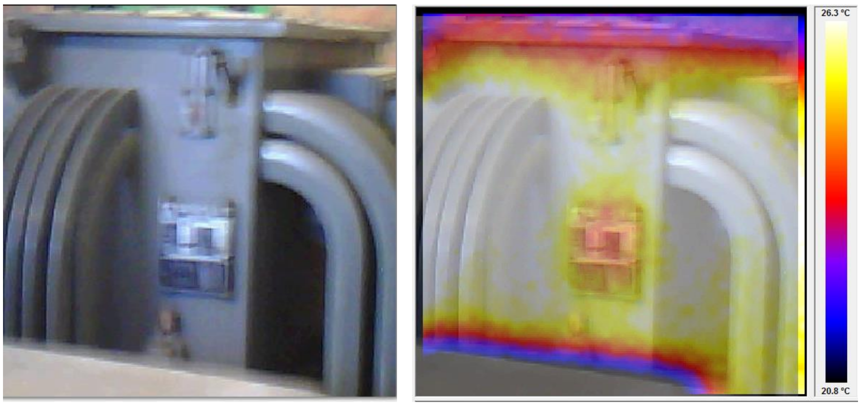


Figure 7: Sample thermal image of an in-service Distribution transformer.

3.3 Data and data transfer

The process of data collection for offline modelling is summarised in Figure 8:

- Temperature measurements:
  - Outdoor air, indoor air (if applicable) and top oil temperatures are sampled and stored locally on the analogue acquisition unit;
  - On a periodic (1 minute) basis, the central (Modbus data) data-logger retrieves and stores the most recent temperature values from the analogue acquisition unit;
  - Weekly extracts were taken from the data logger, and the sampled values averaged to provide 10 min average values;
  - Averaged values were exported as excel sheets for import into the offline models.
- Transformer load current measurements:
  - Gridkey Low Voltage Monitoring (LVM) devices were deployed at the trial substations, these sampled a range of substation load parameters, including current, at LV feeder level, and aggregated the data to provide 10 minute average values for substation/transformer current, by phase. The LVM devices locally stored and retained the 10 minute average values (amongst other data);
  - The locally stored data was retrieved, stored and made available for graphical presentation by the central Gridkey data store;
  - Gridkey data (stored in binary formats) associated with the trial transformers was extracted from the central data store, processed, and re-stored in Access databases with Excel extraction and graphical front-ends. Weekly 10 minute average values of (the highest of the three phase) currents were then extracted on demand, and exported as excel sheets for import into the offline thermal models.

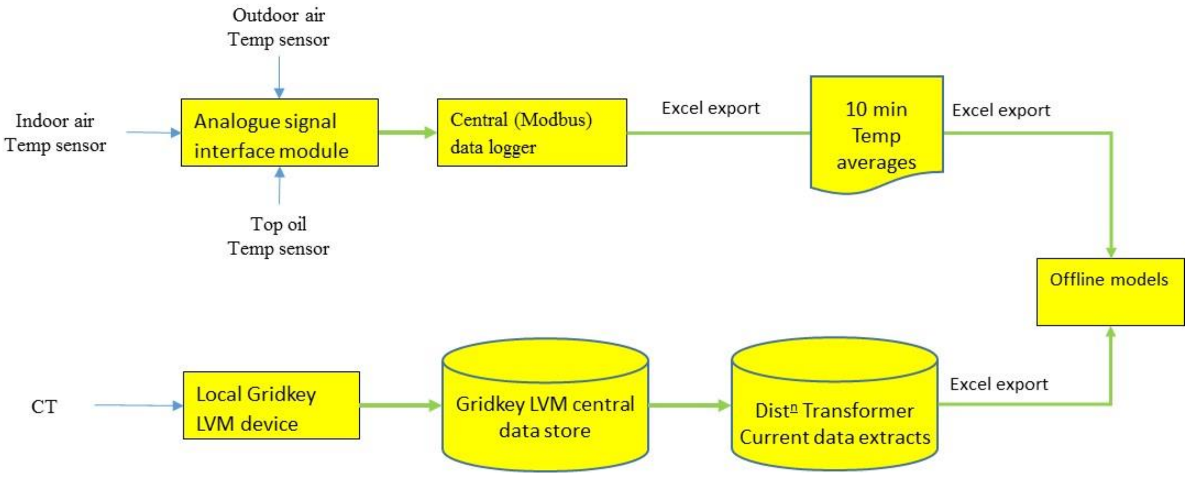


Figure 8: Data collection for offline modelling

Exemys RME1 modules were installed at each site are web-enabled Ethernet I/O modules featuring:

- Built-in web server that allows remote configuration, I/O monitoring and I/O control via a standard browser; and
- Support for Modbus/TCP protocol, providing integration with installed data logging equipment

The modules are essentially configured with thermocouple type (e.g. J), and a signal name for each sensor input. In addition, the modules are given an IP address according to the project schedule of IP addresses.

Configuration of DT80 data logger to poll the Exemys RME1 modules required:

- Reading the RME1 input register (Modbus function code 4);
- Setting of data type to 16 bit signed integer (DT80 default is 16 bit signed integer); and
- No requirement to provide a Modbus "unit id" field setting.

A typical data retrieval command for the DT80 was “4modbus(ad"172.29.***.***",r4:1,0.1,=1..3cv)”, which retrieved the three temperature values from one of the Distribution transformer sites.

3.4 Key Learning from Implementation

3.4.1 Technique-Specific Learning

LP 1.	Had time allowed, further site measurements would initially have been carried out to assess the site maximum demands and to confirm their suitability to take part in the trial. More heavily loaded transformers offer greater scope for proving the technique.

LP 2.	Air temperature sensor should be positioned such that they are out of direct sun, away from air vents and with Stevenson Shields fitted.

LP 3.	To measure top oil temperature; • where fitted, thermometer pockets should be used as the measurement location; and • Where pockets are not fitted to a transformer, the shim position on the tank should be adjusted to be just below the top level of the oil, and a secure fixing ensured.

3.4.2 Generalised and Cross-Technique Learning

The following points of learning have been found across more than one technique. They are presented with examples specific to the Distribution transformer DAR technique.

LP 4.	FALCON demonstrated the importance of establishing measurement and data strategies as part of the programme design phase to help (dis)prove the technique hypothesis being trialled.

- Initial design work anticipated the wide-spread use of the central SCADA system for collection and dissemination of data. Throughout final installation and during commissioning it became clear that alternative data collection systems would provide greater operational flexibility in the context of an innovation project. This led to the Installation of a single data logger that collated all plant temperature measurement data.

LP 5.	Control room interaction with the technique was limited. More complicated control room interaction would be required if this were adopted as a BAU technique.

LP 6.	Limited training of operational staff was undertaken to allow the trial to take place. Additional more widespread training would be required if this were adopted as a BAU technique.

SECTION 4

Thermal Models

All DAR assessment is predicted on a thermal model, and confidence in that model. These models include parameters that are specific to each asset. This section describes the work undertaken within the project to prepare thermal models for Distribution transformers that gave acceptable coincidence to measured oil temperature values, and the learning that resulted.

4.1 Overview of thermal models

There are three models from three standards that apply to mathematical modelling of transformers, see Table 2. Each of the models can be used to describe transformer thermal responses by estimating the hot-spot temperature of windings. As outlined in Section 2.3, the hot-spot temperature is calculated by summing the ambient temperature with the rise in top-oil temperature above ambient and the rise in hot spot temperature above top oil. The time constants may be fixed (unvarying with condition) or variable (changing with conditions) within the calculation.

Standard	Year	Load	Model	Model constants	Transformer specific Time constant	Transformer specific model parameters
IEEE C57.91	2011	Step	Exp	*n,2m*	Variable τ_o, τ_{hs}	$R, \Delta T_{tor}, \Delta T_{hsr}$
IEC 60354	1991	Step	Exp	*x,y*	Fixed τ_o, τ_{hs}	$R, \Delta T_{tor}, \Delta T_{hsr}$
IEC 60076-7	2005	Dynamic	Diff	*x,y*, k_{11}, k_{21}, k_{22}	Fixed τ_o, τ_{hs}	$R, \Delta\theta_{or}, \Delta\theta_{hr}$

Table 2 : Parameters in Transformer Thermal models

Wind and solar effects are not considered in any of the standards. These parameters were also determined to be negligible in a study by EA Technology [2], and partially discussed in the FALCON DAR Primary transformer report.

Mathematically, the models use either exponential or differential numerical functions for both the top-oil and winding hot-spot temperatures to calculate transients between initial and ultimate temperatures. The high level process is illustrated in Figure 9, with key constants that affect top oil temperature highlighted. K is an input variable and is the ratio of measured current to rated current (taken from the nameplate rating).

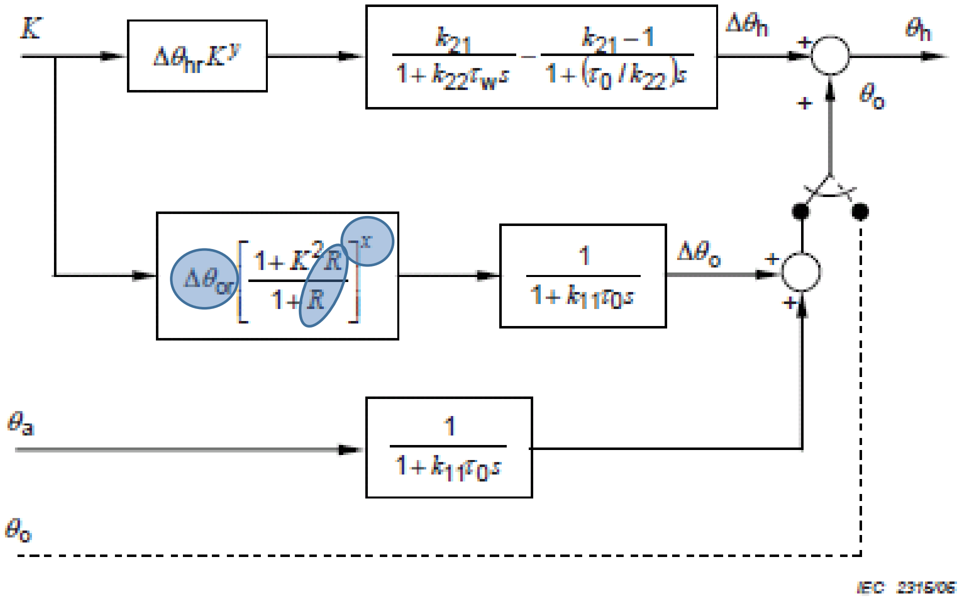


Figure 9 : IEC60076 showing constants that affect the value of calculated top oil temperature rise

Within each model, as shown in Table 2, there exist a number of non-transformer specific constants which have been defined and quantified in the standards to help match their defined model to experimental data.

In addition, there also exists transformer specific data and this includes the following variables:

- R : ratio of load losses at rated current to no-load losses
- $\Delta\theta_{or}$: Top oil temperature rise at rated load
- $\Delta\theta_{hr}$: Hot spot to top oil temperature rise at rated load
- τ_o : Oil time constant
- τ_w : Winding time constant

#	Location	Manufacturer	Year of manufacture	Mass of oil (kg)	Total mass (kg)	Core and windings mass (kg)	Rating/ KVA
1	U32 Blundell	Schneider Electric	2005	965	2780	1090	800
2	Granvills Square	Hawker Siddley	1986	373	1505	667	315
3	Shropshire Court	Schneider Electric	2000	790	1880	725	315
4	Rainsborough	Hawker Siddley	1983	545	2170	1030	500
5	Lakes Lane	Merlin Gerin	1993	441 (500litres)	1490	745	200
6	The Linx	English Electric	1965	765	2450	1135	500
7	Westminster Drive	Bruce Peebles and Co.	1963	545	2110	975	500
8	Cottingham Grove	CG Power Systems	2012	675	1910	870	500
9	Angus Drive	Bonar, Long and Co.	1967	660	2295	1095	500
10	Glazier Drive	Lindley Thompson Ltd	1988	670	2090	1055	315
11	Middlesex Drive	Transformers Watford	1961	777	2385	1052	500
12	Buckingham Gate	CG Power Systems	2012	675	1910	870	500
13	Barnfield Drive West	Parsons Peebles	1975	820	1860	677	315
14	Thorneycroft Lane	Lindley Thompson Ltd	1986	695	2370	1330	500
15	Rickley Lane	Gresham Transformers	1961	795	2550	1130	500
16	Pelham Place	Bonar, Long and Co.	1976	986	3185	1600	500

Table 3: Selected nameplate data from trial Distribution transformers

As can be seen from Table 3, the transformers selected for the technique trial range in manufacture from 1961 to after 2012. There were no test certificates available, and the only data readily available was what is found on the rating plate. Removing the transformers from service to attempt tests to establish parameters values was uncertain of success and potentially disruptive to customers. The consequence of this was that much of the data nominally required to calculate the parameter values for use in the models was not available. As a result, many of the initial values were taken from example values contained in the industry standards. However, Figure 10 shows that using this example set of values results in an overestimation of top oil temperature of up to 15^{o}C compared to measured values.

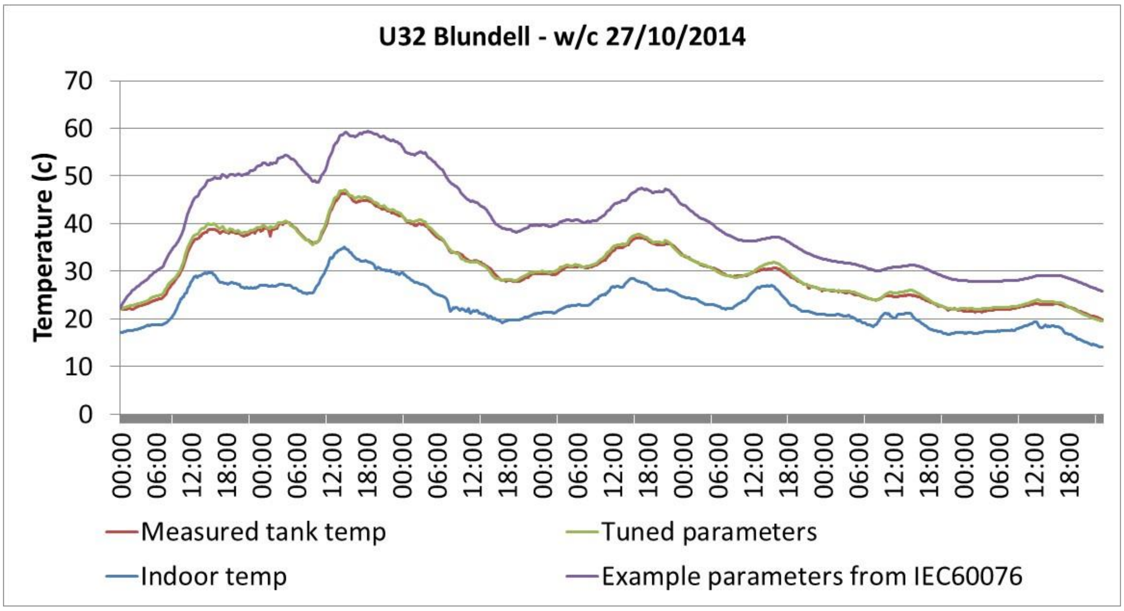


Figure 10 : Measured tank temperature and modelled top oil temperature with IEC600-76 example values and tuned values indicating how accuracy can be significantly improved with tuned parameters.

LP 7.	It was found that initial values of model parameters (largely taken from literature) provided insufficient correlation between modelled and measured top oil temperatures for all Distribution transformers. It is assumed that this is due to variability in the rating and physical size of the transformers, age, and cooling system design.

As a result of this initial finding, the models were further examined to identify routes to improving the model accuracy. Improvements were made to the R parameter, with typical values identified for each transformer (kVA) rating. The adopted values are shown in Table 4.

Transformer rating (kVA)	No load loss (W)	Full load loss (W)	Parameter R - Ratio of load losses at rated current to no load losses
200	450	2500	5.55
315	500	3000	6.00
500	800	5000	6.25
800	1000	7000	7.00

Table 4 : Typical values for model parameter R (ratio of load losses at rated current to no load losses)

Further to this:

LP 8.	Sensitivity analysis of the IEC 60076 thermal model determined that there were two key parameters whose values were initially uncertain that substantially affected the modelling accuracy, parameters: $\Delta\theta_{or}$; and τ_o.

Within Figure 9 the values circled in blue are those values that affect the absolute value of oil temperature which, when adjusted, could give a better correlation to measured values than using values obtained from the Standards.

From Figure 8, the top oil temperature, $\Delta\theta_o$ is calculated from

$$\Delta\theta_o = \Delta\theta_{or}\left[\frac{1+K^2R}{1+R}\right]^x \frac{1}{1+k_{11}\tau_o s}$$

The $\Delta\theta_{or}\left[\frac{1+K^2R}{1+R}\right]^x$ expression relates to the final absolute value of oil temperature following a step increase in load. The $\frac{1}{1+k_{11}\tau_o s}$ is the transfer function that models the time delay caused by this step change. Therefore under steady state conditions, the R and x parameter affect the range of the results under different load conditions, while the $\Delta\theta_{or}$ value effects the offset at rated load.

Sensitivity studies around this showed that the differences between measured and modelled top oil temperatures were most heavily influenced by the accuracy of the transformer top oil temperature at rated load, $\Delta\theta_{tor}$ and the time constant τ_o parameters (while $\Delta\theta_{hr}$ and τ_w largely influence the hot spot temperature) and therefore fixing R while allowing the other parameters to vary was deemed an appropriate approach.

LP 9.	Despite the use of an amended R value specific to a given transformer's rating, and example values from the standards [1], [3], [4] for these two key parameters, insufficient correlation between modelled and measured oil temperature still remained. Further methods of improving the parameter values for $\Delta\theta_{or}$ and τ_o were sought, and approaches to tuning parameters were considered.

4.2 Final parameter value selection and tuning

4.2.1 Overview of approaches to tuning parameter values

In the context of DAR and transformer thermal modelling, parameter estimation is a crucial first step in accurately modelling individual transformers. If initial estimates of parameter values do not deliver adequate accuracy to measured values, then various forms of regression analysis may be applied to identify improved model parameter values.

Within published literature, regression has been applied specifically to improve (primary) transformer modelling:

- Least-squares regression [5] is applied to estimate parameters for a primary transformer in the US using the IEEE Clause 7 model [4];
- Parameter estimation using genetic algorithms to find the relevant values for a single transformer [6]. As a measure of model effectiveness they apply a fitness function, which they define as the error between modelled and measured top oil temperature and also bottom oil temperature. This approach ensures a similar output to a least squares method, as in [5].

Parameter estimation for complex differential equations has also been applied in other fields [7]–[9] with various numerical methods used depending on the circumstances. Typically, parameter values are iterated and the difference of least squares is found for each set, but in some situations a weighted function can provide a more tailored solution.

For instance, [10] employs a weighted function based on the difference between various quantiles. This is due to the fact that some parts of a distribution or model are deemed more important than others. [11] discusses weighted regression generally, observing that certain local conditions may require specific weighting, or that other parts of a distribution may require a lesser weight – such as at boundaries or for initial values of a curve.

As a result of this work it was found that:

LP 10.	For transformer thermal models it is prevalent to ensure the maximum modelled daily values closely match the actual maximum values – as these values are key to determining the load allowance/life of insulation in the transformer. By extension other parts of the curve may be seen as less crucial – and so a better regression at these points may not always be desirable (especially if the accuracy at the maximum is jeopardised). This indicates a weighted method of tuning is preferred.

4.2.2 Top oil-related parameter tuning for FALCON Distribution Transformer thermal model

To help determine reliable parameters for $\Delta\theta_{tor}$ and τ_o across each transformer, a weighted regression method was developed within the project. This approach improves upon a uniform least-squares method by emphasising the importance of certain values throughout various time periods. Specifically, regression is performed locally where the maximum values occur each day. Additionally, an acceptable error value is built in such that conservative modelled values – which slightly overestimate the actual temperature – are preferred.

From analysis of the thermal model:

LP 11.	It was found that the $\Delta\theta_{or}$ parameter affected the overall temperature of the model (i.e. along the y-axis), and the τ_o parameter affected the time at which predicted values occurred (i.e. along the x-axis).

An example of how the τ_o parameter affects accuracy of the model outputs is shown in Figure 11.

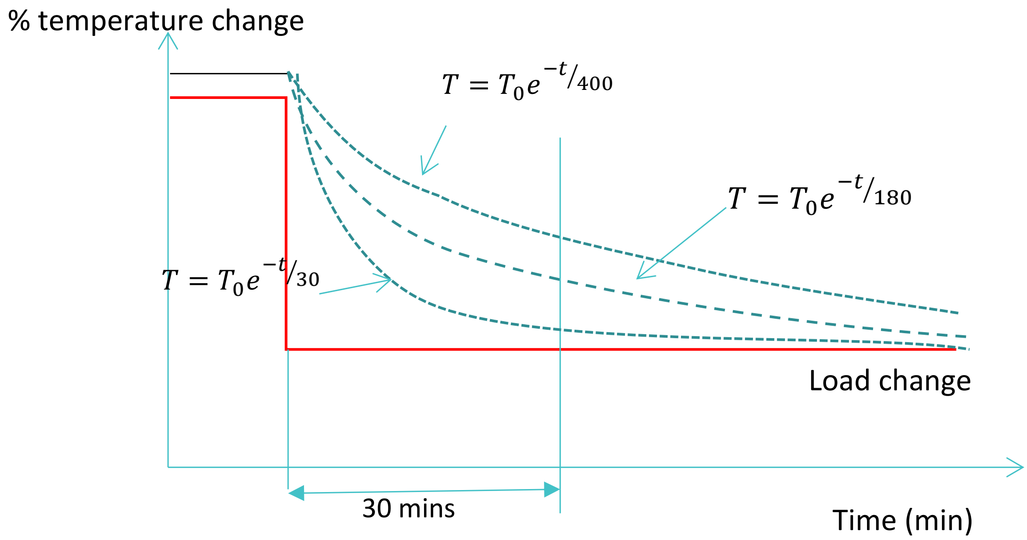


Figure 11 : effect of time constant on accuracy of temperature calculation

After a 30 minute period, $e^{-t/400} = 0.927$, $e^{-t/180} = 0.846$, and $e^{-t/30} = 0.368$ therefore the difference in cooling after 30 minutes is about 20°C for a T_0 value of 40°C. The oil time constant is heavily dependent on the mass of oil in the transformer, and significant variation in this value is seen across the transformers within the technique trial (see Figure 12).

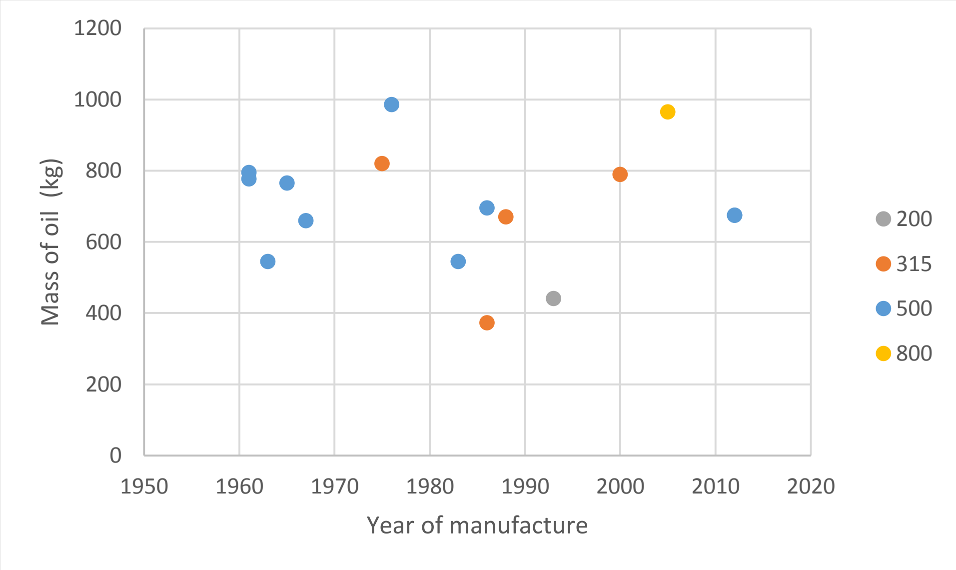


Figure 12 : Variation in mass of oil in transformers

LP 12.	The variation seen in mass of oil installed in transformers is an example of the need for asset specific parameter value selection.

As such, a combination of localised regressions was performed to ensure an accurate forecast of the maximum temperature could be obtained. Each regression score was then normalised and multiplied by a specific weighting. The combinations involved in this weighting are shown in Table 5.

Function	Weight
Root mean square error across week	12
Root mean square error on day with highest temperature	3
Difference in peak values – averaged across week	8
Difference in peak values – on day with highest temperature	2
Time difference in peak (taken from median value) averaged across week	3
Time difference in peak (taken from median value) on day with highest temperature	1

Table 5 : Weightings applied for regression

To determine the best fit curve, each parameter is iterated between sensible bands (from 0 to 60 in steps of 1 for $\Delta\theta_{or}$ and from 0 to 500 minutes in steps of 10 for τo). Each parameter set produces a unique score derived from the weighted functions in Table 5, with the lowest score corresponding to the most suitable curve and parameter values.

Further details of the approach include:

- The root mean square error (RMSE) was calculated using an ordinary least-squares regression where the difference in every set of values is compared;

- The 'difference in peak values' regression is applied only to the 30 points either side of the maximum daily value (roughly equivalent to the top 20% from each day). A value of $1^{o}C$ is also added to the peak measured values, such that modelled values above the maximum are preferred. A slightly higher modelled value is preferable since the ultimate aim of this work is to determine an upper loading value – which is set so that insulation life is not compromised. As such, it is better to underestimate rather than overestimate the ampacity and cause unanticipated damage to transformer insulation.
- The 'time difference in peak' is calculated by comparing the time of the median value of the measured peak with that of the modelled peak. This helps choose parameters which produce modelled peaks at coincident times to measured values. Each regression is performed across a week of values.
- As outlined above, the regression scores are normalised and the weightings in Table 5 applied. The sum of these regressions is calculated for each iteration of parameter value, with the lowest score representing the preferred parameter value choice.
- The thermal models have differences associated with them through their calculation technique. This method was tried against all of the models from the standards. It should be noted that the measurement point on some transformers was moved (see Table 11). This regression approach was only applied after the movement.

Modelled results were produced using data from the Distribution transformers with parameters found using the weighted regression (as described above) and a non-weighted RMSE regression. Time series modelled oil temperatures were compared against each other, and compared against measured values. Figure 13 shows an example of a week's data from one of the transformers.

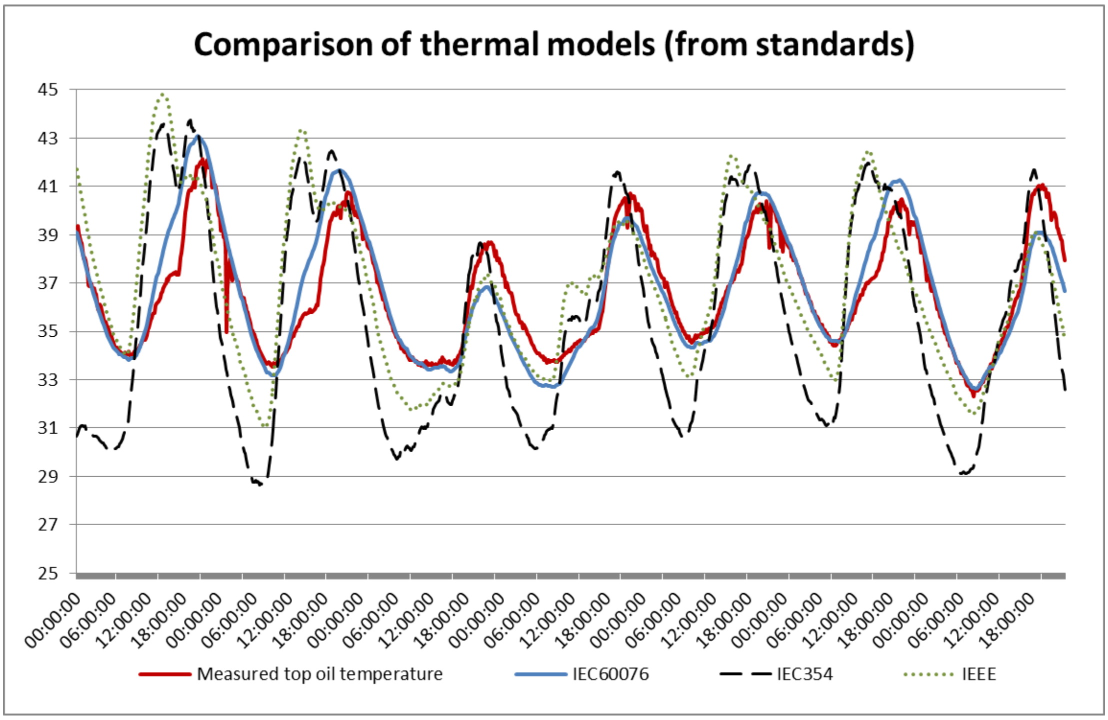


Figure 13 : Sample results of top oil temperature modelling via the three Industry Standards, and the measured oil temperature.

From Figure 13 it was concluded that:

LP 13.	The IEC60076 model provided a better correlation to the measured data, and was deemed the most appropriate for use with the Distribution transformers under study and this technique

Applying the IEC60076 model, comparison of the two regression methods (weighted and RMSE) was carried out. Figure 14 shows results from both regressions for Transformer 1, plotted against the measured tank temperature. Both modelled curves provide good approximations to the measured temperature. In this example, the parameters identified by the two regression methods were only slightly different ($\Delta\theta_{or}$ = 25 from both regression methods, τ_o = 100 from the weighted regression, and τ_o = 90 from the RMSE regression).

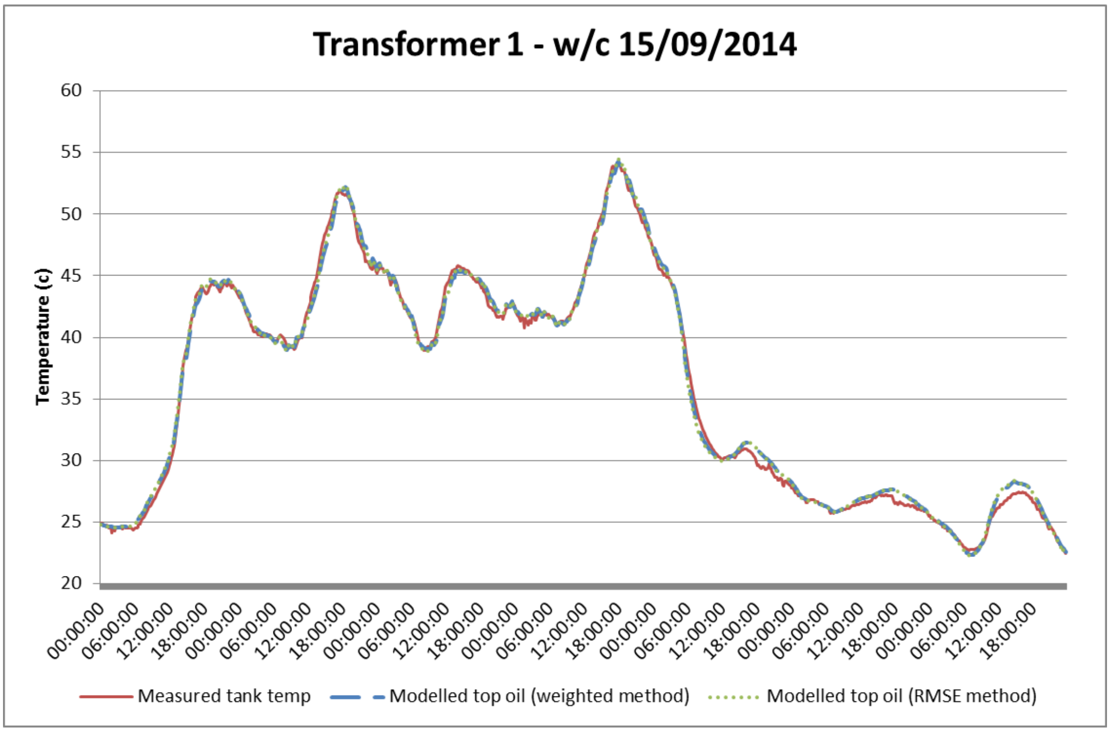


Figure 14 : Thermal model curves for transformer that can be reliably modelled

From Figure 14 it can be seen that in at least some instances, very high degrees of correlation between modelled and measured temperatures can be achieved using either regression method.

However, not all transformers showed the same degree of correlation for both regression approaches. Figure 15 shows an example of the outputs from the two regression methods for Transformer 7, where the thermal behaviour of the oil temperature was more difficult to replicate.

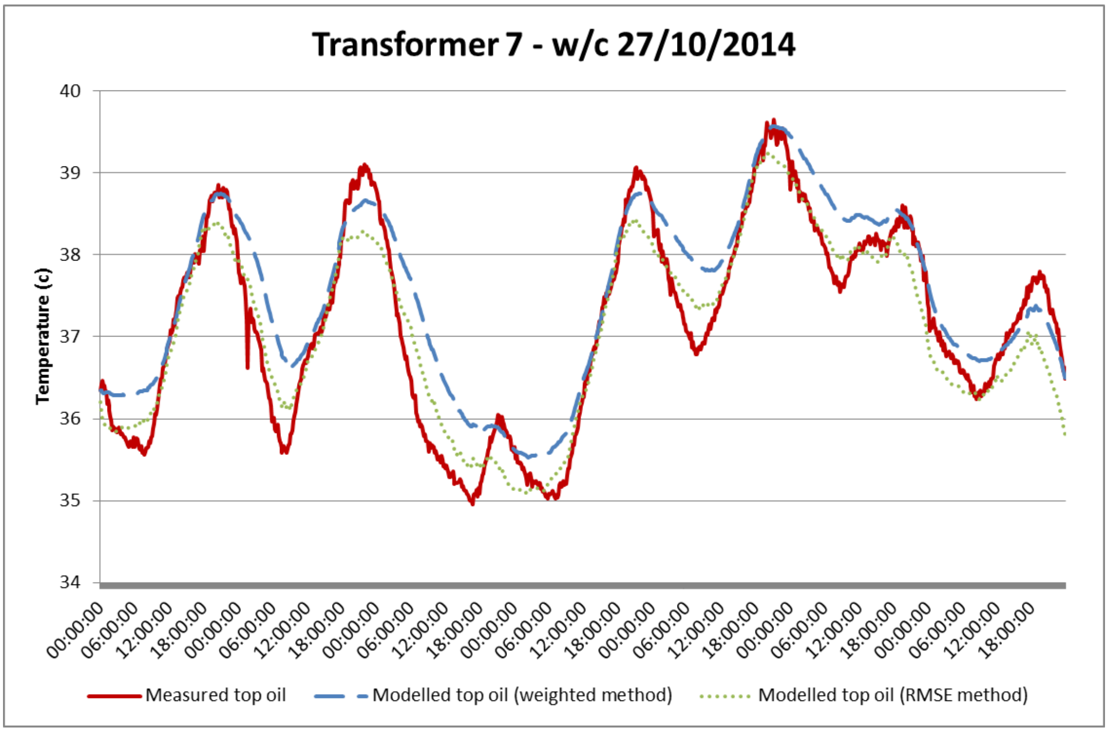


Figure 15 : Thermal model curves for transformer difficult to model

Since the RMSE method weights all parts of the distribution equally, there is an even amount of underestimating and overestimating. For a curve which is more exaggerated at the peaks, the RMSE method tends to underestimate at these points – which, in the context of DAR, could result in a shorter insulation life for the transformer. The weighted regression, however, is specifically weighted to more accurately forecast the temperature peaks. As such, this method produces a more suitable representation by ensuring that peak temperatures are underestimated less often, and to a lesser extent.

Appendix C shows the tuned $\Delta\theta_{or}$ and τ_o parameters for each transformer with date.

For each of the 16 transformers, the most suitable parameters were chosen using both regression methods for every week of data. Due to variations in ambient temperature, loading, and other external variables, parameter choice can vary between weeks.

LP 14.	The tuned parameters changed within weeks but there was no obvious seasonal trend. Therefore a fixed parameter value can be calculated and used across the year.

For use in DAR, it is necessary to find the most robust parameter value that is suitable across all weeks. For each regression method, the median, maximum, and standard deviation (St Dev) of parameter values were found for each transformer. Outputs for the $\Delta\theta_{or}$ parameter are shown in Table 6.

	RMSE method			Weighted method		
Transformer	Median	Max	St Dev	Median	Max	St Dev
1	24	26	1.40	25	27	0.84
2	34	37	2.33	33	37	3.02
3	38	42	1.69	39	44	2.62
4	48	49	1.07	48	51	1.65
5	8	11	2.33	6	10	2.82
6	46	50	4.13	45	49	3.50
7	49	53	2.24	50	54	2.36
8	39	45	3.15	39	49	4.15
9	33	37	1.33	34	38	1.98
10	33	35	1.46	34	37	1.66
11	45	47	0.66	46	48	0.98
12				40	57	5.41
13				36	44	2.96
14	32	34	2.93	32	35	1.98
15	49	50	1.02	49	51	1.33
16	24	26	1.64	25	28	2.11

Table 6 : Parameter choice for $\Delta\theta_{or}$ for each transformer

In most cases the value for $\Delta\theta_{or}$ is slightly higher when using the weighted regression, which is indicative of its bias towards higher temperatures at the peaks. For certain transformers the parameter choice is fairly robust (indicated by a low St Dev). Significantly, $\Delta\theta_{or}$ values vary across transformers considerably regardless of location, mass of oil, size etc., again highlighting the need to determine parameter values on an individual basis (There exist formula to calculate τ_o within the standards but these are dependent on knowing a modified value of $\Delta\theta_{or}$). The Weighted method appeared to work best for the IEC 60076-7 model as shown in Figure 13.

To determine the effectiveness of potential parameter values, the median, and separately the maximum values from this analysis, were applied to the model for each respective transformer throughout the total study period. From this modelling, for each transformer, the differences between the modelled results and the measured results for the daily maximum temperature were found. This is the most important test for the long term applicability of the thermal model because it shows that the values of parameter values chosen are not dependent on variations in loading or ambient temperature. In general, a modelled temperature which is slightly higher than the actual oil temperature is preferred on the basis of modelling conservatism.

Table 7 summarises the difference in maximum measured temperature, and the modelled temperature at the same instance, for each regression method.

Daily Maximum Difference	RMSE regression values		Weighted regression values	
	Median	Maximum	Median	Maximum
Median	**0.06**	**0.56**	**0.37**	**1.12**
Max	5.41	6.55	5.76	6.79
% of modelled maximums that are less than measured maximums	47%	34%	35%	15 %
St Dev	1.24	1.56	1.23	1.35

Table 7 : Performance of regression methods with fixed parameters

From Table 7 it can be seen that:

- When the parameter values are fixed using the RMSE values:
  - The modelled temperatures are on average 0.06^{o}C higher than the measured temperatures (considering median values); however,
  - On 47% of days this difference was negative (significant because it shows that for a significant proportion of time the daily top oil temperature is being underestimated).
- When the parameter values are fixed using the weighted regression:
  - The underestimates of the maximum temperature occur less often; though
  - The differences to measured temperatures are marginally higher.
- If the weighted regression analysis maximum value is chosen as the parameter value the temperature is underestimated 15% of the time, with a max difference of 6.8^{o}C with an average of 1.12^{o}C.

As a result of extensive work on parameter tuning it was concluded that:

LP 15.	Regression methods could and should be used to determine key top oil-related parameter values for use within the FALCON Distribution Transformer thermal model.

LP 16.	A weighted regression method developed within the project was preferred over a RMSE regression method. The long term values identified from the weighted regression analysis were used as top oil-related parameter values within the model.

LP 17.	Following the extensive modelling of Distribution transformers using data derived from the trials, it has been found that greater accuracy of top oil temperature can be achieved with IEC 60076-7, rather than IEEE Standard C57.91. Given IEC 60076-7 is an update of IEC 60354, the preferred and utilised basis Distribution Transformer thermal modelling for the FALCON DAR technique trial was IEC 60076-7.

Table 8 shows the selected values for key top oil temperature related parameters for all the transformers in the technique trial. There is no obvious correlation between these parameters and the transformer attributes (mass, size, location, year manufacture).

#	$\Delta\theta_{or}$ (oC)	τ_o (min)
1	25	80
2	33	220
3	39	380
4	48	260
5	6	40
6	45	65
7	50	30
8	39	380
9	34	130
10	34	360
11	46	240
12	52	400
13	38	175
14	32	125
15	49	310
16	35	80
Example from standard	55 [6]	180

Table 8 : Tuned parameter set

LP 18.	Significantly more work on different transformers would be required to allow a general formula to be used to produce values of parameter for use in the model based entirely on name plate data. This would also result in significant uncertainty in dynamic asset rating.

4.2.3 Hot spot-related parameter tuning for FALCON Distribution Transformer thermal model

As described in Section 4.2.2, regression analysis was explored and subsequently used to find top oil temperature-related parameter values giving sufficient correlation between modelled and measured temperatures. Regression analysis was only possible because measured values for top oil temperature were obtainable. As discussed in Section 2.3, measured values for hot-spot temperatures are not available on small, relatively low value, Distribution transformers and therefore further application of regression analysis was not possible.

[6] P15 also states this value should be used in the absence of other data

Whilst standards and literature outline tests that can be undertaken on transformers to provide measurements that can be used to calculate hot spot temperature-related model parameters, it was: far from certain that these tests could be successfully completed; not anticipated within the project scope; and would have necessitated taking plant out of service, potentially requiring customer supply interruptions.

Initially the use of example values for $\Delta\theta_{hr}$ (Hot spot to top oil temperature rise at rated load) from Industry Standards, with tuned top oil temperature related parameters from regression analysis, was tested. With these there appeared to be a large underestimate of modelled hot spot temperature under modelled rated conditions in some cases. I.e. the modelled full load hot spot temperature was significantly less than 98°C, the nominal design point for sustained full load operation. Whilst this may actually have been the case (not testable due to measurements being unobtainable), use of these values could potentially lead to estimates of dynamic rating that were considerably greater than might be the case, and operation to these levels potentially leading to reduced transformer service life.

Therefore a second approach, as illustrated in Figure 16, was developed. This allowed a hot spot to top oil temperature to be calculated based on the assumption that the manufacturer designed their transformer not to exceed a hot spot temperature of 98°C under rated conditions.

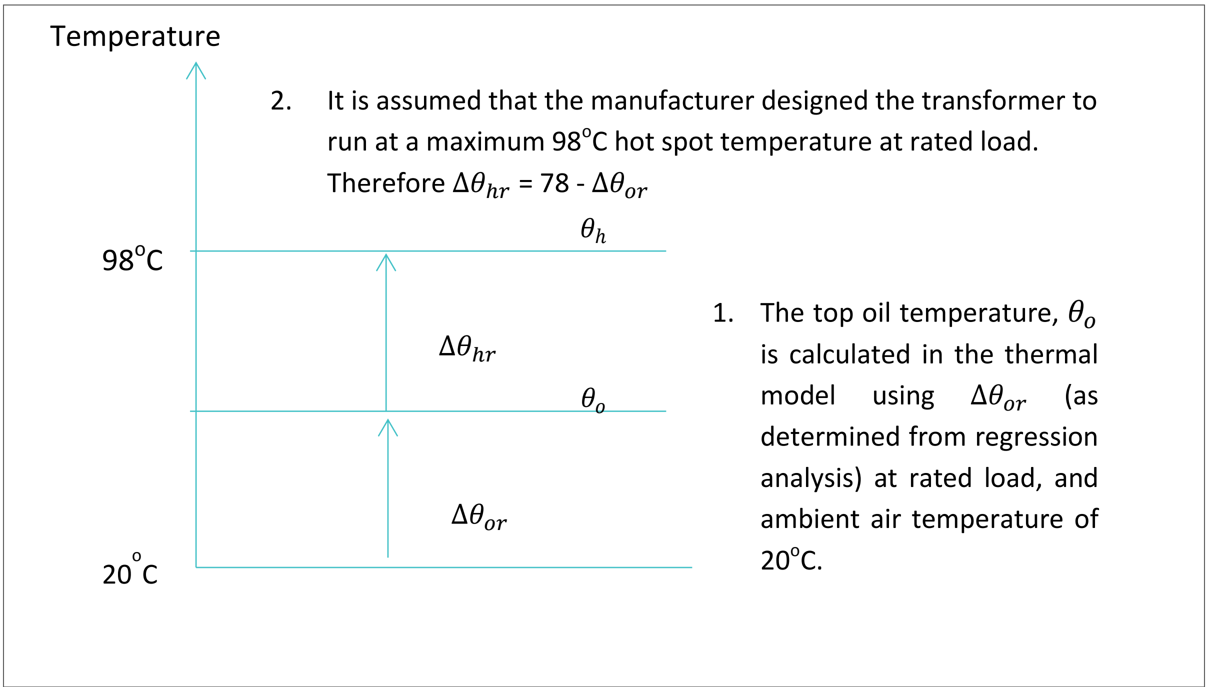


Figure 16 : Illustration of method for determining ΔT_{hsr}

Although this is likely to be conservative for older physically larger transformers, it allows the $\Delta\theta_{hr}$ parameter to be estimated for each transformer and subsequently the thermal model to be used in dynamic asset rating calculations. The resulting $\Delta\theta_{hr}$ parameter values are judged to be more (conservatively) appropriate than using example values with unestablished basis for the technique transformers. The time constant from Industry Standards (in the order of minutes) was judged to be appropriate (given its value compared to the data collection times) and was used.

Therefore:

LP 19.	A further novel approach to parameter selection for transformer thermal models was developed within the project. This approach has been used to set the $\Delta\theta_{hr}$ parameter value for each transformer within the trial.

LP 20.	The opportunity exists to cross-estimate the $\Delta\theta_{hr}$ parameter values established for the technique trial through an investigation of off-load tests of transformers identified in Industry Standards and literature.

Table 9 shows the selected values for key top oil temperature related parameters for all the transformers in the technique trial.

#	$\Delta\theta_{hr}$ (oC)	$\Delta\tau_w$ (min)
1	53	4
2	45	4
3	39	4
4	30	4
5	72	4
6	33	4
7	28	4
8	39	4
9	44	4
10	44	4
11	32	4
12	26	4
13	40	4
14	46	4
15	29	4
16	53	4
Example from standard	23[7]	4

Table 9 : Tuned values for hot spot temperature -related parameters

[7] P15 recommends this value in the absence of other data.

4.3 Distribution Transformer thermal model results and learning

4.3.1 Model results and comparison to available measured values

A set of thermal model parameters was assembled for each transformer, and the model was run for a full year using measured load and ambient air temperature. An example of a week long period is shown in Figure 17.

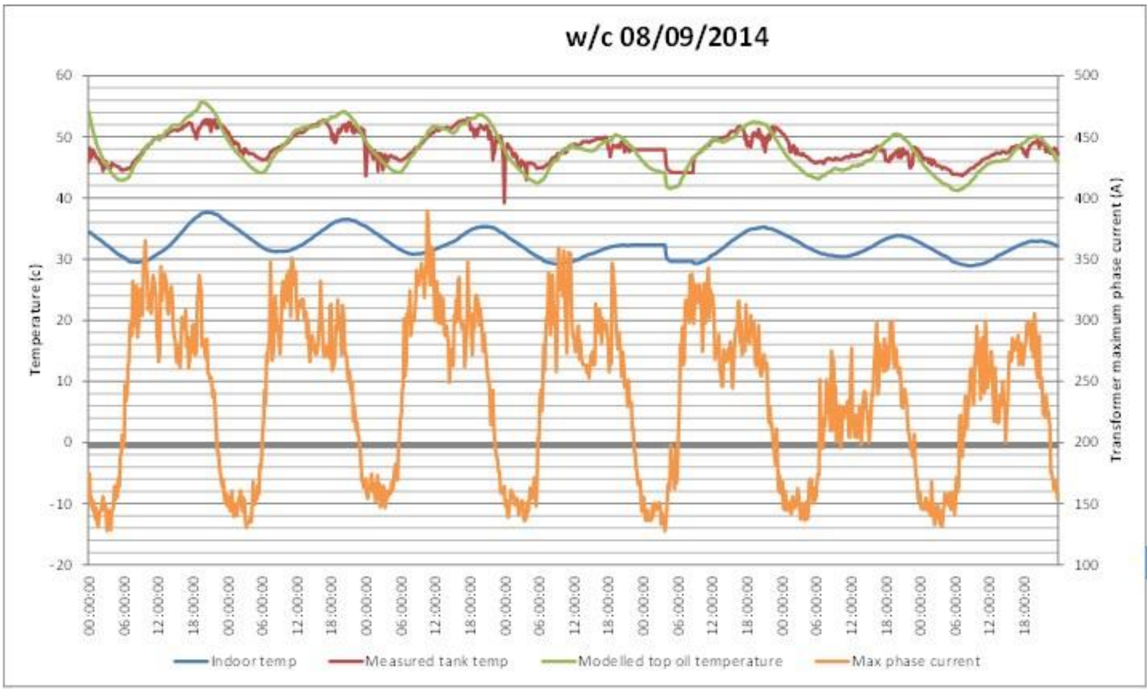


Figure 17: Correlation between calculated and measured top oil temperature for Rickley Lane

From Figure 17 the effect of ambient air temperature can clearly be seen.

The range of key input data for the modelling work is shown in Figure 18, as a heat map-style representation. Deep blue indicating regions of zero instances, and red indicating regions with more than 350 measurement instances.

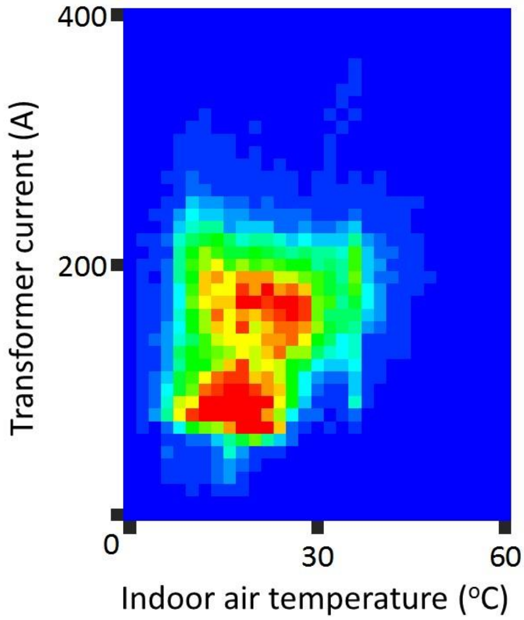


Figure 18: Heat map-style representation of range of load and ambient air temperatures experienced at Granvills Square Distribution Transformer.

Review of the extensive result set showed some areas of data unavailability (principally for ambient air temperature due to periods of poor communications network connectivity to sites), and these have been filtered out.

To provide a representative sample from this data set over the year Appendix D shows five graphs representing a week in each season (spring, summer, high summer, autumn, winter) for each transformer using the parameters from Table 8 and Table 9, for the dates listed in Table 10. Any transformer with a significant quantity of missing data uses data from week's as close as possible to those in Table 10.

Season	w/c
Spring	20/04/2015
Summer	23/06/2014
High Summer	21/07/2014
Autumn	13/10/2014
Winter	19/01/2015

Table 10 : Typical weeks over the course of the year

Table 11 shows the maximum difference between measured and modelled data for each transformer over the five one-week periods and the 90% percentile difference within that week (to remove any outlying erroneous data). In some cases the location of the thermocouple changed (from tank to pocket for greater accuracy). Figure 6 shows an example of the good correlation that is achieved between a well-placed tank measurement position, and the pocket measurement position. For these cases only the differences after the date of change of measurement are shown. The graphs in Appendix D for those dates before the measurement moved show a higher degree of mismatch in temperature calculation which is to be expected and this highlights the importance of accurate top oil measurement.

#	Maximum difference (°C)	90% percentile difference (oC)	Date of measurement change
1	2.4	1.5	-
2	4.9	2.6	30 June 2014
3	5.2	3.3	-
4	2.8	1.7	19 August 2014
5	6.4	4.0	-
6	5.9	3.7	30 June 2014
7	2.8[8]	1.4	30 June 2014
8	3.4[9]	2.9	30 June 2014
9	2.2	1.0	30 June 2014
10	3.4	2.8	-
11	2.1	1.7	11 August 2014
12	3.1	2.7	-
13	13.6[10]	12.9	-
14	2.8	2.1	18 August 2014
15	8.4[11]	2.9	11 August 2014
16	6.3	4.4	-

Table 11 : Error between measured and modelled top oil

4.3.2 Key learning from thermal modelling results

There are several points of learning that emerge from the thermal modelling work:

LP 21.	Well over 90% of all top oil temperature collected and compared to calculated top oil temperature agree within 4°C

LP 22.	Some transformers showed an accuracy as tight as 1°C over the winter season where calculation is mostly closer than in the summer months

[8] Spring 2015 results not available so spring 2014 results used in Appendix B

[9] Some data ambiguity in spring so these values have been excluded from this table

[10] Some very dubious data with large periods of data loss over high summer. In winter these numbers are 2.8°C and 1.6°C much more representative of other transformers.

[11] The data is spiky in nature in places indicating an instrumentation issue – hence the difference between maximum and 90% of data.

LP 23.	Transformer data collected from different measurement points (oil pocket/tank) show a reasonable correlation provided that the tank location was optimal.

LP 24.	Indoor winter temperature is very variable across sites. Some temperatures dip to around 0°C, while others such as Rickley Lane don't drop below 15°C. The ambient temperature is fundamental to the assessment of hotspot temperature, and consequential dynamic asset rating. This point is further developed later in the report.

LP 25.	Satisfactorily accurate thermal models of Distribution transformers were developed, on an individual basis, for Distribution transformers included in the FALCON DAR technique trial (less than 5°C difference between modelled and measured top oil temperature for over 90% of the time).

LP 26.	Due to the nature of the developed technique for model parameter value tuning, it is not feasible (based on work to date) to apply anything other than generic and conservative parameters to the Distribution Transformer DAR assessment in the SIM. The key recommended parameter values for use in the SIM (based on IEC 60354) are: ΔT_{tor}=52°C; ΔT_{hsr}=78°C; τ_w=10min; and parameters m & n both set to 0.8. For indoor substations, the ambient temperature should be set as 10°C above external ambient temperature.

LP 27.	It is recommended that consideration be given to implementing IEC 60076-7 calculation in any future implementations of SIM.

SECTION 5

Dynamic Asset Rating

This section describes the work undertaken within the project to use the developed Distribution Transformer thermal model to derive dynamic asset ratings, and compare these to the sustained static ratings associated with the transformers.

5.1 Boundaries of operation

Sustained, cyclic and emergency ratings are given by manufacturers, sometimes with different cooling mechanisms, to limit operating insulation temperatures.

Typically, transformers are designed and rated by the manufacturer to operate with a winding hot spot temperature of less than 98°C for a range of ambient temperatures with an average of 20°C under sustained operation[12], to guarantee that an acceptable service life of at least 20 years. In practice, operating temperatures are significantly less than this for the vast majority of service life, with actual service lifetime potentially being multiples of 20 years.

IEC 60076-2 (2011) and IEC 60076-7 (2005) identifies boundaries or limits of operation for Distribution transformers as shown in Table 12.

Type of loading	Limiting parameter	Limit	Comments
Normal sustained rating	Current (p.u.)	1.0	Name plate rating under ONAN[13]
Normal sustained loading	Winding hot spot temperature (°C)	98	
Normal cyclic loading	Current (p.u.)	1.5[14]	
Normal cyclic loading	Top oil temperature (°C)	105	
Normal cyclic loading	Winding hot spot temperature	120	Also includes any metallic parts in contact with cellulosic insulation material
Long-term emergency loading	Current (p.u.)	1.8	
Long-term emergency loading	Top oil temperature (°C)	115	
Long-term emergency loading	Winding hot spot temperature	140	Also includes any metallic parts in contact with cellulosic insulation material
Short-term emergency loading	Current (p.u.)	2.0	Usually impractical to limit the duration of short-term emergency loading. Note: when hot-spots exceed 140°C gas bubbles may develop that could lead to transformer failure.
Short-term emergency loading	Top oil temperature (°C)	Undefined	
Short-term emergency loading	Winding hot spot temperature	Undefined	

Table 12 : IEC 60076-7 current and temperature limits

Operation above 98°C hot spot temperature causes accelerated aging which is non-linear. All results within this report look at a maximum of 98°C so that dynamic asset rating is not seen to impinge on Asset life span.

[12] Table 1, IEC600-76-2 2011

[13] ONAN – Oil Natural Air Natural Cooling

[14] This is listed as 1.4pu outdoor and 1.3pu indoor within other standards such as P15 and other documentation e.g. EA technology [2]

5.2 Approach to calculation of Dynamic Asset Rating

IEC 60076 does not define a method for utilising a thermal model to determine a dynamic asset rating. For the purposes of this project work, sustained ratings of the transformers have been considered together with a sustained limit temperature of 98°C.

Using this information in conjunction with the IEC 60076-7 differential model, the maximum load current in conjunction with the ambient air temperature for a specified time step period was used to determine the maximum loading on the transformer compared to the sustained rating for ONAN[15] cooling (all the Distribution transformers have ONAN cooling on this trial).

"Of the moment" Ampacity for the transformer (using ambient conditions for a moment in time to determine ampacity at that same moment) may be estimated by repeatedly incrementing the input load current to the model until a hot-spot temperature limit is reached. This is then set as a sustained dynamic rating for that moment in time based on a sustained load. Standards typically state that 98°C is the unit life winding temperature for non-thermally upgraded paper. This means that the winding temperature can reach 98°C without there being any noticeable additional loss-of-life beyond a nominal design rate.

The dynamic rating calculated in this way is most appropriate for the aims of the FALCON project in looking at DAR of transformers within a planning tool and therefore studying the rating appropriate to operation without loss of transformer life is deemed to be the most appropriate at this time. Further work into summer cyclic rating is complicated by the varying nature of the load and how this load would increase in future.

5.3 Distribution transformer trial DAR results.

Figure 19 shows a sample set of dynamic asset rating results for the Distribution transformer installed at the Granvills Square Distribution substation. The upper chart in the figure shows a continuous trace of the calculated DAR value, and a bar chart showing mean DAR values by month, with the maximum and minimum DAR values shown as error bars. In addition, for the bar chart the calculated DAR values are compared to the static sustained rating of the transformer (shown as a black line).

At a high level, this sample result indicates a number of points that are broadly replicated across the Distribution transformers within the technique trial:

LP 28.	The mean DAR values are above the static sustained rating up to six months of the year, typically in colder periods coinciding with the conventionally higher utilisation.

[15] Heat is dissipated to atmosphere naturally by conduction, convection and radiation.

LP 29.	During January and February the minimum calculated DAR values are either at or only slightly lower than static rating, indicating that in the typically coldest and highest electrically loaded months there is good scope to enhance capacity.

LP 30.	The December results show lower than expected DAR values, due to the unseasonably high recorded temperatures (over a number of sites).

LP 31.	The warmer months period shows mean DAR values that are lower than the static value – indicative that within a substation housing, the summer temperatures regularly rises above 10^{o}C of ambient temperature reducing scope for capacity gain.

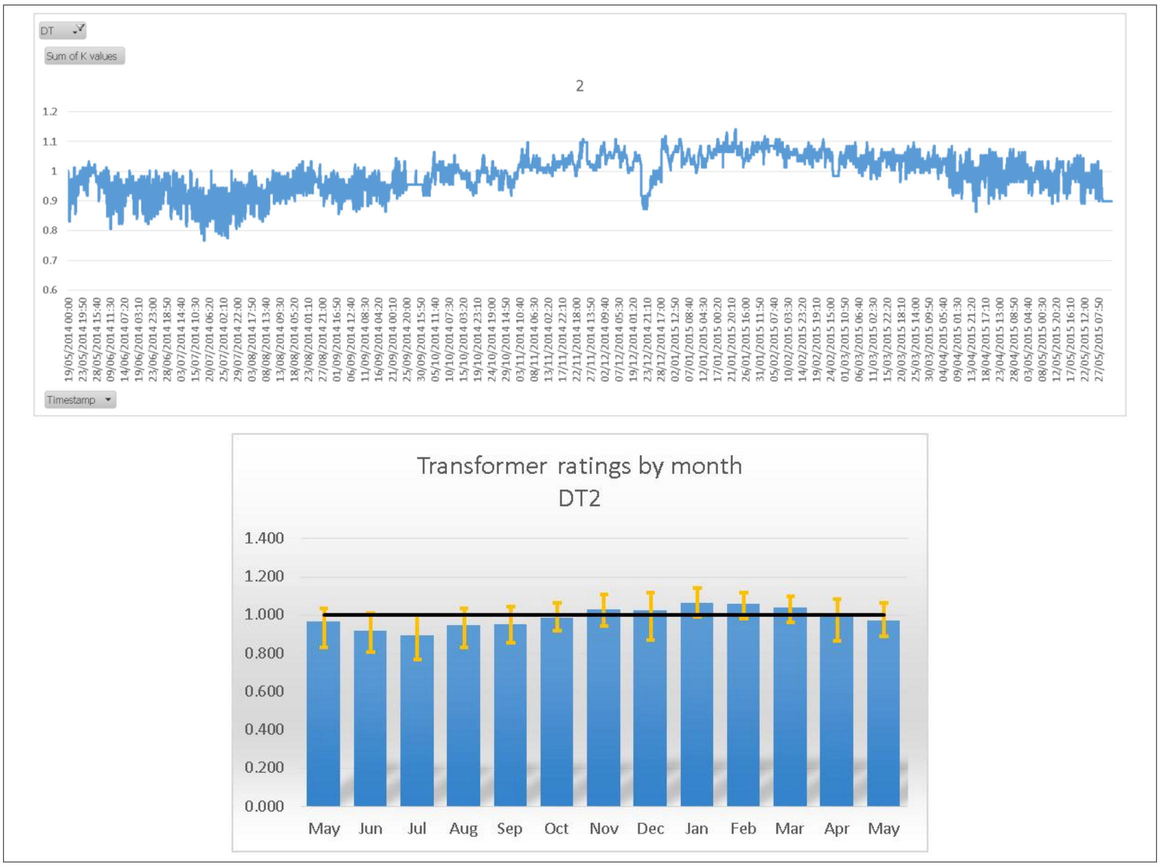


Figure 19: Calculated Dynamic asset rating at Granvills Square Distribution Transformer over the year and on a month by month basis.

Appendix E shows the calculated ampacity against the sustained rating for each transformer throughout the year. These values are summarised on a transformer basis below in Table 13. Note transformer 6, 8 and 16 are outdoors with the remainder being indoor.

Transformer #	% time dynamic rating > sustained rating	Max dynamic rating (p.u.)	Months where average dynamic rating > sustained rating	Substation ventilation	Comments
1	44	1.13	Nov to Mar	good	
2	49	1.14	Nov to Apr	good	Dubious temperature data in Dec. resulting in a drop in calculated rating which reflects in a lower average for this month.
3	44	1.11	Nov, Jan to Mar	No vents	As per transformer 2
4	44	1.13	Nov, Jan to Mar	good	As per transformer 2
5	46	1.13	Nov to Apr	good	Some areas with missing data
6	67	1.18	Oct to May	outside	Some areas with missing data
7	3	1.13	-	good	Poor data after Dec. Indoor temperatures rarely dip below 15°C even in winter.
8	57	1.15	Oct to May	outside	As per Transformer 2
9	27	1.07	Dec to Mar	some	
10	36	1.10	Jan to Mar	good	
11	18	1.0	Jan, Feb	No vents	No obvious benefit and values marginal as accuracy is +/- 0.25pu
12	17	1.16	Oct to May	No vents	As per Transformer 2. Data is for Oct to May only.[16]
13	35	1.09	Jan to Mar	outside but GRP housing	July to Sept has missing data
14	54	1.15	Oct to Apr	good	
15	15	1.04	Jan. Feb	No vents	Issues with data in Nov
16	18	1.06	Jan, Feb	outside	

Table 13 : Summary of ratings

The outdoor located transformers are situated in an ambient temperature which is more variable that the indoor temperatures. This means there is more scope to undertake DAR on these transformers and in particular to get benefit from this over the winter months.

The majority of indoor transformers have scope to show benefit in winter when the indoor temperature is lower than the average 20°C from Figure 16 (page 43). Note: some

[16] The time with DAR above unity per unit (39%) gives an exaggerated number due to the data only being from Oct to May, missing the (lower) summer months.

indoor transformers show very few occasions when the temperature drops below 15^{o}C (e.g. transformer 7 and 11).

The dynamic rating is therefore a function of: the ambient temperature, which is modified by housing type and transformer loading; and transformer type, which modifies thermal characteristics. Benefits of over 10% in rating are available within the winter months for not insignificant periods of time.

Table 14, shows an extract from IEC600-76 with, details of an extra component that should be added to the ambient (outdoor) temperature to deal with enclosures and thus reduce transformer name plate rating. This is of the order of 7 to 10^{o}C and as such will impact on the rating. This extra value is not obviously noticeable on the defined ratings in Table 1 (where all values are listed at 20^{o}C ambient). However it is noticeable on the calculated summer dynamic rating as the measured indoor temperature replicates this additional temperature rise and reduces the rating below name plate value.

8.3.2 **Correction of ambient temperature for transformer enclosure**

A transformer operating in an enclosure experiences an extra temperature rise which is about half the temperature rise of the air in that enclosure.

For transformers installed in a metal or concrete enclosure, $\Delta\theta_{or}$ in equations (5) and (6) should be replaced by $\Delta\theta'_{or}$ as follows:

$$\Delta\theta'_{or} = \Delta\theta_{or} + \Delta(\Delta\theta_{or}) \qquad (11)$$

where $\Delta(\Delta\theta_{or})$ is the extra top-oil temperature rise under rated load.

BS IEC 60076-7:2005

60076-7 © IEC:2005 – 33 –

It is strongly recommended that this extra temperature rise be determined by tests, but when such test results are not available, the values given in Table 6 for different types of enclosure may be used. These values should be divided by two to obtain the approximate extra top-oil temperature rise.

NOTE When the enclosure does not affect the coolers, no correction is necessary according to equation (11).

Table 6 – Correction for increase in ambient temperature due to enclosure

Type of enclosure	Number of transformers installed	Correction to be added to weighted ambient temperature K Transformer size kVA			
		250	500	750	1 000
Underground vaults with natural ventilation	1	11	12	13	14
	2	12	13	14	16
	3	14	17	19	22
Basements and buildings with poor natural ventilation	1	7	8	9	10
	2	8	9	10	12
	3	10	13	15	17
Buildings with good natural ventilation and underground vaults and basements with forced ventilation	1	3	4	5	6
	2	4	5	6	7
	3	6	9	10	13
Kiosks (see Note 2)	1	10	15	20	-

NOTE 1 The above temperature correction figures have been estimated for typical substation loading conditions using representative values of transformer losses. They are based on the results of a series of natural and forced cooling tests in underground vaults and substations and on random measurements in substations and kiosks.

NOTE 2 This correction for kiosk enclosures is not necessary when the temperature rise test has been carried out on the transformer in the enclosure as one complete unit.

Table 14 : Extract from standard

Further generalising the results gives the following conclusions:

LP 32.	There is more scope to dynamically rate outdoor transformers than indoor transformers. Well ventilated indoor transformers offer some scope for dynamically rating assets during winter months.

LP 33.	Indoor transformers with no vents are unlikely to be able to be used for dynamic asset rating and there is some evidence to support de-rating from the trial, though this would be on a site specific basis.

LP 34.	Based on the outdoor Distribution transformers, dynamic ratings are principally drive by ambient air temperature. The Trial results suggest that over winter there is scope to run the transformers with around a 10% increase in sustained rating with no increases in aging (as hot spot temperature is limited to operation below 98^{o}C.)

LP 35.	Based on the outdoor Distribution transformers, the Trial results suggest that over summer it may be necessary to run the transformers with a lower rating in the summer

LP 36.	For transformers located at indoor secondary substation, trials suggest that for many sites the (indoor) ambient air temperature is significantly above assumptions that form the basis of name plate ratings. Therefore reducing this air temperature (towards surrounding outdoor air temp) can have a significant ratings benefit.

LP 37.	Standards indicate that a drop in rating from name plate is needed for Distribution transformers located indoors. It is not clear to what extent this has been undertaken by the DNO and further work looking at a review of the approach to rating of identical transformers situated outside versus the types of indoor location (GRP, Brick built, flat roof, pitched indoors) is recommended.

LP 38.	The work has been based on a sustained rating, and it is recommended that consideration be given to extending this work to cyclic loading basis. This could include investigation of the impact of real load curve shapes compared to the standard load curve shapes.

It should be noted that whilst modelled top oil temperatures were validated against measured values, this is not possible for winding hot-spot temperature, the ultimate thermal limit, and basis for life-usage assessment.

SECTION 6

Forward Ampacity based on forecast ambient conditions

This section describes the work undertaken within the project to develop forward estimates of dynamic asset ratings, based on forecast air temperatures, addressing the issue that "of-the-moment" instantaneous values of DAR do not provide a secure basis for operation in a forthcoming period.

6.1 Overview of forward ampacity

"Of the moment" ampacity may not be useful from an operations perspective as to take advantage of ampacity it is necessary to know what this is going to be. This involves looking at anticipated benefits of forward ampacity values, the dependency on accuracy of forecast ambient conditions, and the introduction of probabilistic approach that seeks to manage key risk of exceeding thermal limits.

6.2 Description of derivation of forward ampacity values

The IEC60076-7 model and the same DAR calculation process are used for the calculation of forward ampacity. Ambient temperature forecast values from the BBC forecast (day ahead and week ahead for the Milton Keynes area) in 2014/2015 were used to predict one minute values across the whole period. These are constant within every minute.

Differences were found between the BBC predicted values for (outdoor) temperature, and the measured outdoor temperatures at some of the sites. It is believed that this was due to remaining issues of solar gain on the temperature sensors, and this was adjusted for accordingly. In addition, the BBC predicted (outdoor) temperatures needed to be translated to indoor temperatures (where applicable). The offset to adjust the temperature prediction is completed on an individual site basis, and is based on the mean temperature differences and is shown in Table 15. Comparing the Table 15 values to those in Table 14 shows that some indoor temperatures exceed outdoor temperatures by over $10^{o}C$ in some instances. These are also the transformers which show the lowest benefits. This implies that transformers operating in relatively hot housings showed least benefit.

These combined offsets are shown along with the benefits in Appendix F using day ahead predicted values.

DT		Median temp diff (day ahead adjustment)	Median temp diff (week ahead adjustment)	Location Brick =B GRP =G OD =O	Ventilation
1	UNIT 32 BLUNDELLS RD BRADVILLE	9.92	8.35	G	Good
2	GRANVILLS SQUARE	8.05	6.87	G	Good
3	SHROPSHIRE COURT	9.80	8.11	B	No vents
4	RAINSBOROUGH GIFFARD PARK	9.37	7.92	G	Good
5	LAKES LANE NEWPORT PAGNELL	7.73	6.31	G	Good
6	THE LINX BLETCHLEY	4.76	3.51	O	Outdoors
7	WESTMINSTER DRIVE BLETCHLEY	19.22	17.62	B	Good ventilation
8	COTTINGHAM GROVE BLETCHLEY	5.71	4.89	O	Outdoors
9	ANGUS DRIVE BLETCHLEY	13.08	11.28	B	Some ventilation
10	GLAZIER DRIVE NEATH HILL	10.57	9.03	G	Good
11	MIDDLESEX DRIVE BLETCHLEY.	14.08	12.34	B	No vents
12	BUCKINGHAM GATE EAGLESTONE	6.51	4.37	B	No vents
13	BARNFIELD DR. WEST NETHERFIELD	11.45	10.47	O/G	GRP housing
14	THORNEYCROFT LANE DOWNHEAD PARK	7.59	5.92	B	Good
15	RICKLEY LANE BLETCHLEY	15.30	13.44	B	No vents
16	PELHAM PLACE DOWNSBARN	4.47	3.12	O	Outside

Table 15 : Adjusted predicted temperature offset

LP 39.	It is difficult to translate a forecast outdoor temperature into an indoor temperature due to the variation in the individual characteristics of each site. These differences include the transformer load (influencing interior heating), building thermal mass, and ventilation, building aspect (south facing etc.).

LP 40.	The IEC 60076 recognises the need for a correction from outdoor temperature due to enclosure, though the values they specify are lower than the trial data suggests.

6.3 Calculated forward ampacity

The predicted day ahead and week ahead ambient temperatures were used to generate an ampacity that could then be retrospectively compared to the ampacity obtained using measured values. Appendix F and Appendix G show the forecasted day ahead temperatures compared to the measured ambient temperatures for each transformer. A graph for each transformer shows the predicted rating for each month derived from the day ahead and week ahead forecasts (similar to the second graph in Appendix E). Figure 20 to Figure 22 show examples of the benefits of using the predicted data to calculate the ampacity from the forecast data. Transformer 2 is an indoor ventilated transformer, Transformer 6 is an outdoor transformer and Transformer 15 is an indoor transformer with no vents.

The graphs show a benefit in ampacity in the winter months when the temperature is lower.

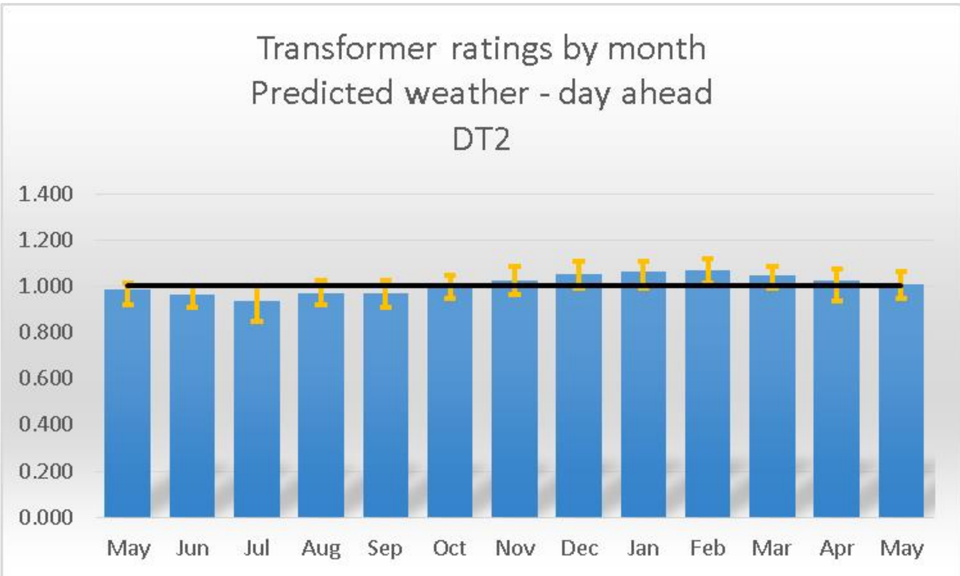


Figure 20: Transformer 2 : Predicted benefits using day ahead weather forecast

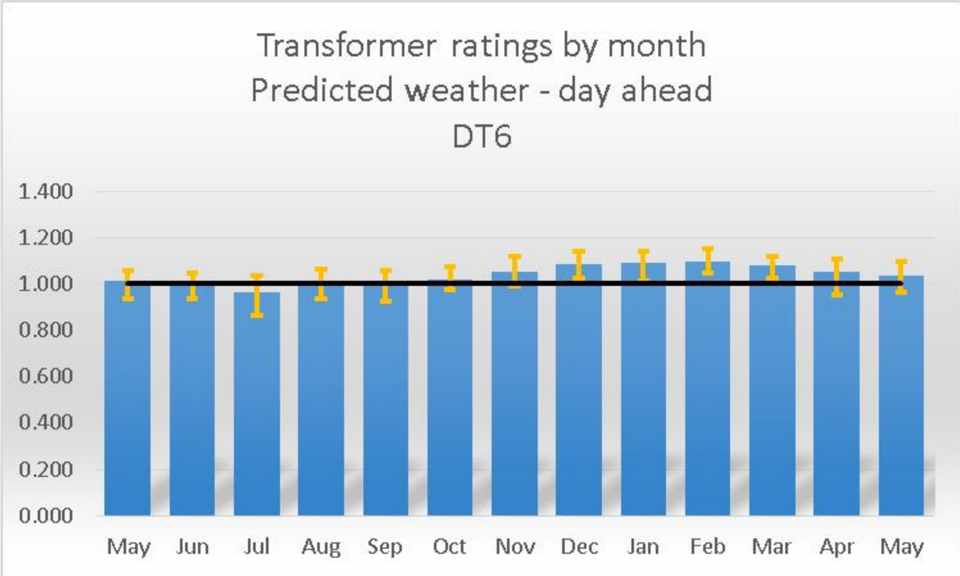


Figure 21: Transformer 6 : Predicted benefits using day ahead weather forecast

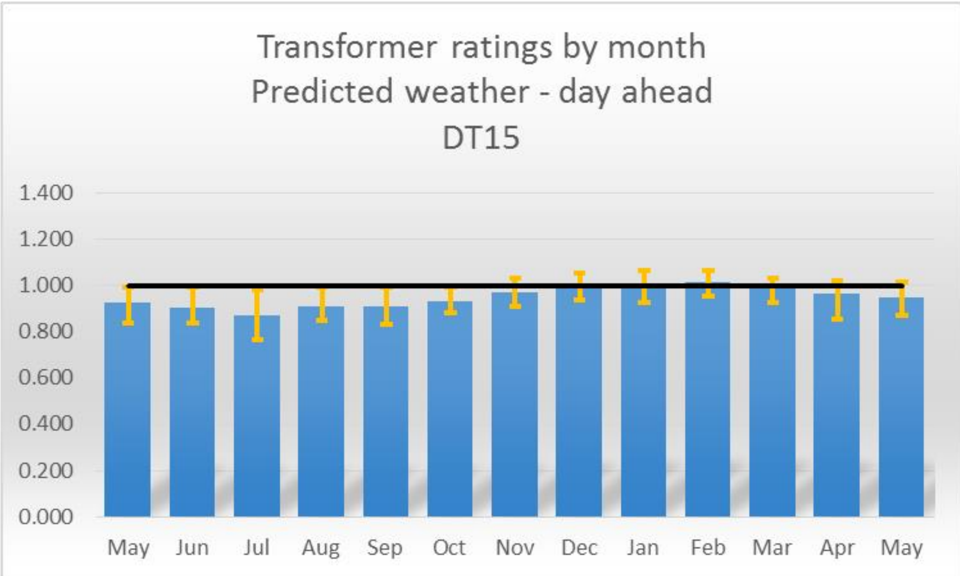


Figure 22: Transformer 15 : Predicted benefits using day ahead weather forecast

The ratings generated from predicted temperatures shown in Appendices F and G and above provide values assuming the predicted weather is totally accurate. Given that there is inherent inaccuracy in these predictions, it is necessary to apply confidence margins so that the predicted ratings could be used with a degree of assurance. In the table below, confidence margins have been calculated for each. These have been calculated by assessing the difference between the calculated rating generated from real-time measured temperature data, and the predicted ratings using the forecast temperatures.

The values shown represent the margin that could be subtracted from the forecast ratings (shown in Appendices F and G) to provide ratings to a 90% confidence level.

Transformer	Error margin needed for 90% confidence (p.u.)	
	Day ahead	Week ahead
1	0.109	0.101
2	0.061	0.054
3	0.046	0.047
4	0.044	0.046
5	0.043	0.045
6	0.057	0.049
7	0.075	0.058
8	0.056	0.047
9	0.055	0.053
10	0.030	0.037
11	0.049	0.045
12	0.024	0.034
13	0.266[17]	0.257
14	0.047	0.048
15	0.061	0.061
16	0.035	0.035

Table 16: Error margin to ensure 90% confidence in predicted transformer ampacity

The values above (with a couple of exceptions) indicate that around 5% error margin should be applied to the rating to allow 90% confidence that the predicted ampacity will be lower than that with measure "of the moment" data.

Applying the error margin to the predicted benefit reduces the benefit available as shown in Appendix H. The graphs of the day ahead benefits for two of the three transformers above are shown in Figure 17 and Figure 18. The Figures show the months where there is calculated benefit with the error margin included. The blue block shows the mean calculated dynamic rating in per unit (p.u.) and the yellow bar the maximum calculated dynamic rating in per unit (p.u.). Also shown is the percentage of time that the transformer has a DAR rating greater than 1 per unit (p.u.) over the months where there is benefit. Note: by applying the error margin to transformer 15 – there is no benefit in ampacity to be gained. Similarly in Appendix H where there is no benefit for a transformer no graph is included.

[17] This is calculated high due to large quantities of poor quality measured data and is not representative of what could be expected. Additional data processing could be used to remove ambiguous data.

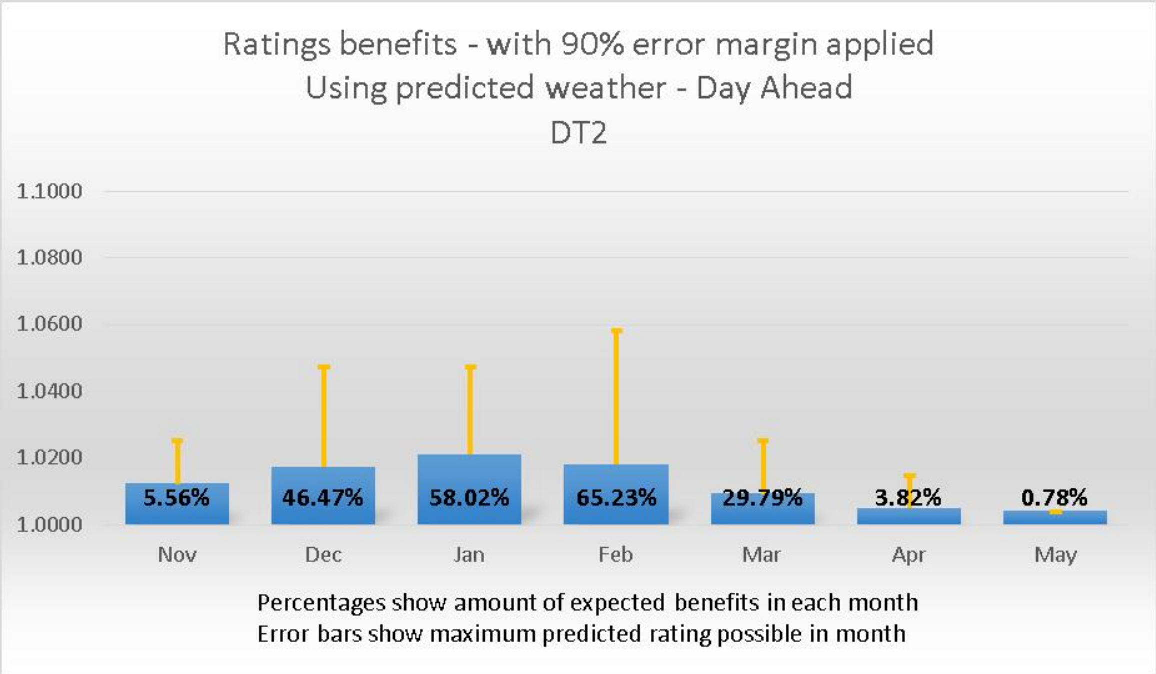


Table 17: Transformer 2: Predicted day ahead benefit with error margin applied

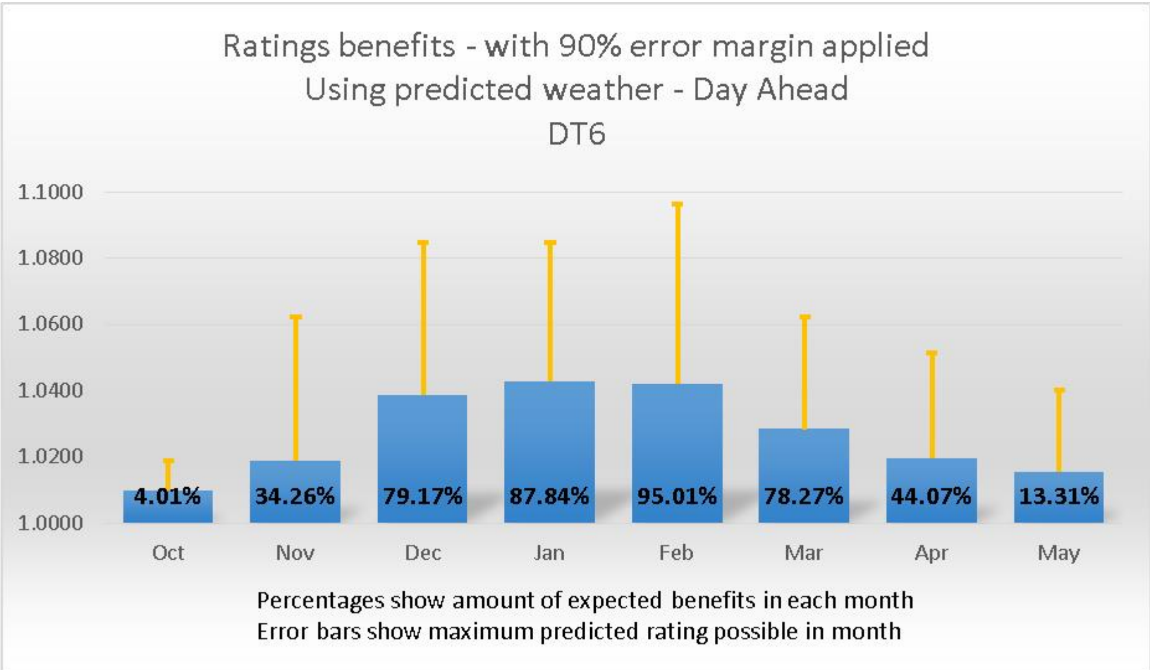


Table 18: Transformer 6: Predicted day ahead benefit with error margin applied

The table below shows a summary of the benefits over the months of January and February (peak load) using day ahead and week ahead predicted data with the error margins from Table 16.

Transformer	Day ahead				Week ahead			
	January		February		January		February	
	% Mean benefit	% time	% Mean benefit	% time	% Mean benefit	% time	% Mean benefit	% time
DT1	No benefit							
DT2	2	60	1	30	1.5	65	1	36
DT3	2.5	60	2	65	1	13	1	17
DT4	2	70	2	85	1	20	1	20
DT5	3	85	3	94	2	40	2	50
DT6	4	88	4	95	2	90	2	80
DT7	No benefit							
DT8	3.5	76	3	90	2	73	2	72
DT9	1	8	1	9	No benefit			
DT10	3	72	2	88	1	15	1	22
DT11	1	9	1	10	No benefit			
DT12	5	90	5	98	3	94	3	93[18]
DT13	No benefit[19]							
DT14	4	78	3	90	1	51	1	53
DT15	No benefit							
DT16	1	8	1	10	No benefit			

Table 19: Summary of mean benefits

Based on Table 19, and Appendix H, the outdoor transformers ampacity using predicted weather result in a gain in peak ampacity of up to ~10% with a mean of up to 5% for a large proportion of the winter months. This compares to peak "of the moment" ampacity gains of up to ~15% based on measured conditions at the time.

Well ventilated indoor transformers show calculated ampacity gains in the winter months of up to 3% for around 70% of the time. Indoor transformers with no ventilation may have no benefits at all. From a planning perspective the housing type should be considered within any DAR application.

The cyclic rating is based on a fixed percentage of the (sustained) name plate rating (e.g. 150% from Table 12). Therefore an increase in the sustained dynamic rating should result in the same percentage increase in cyclic and emergency ratings. However further work outside of these trials is required to prove this.

[18] Based on outdoor temperature. No benefit based on indoor temperature which is reported high

[19] High error margin due to poor quality data – not representative of an outdoor transformer

SECTION 7

Cross-technique Comparison[20]

[20] This section is common to all the engineering technique Final Reports.

Table 20 provides a high level summary of which techniques impact what network metric, with the remainder of the section providing comparison of the DAR Cable technique with other trials, on a network-metric basis.

	DAR - OHL	DAR-Tx	DAR-Cables	ALT	Mesh	Energy Storage
Thermal limits /capacity headroom	✓	✓	✓	✓	~	✓
Voltage limits	No impact	No impact	No impact	✓	~	✓
Fault levels	No impact	No impact	No impact	No impact	×	×
PQ	No impact	No impact	No impact	~	~	✓
Enablement of DG	✓	✓	✓	✓	✓	✓
Losses	×	×	×	✓	✓	×
CI/CMLs	No impact	No impact	No impact	~	~	No impact
Grid/ network services	No impact	No impact	No impact	No impact	No impact	✓

Key: ✓Positive impact; ×negative impact; ~ network dependant, may have positive or negative impact

Table 20: Cross-technique comparison of impact.

Network capacity:

- All techniques altered capacity on the network;
- DAR evaluates capacity more accurately than static ratings which may suggest additional or in some cases less capacity. OHLs are predominately affected by wind speed/direction meaning significant variations occur both across seasons and within short time scales (minutes). When this variability of rating is combined with the low thermal capacities of OHLs (i.e. the OHL temperatures respond rapidly to the environmental changes), taking advantage of this technique is limited to particular circumstances. The dynamic ratings of both cables and transformers are dependent on ambient temperatures, meaning diurnal (for transformers only) and seasonal variations are clearly present, and the larger associated thermal capacities means short-time duration changes in ambient conditions cause less short term variability in asset ampacity;
- ALT and mesh shift load from one part of a network to another, thereby potentially relieving constraints. ALT offers a far more intuitive mechanism, whilst mesh is continually dynamic by its very nature. The extent to which benefits exist is highly dependent on the connectivity of any candidate network, and loads/generation connected to the network, and the extent to which the loads vary relative to each other; and
- Energy storage shifts load in time, reducing load at a capacity constrained key point in time, only to increase the load at a less critical point in time. The specified power and storage energy capacity clearly need to be appropriately matched to the network load; and adaptive triggering is required to deal with individually daily variations in load, to optimise the impact that the installed system can have on the network.

Energy Storage may complement DAR by providing a mechanism to alter load patterns such that constrained assets might make the best use of available ampacity.

Voltage:

- Three of the techniques offer some potential for benefits (ALT, Mesh, ES);
- ALT demonstrated the largest benefit (4%), on some of the rural circuits that were trialled, but no significant benefit was found on urban circuits;
- Mesh considered a small urban network and for this example there was no significant impact on voltage;
- In general the voltage benefit of the ALT and mesh techniques networks will depend on the voltage difference across pre-existing NOPs, and does not directly address voltage issues at the end of branches
- The installed energy storage systems achieved little impact. In general, the reactive power capacity in relation to the magnitude and power factor of the adjacent load is modest, and can be expected to be expensive to deliver for this benefit alone.

Fault level:

- As is clearly already recognised, introducing generation (including ES) to a network will ordinarily increase fault level, in this instance the ES were small compared to pre-existing fault levels, and so had negligible impact. Meshed networks will also increase fault level due to the reduced circuit impedance. For the mesh technique trial, this was within the ratings of all circuit equipment.

Power Quality (PQ):

- Mesh trials showed no discernible impact on power quality. Super-position theory and the feeding of harmonic loads via different sources means that harmonics presently fed from one source could be fed from two sources (depending on Network impedances), however, it is unlikely that larger scale trials will show any marked appreciable benefits as the majority of loads are within limits defined by standards and as such it will be difficult to differentiate small changes;
- The installed energy storage equipment did not specifically have functionality aimed at improving PQ. At one site, improvement was noted, however this was a beneficial coincidence arising from the nature of a local (within standards) PQ disturbance and the inductance/capacitance smoothing network in the Energy storage system;
- More targeted studies of a network that has a known PQ issue could be identified to further examine the potential of mesh/ALT techniques to beneficially impact this issue.

Enablement of DG:

- This was not specifically studied as part of the engineering trials (e.g. interaction between the engineering techniques and DG was not designed into the trials);
- Whilst not a direct focus of the FALCON trials, it is clear that DAR systems may offer potential benefit to distributed generation, but is highly dependent on circumstances.

For example, OHL DAR can increase export from OH connected wind farms on a windy day; but solar farm output peaks occur on clear summer days when DAR OHL is less likely to provide additional benefit;

- ALT may facilitate the connection of more distributed generation. However, this needs to be looked at on a case-by-case basis as the location of the generation along the feeder, in relation to the ratings and load, can have an impact. Where the generation is close to the source (such as in the FALCON ALT OHL trial), there is scope to add a significant amount of generation so that the feeder is able to export at the Primary and also meet the load requirements along this feeder. The nominal location for the open point may well be different between when the generation is running or is off and this may impact other metrics such as losses and voltage regulation if generation operating condition is not considered.
- Meshing may facilitate the connection of more distributed generation by providing a second export route in certain scenarios, thus saving on line and cable upgrades. Modelling also indicates that there may be cost savings from reductions in feeder losses when meshing a network with DG connected to one feeder. However, the benefits of reduced losses would have to be compared on a case-by-case basis with the costs of more complex protection required for meshing (potentially necessitating replacement of existing protection relays as well as new relays).
- ES systems offer potential benefit to distributed generation. Examples of this include: peak generation lopping - storage of peak energy production (say above connection agreement levels) for later injection to the grid; and storage of energy to allow market arbitrage.

Losses

- As discussed in the preceding technique-trial specific section, ALT and Mesh offer some potential, though the magnitude is network specific.
- The trialled ES systems increased losses, and DAR will tend to increase losses if higher circuit loads are facilitated.

CIs and CMLs

- ALT changes NOP positions and consequently affects numbers of connected customers per feeder. The trial algorithms:
  - Increased one feeder numbers by 15% (whilst optimising capacity headroom) on a rural/OHL network; and
  - Increased one feeder numbers by 50% (whilst optimising losses/voltage) on an urban/cable network.
- Meshing networks does not improve customer security as such; the improvement only occurs if additional automatic sectioning/unitising occurs beyond that offered by the pre-existing NOP. Due to communication system limitations, the implemented trials did not increase the number of sections, essentially maintaining the pre-existing customer security.

Grid/network Services:

Whilst these trials have demonstrated that frequency response is possible with the ES technique, a marketable service is not fully delivered by the installed equipment. In addition, further work would be required to put DNO owned energy storage on an appropriate commercial basis. Refer to the WPD Solar Store NIA project.

SECTION 8

Conclusions and recommendations

Transformer DAR is dependent on thermal models. These contain transformer specific data that is not readily available. A method of determining this data by parameter tuning has been investigated over several months. For implementing on a transformer outside the trial, a period of data collection would be required to calculate necessary model parameters. This complicates the use of Distribution transformer DAR in a planning context: either extensive data collection is required, or conservative generic assumptions of model parameters would have to be used (leading to little benefit). However, the period of data collection is not so great as to preclude it from assessing a transformer nearing its operating limits.

Outdoor transformers ampacity assessments, using predicted weather, result in a gain in peak ampacity of up to ~10% with a mean of up to 5% for a large proportion of the winter months. This compares to peak “of the moment” ampacity gains of up to ~15% based on measured conditions at the time.

Well ventilated indoor transformers show calculated ampacity gains in the winter months of up to 3% for around 70% of the time. Indoor transformers with no ventilation may have no benefits at all. From a planning perspective the housing type should be considered within any DAR application. Planning tools should allow for a wider range of asset attributes to be included, such as housing type and ventilation.

The cyclic rating is based on a fixed percentage of the (sustained) name plate rating. Therefore an increase in the sustained dynamic rating should result in the same percentage increase in cyclic and emergency ratings. However further work is required to prove this.

Therefore, the technique trial indicates that there is potential benefit from the deployment of Distribution transformer DAR, to reassess thermal capacity on a case by case basis.

Such potential could be targeted at existing transformers that are approaching thermal/load limits, involve limited installation of temperature & load monitoring, tuning of transformer specific models, and assessment of potential to run at higher than nominal ratings.

This approach could include addressing the issue of risk management with respect to transformer life. With this method, there will be a small number of days were the ambient temperatures are materially above seasonal averages, and accelerated (vs par) life usage could occur on such days. It is recommended that further work should initially focus on a candidate outdoor secondary transformer to trial actual solution provision.

Dynamic asset rating of indoor secondary transformers also appears to offer some potential, though the potential improvements would arise from additional ventilation. Again this potential opportunity could be taken by investigating specific examples of secondary substations approaching thermal/load limits, installing simple monitoring and assessment equipment, and specifically look at improving ventilation as a means of enhancing available capacity.

Appendices

A References

[1] International Electrotechnical Commission (IEC). "Power transformers - Part 7: Loading guide for oil-immersed power transformers," *IEC 60076-7,* pp. 1-110, (2005).

[2] EA Technology, "Transformer Dynamic Ratings," STP report, project S5196_4, Mar. 2011

[3] International Electrotechnical Commission (IEC). "Power transformers - Part 7: Loading guide for oil-immersed power transformers," *IEC 60354,* pp. 1-110, (1991).

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[8] T. Raıssi, N. Ramdani, and Y. Candau, "Set membership state and parameter estimation for systems described by nonlinear differential equations," Automatica, vol. 40, no. 10, pp. 1771–1777, Oct. 2004

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[10] T. Gneiting and R. Ranjan, "Comparing Density Forecasts Using Threshold- and Quantile-Weighted Scoring Rules," J. Bus. Econ. Stat., vol. 29, no. 3, pp. 411–422, Jul. 2011

[11] D. Ruppert and M. P. Wand, "Multivariate Locally Weighted Least Squares Regression," Ann. Stat., vol. 22, no. 3, pp. 1346–1370, Sep. 1994

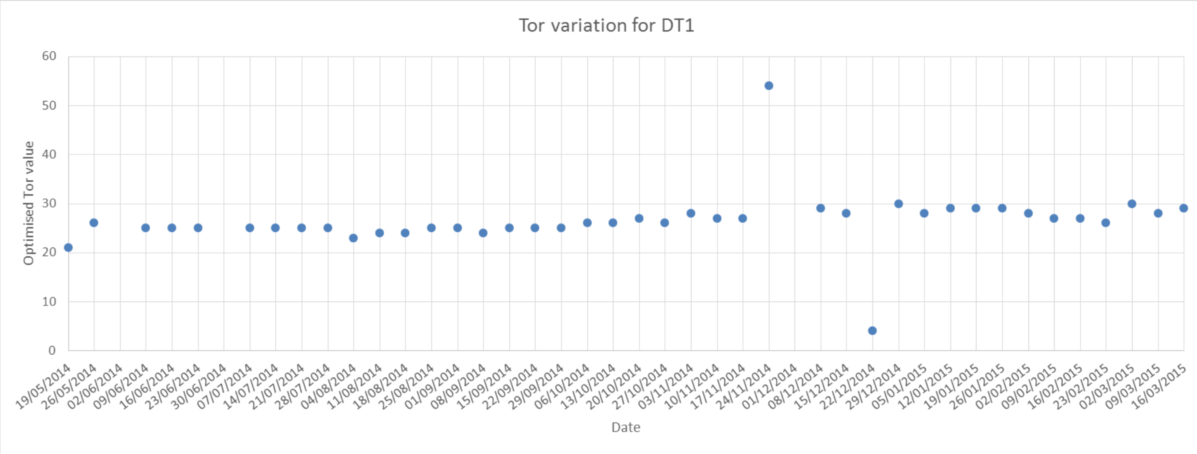
B Learning Objectives

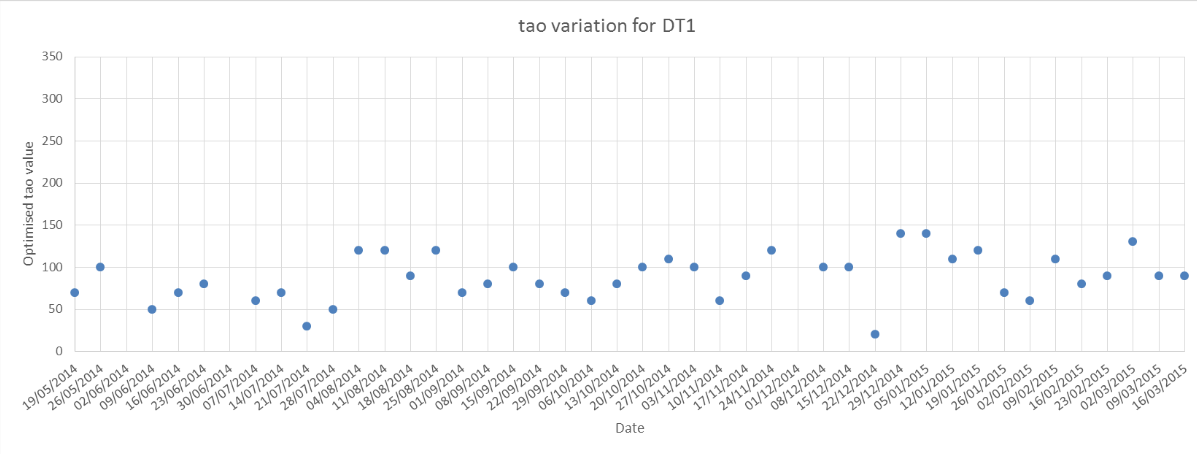
	A	B	C
1	A1 - Understand thermal models of assets	B1 - Define the boundaries or limits of safe operation	C1 - Define the effect of ambient temperature on assets
2	A2 - Understand changes in maintenance required for all components	B2 - Define the effect of solar irradiation on different asset types	C2 - Define the effect of wind speed and direction on different asset types
3	A3 - Applications of pre-emptive transformer cooling	B3 - Define the granularity of ampacity values required by control	C3 - Communications template/model for technique
4	A4 - Benefits of using MET office data versus real-time data	B4 - Validity of external data, e.g. MET office and own internal predictions/assumptions	C4 - Applications of forward predictions of ampacity values versus load required
5	A5 - Benefits comparison of sensor types and location of placement	B5 - Template for sensor installation on asset types	C5 - Analysis of relationships between different sensor values
6	A6 - Variability of conditions across an asset/confidence in data obtained	B6 - Analysis of effectiveness of assumptions versus real-time obtained values	C6 - Required post-fault running conditions
7	A7 - Application of short term overload on different asset types	B7 - Running conditions required during adjacent outages	C7 - Analysis of probabilistic and deterministic ratings of lines
8	A8 - Future policy for application of dynamic asset ratings across the network	B8 - Quantification of length of reinforcement deferral after implementation	C8 - Standard technique for retrofitting DAR on each asset class

Note: The Learning Objectives presented above were developed generally for the DAR technique (including overhead lines and cables). As such, not all of the objectives are directly applicable to Distribution transformers. The following Learning objectives do not apply:

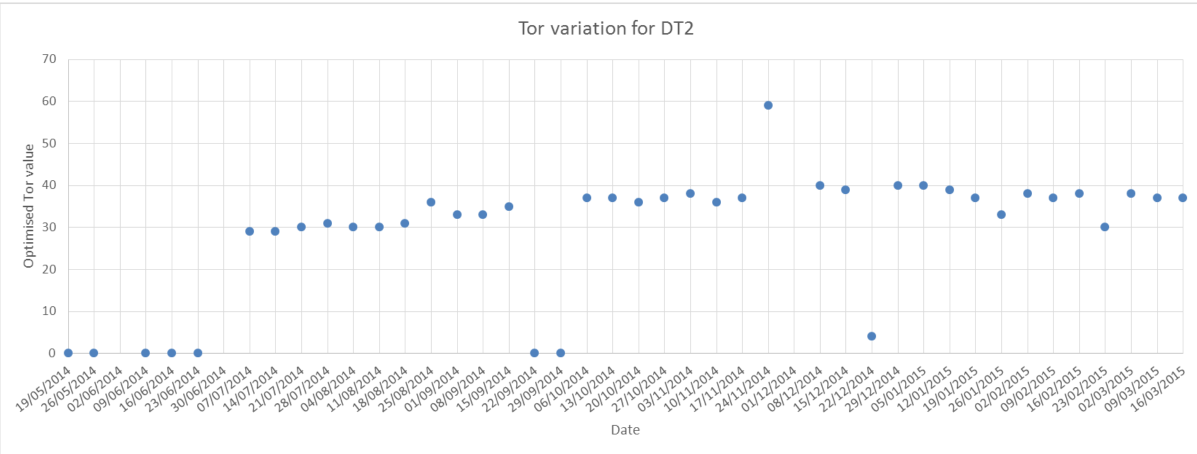
- A3 - Applications of pre-emptive transformer cooling (discussed in Primary Transformer report);
- C5 - Analysis of relationships between different sensor values;
- C6 - Required post-fault running conditions;
- A7 - Application of short term overload on different asset types (discussed in primary Transformer report); and
- B7 - Running conditions required during adjacent outages.

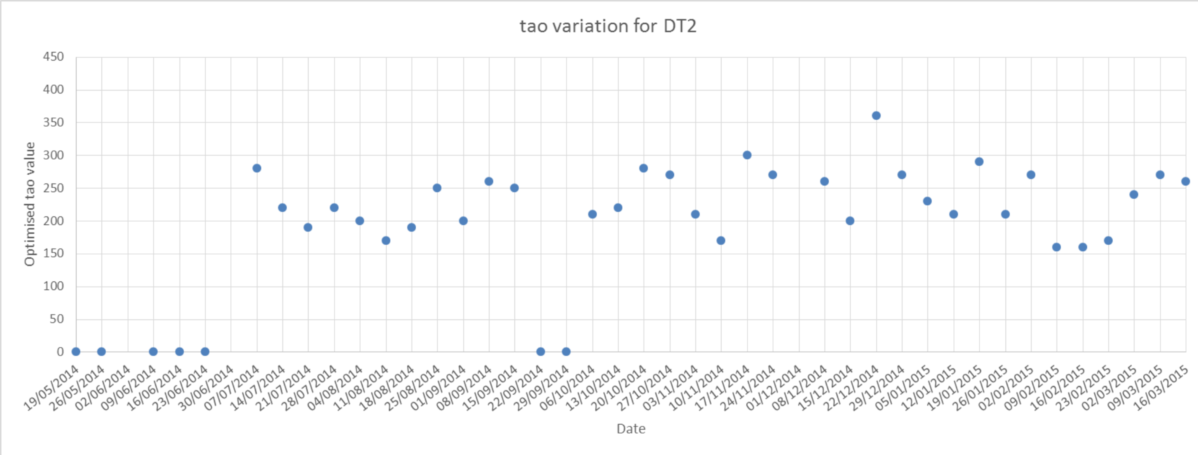
C Tuned top oil parameters for each transformer



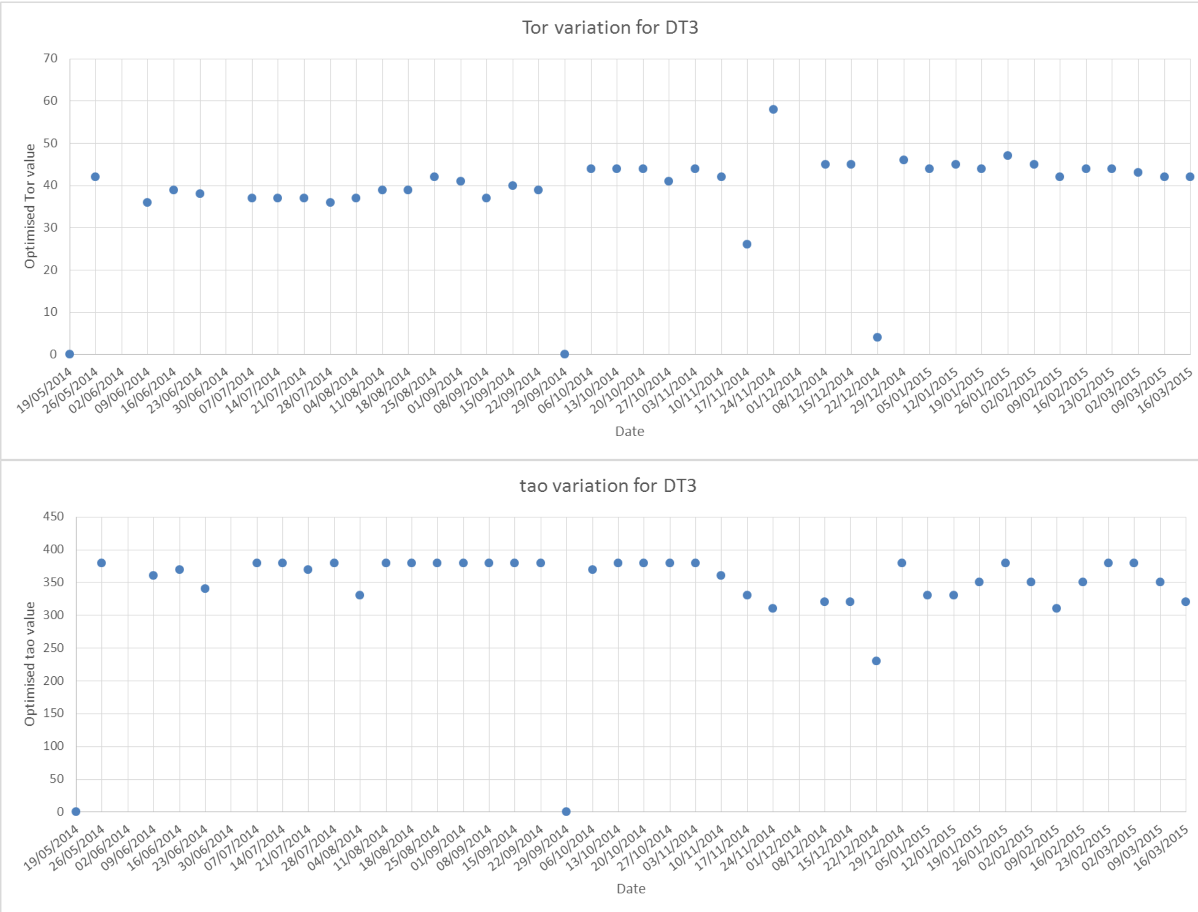


Tuned ΔT_{tor} and τ_o parameters for transformer 1





Tuned ΔT_{tor} and τ_o parameters for transformer 2



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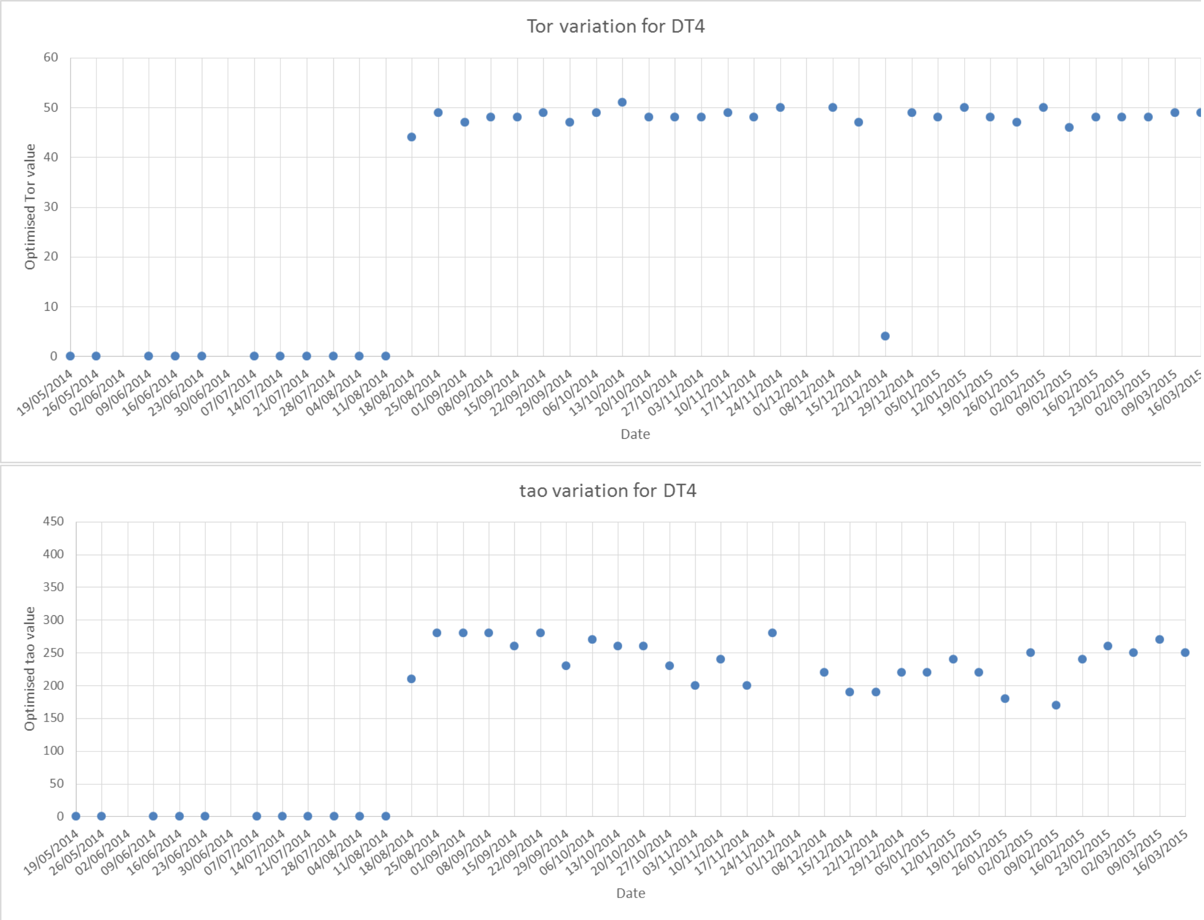

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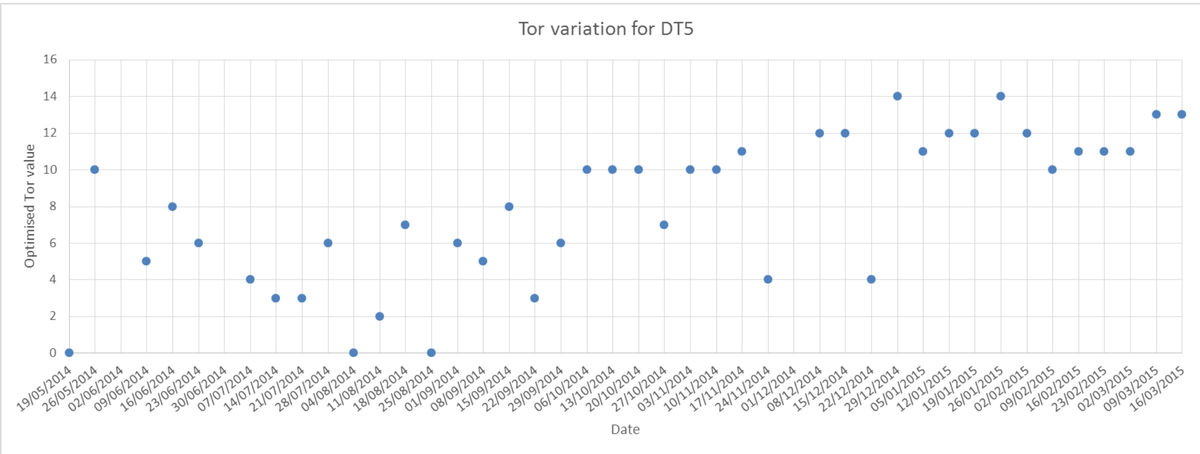

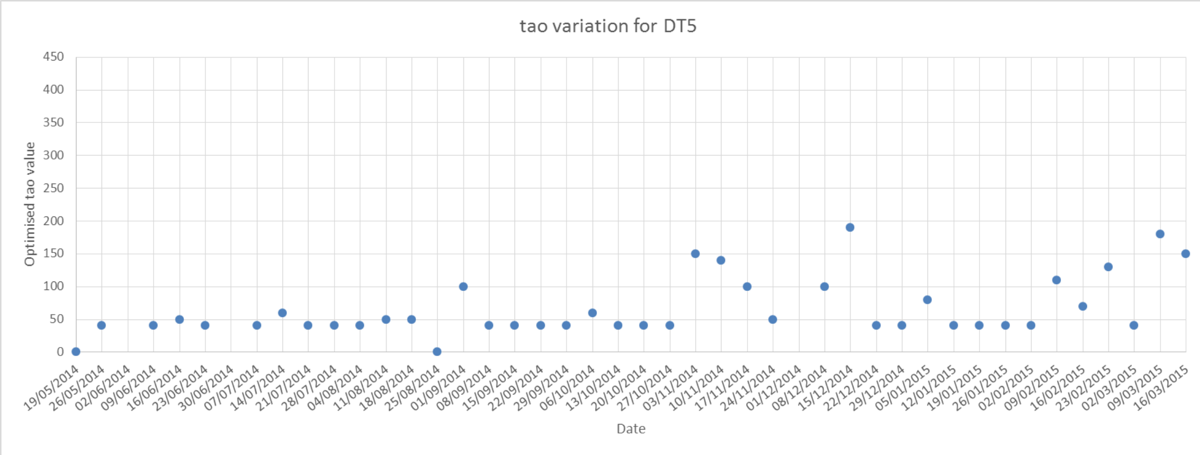

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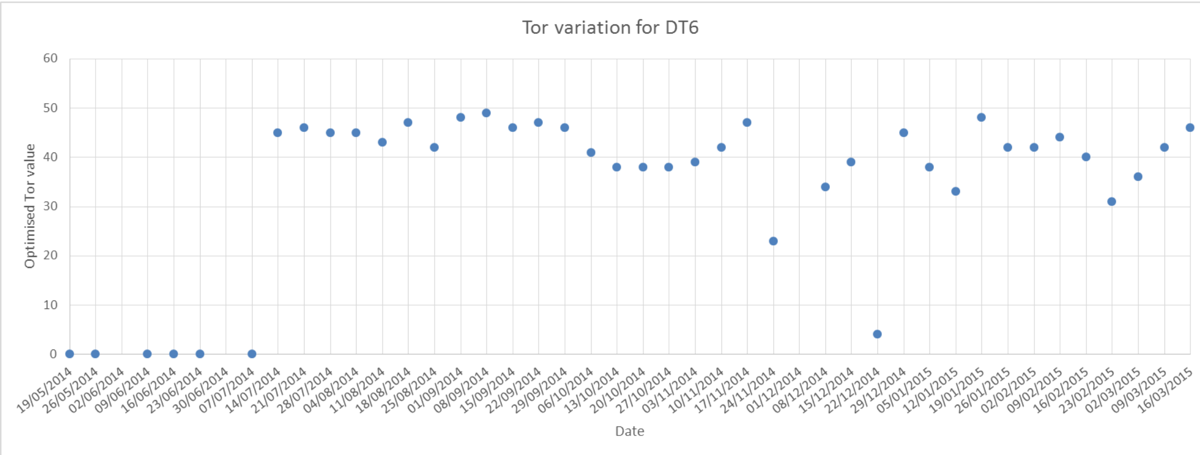

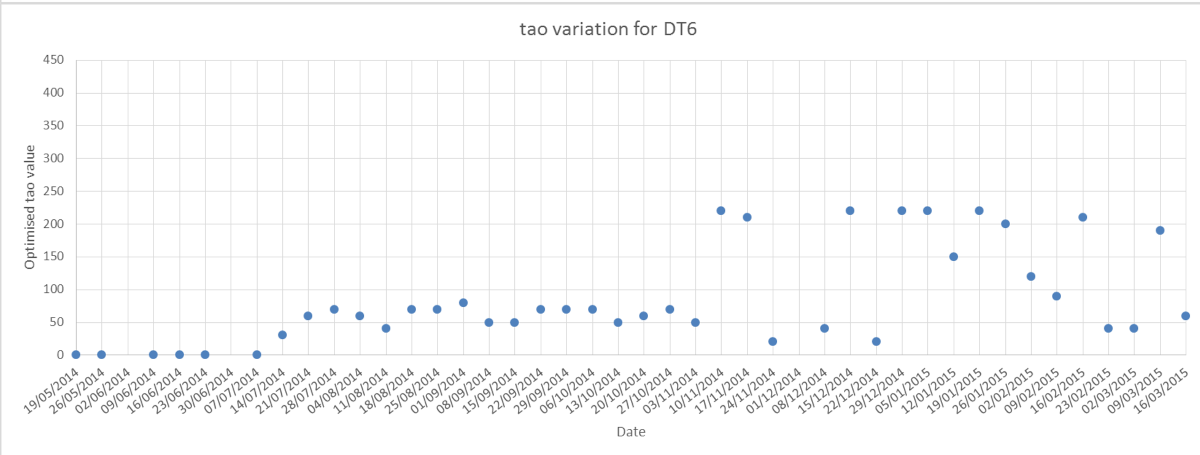

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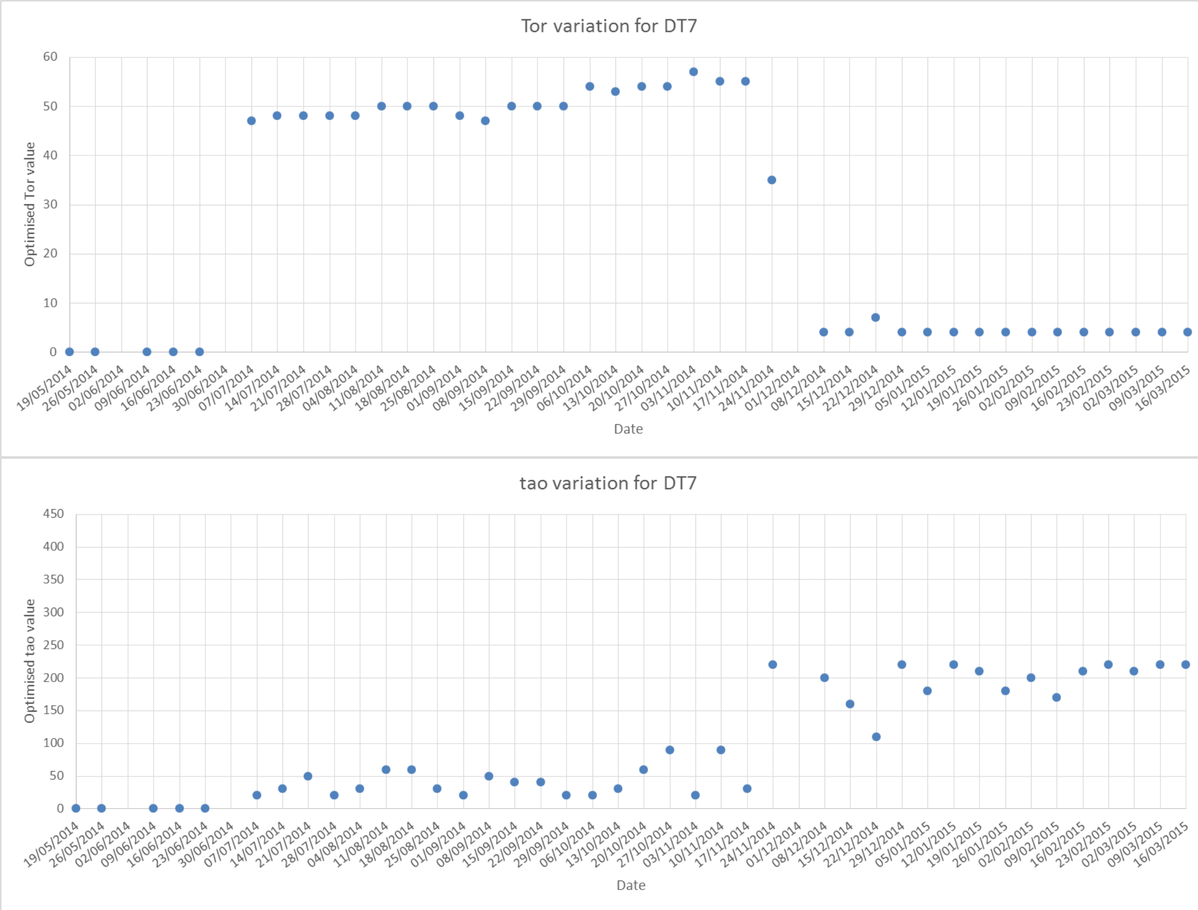
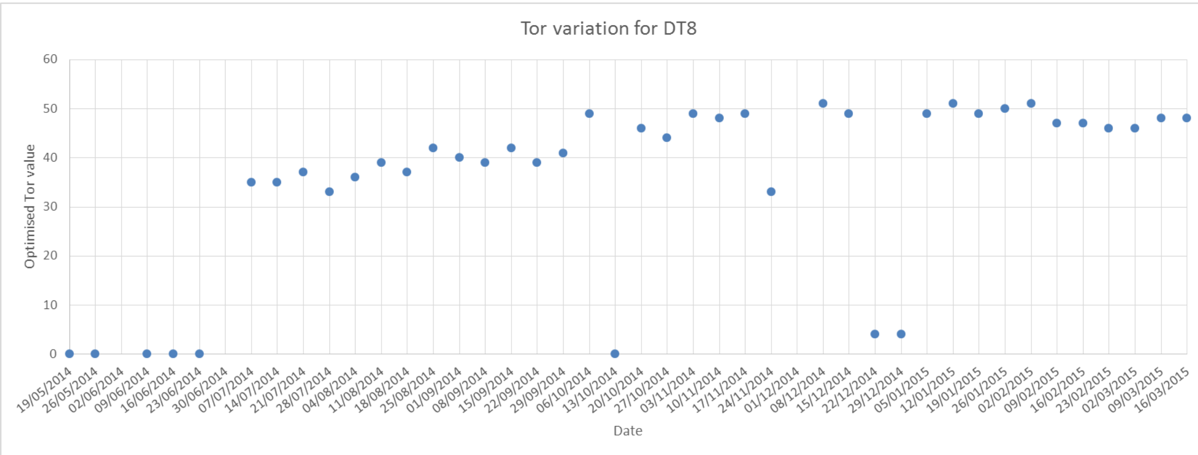
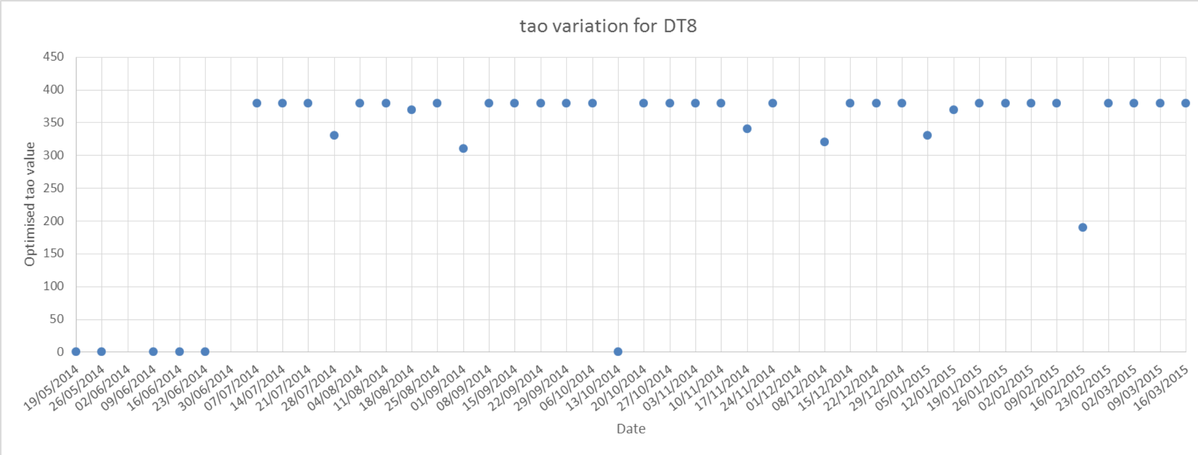
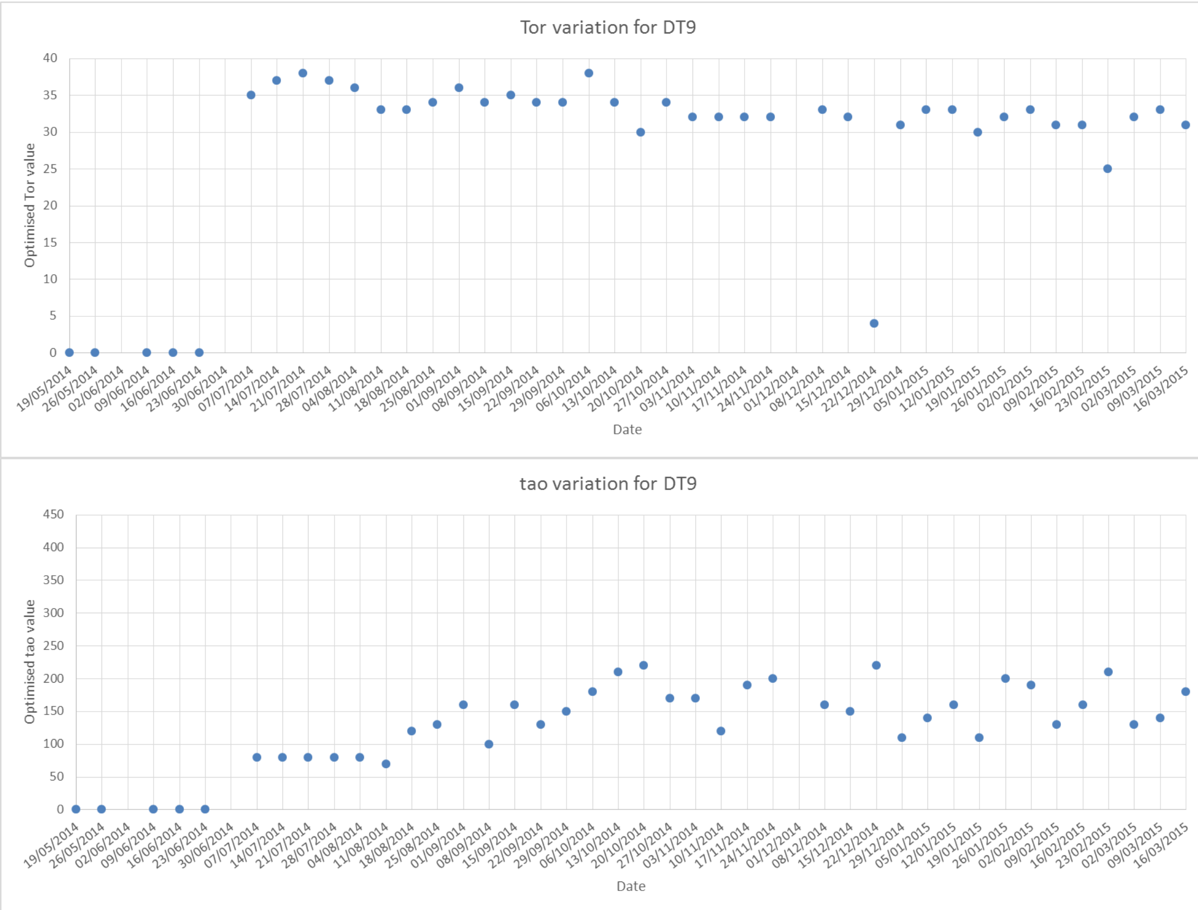


Tuned ΔT_{tor} and τ_o parameters for transformer 7





Tuned ΔT_{tor} parameters for transformer 8



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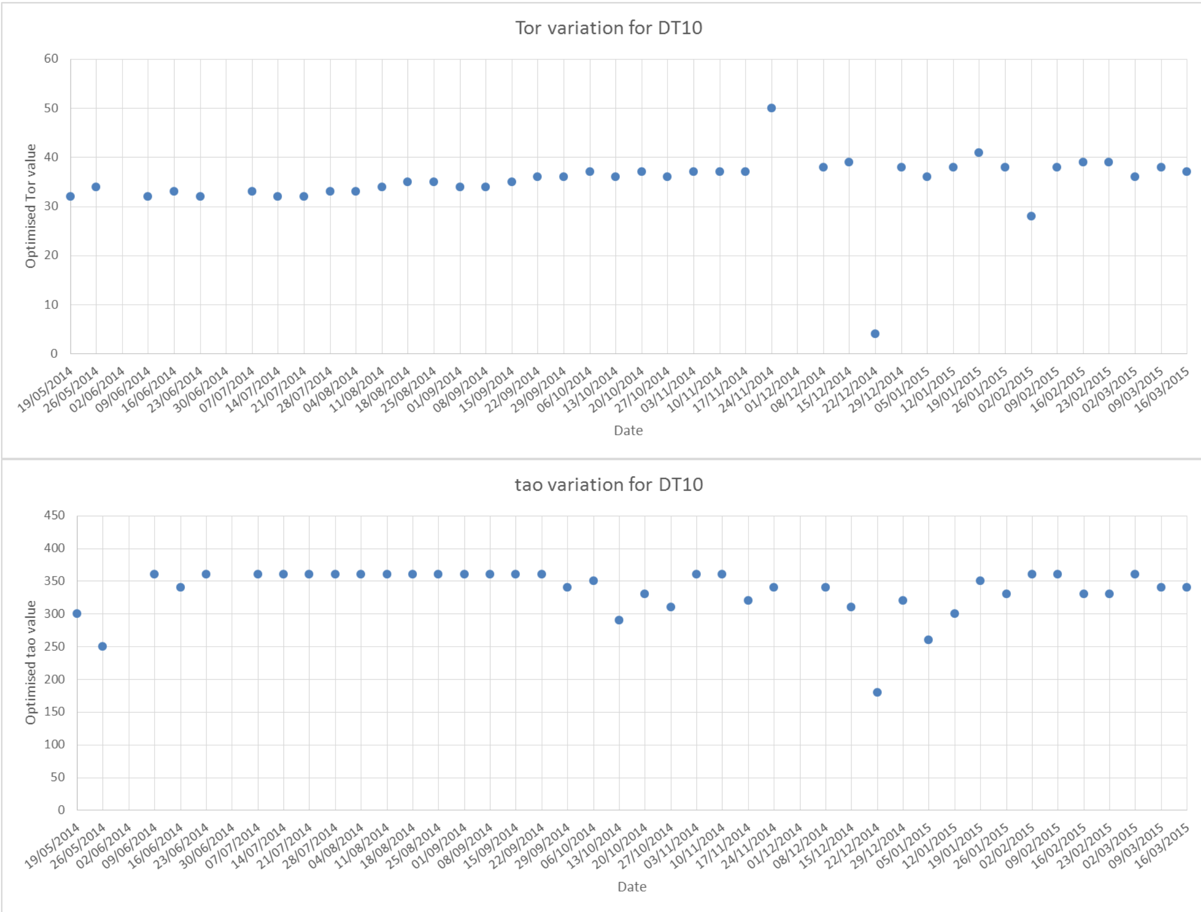

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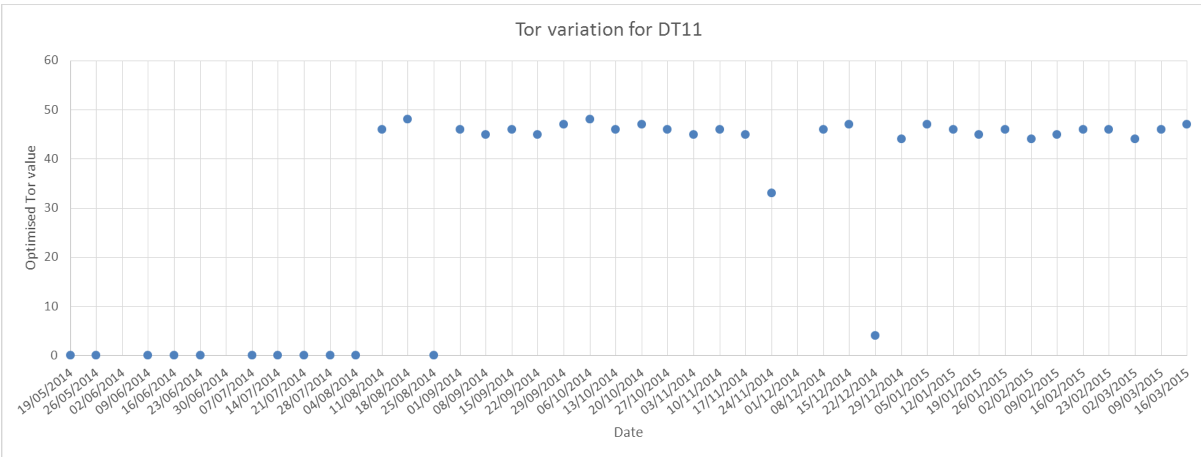

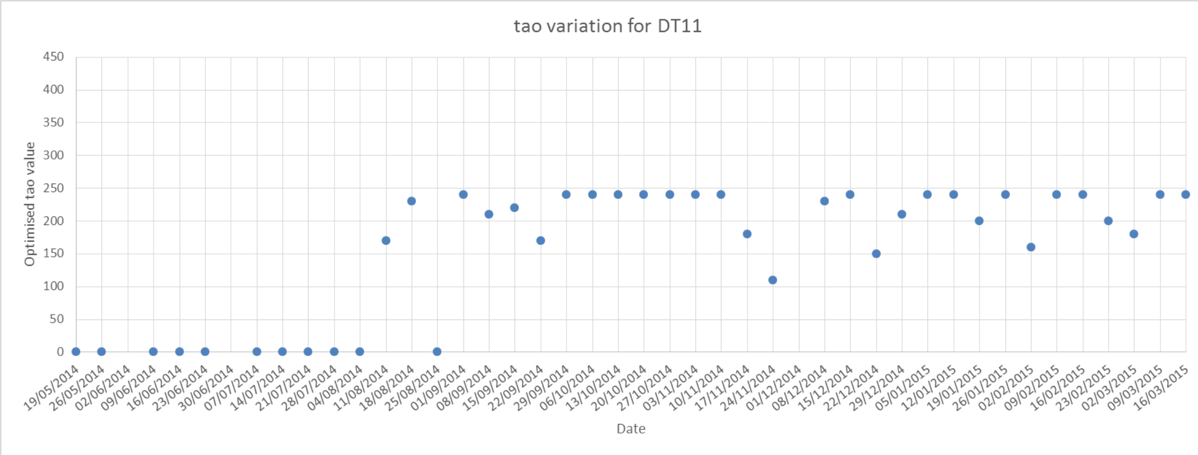

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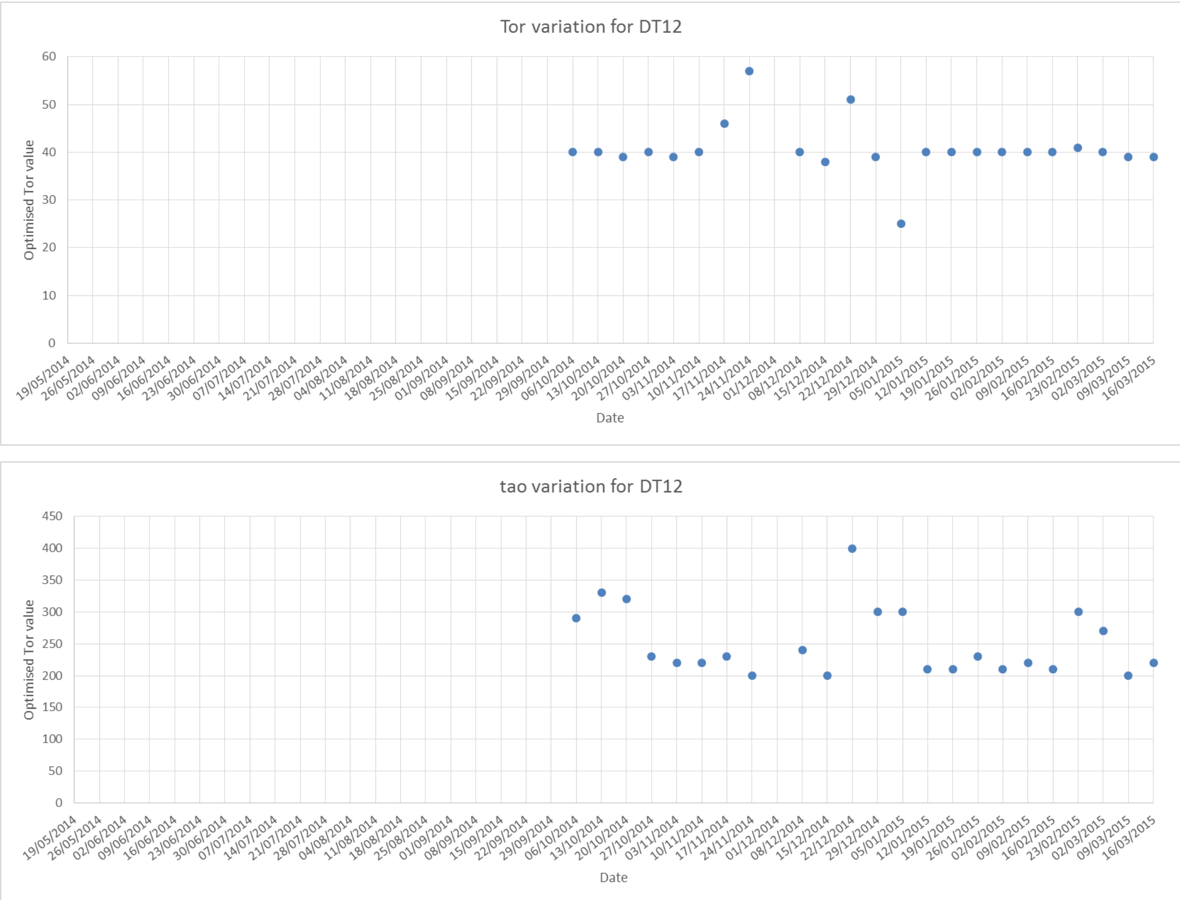
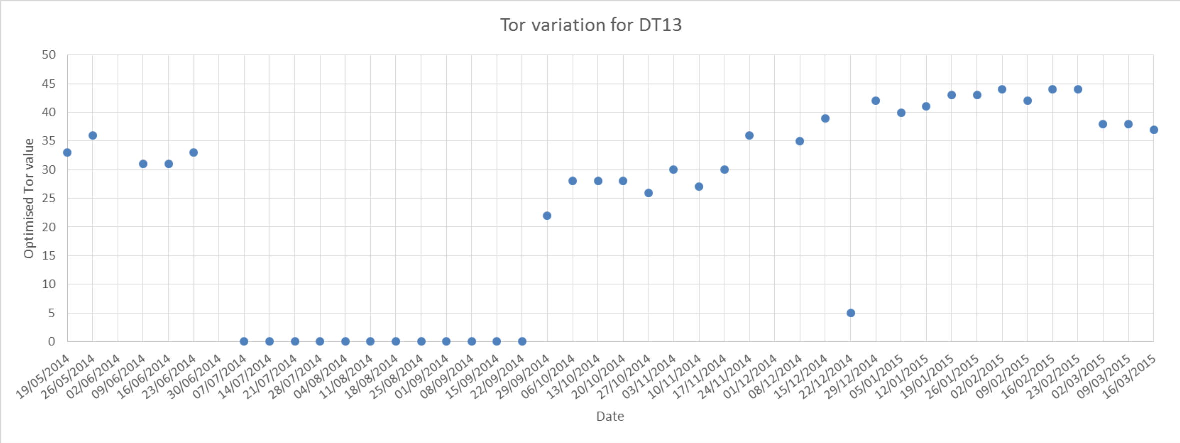
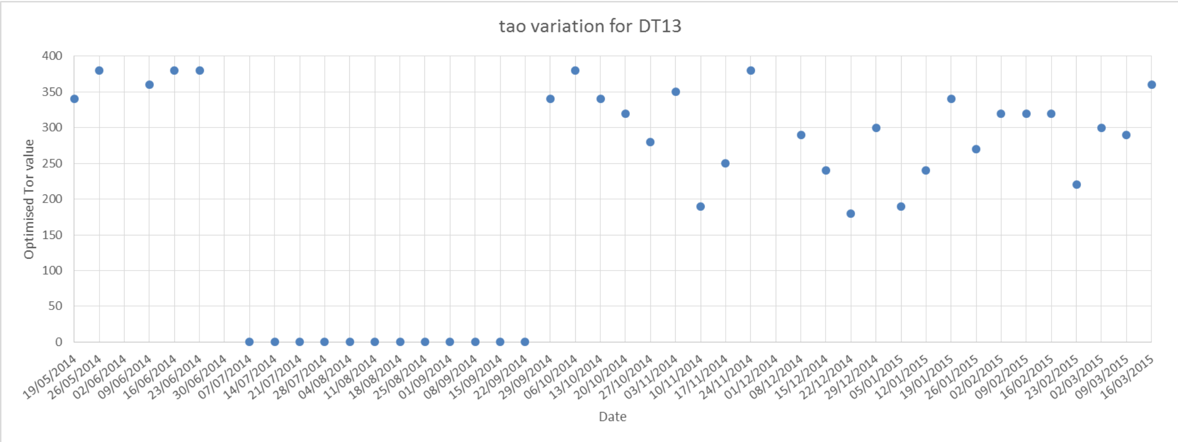


Tuned ΔT_{tor} and τ_o parameters for transformer 12





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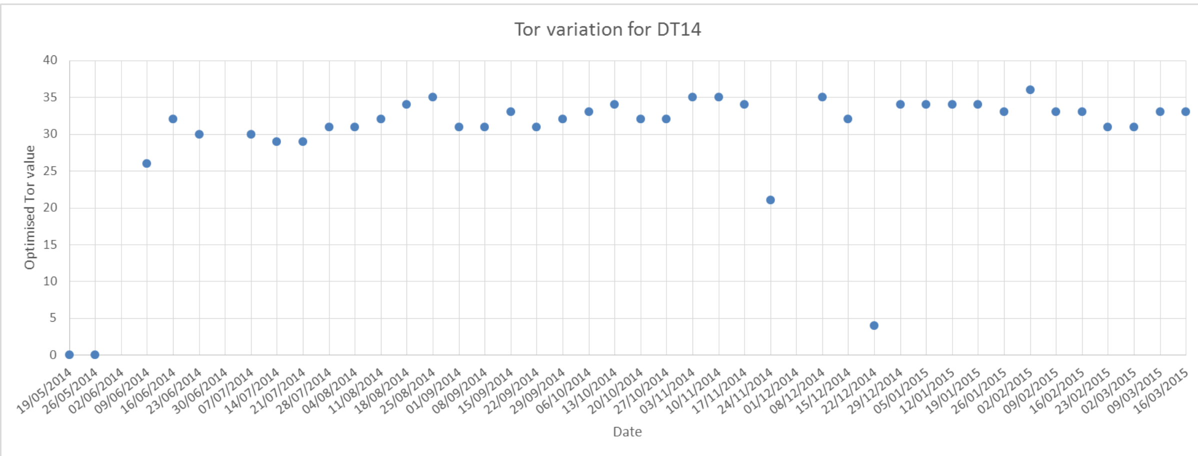

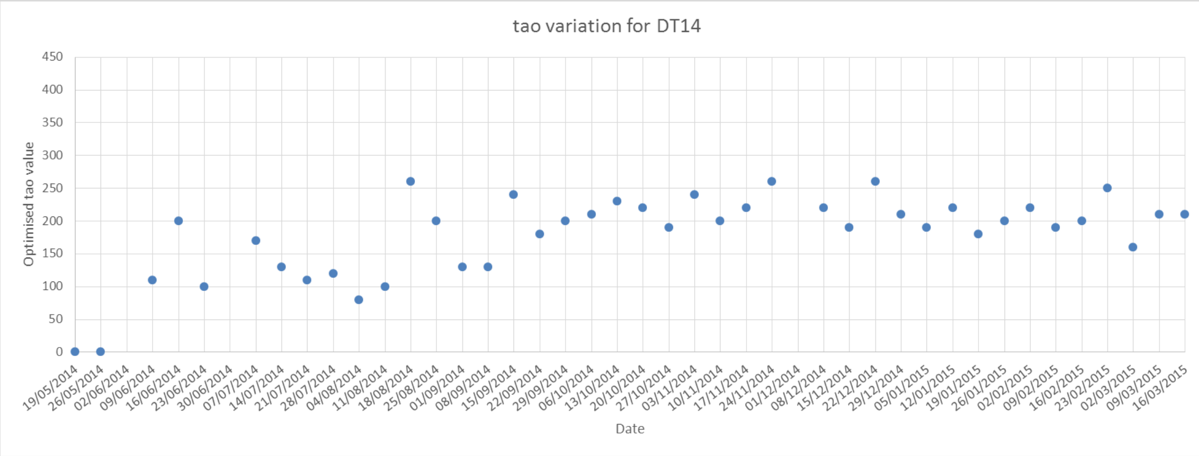

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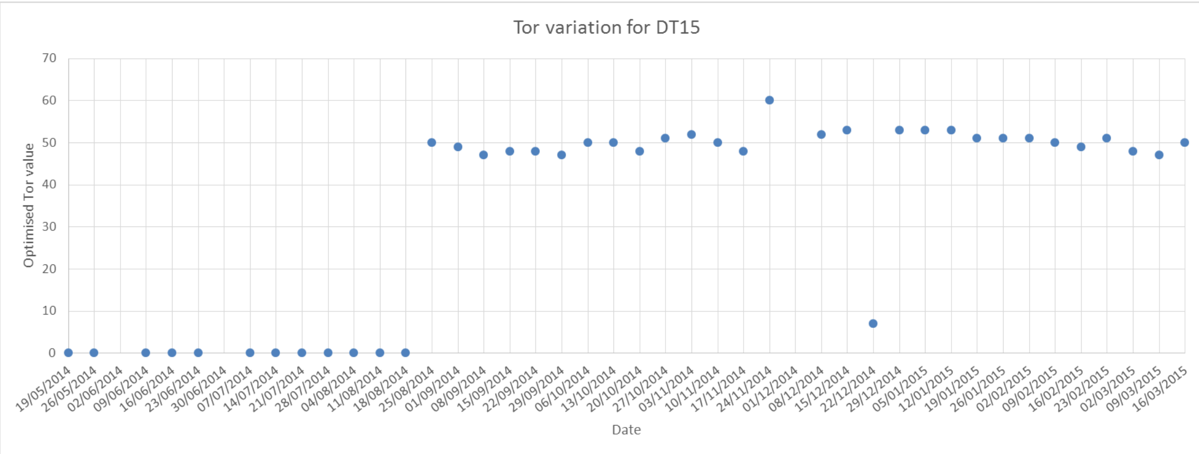
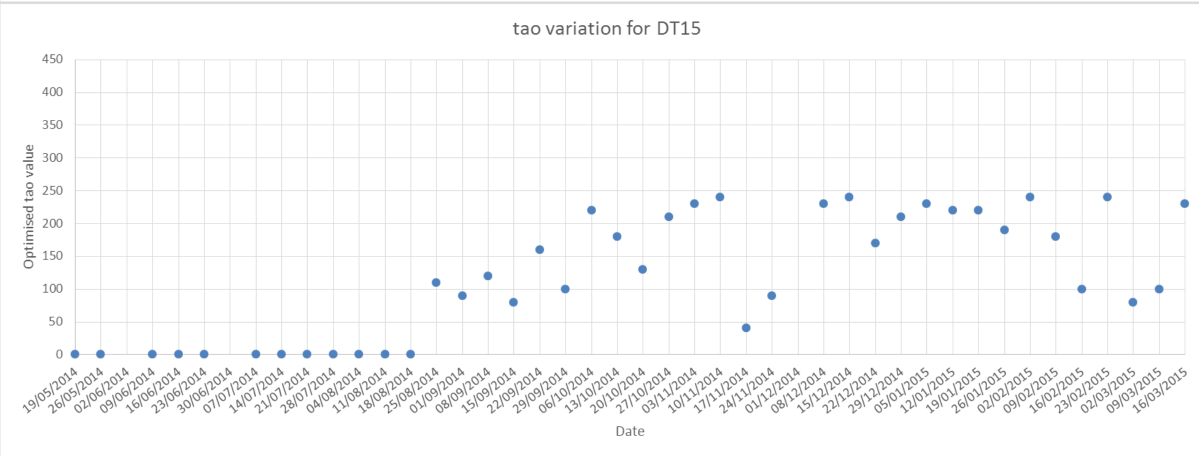
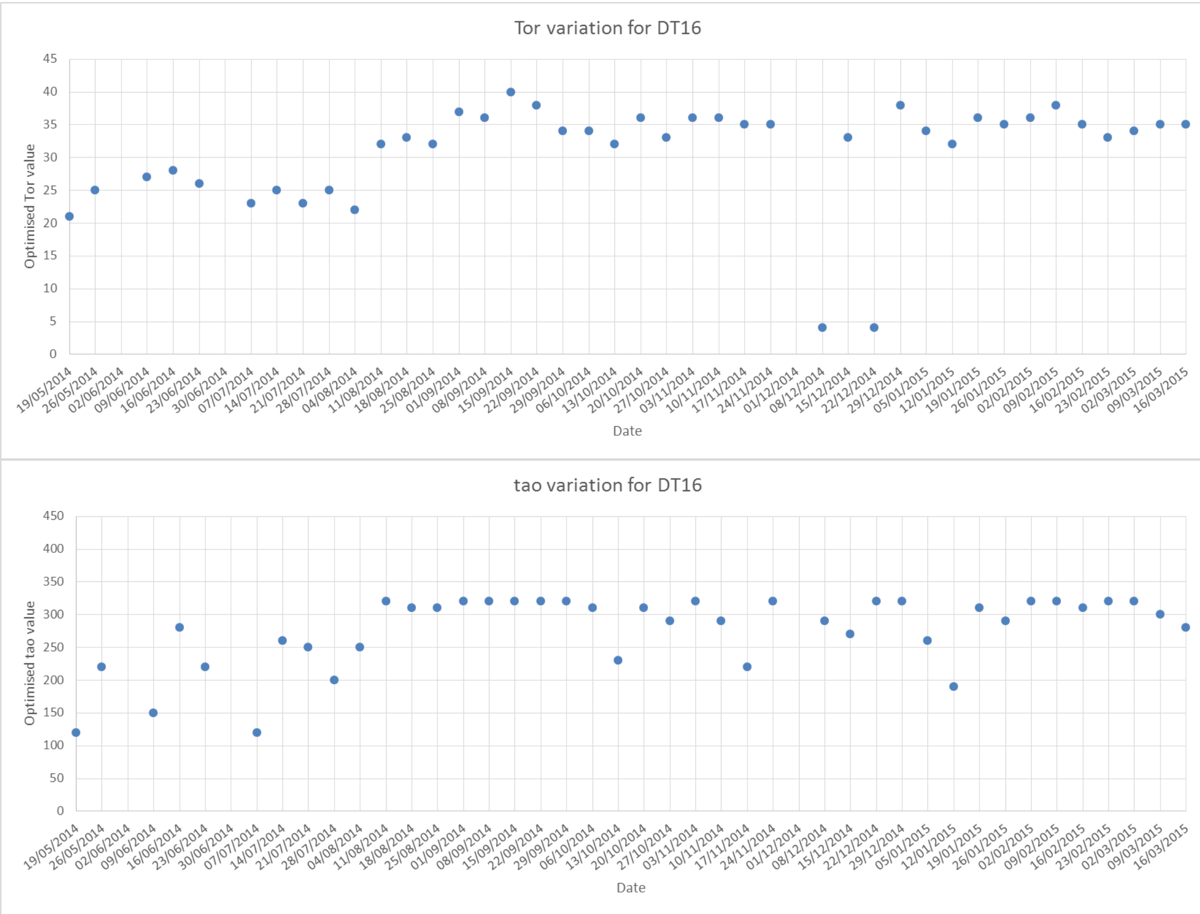




Tuned ΔT_{tor} and τ_o parameters for transformer 15

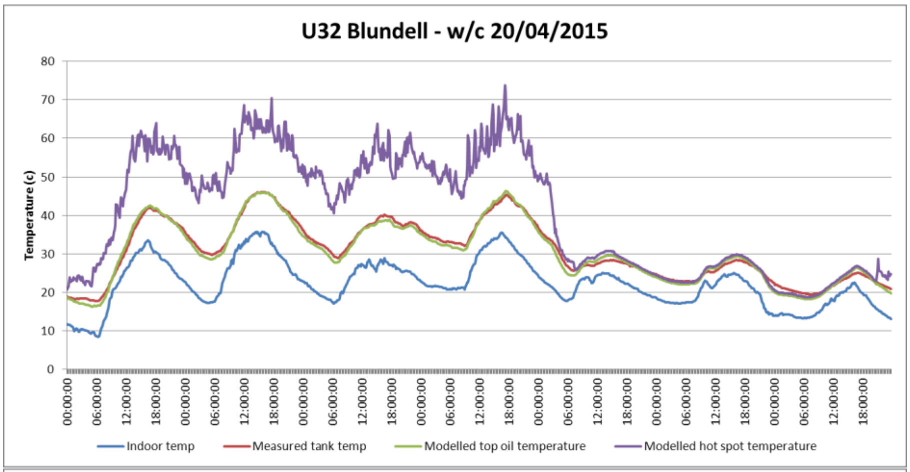


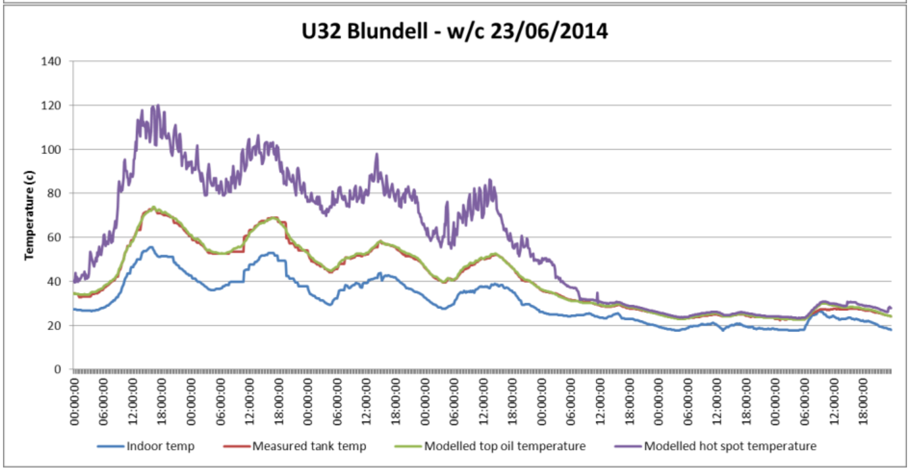
Tuned ΔT_{tor} and τ_o parameters for transformer 16

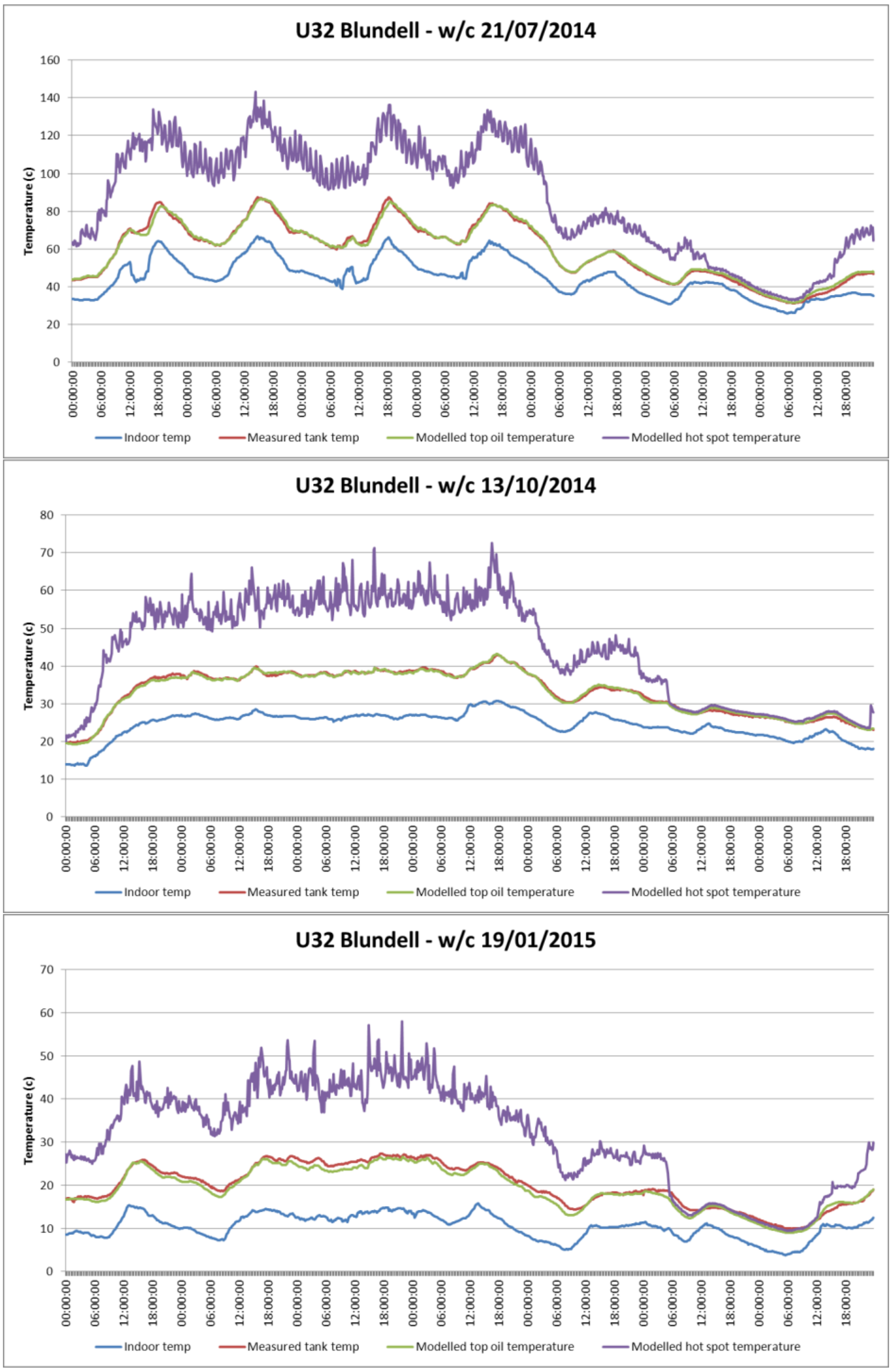
D Model vs measured top oil temperature comparison for each transformer

D.1 Transformer 1- U32 Blundells

This transformer was heavily loaded within the early part of the trial (see summer and high summer 2014 result). However an upgrade to the circuit reduced the loading and brought the transformer temperature down.

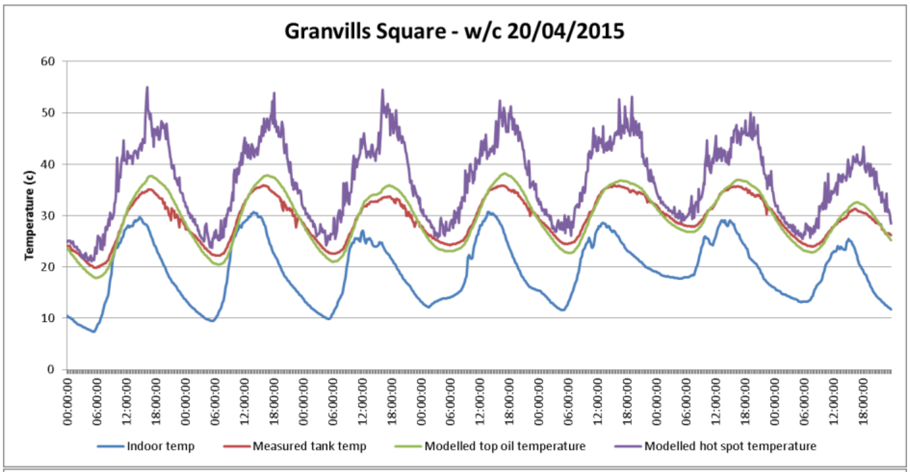


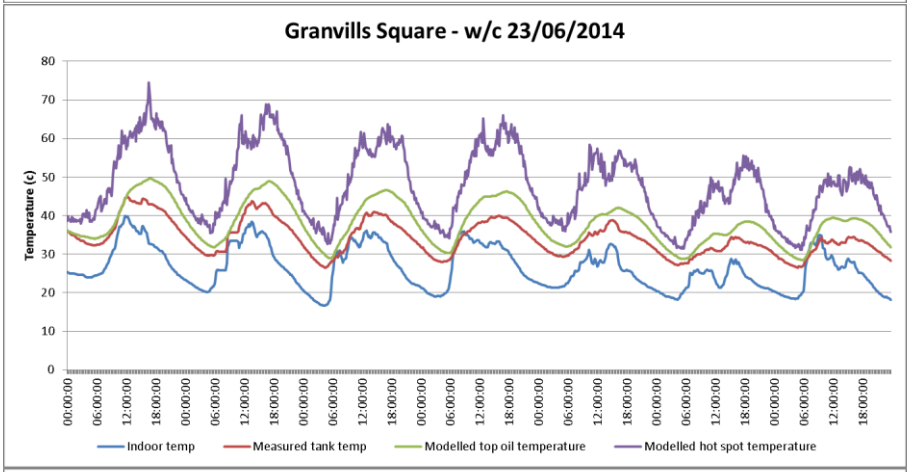


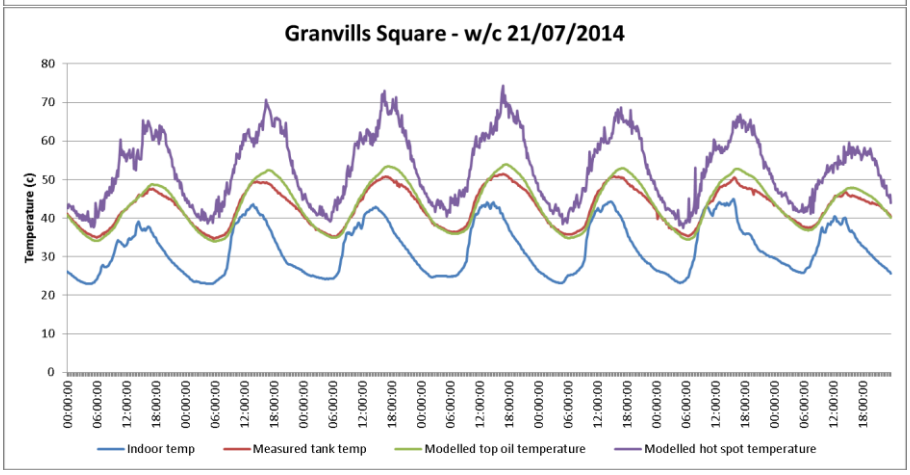


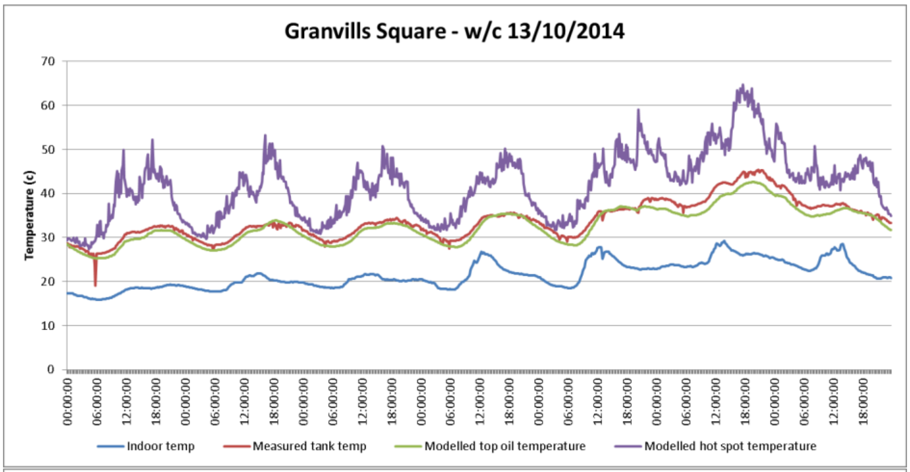
Transformer 1: spring, summer, high summer, autumn and winter

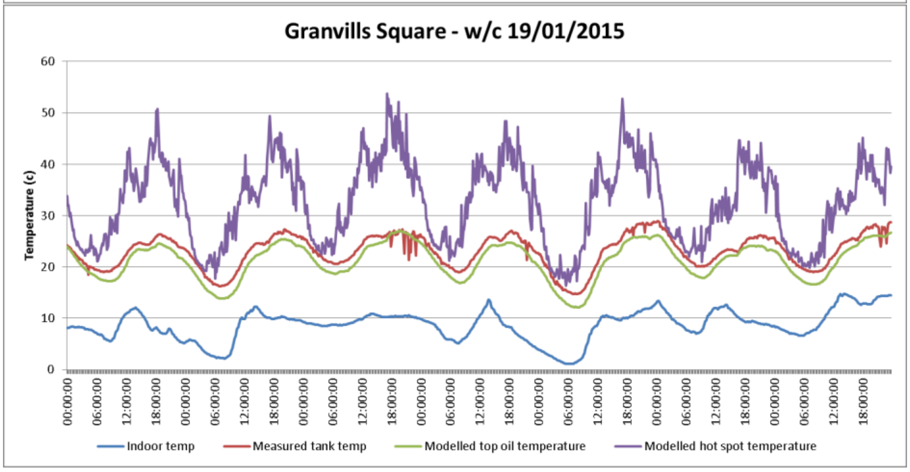
D.2 Transformer 2- Granvills Square





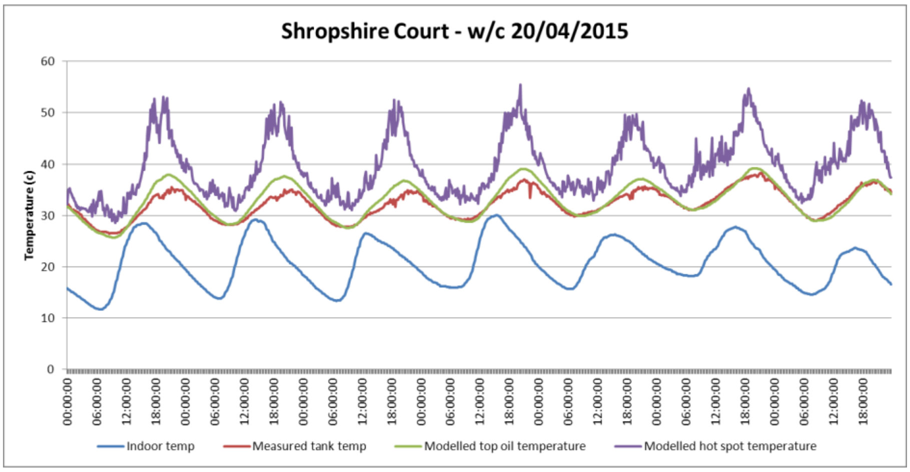


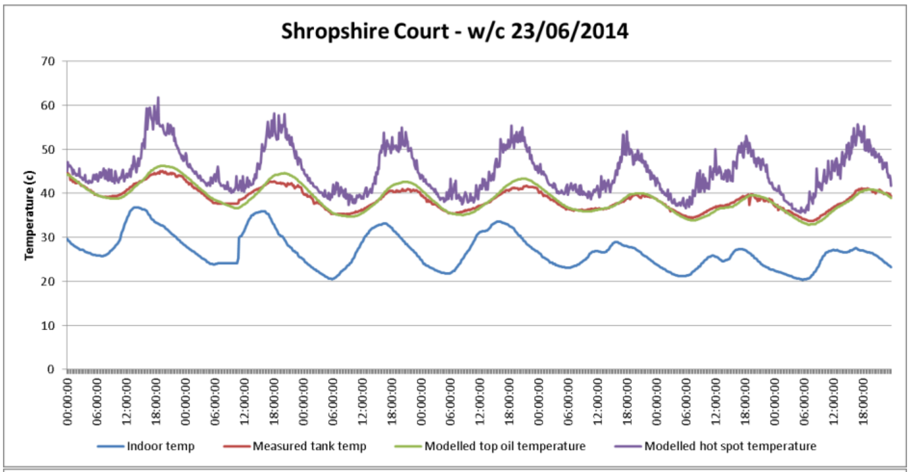


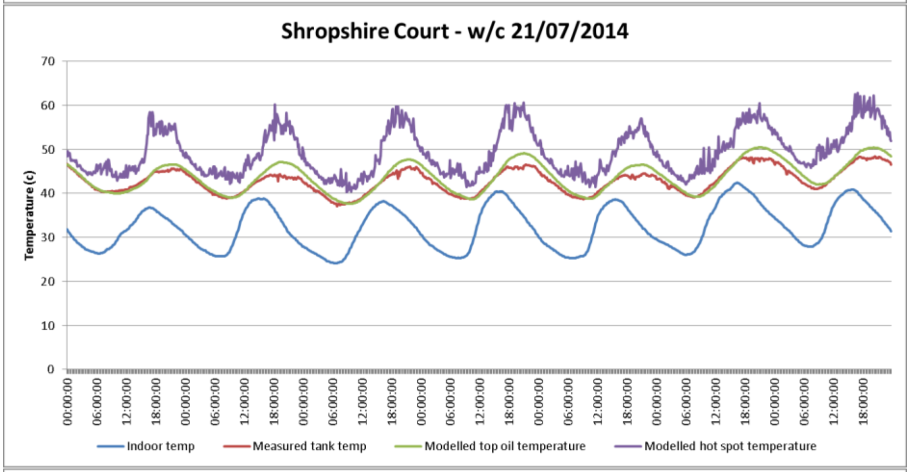


Transformer 2: spring, summer, high summer, autumn and winter

D.3 Transformer 3- Shropshire Court




Shropshire Court - w/c 23/06/2014
Temperature (c)
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature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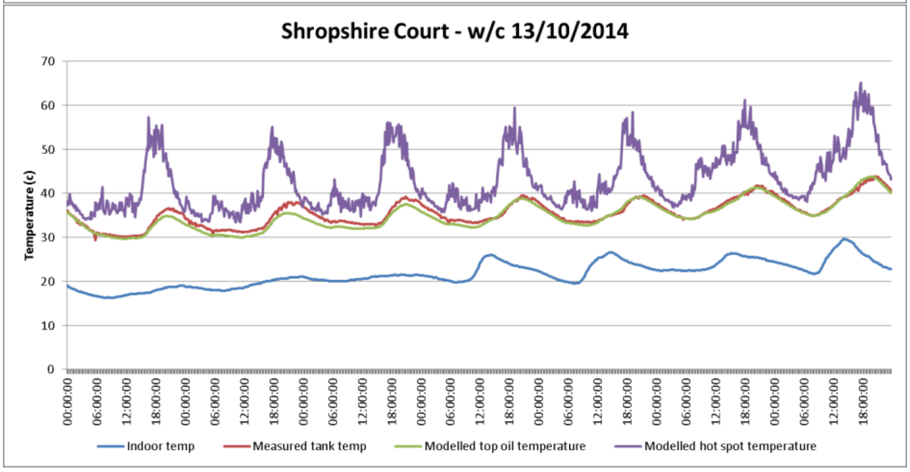
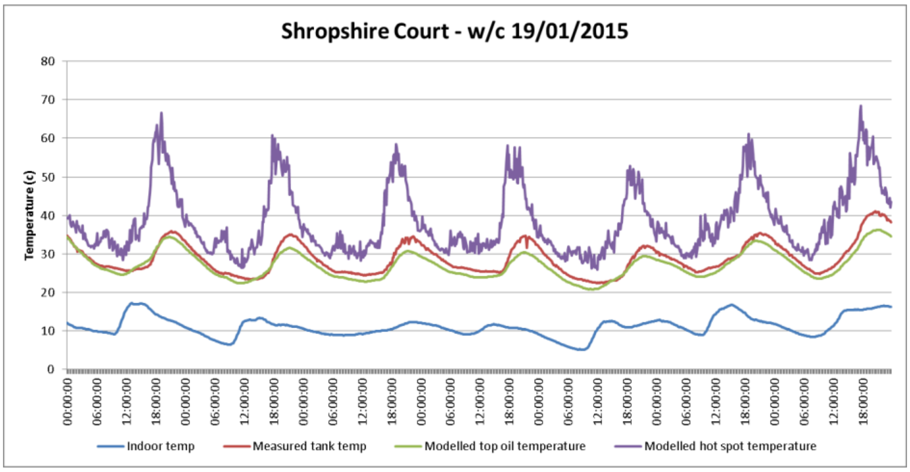
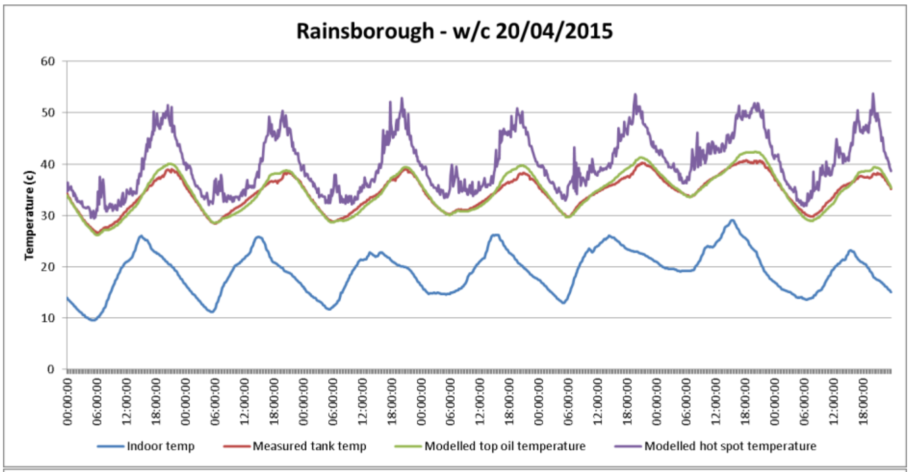
Temperature (c)
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

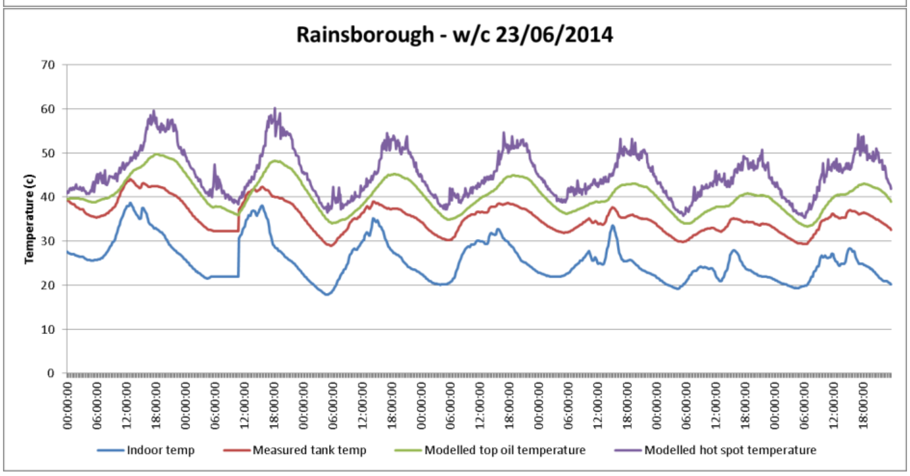

Shropshire Court - w/c 13/10/2014
Temperature (c)
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

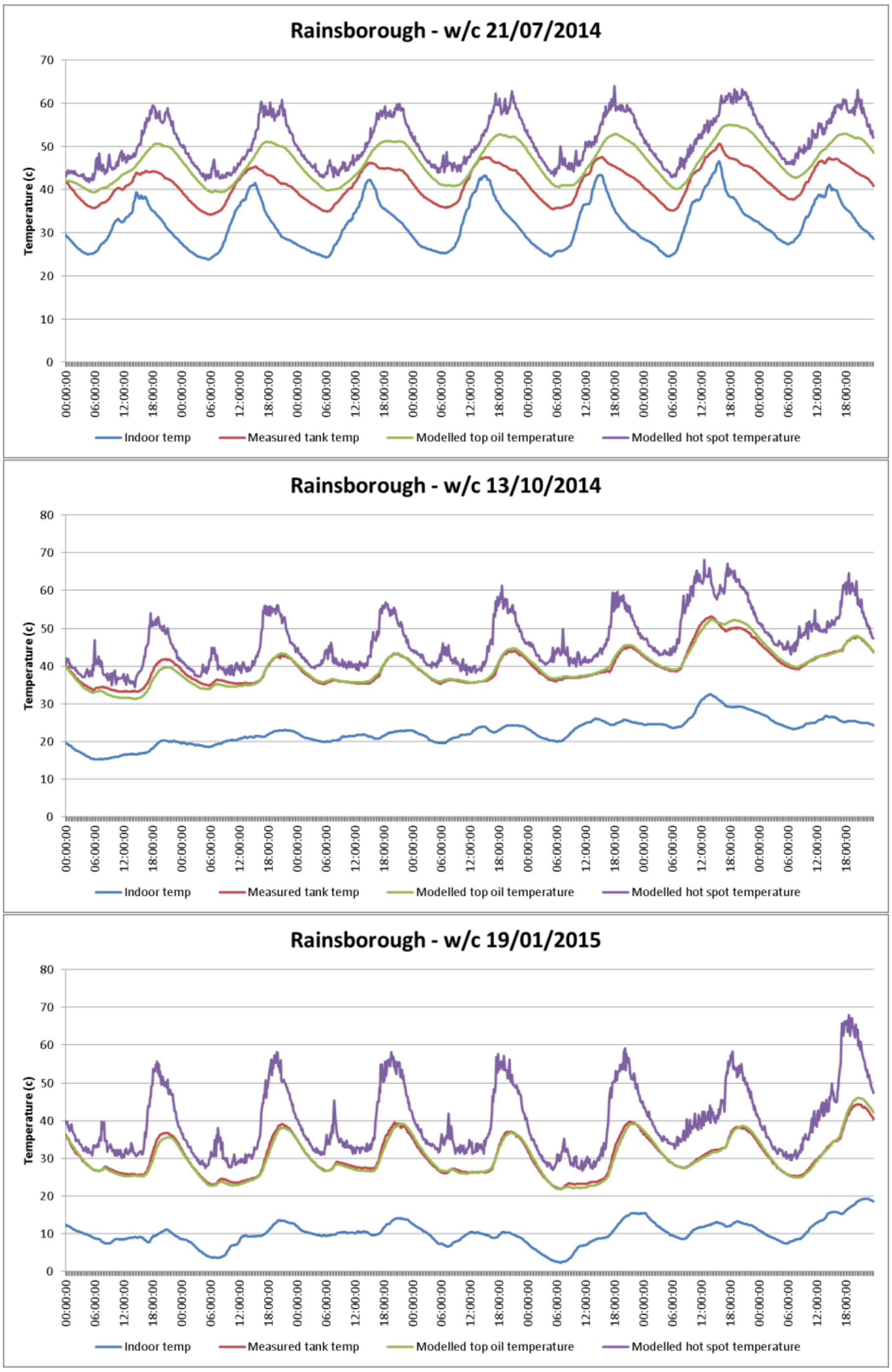


Transformer 3: spring, summer, high summer, autumn and winter

D.4 Transformer 4- Rainsborough

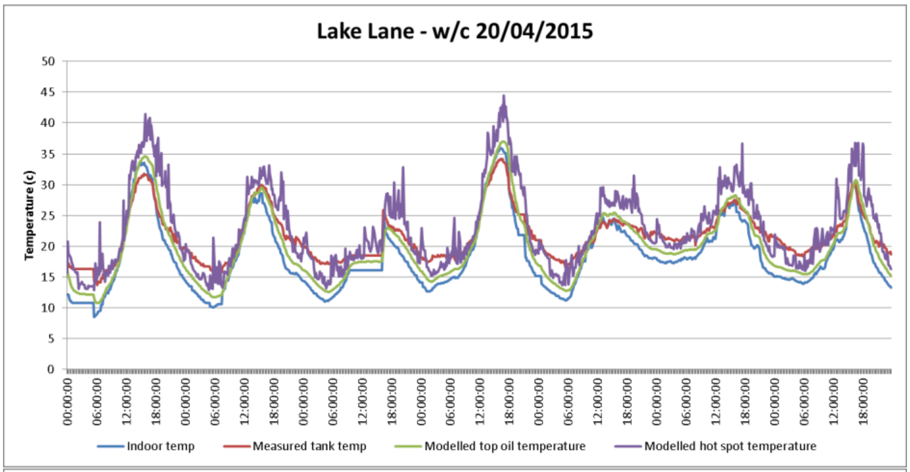


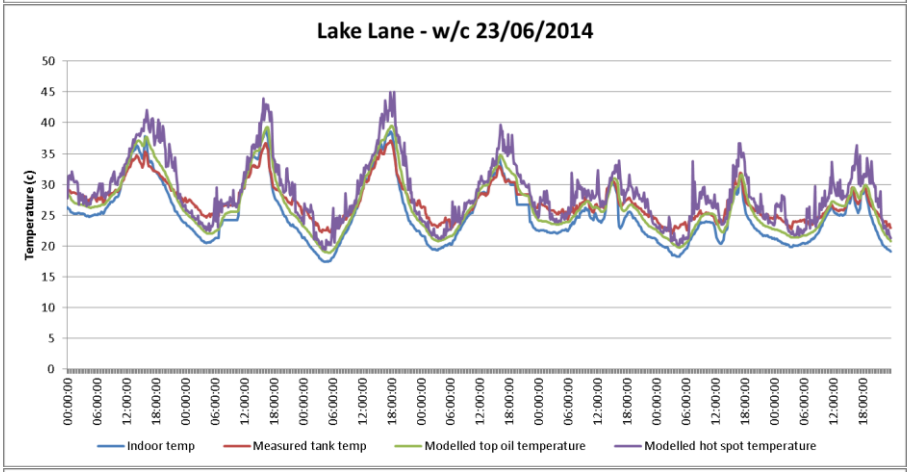


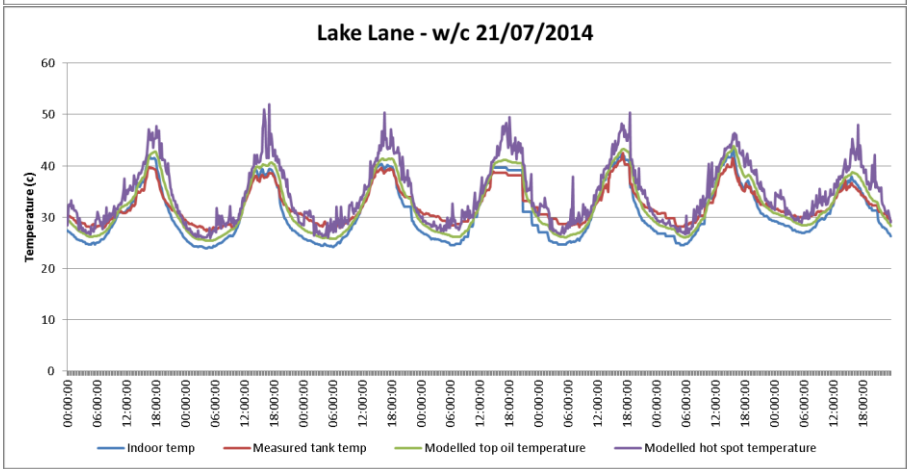


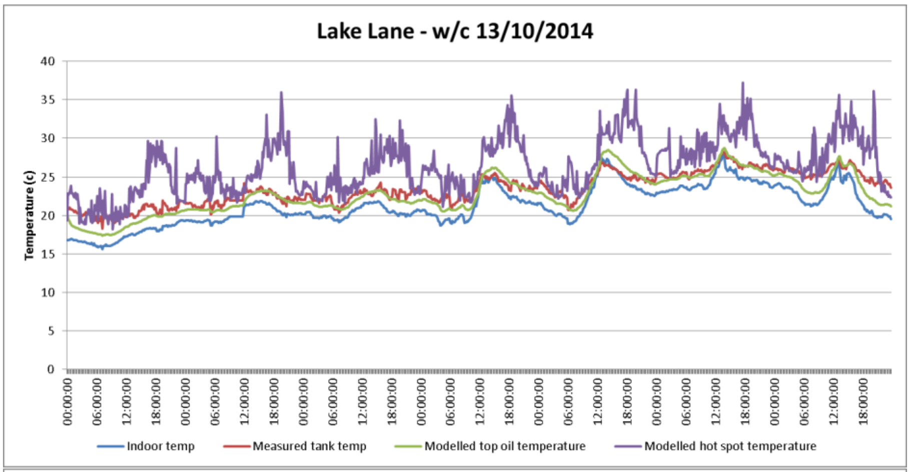
Transformer 4: spring, summer, high summer, autumn and winter

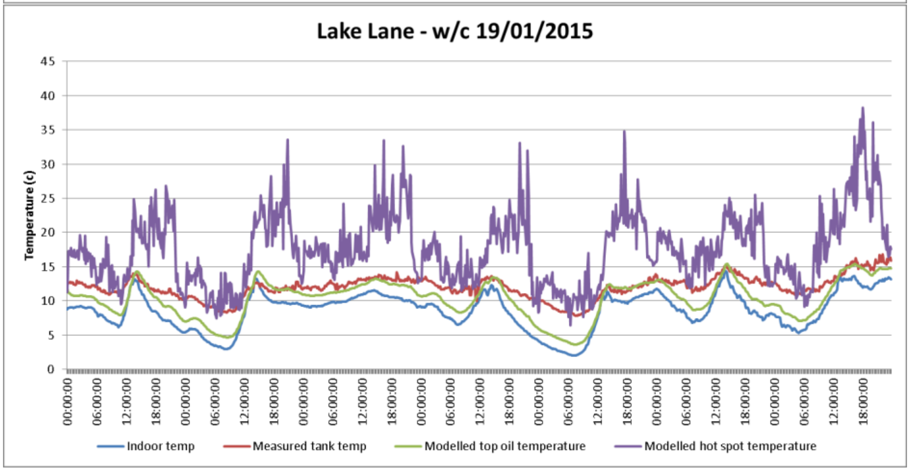
D.5 Transformer 5- Lakes Lane





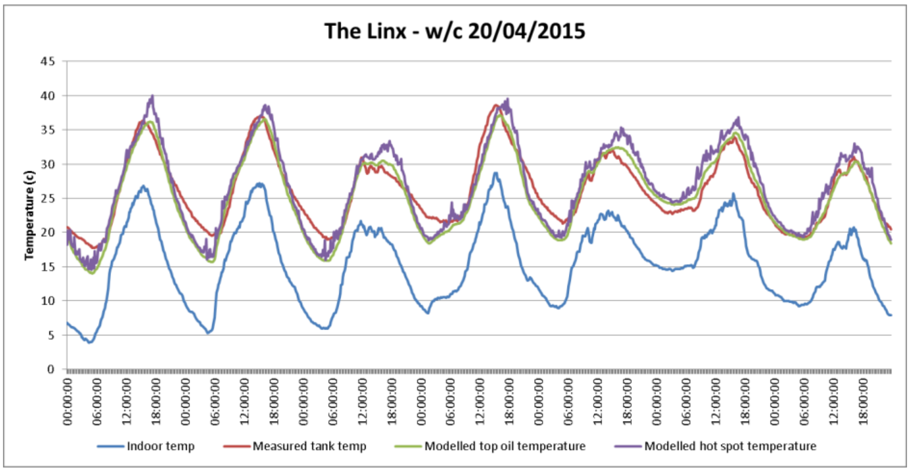


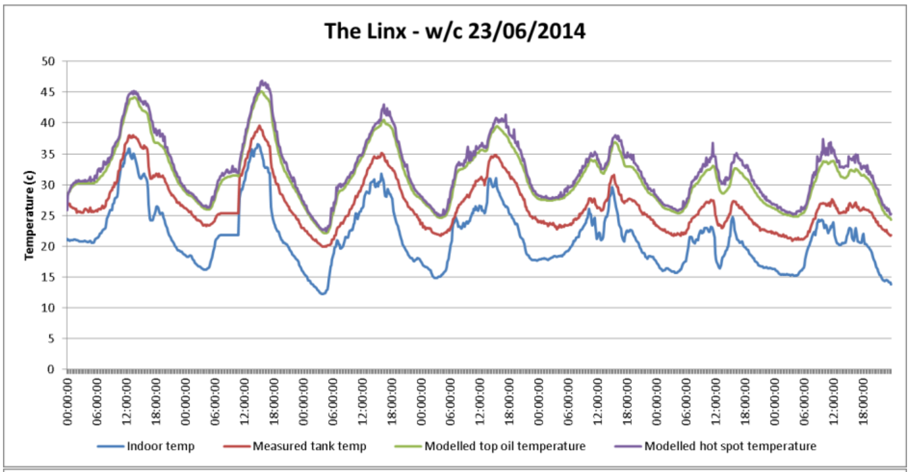


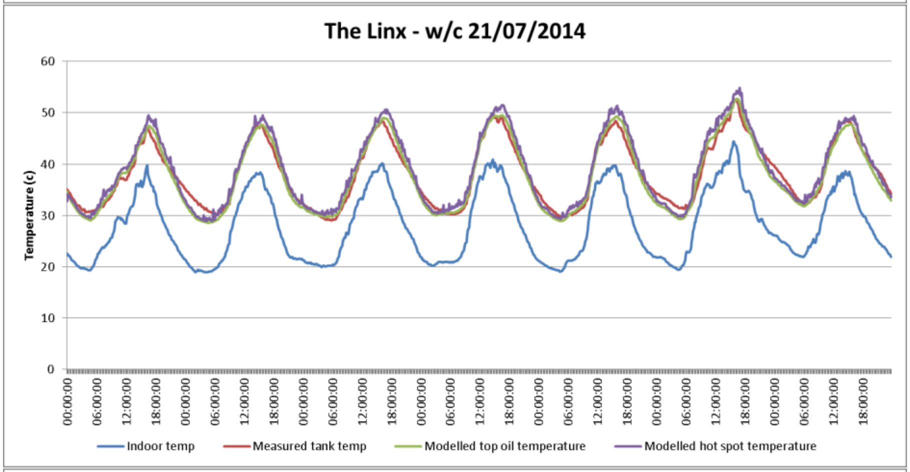


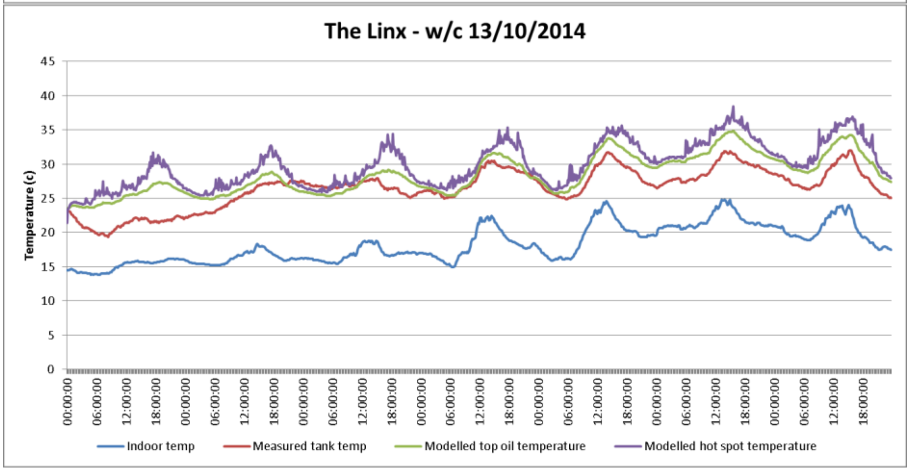
Transformer 5: spring, summer, high summer, autumn and winter

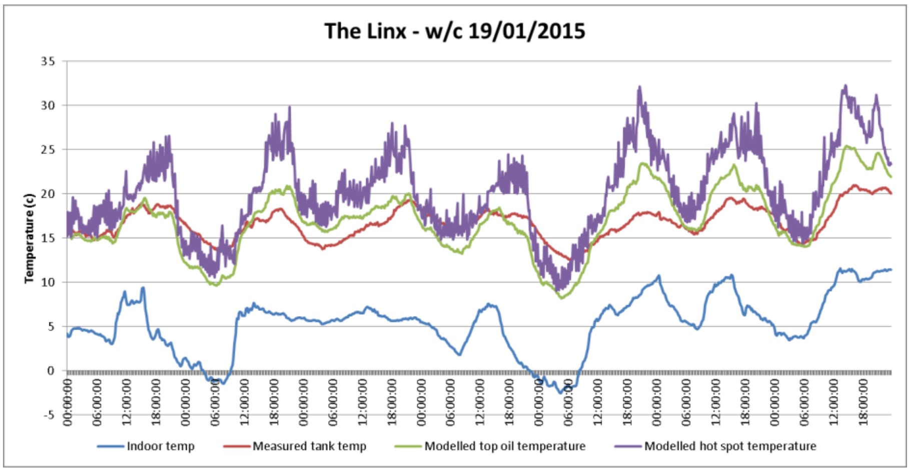
D.6 Transformer 6- The Linx




The Linx - w/c 23/06/2014
Temperature (c)
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature


The Linx - w/c 21/07/2014
Temperature (c)
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

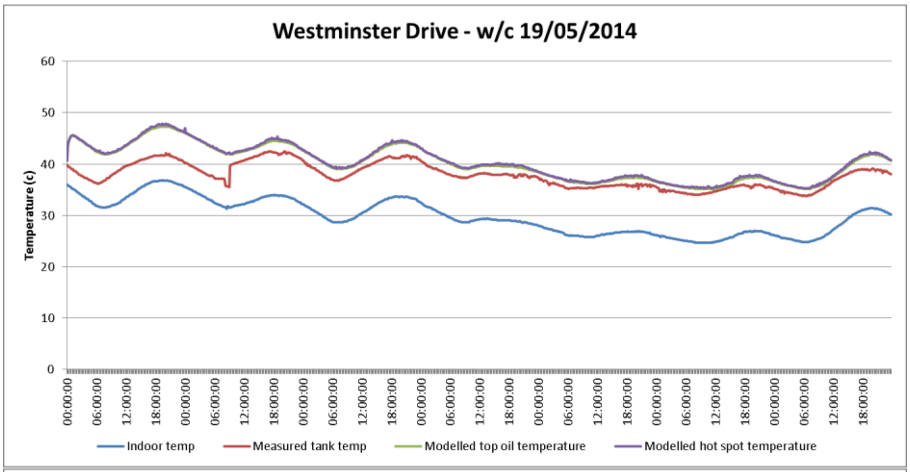

The Linx - w/c 13/10/2014
Temperature (c)
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

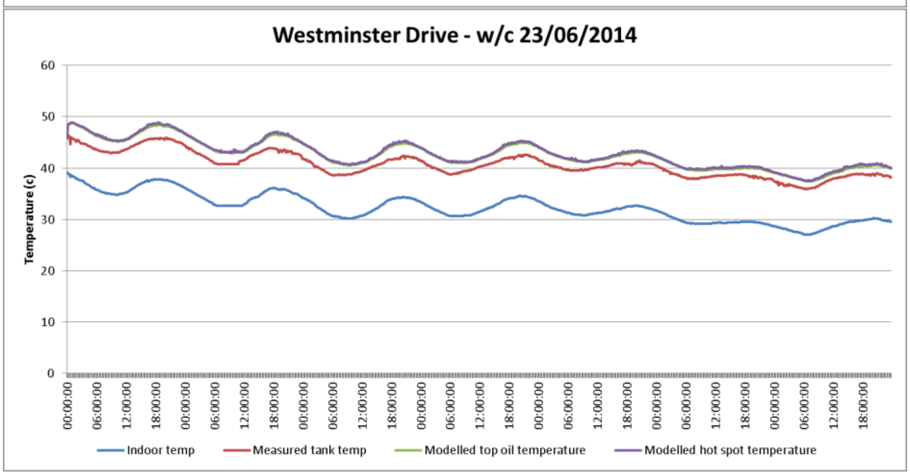


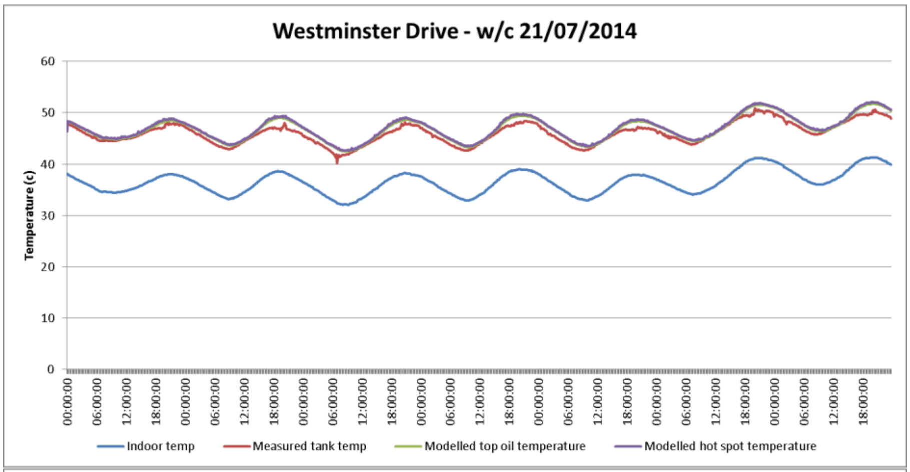
Transformer 6: spring, summer, high summer, autumn and winter

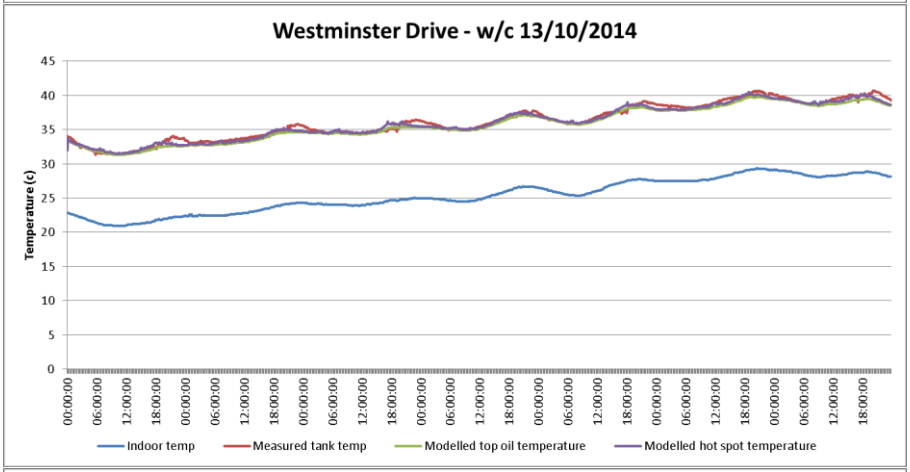
D.7 Transformer 7- Westminster Drive

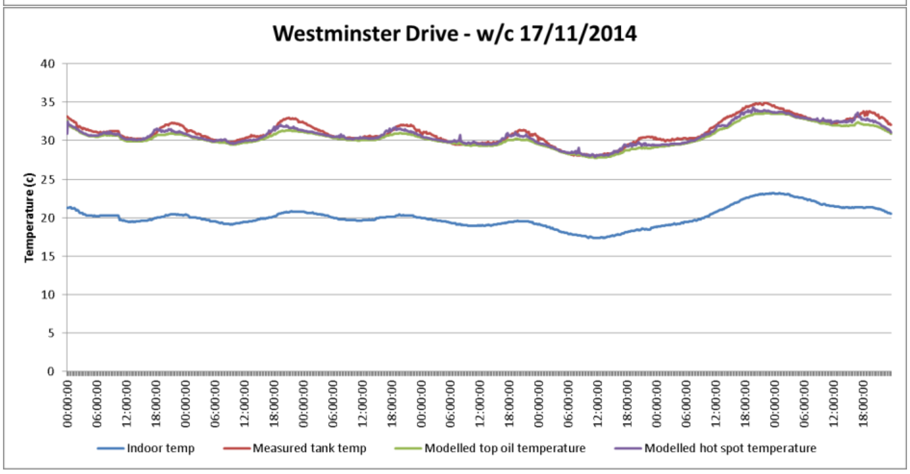
No tank temperature after the w/c 15/11/14. Therefore w/c 20/04/15 and 19/01/15 data has been replaced with earlier collected data.





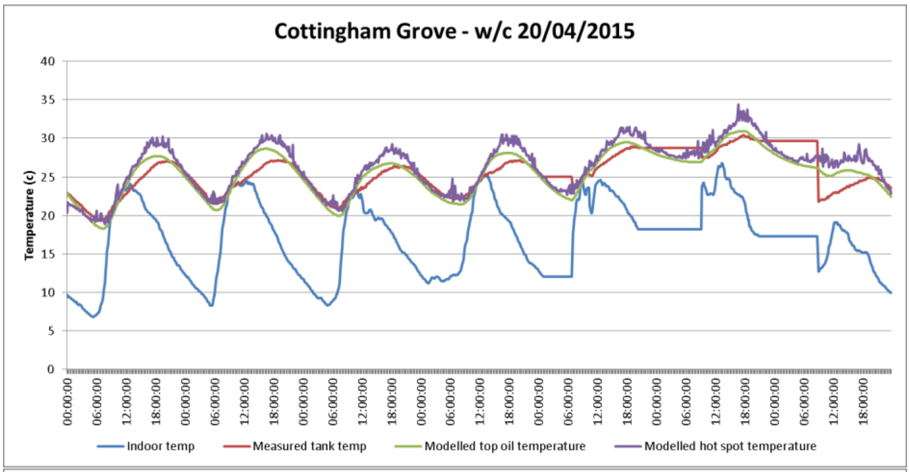


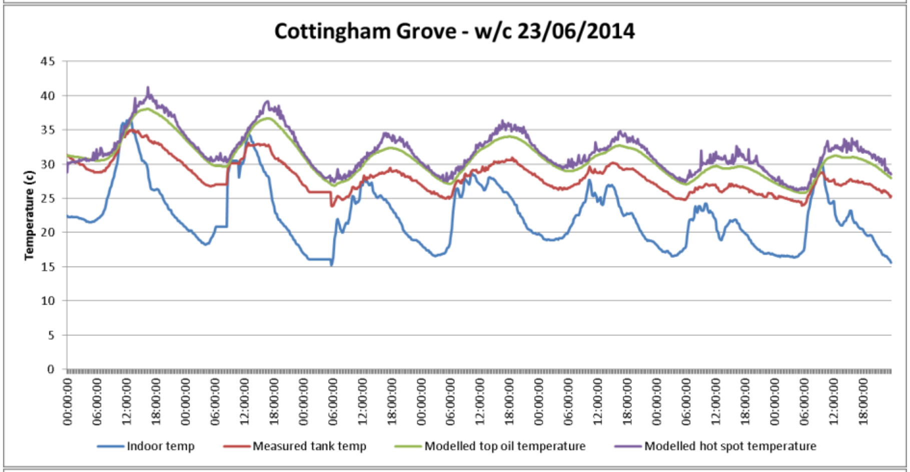


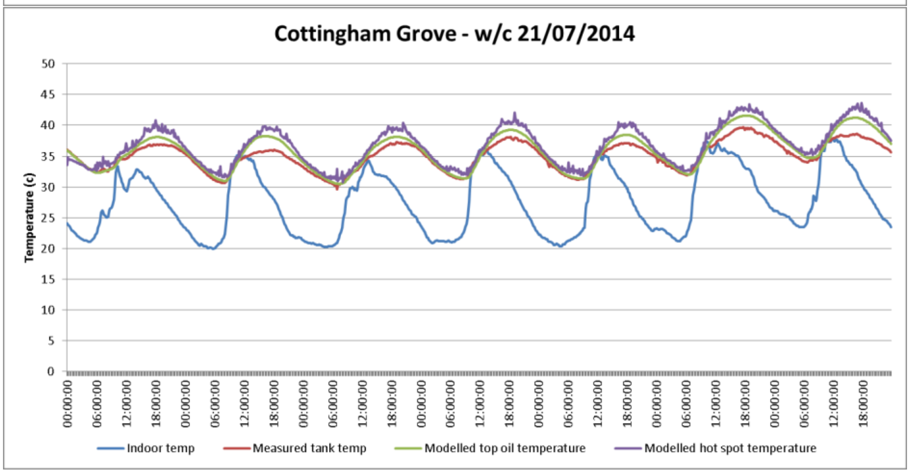


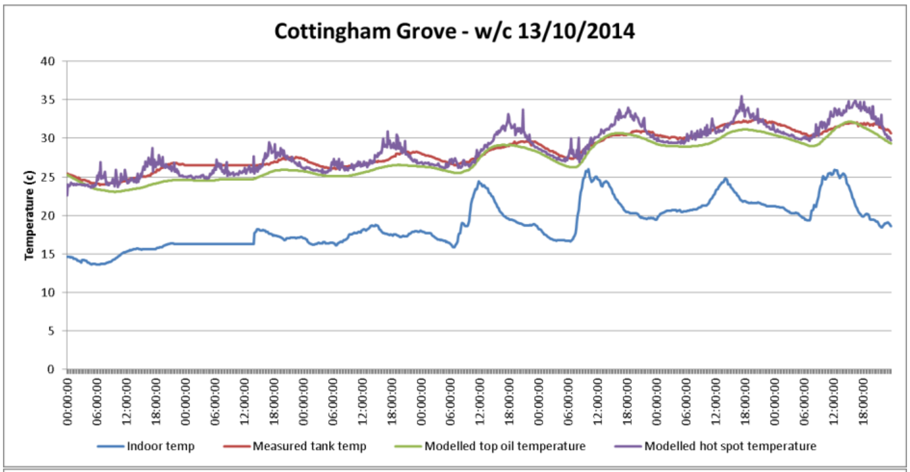
Transformer 7: spring, summer, high summer, autumn and winter

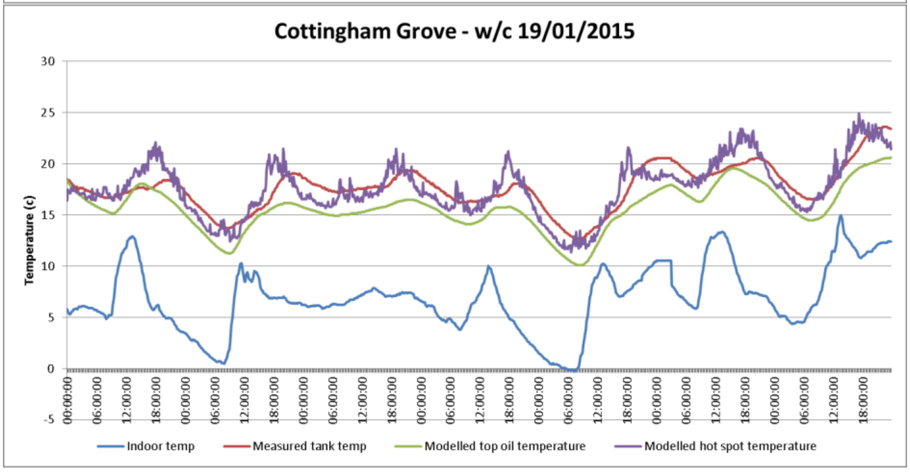
D.8 Transformer 8- Cottingham Grove





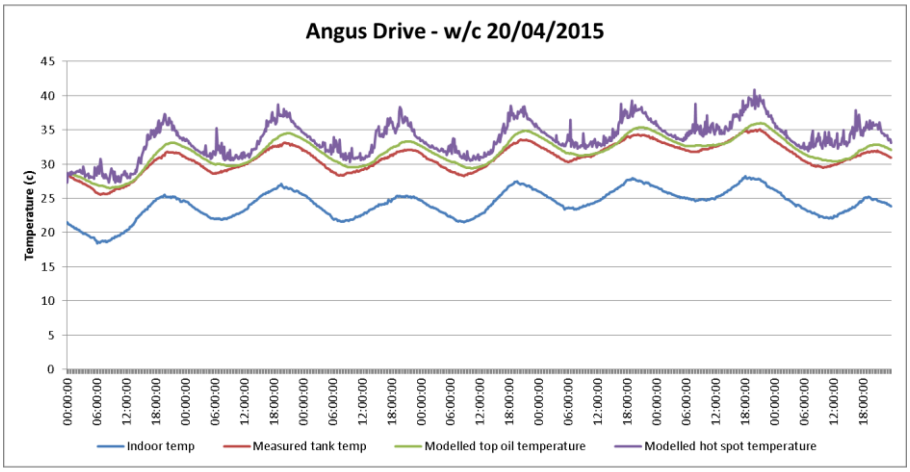


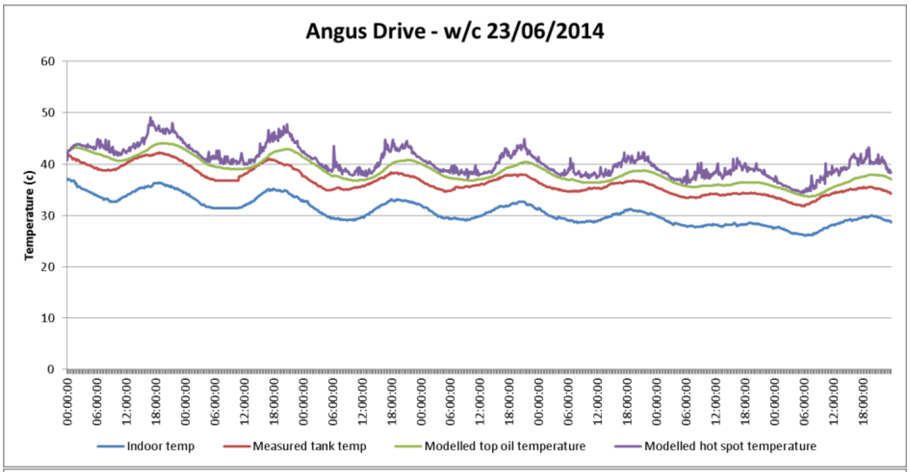


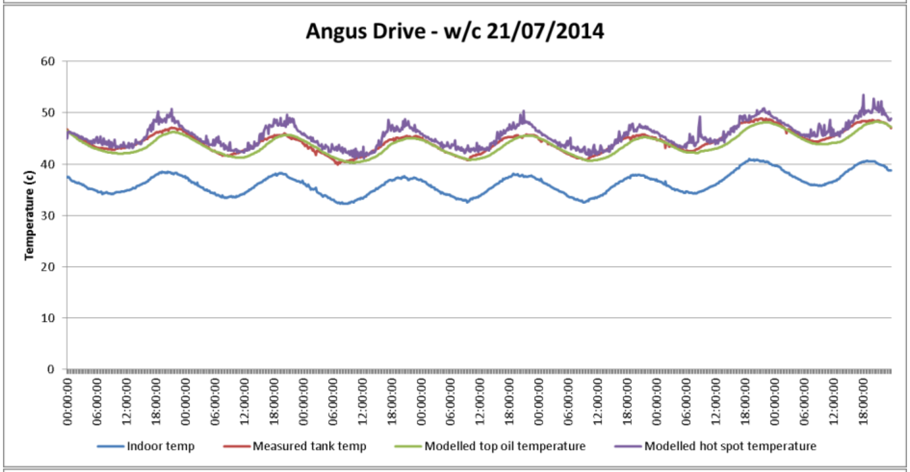


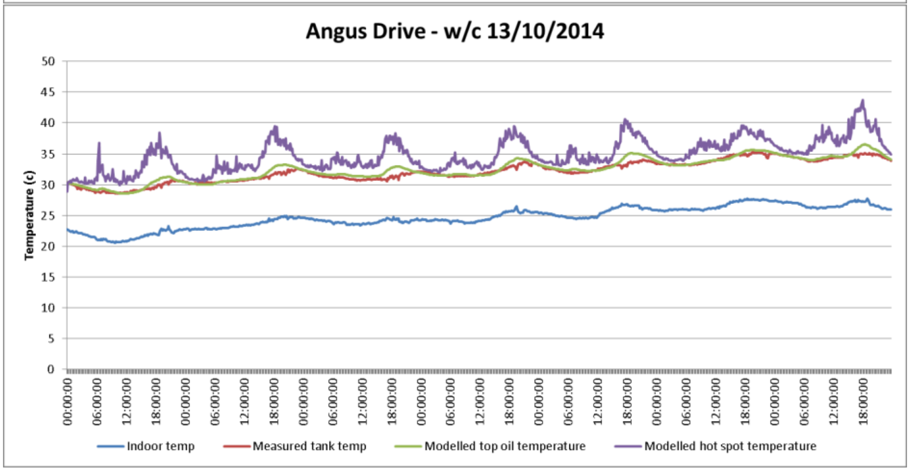
Transformer 8: spring, summer, high summer, autumn and winter

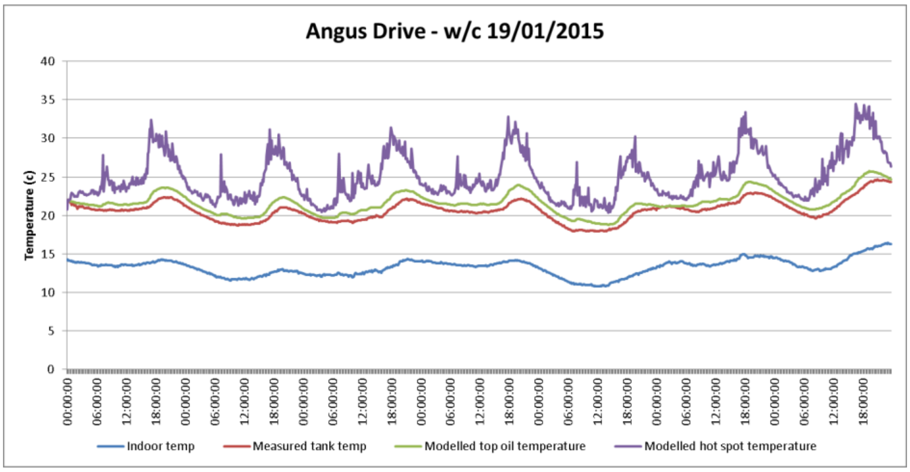
D.9 Transformer 9- Angus Drive




Angus Drive - w/c 23/06/2014
Temperature (c)
60
50
40
30
20
10
0
00:00:00
06:00:00
12:00:00
18:00:00
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

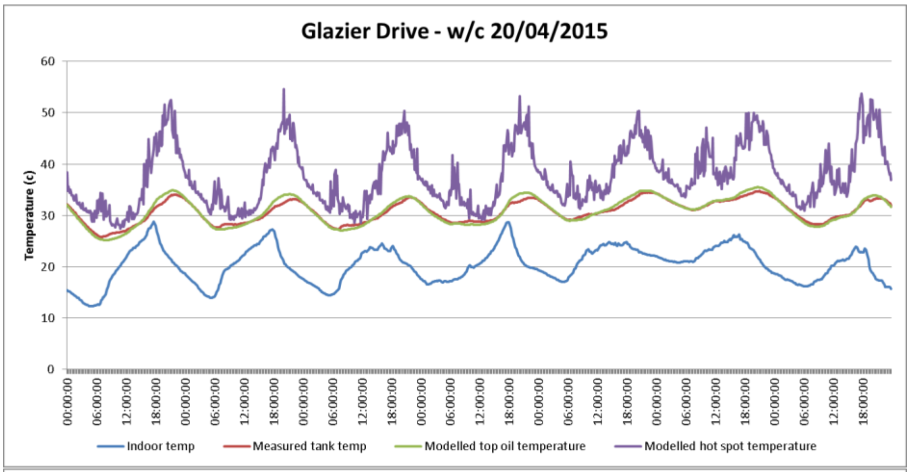

Angus Drive - w/c 21/07/2014
Temperature (c)
60
50
40
30
20
10
0
00:00:00
06:00:00
12:00:00
18:00:00
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

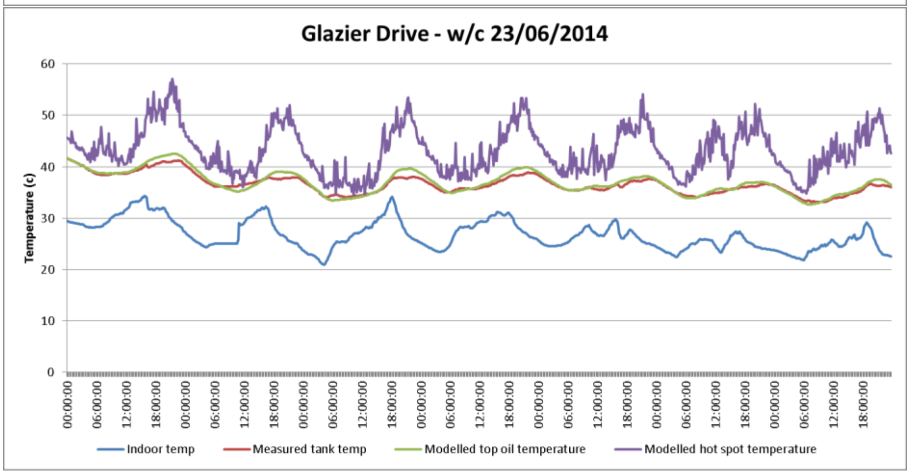

Angus Drive - w/c 13/10/2014
Temperature (c)
50
45
40
35
30
25
20
15
10
5
0
00:00:00
06:00:00
12:00:00
18:00:00
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

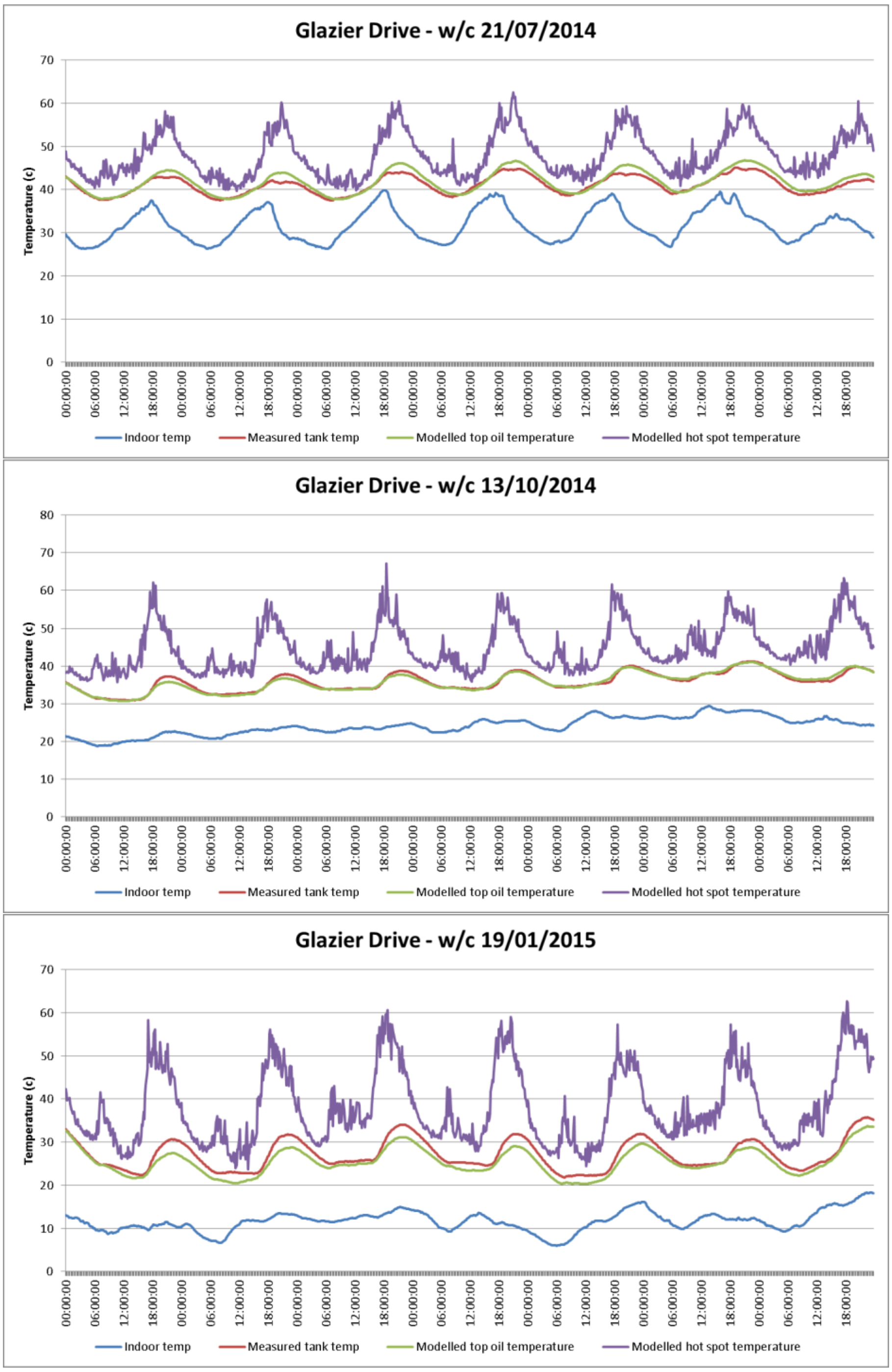


Transformer 9: spring, summer, high summer, autumn and winter

D.10 Transformer 10- Glazier Drive

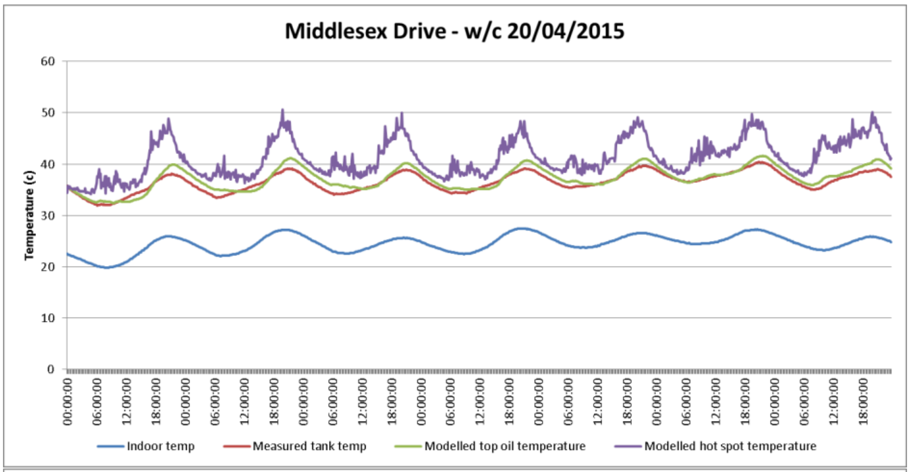


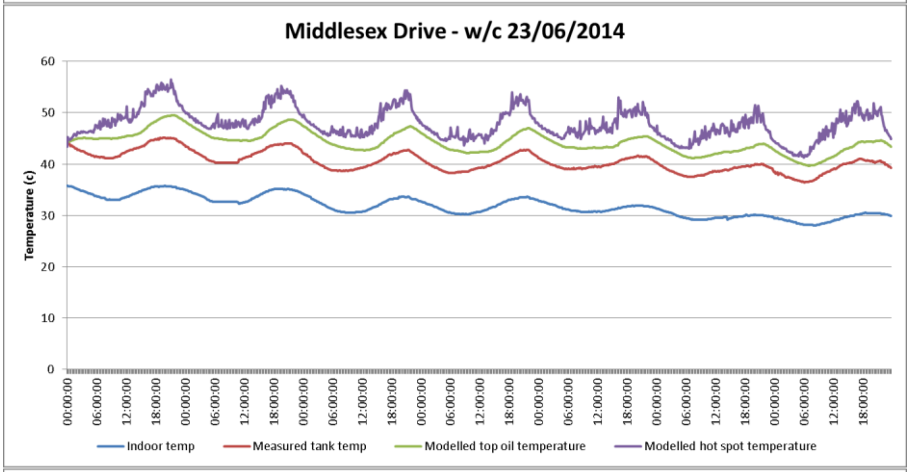


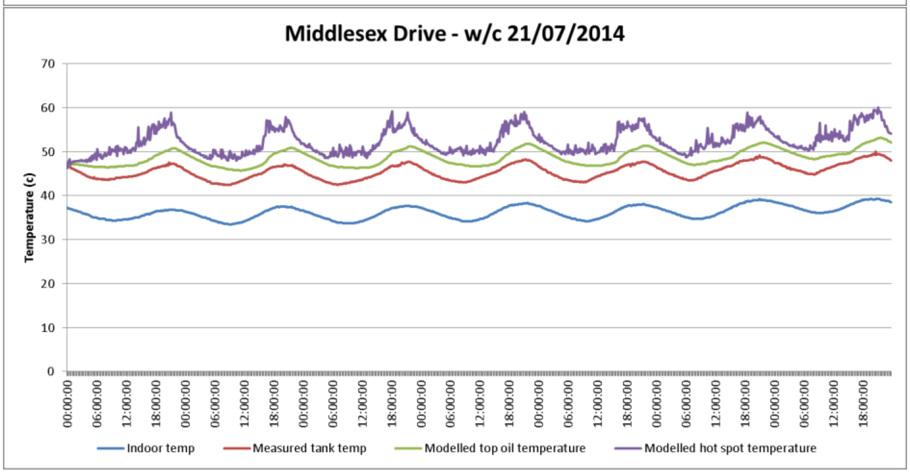


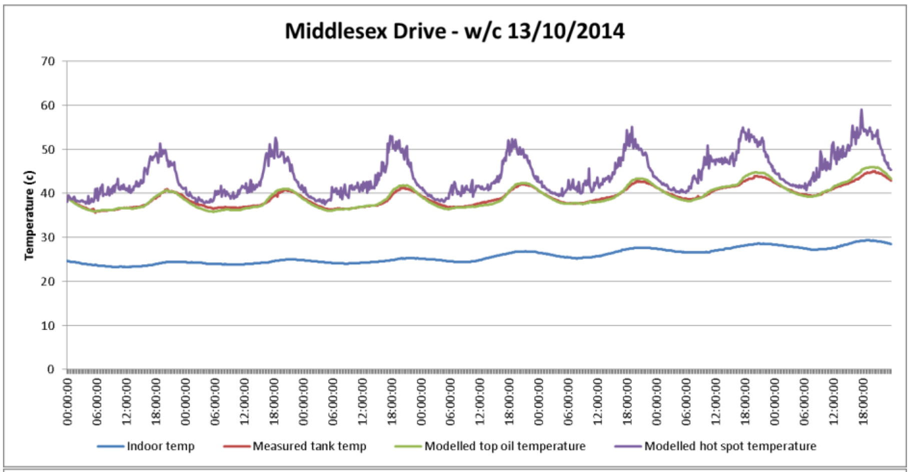
Transformer 10: spring, summer, high summer, autumn and winter

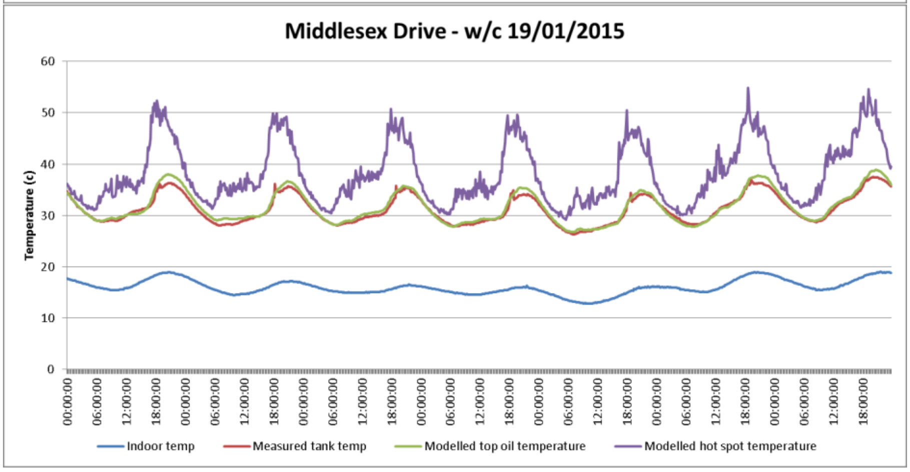
D.11 Transformer 11- Middlesex Drive





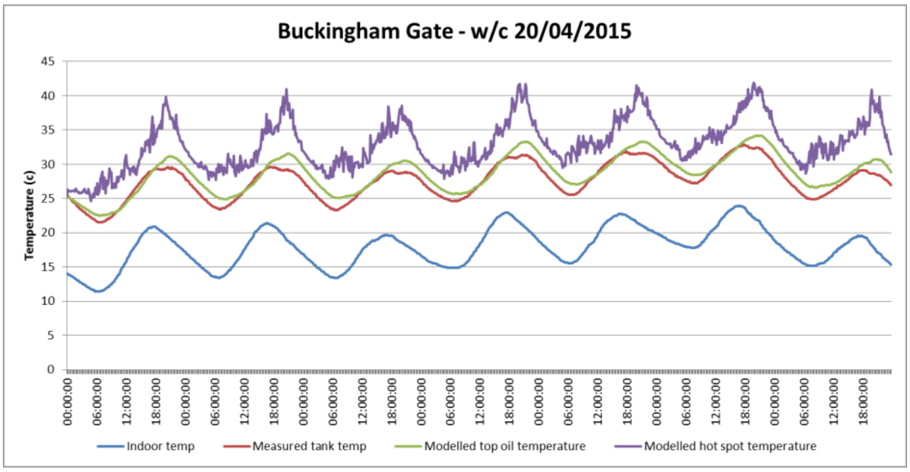






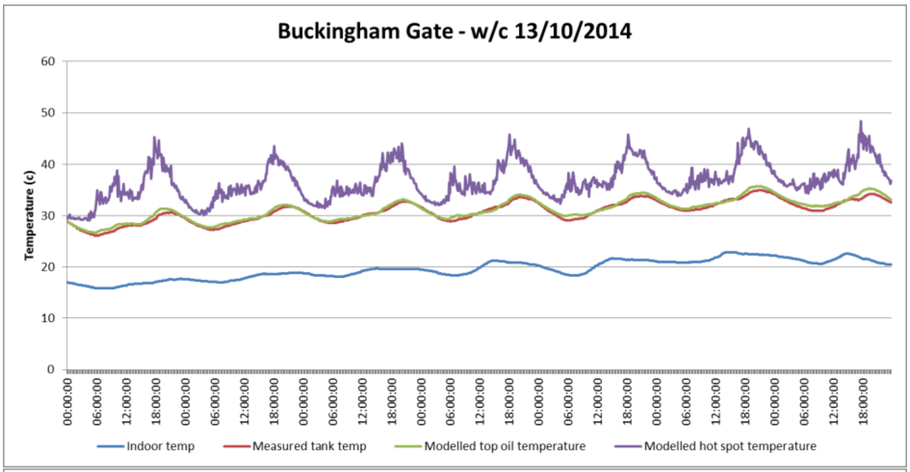
Transformer 11: spring, summer, high summer, autumn and winter

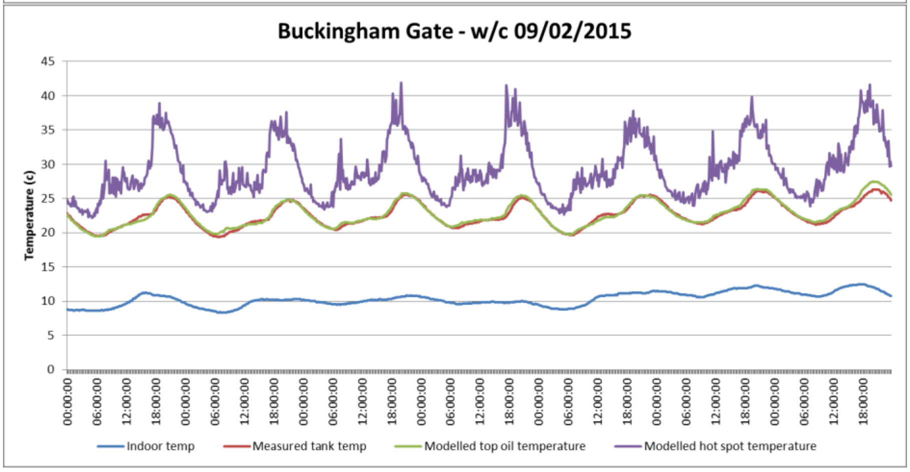
D.12 Transformer 12- Buckingham Gate



No summer data available

No High Summer data available

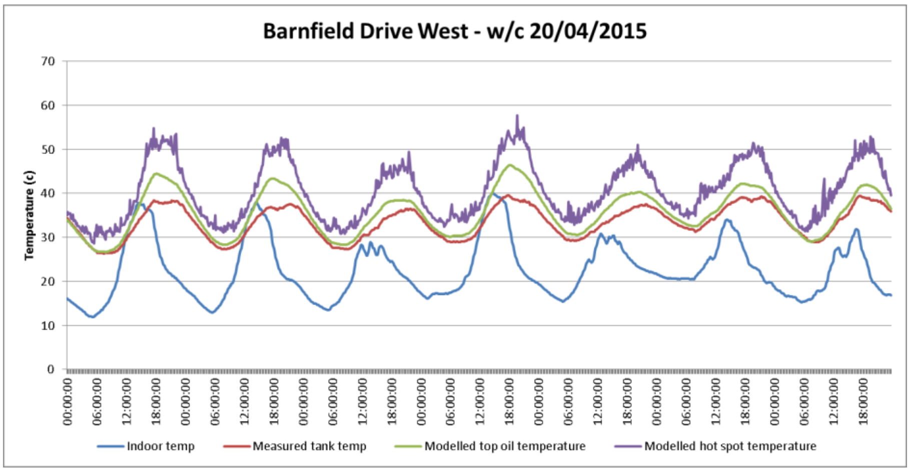


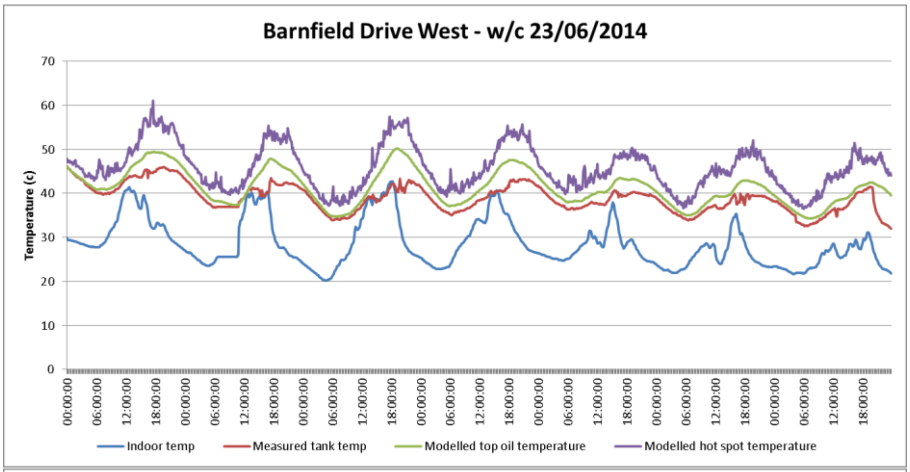


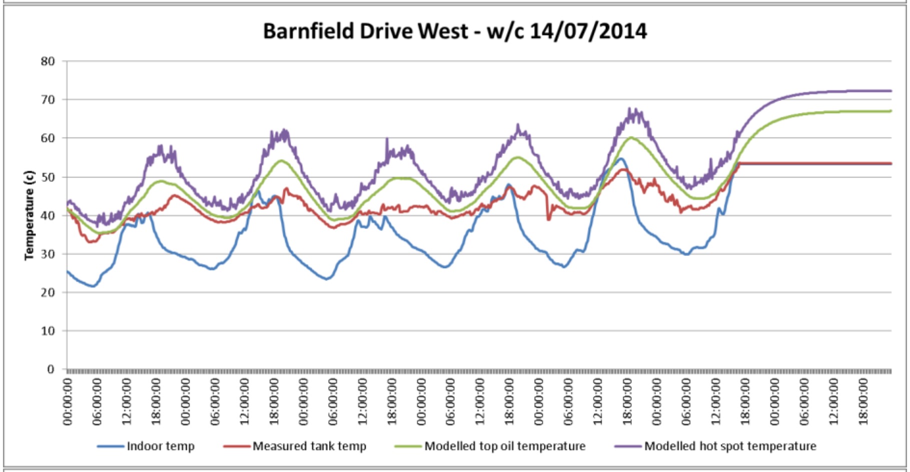
Transformer 12: spring, summer, high summer, autumn and winter

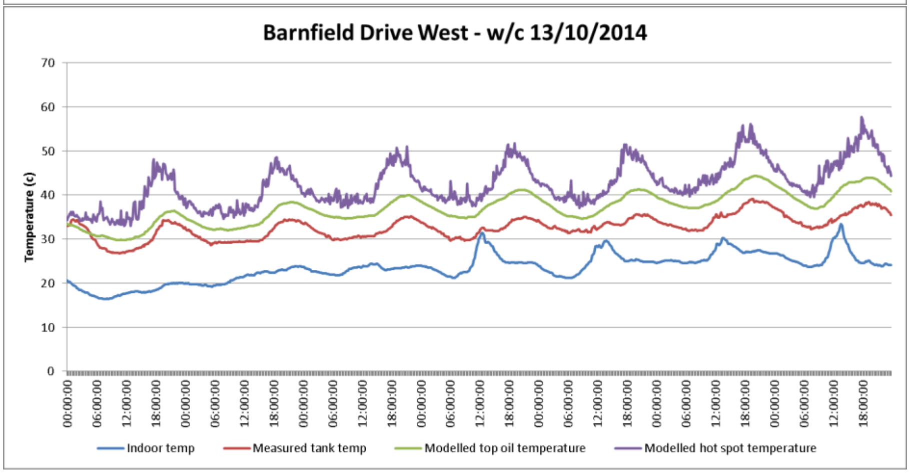
D.13 Transformer 13- Barnfield Drive West

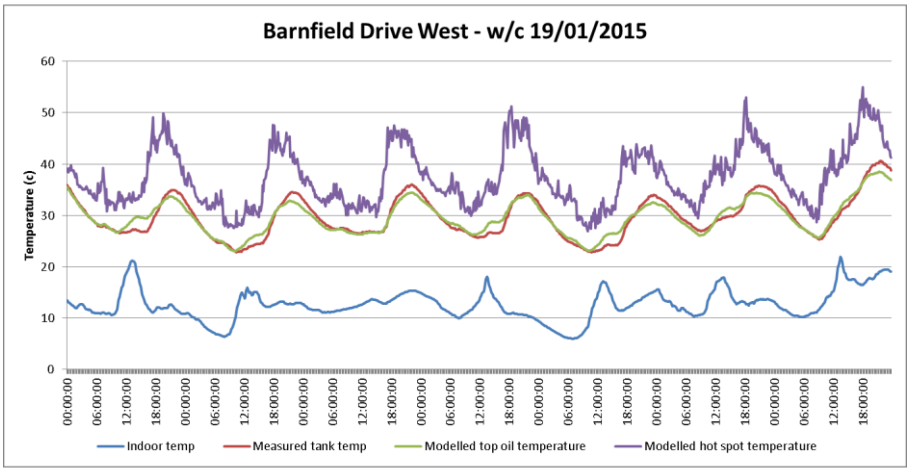
Data was lost at Barnfield west from 20/07/14 through to 29/09/14.




Barnfield Drive West - w/c 23/06/2014
Temperature (c)
70
60
50
40
30
20
10
0
00:00:00
06:00:00
12:00:00
18:00:00
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

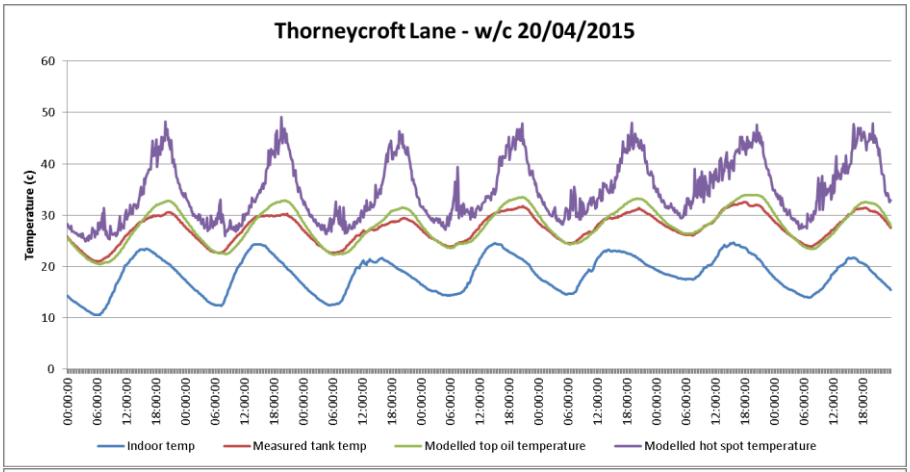

Barnfield Drive West - w/c 14/07/2014
Temperature (c)
80
70
60
50
40
30
20
10
0
00:00:00
06:00:00
12:00:00
18:00:00
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

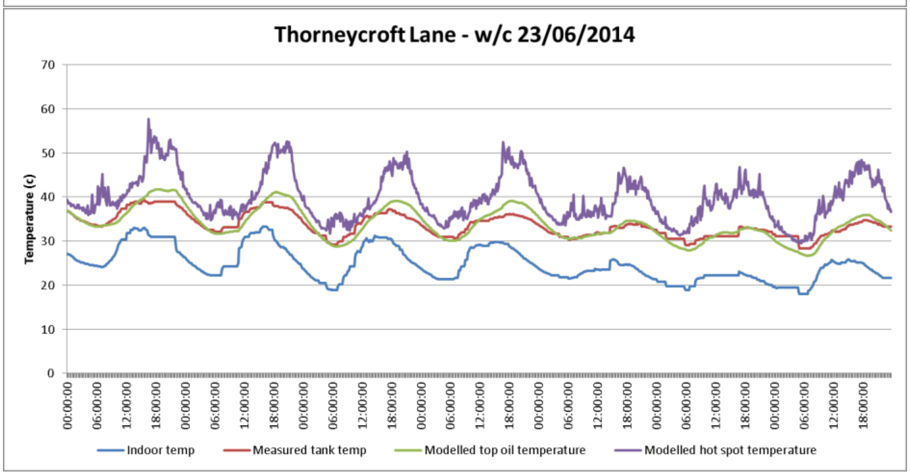

Barnfield Drive West - w/c 13/10/2014
Temperature (c)
70
60
50
40
30
20
10
0
00:00:00
06:00:00
12:00:00
18:00:00
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

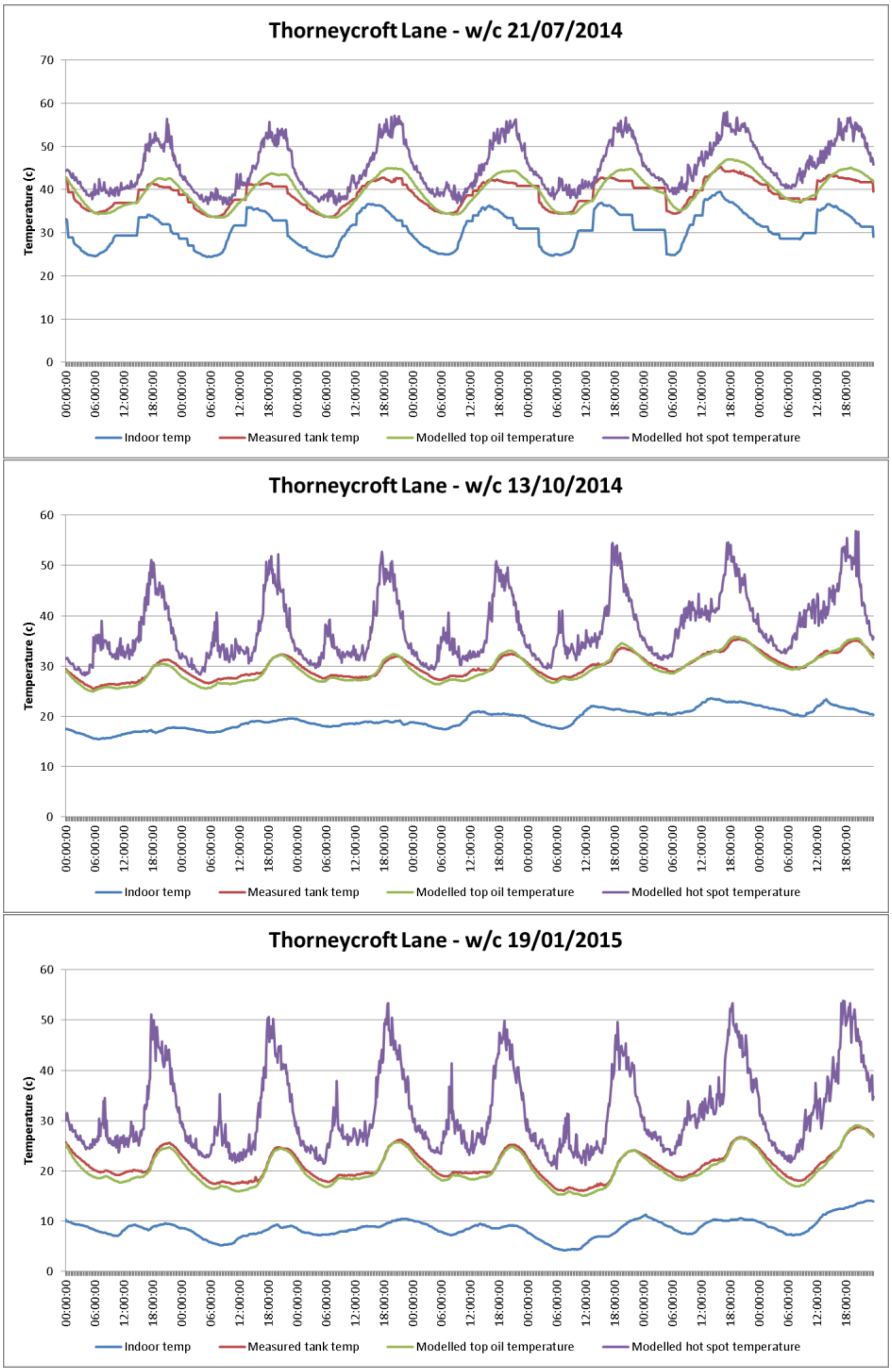


Transformer 13: spring, summer, high summer, autumn and winter

D.14 Transformer 14- Thorney Croft Lane

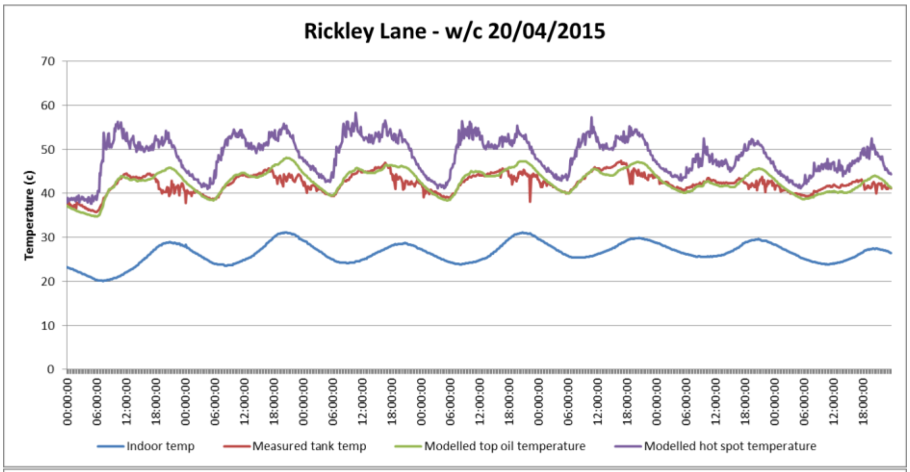


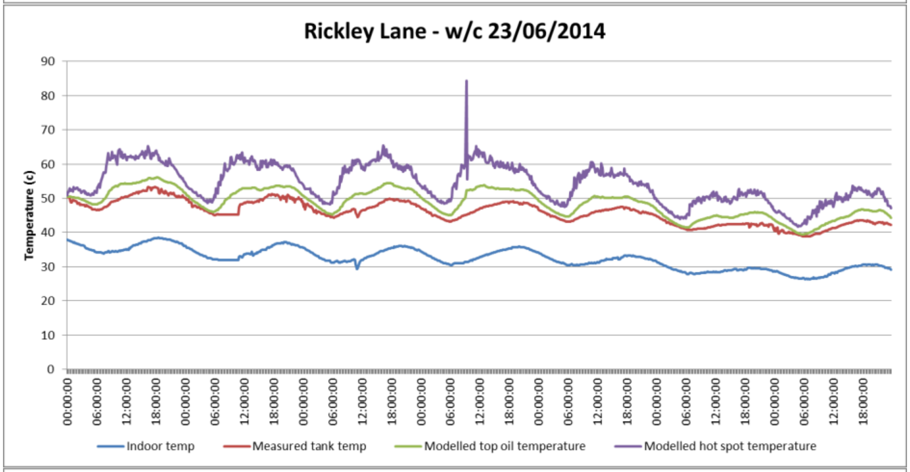


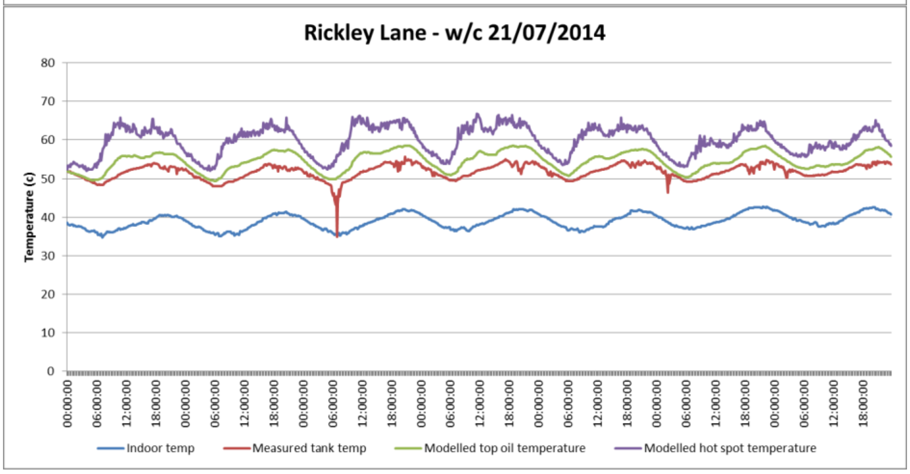


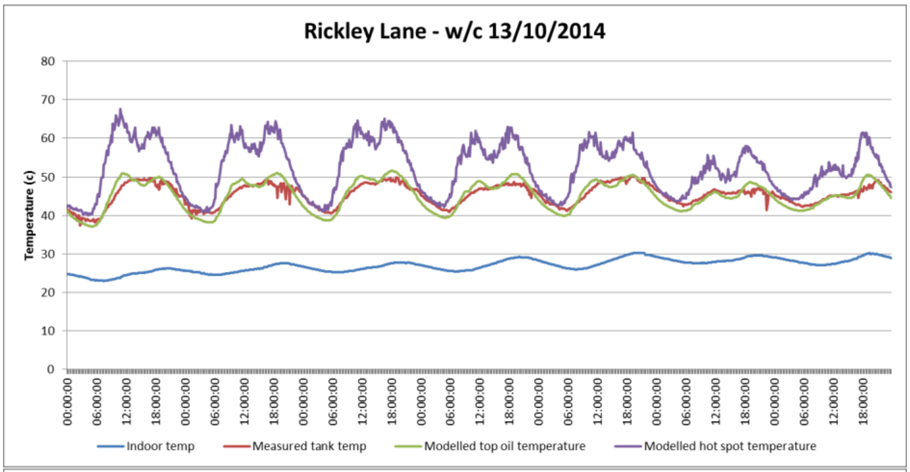
Transformer 14: spring, summer, high summer, autumn and winter

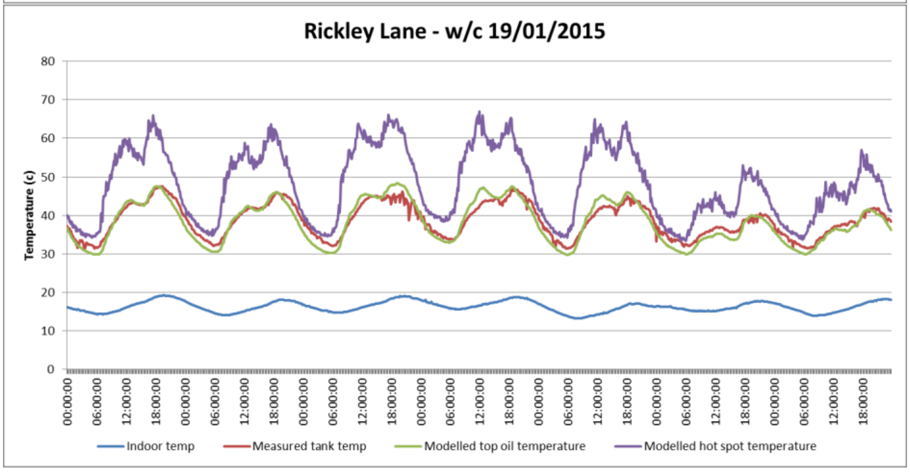
D.15 Transformer 15- Rickley Lane





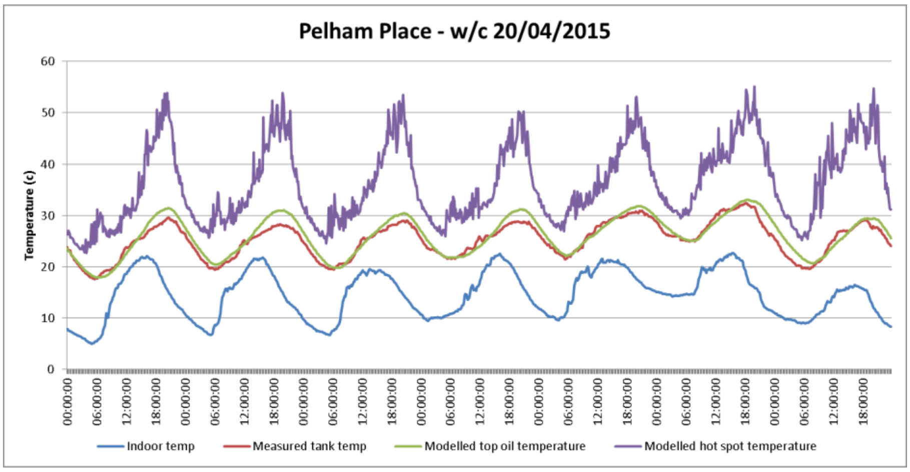


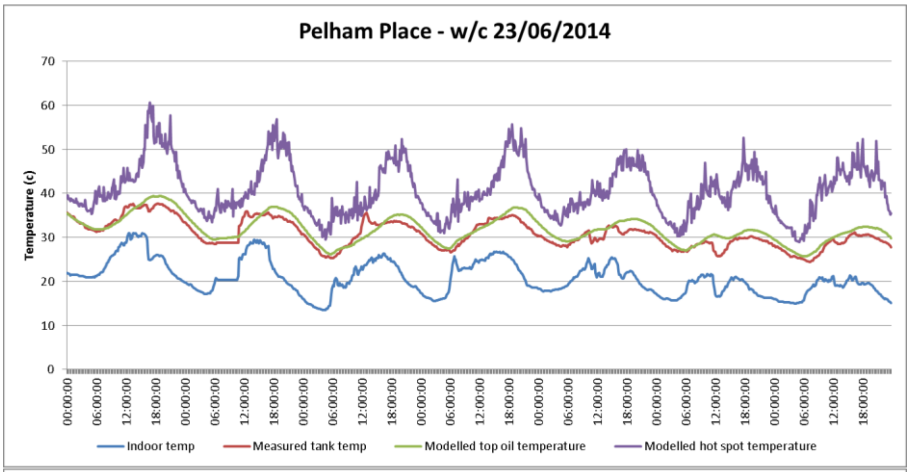


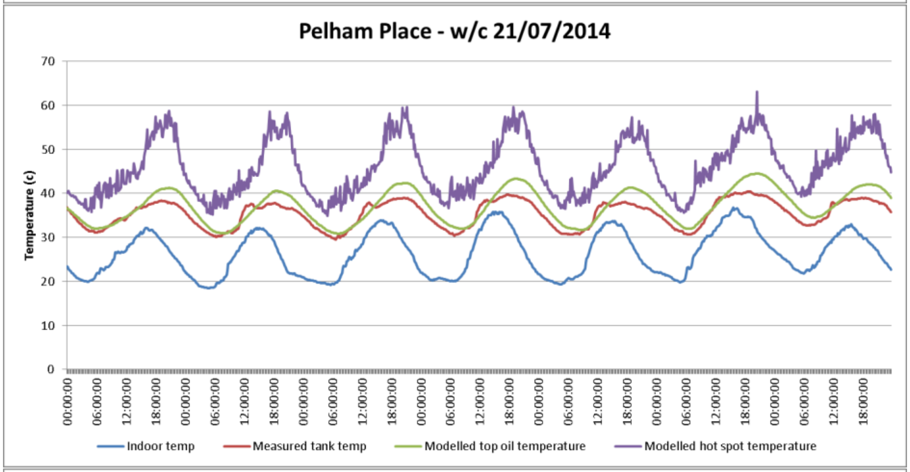


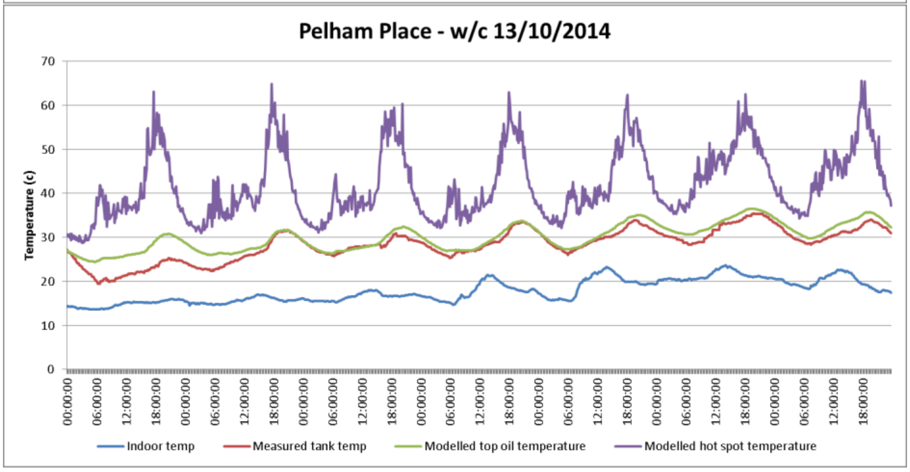
Transformer 15: spring, summer, high summer, autumn and winter

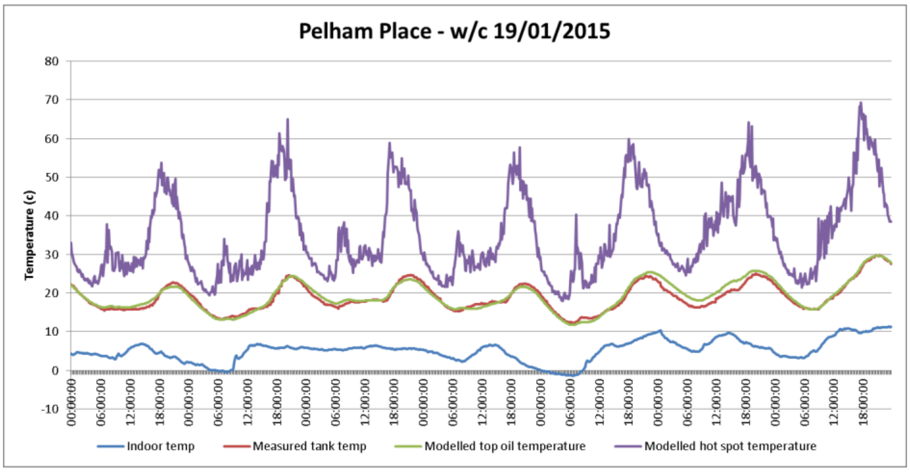
D.16 Transformer 16- Pelham Place




Pelham Place - w/c 23/06/2014
Temperature (c)
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature


Pelham Place - w/c 21/07/2014
Temperature (c)
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature

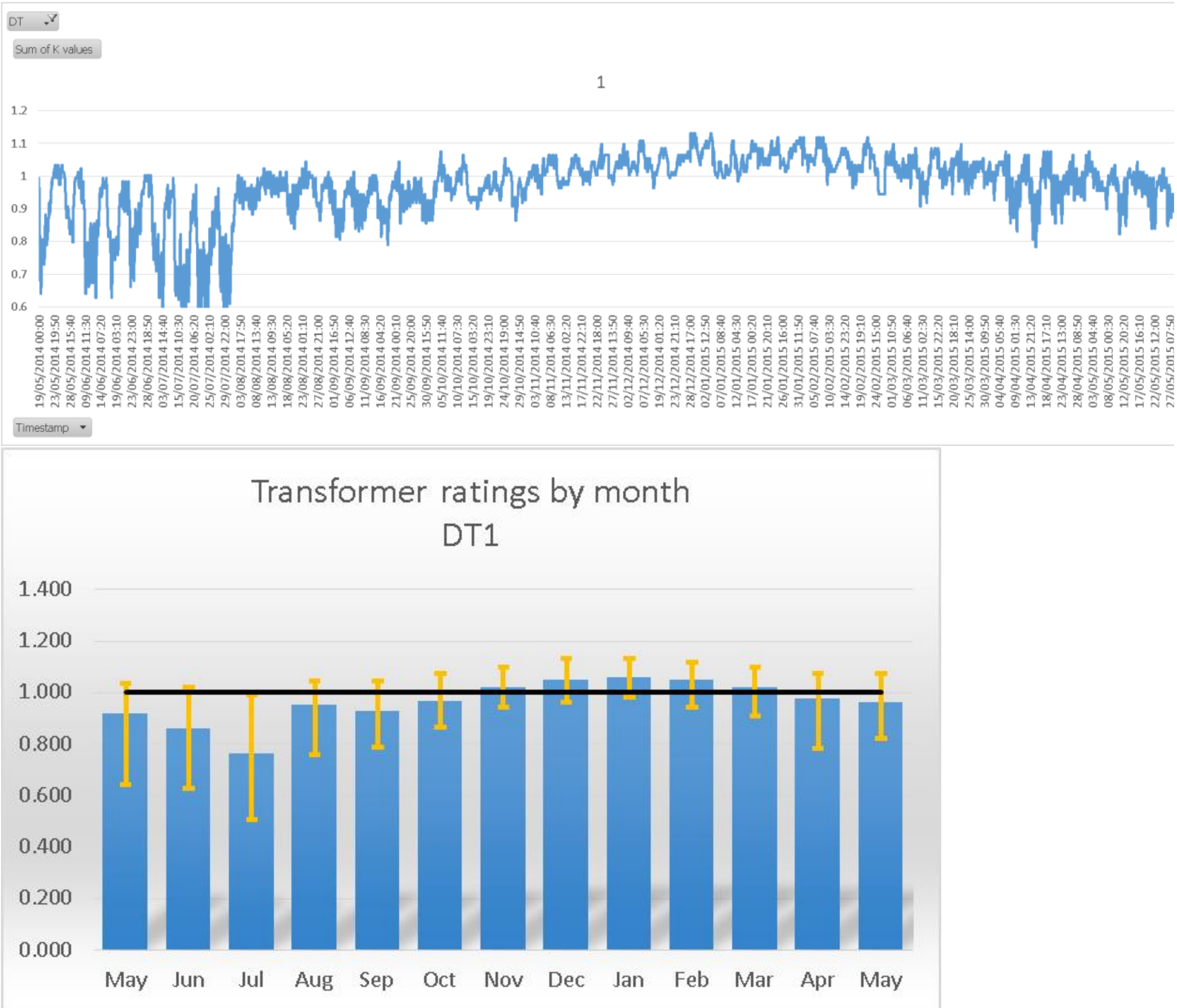

Pelham Place - w/c 13/10/2014
Temperature (c)
Indoor temp
Measured tank temp
Modelled top oil temperature
Modelled hot spot temperature



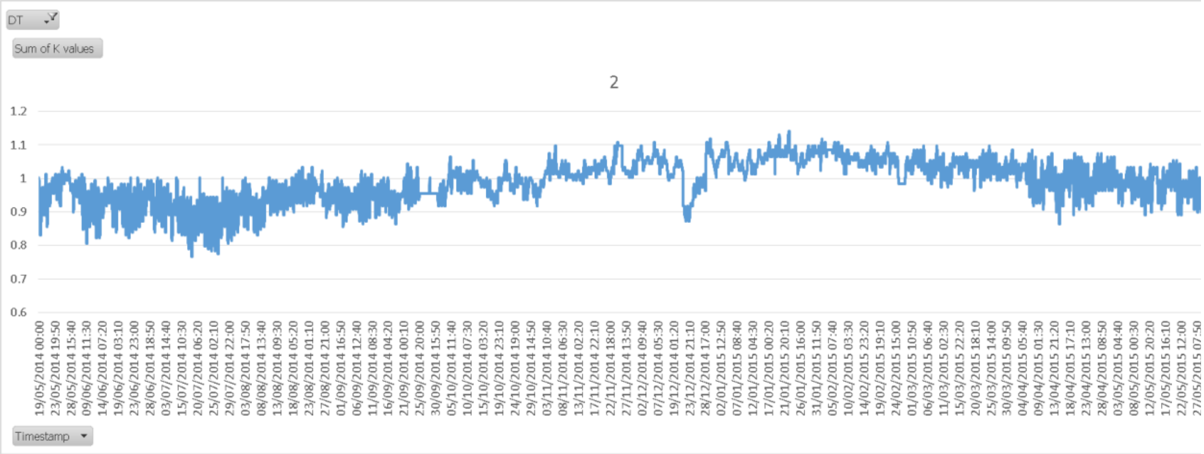
Transformer 16: spring, summer, high summer, autumn and winter

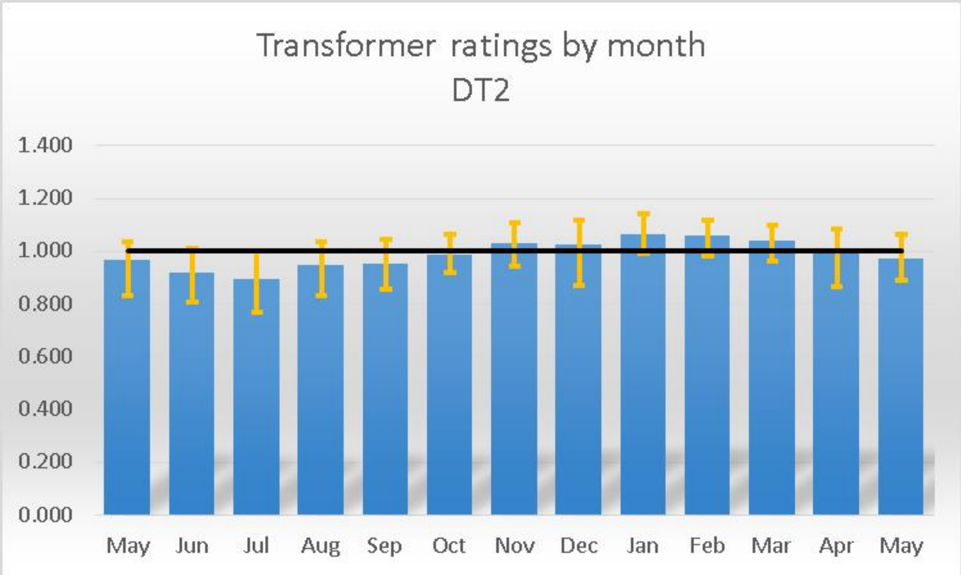
E Ampacity and Benefits

This Appendix shows the calculated 10 minute ampacity across the data period for each transformer based on the measured data (graph 1). In addition, the calculated ratings are also shown, split by month, for each of the transformers (graph 2). This graph shows the average dynamic rating, based on accurate measured data, compared to the static rating. The blue column represents the average rating value (typically above static in winter, and below in summer) and the orange error bars show the range of values for that month (maximum to minimum).

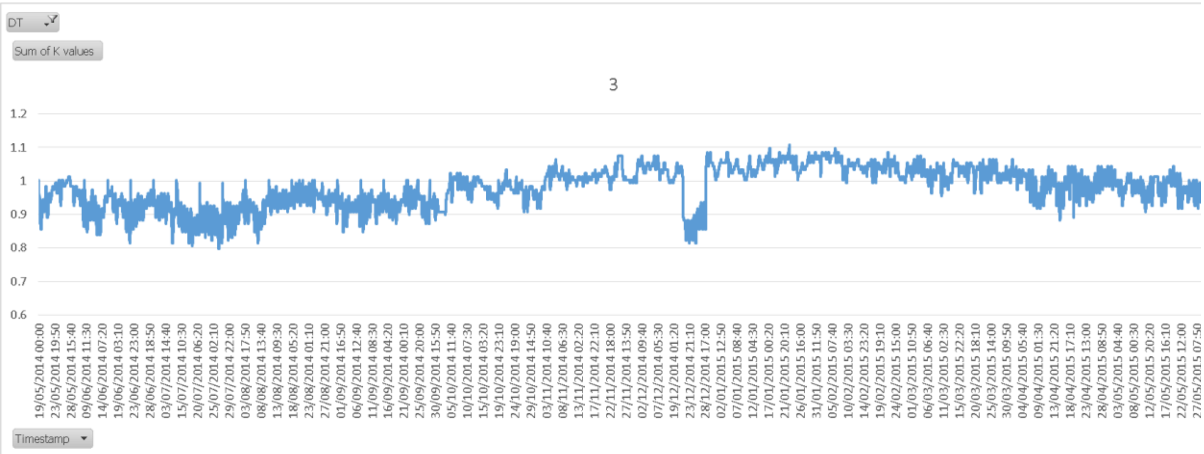


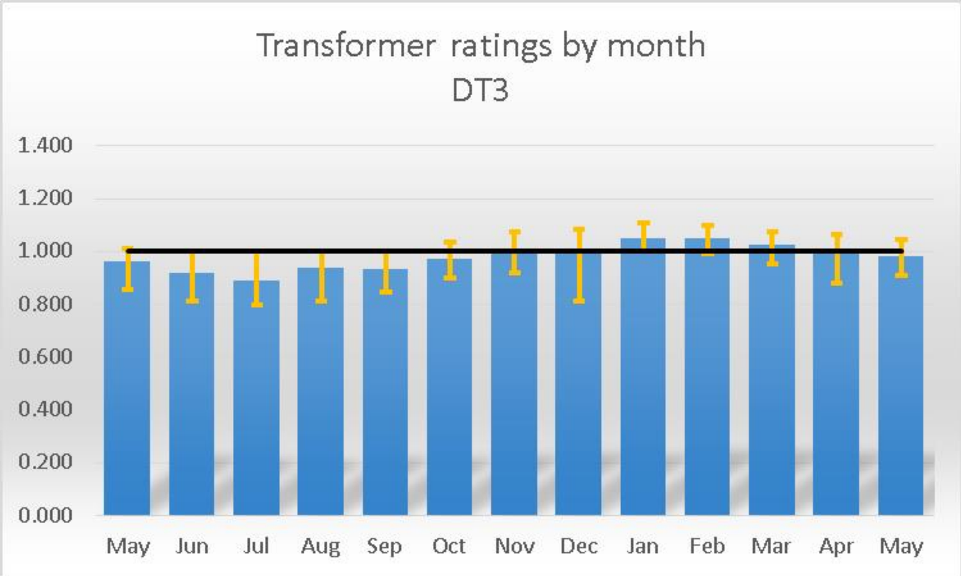
Transformer 1 – Time varying and per month summary



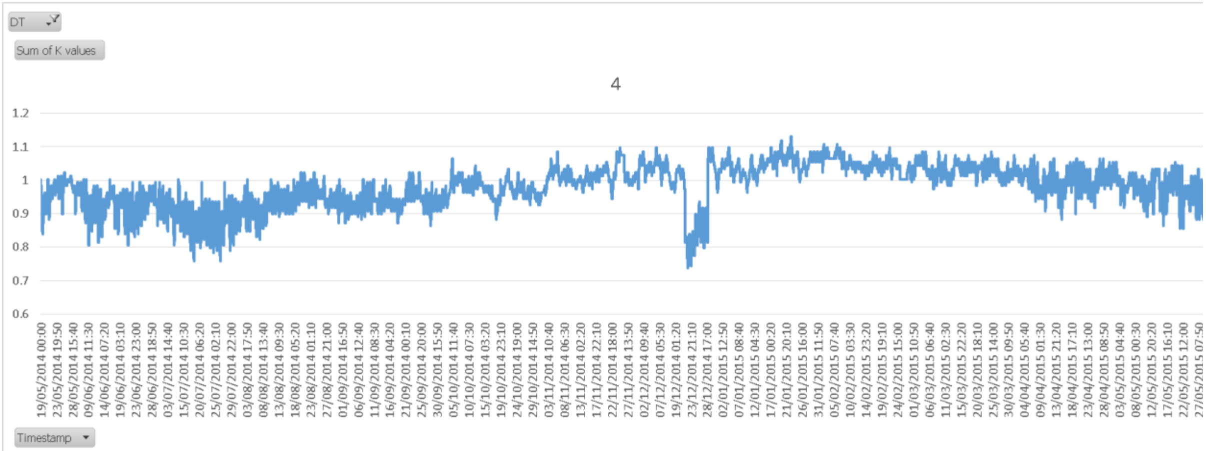


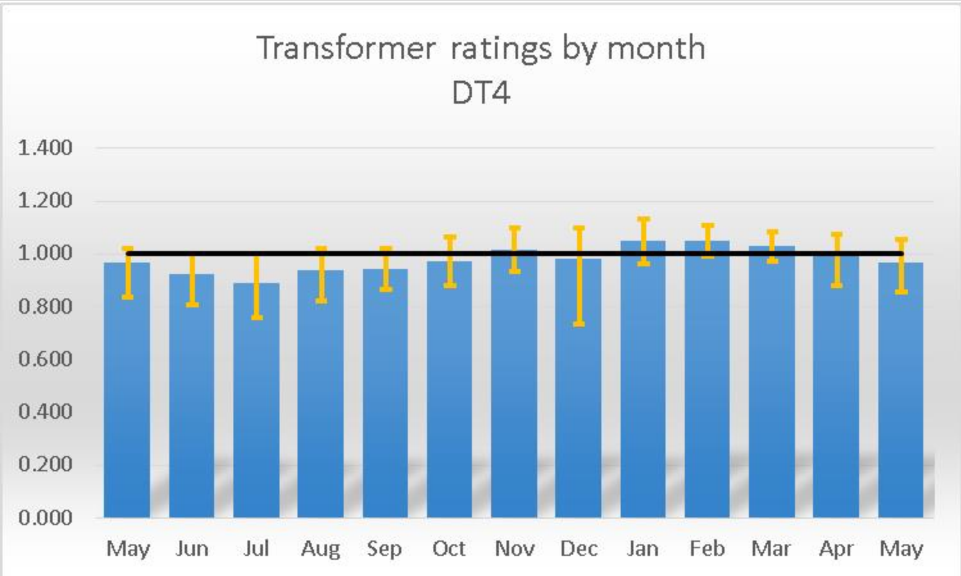
Transformer 2 – Ampacity and benefits



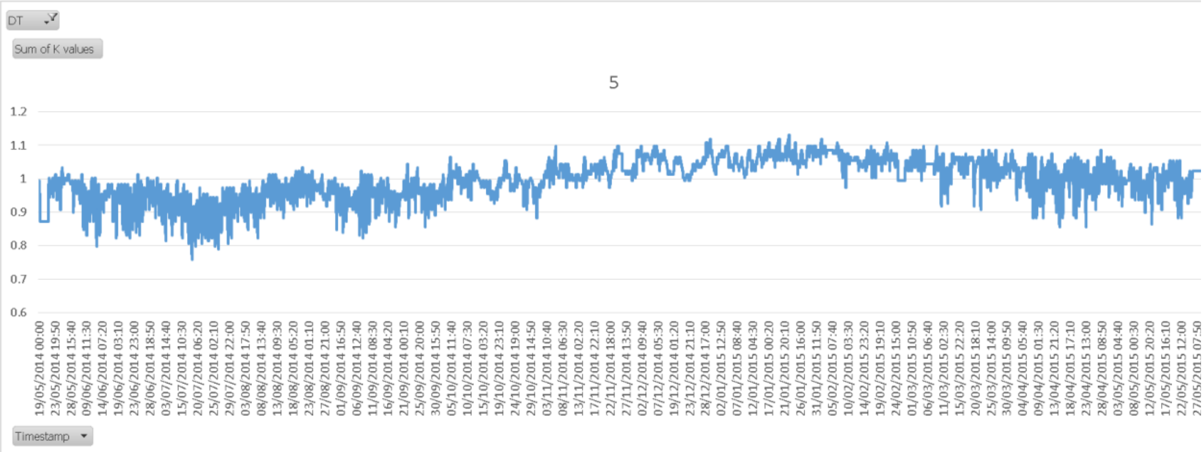


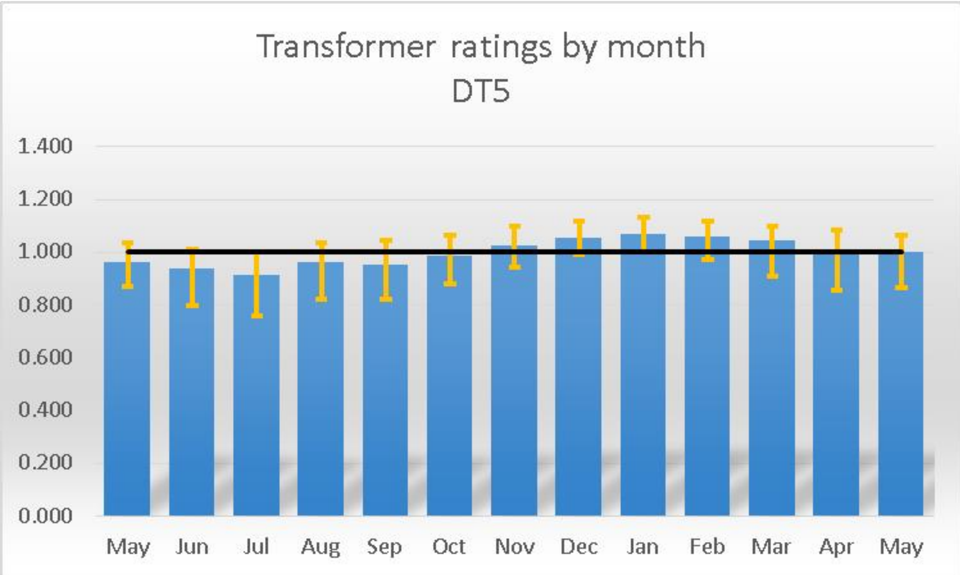
Transformer 3 – Ampacity and benefits



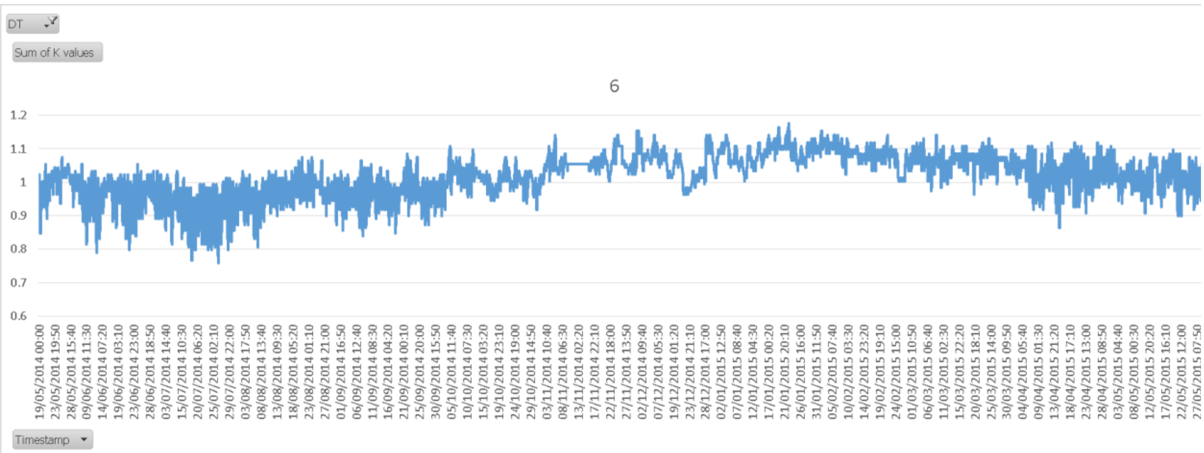


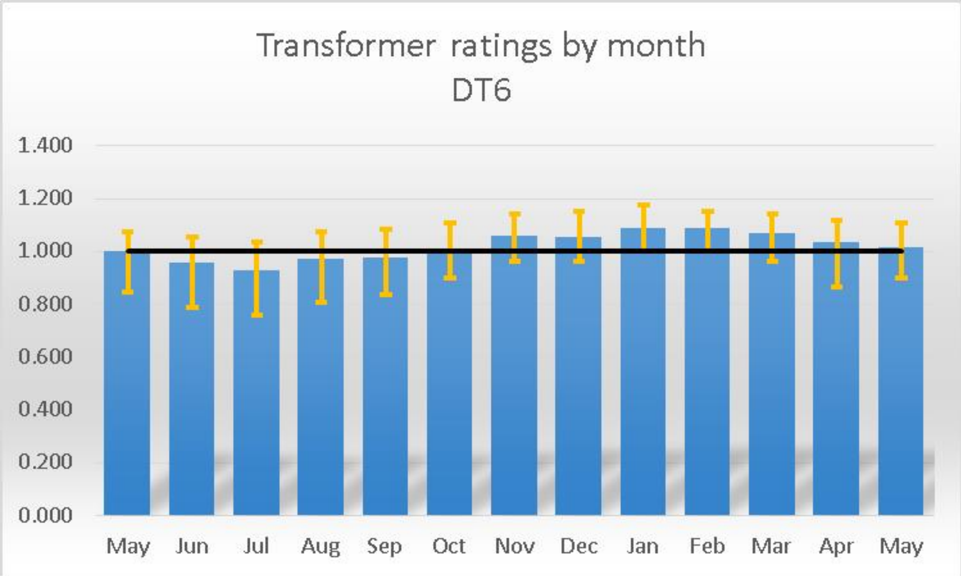
Transformer 4 – Ampacity and benefits



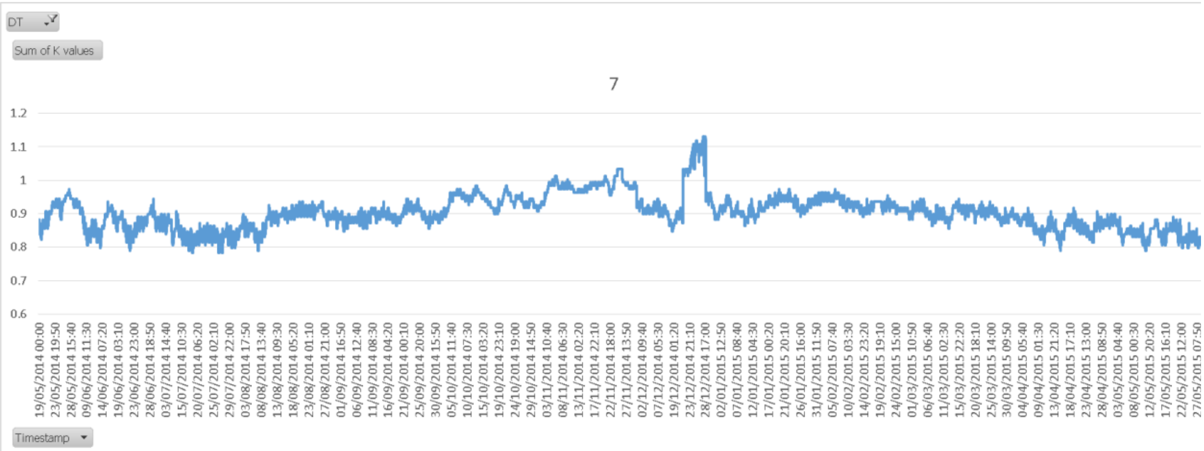


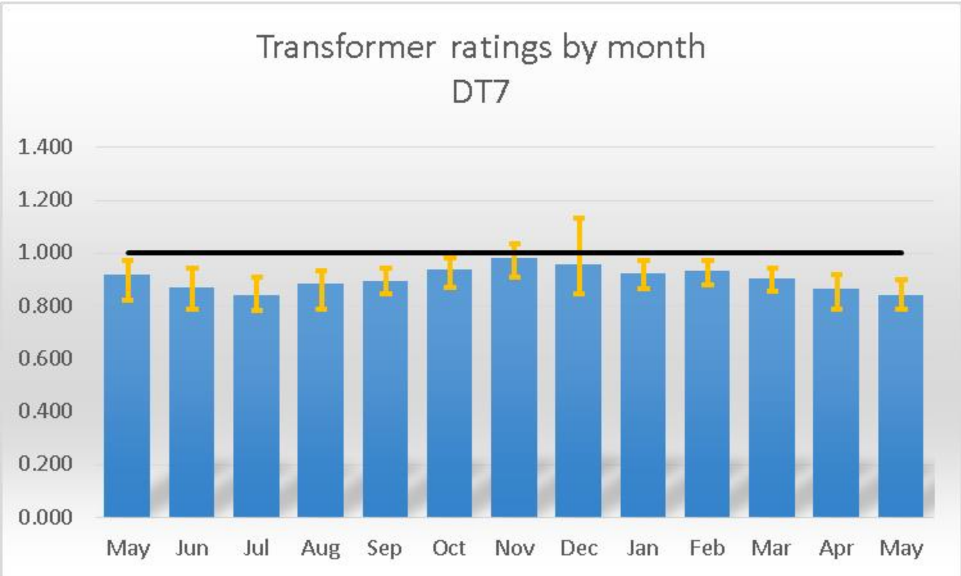
Transformer 5 – Ampacity and benefits



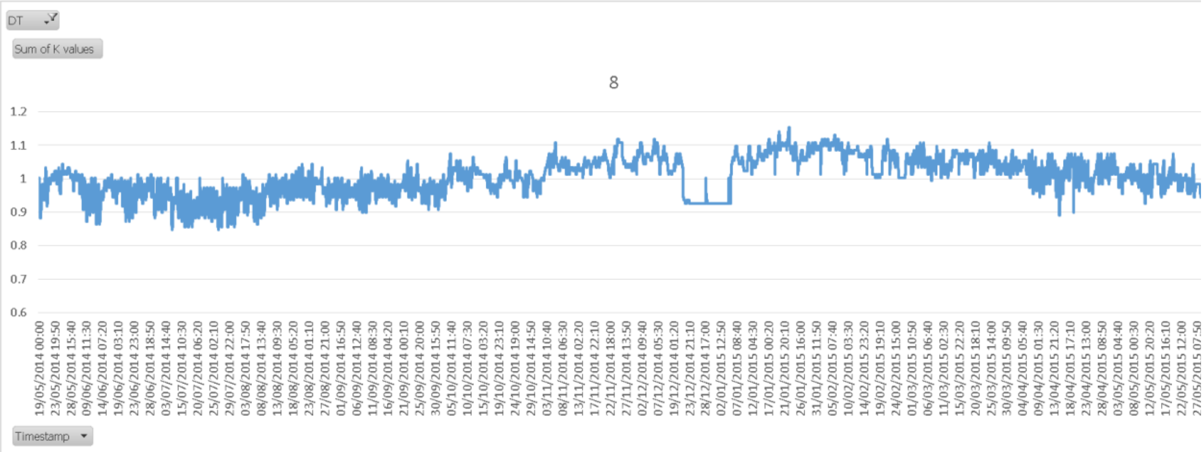


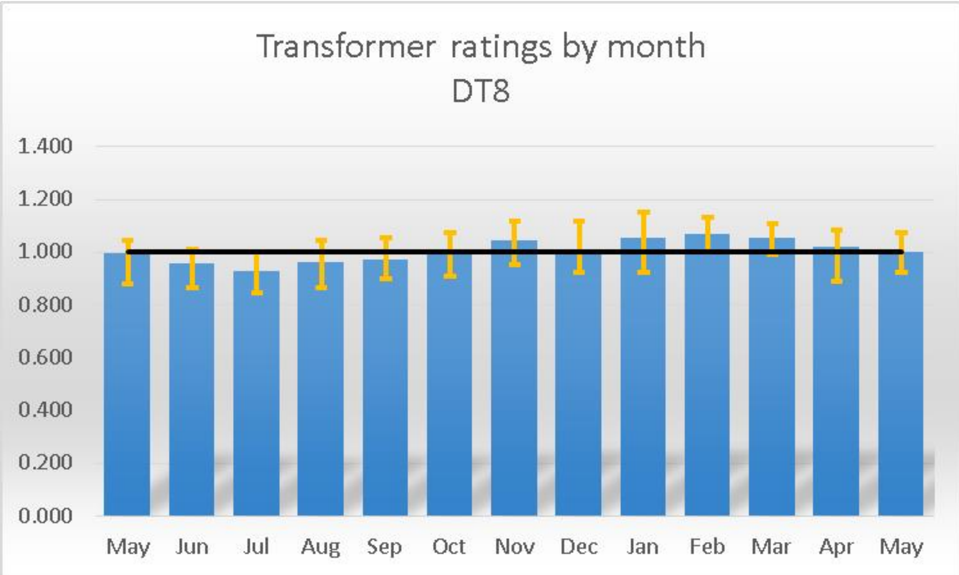
Transformer 6– Ampacity and benefits



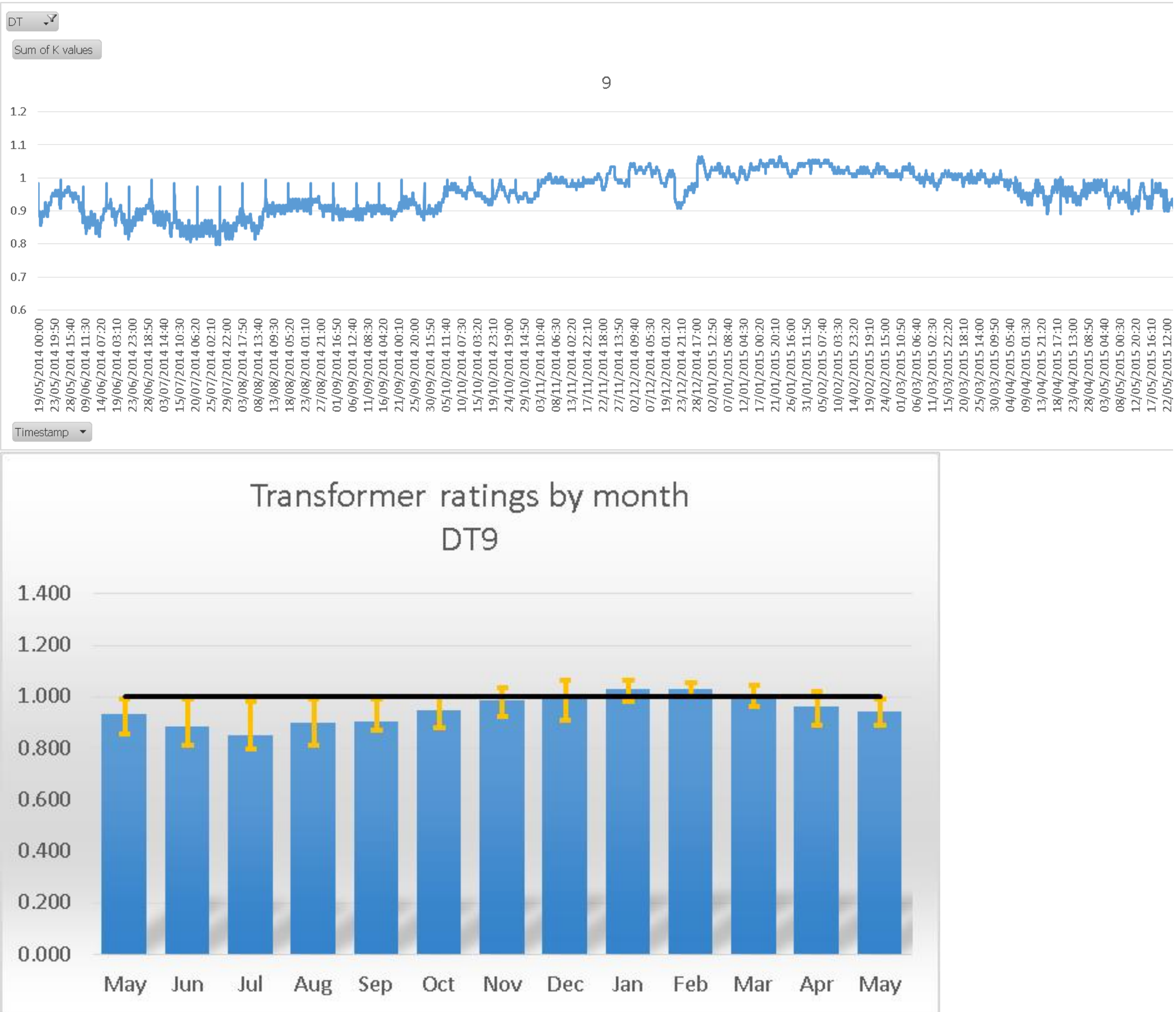


Transformer 7– Ampacity and benefits

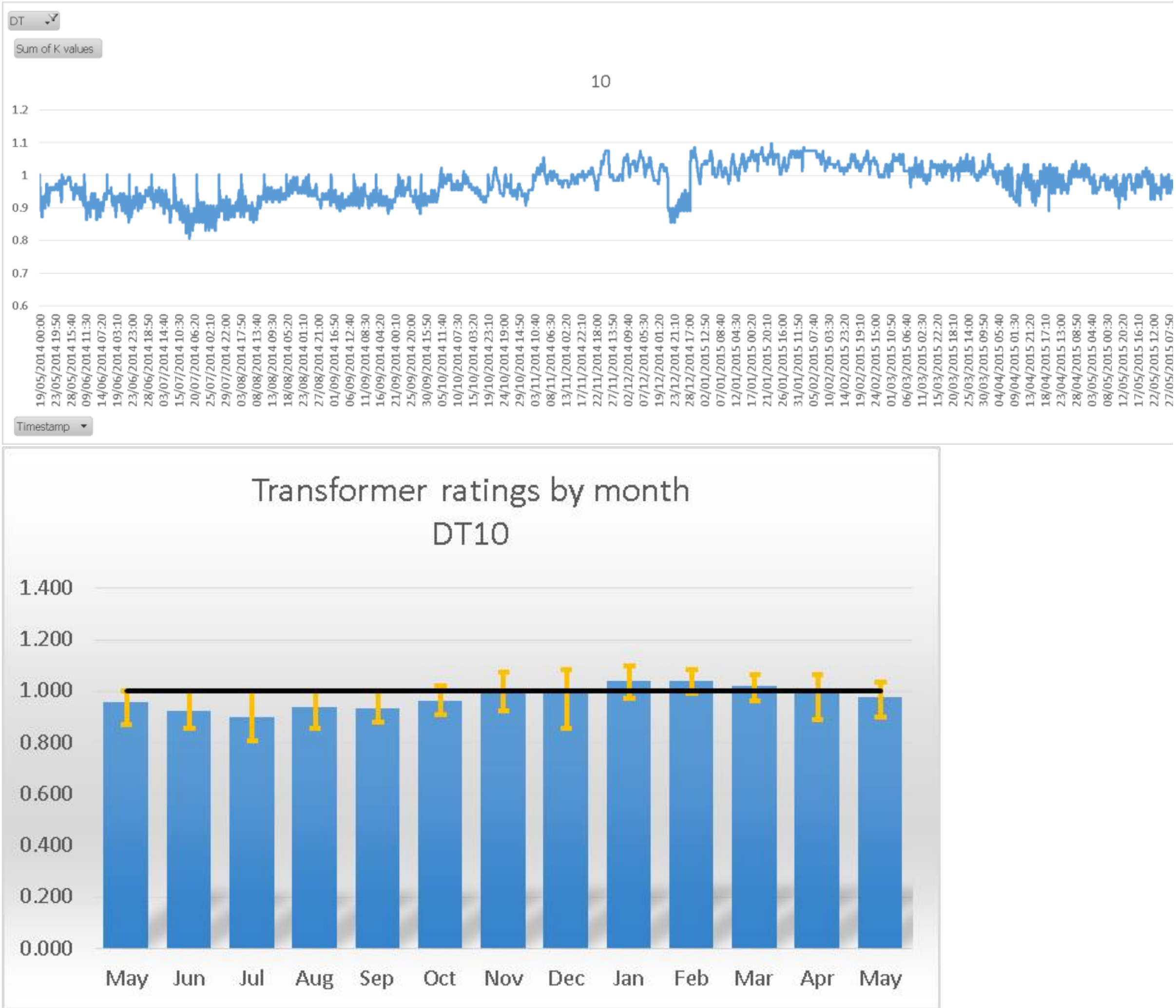




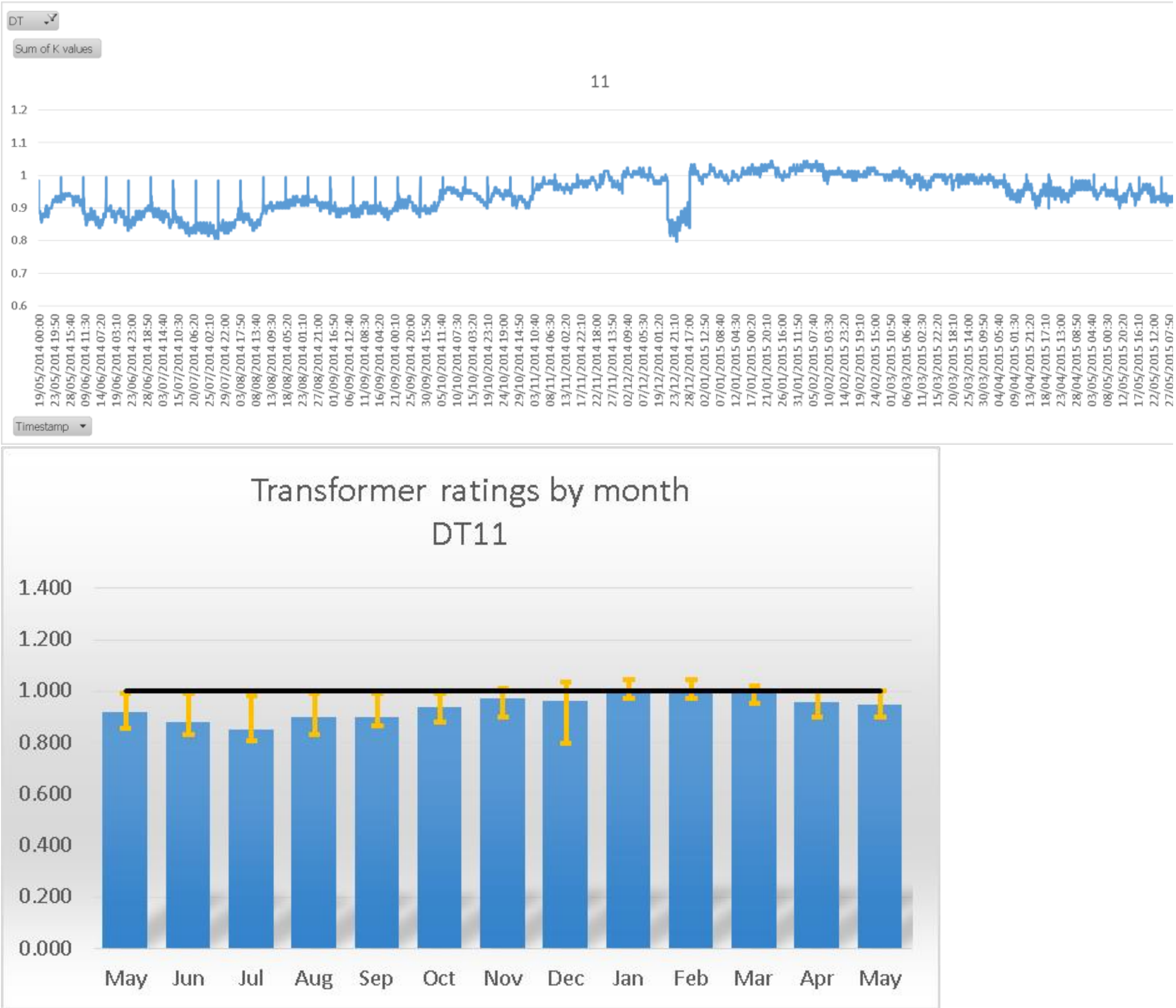
Transformer 8– Ampacity and benefits



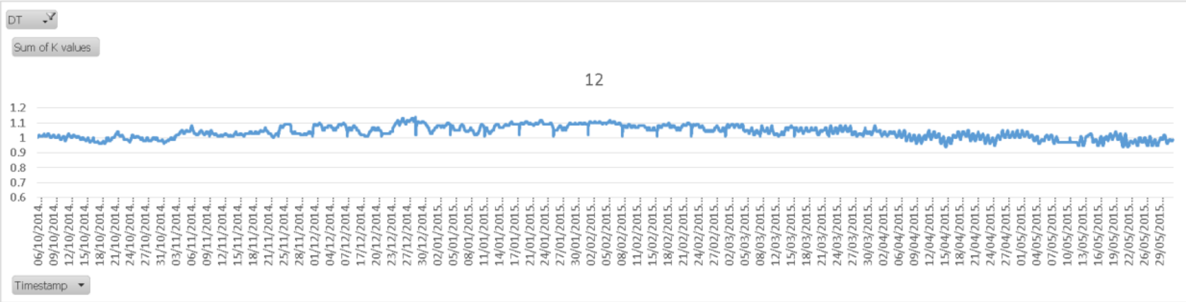
Transformer 9– Ampacity and benefits

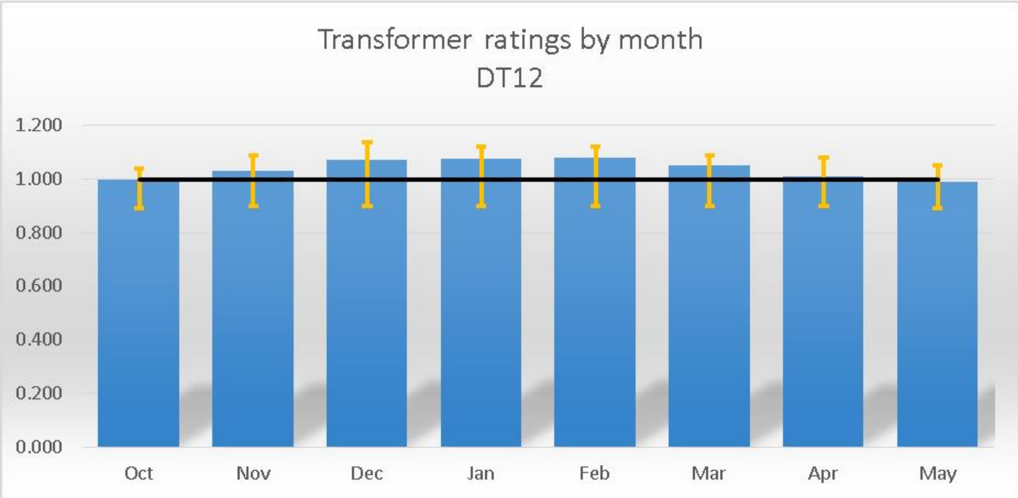


Transformer 10– Ampacity and benefits

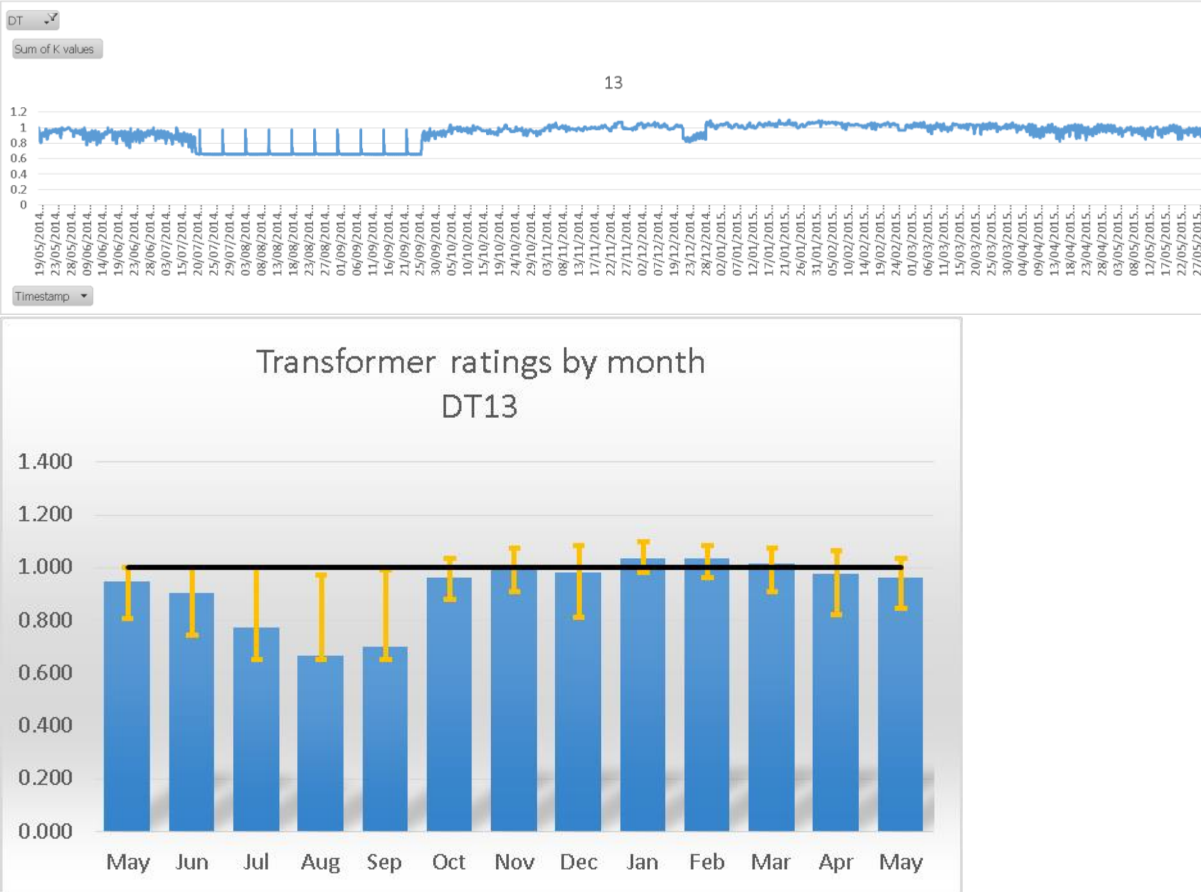


Transformer 11– Ampacity and benefits

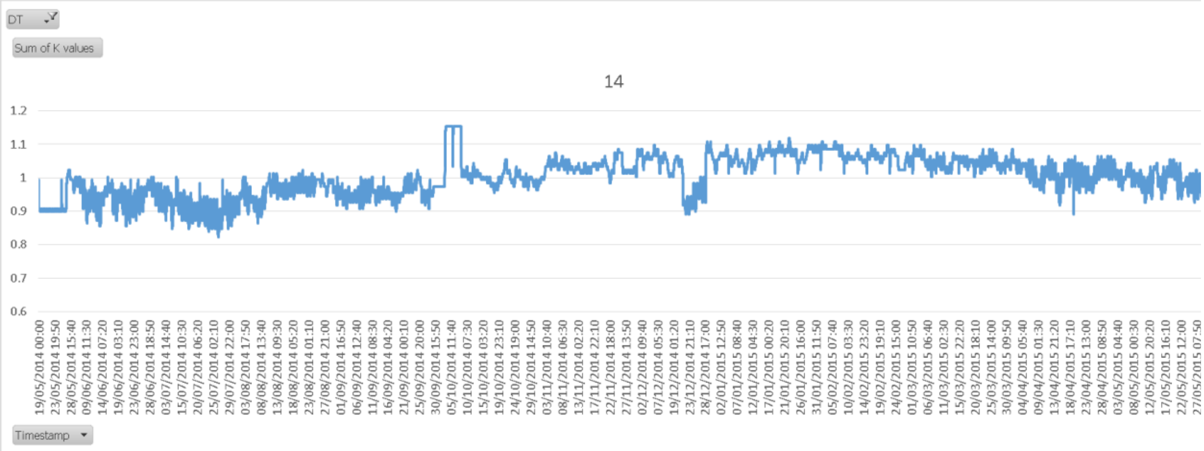


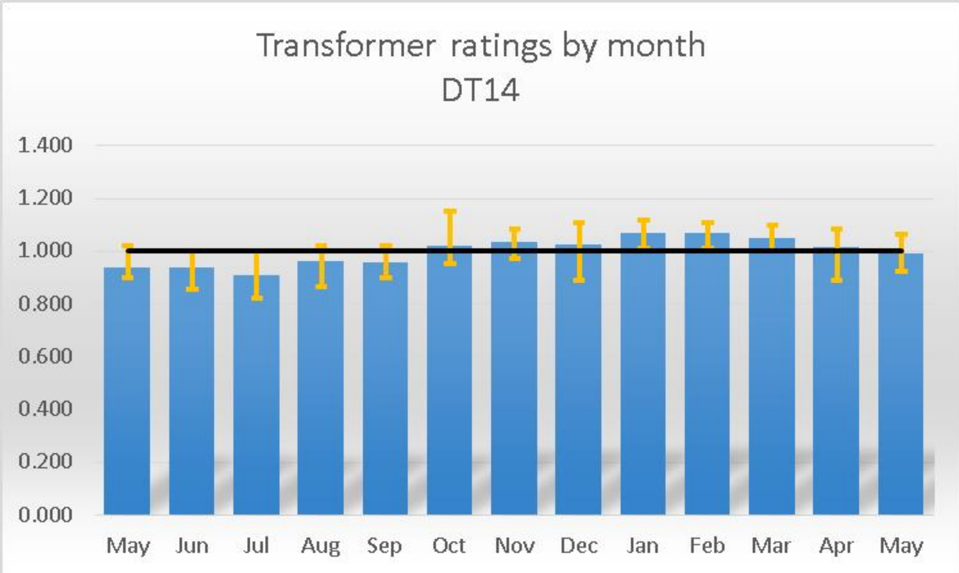


Transformer 12– Ampacity and benefits

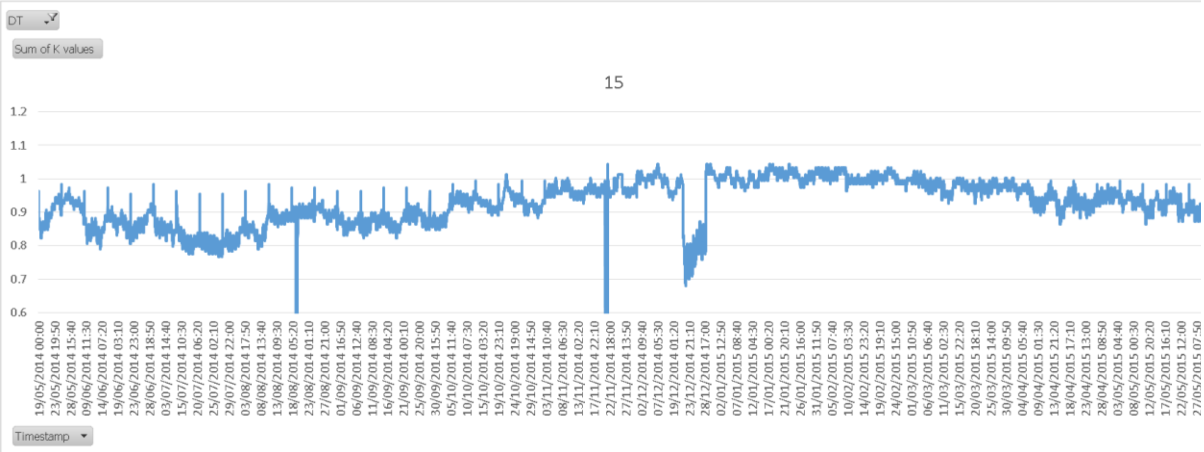


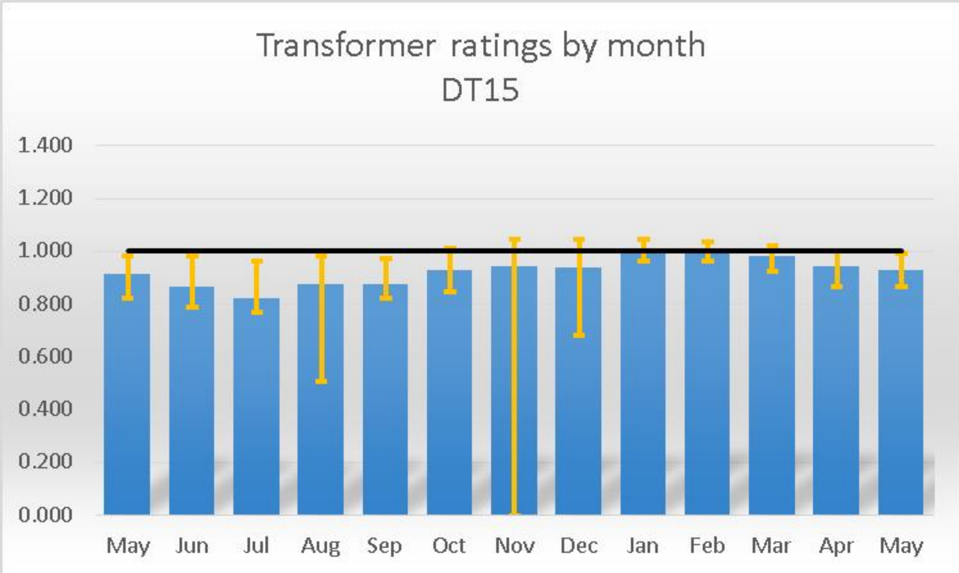
Transformer 13– Ampacity and benefits



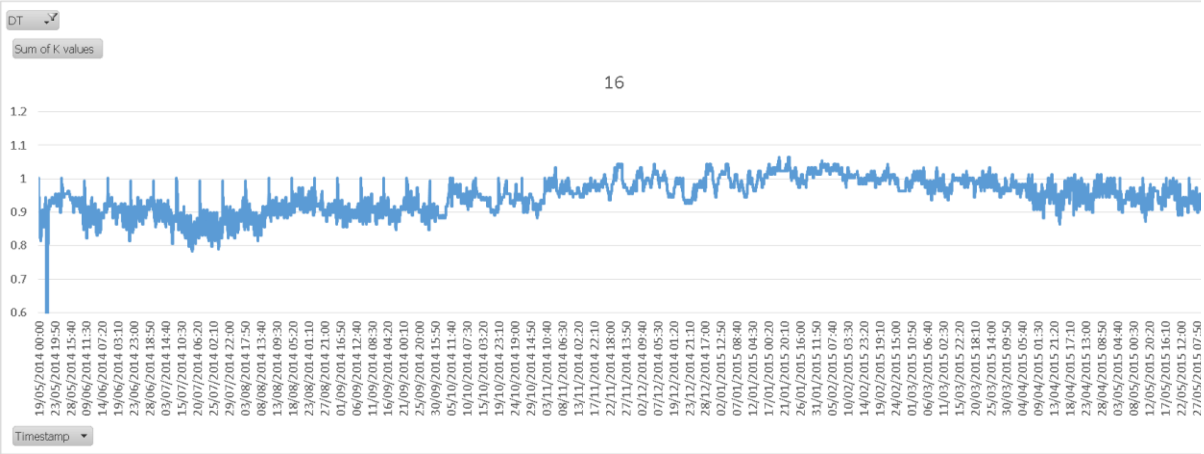


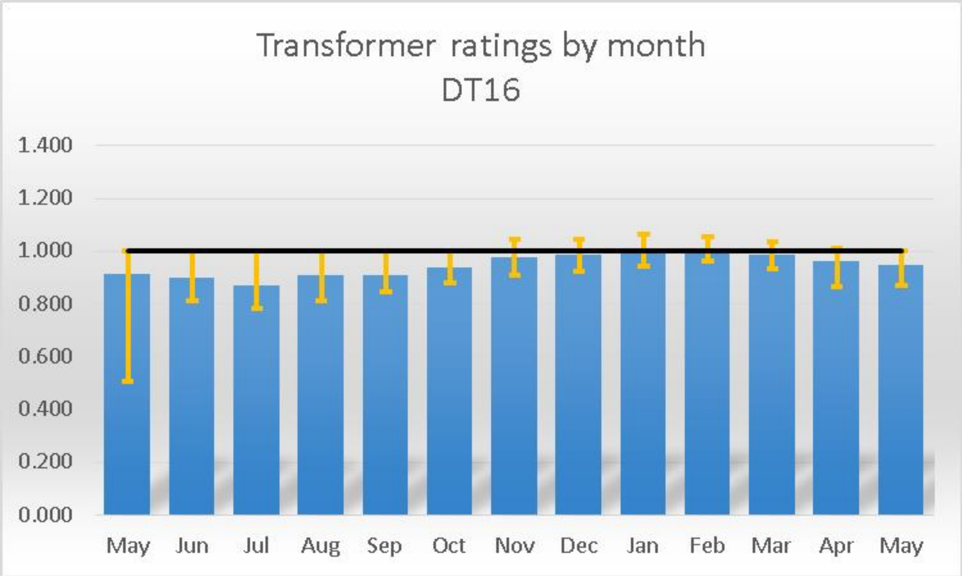
Transformer 14– Ampacity and benefits





Transformer 15– Ampacity and benefits

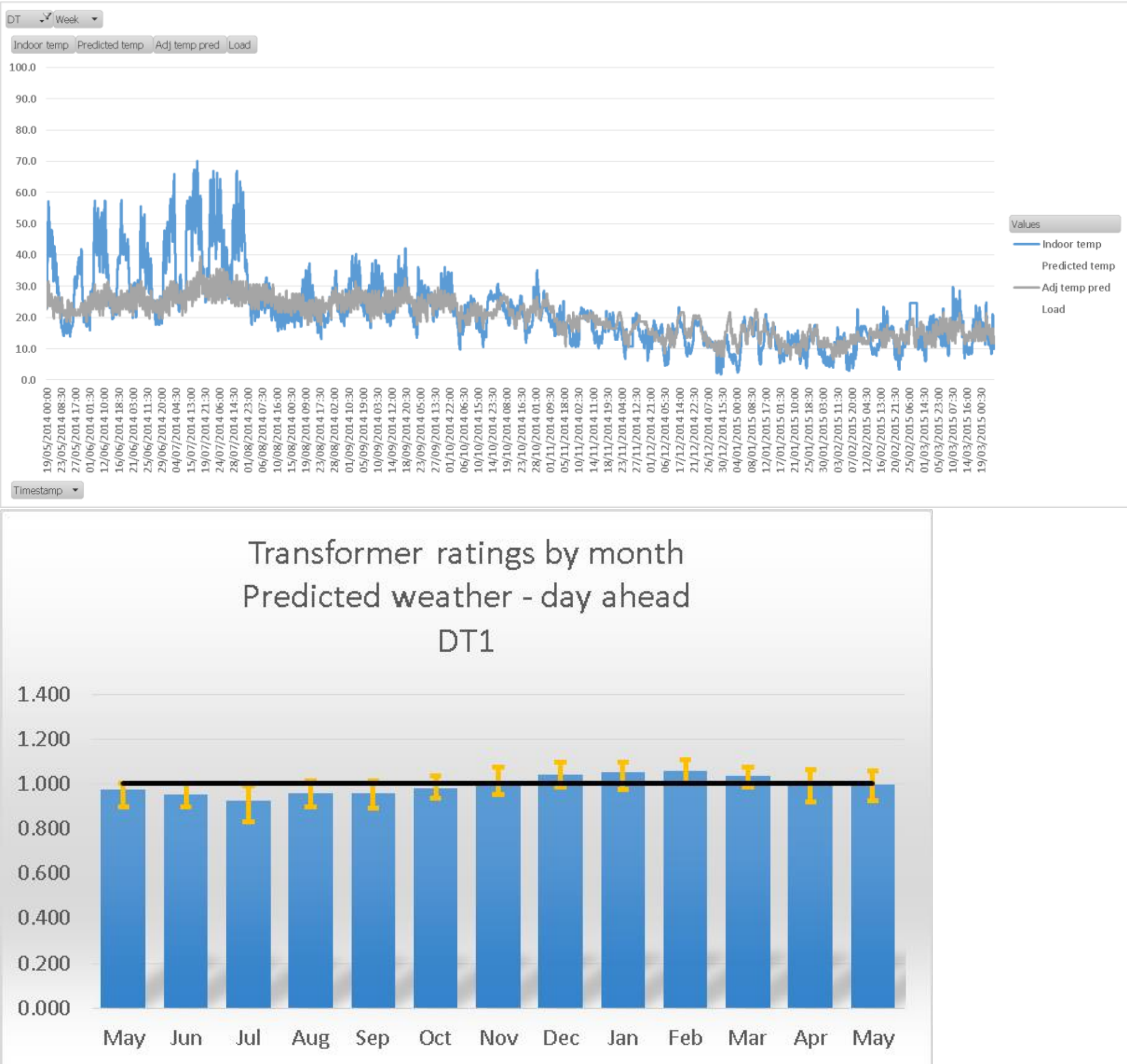




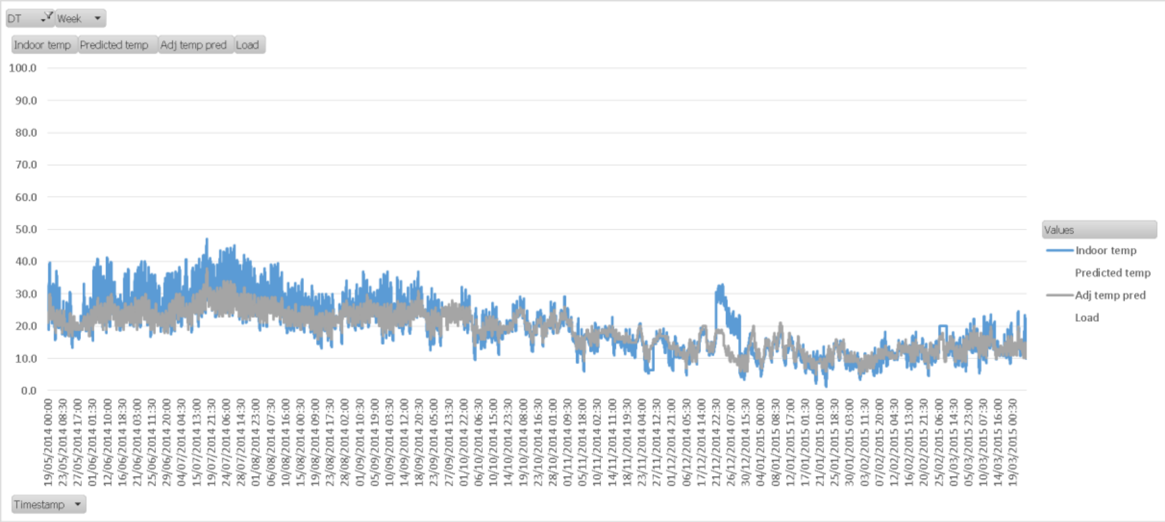
Transformer 16– Ampacity and benefits

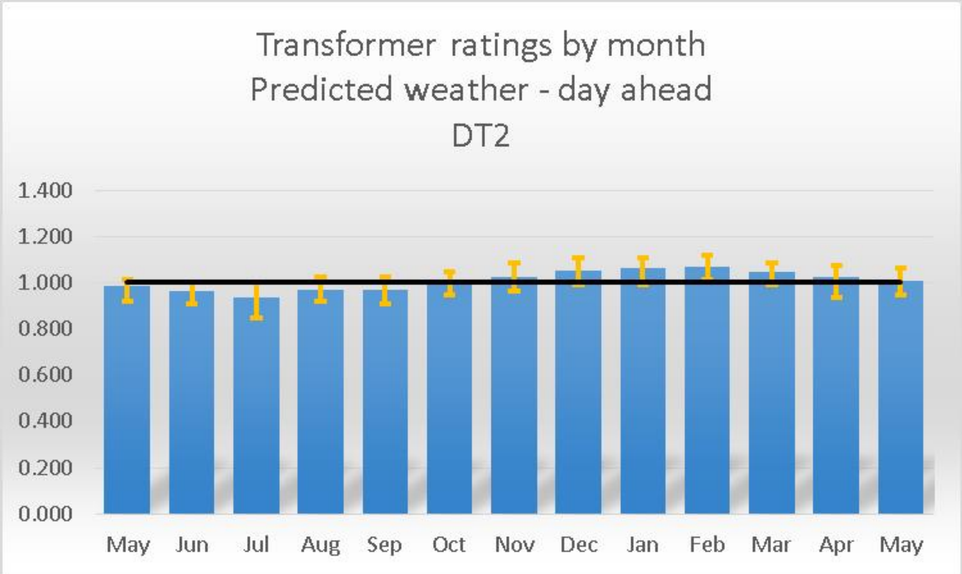
F Day Ahead Forecast Temperature and Ampacity

This Appendix shows the forecasted day ahead temperatures compared to the measured ambient temperatures for each transformer (graph 1). The blue line represents the 10 minute ambient temperature recorded at each site, and the grey line represents the adjusted forecast temperature. This adjustment takes into account the typical temperature difference for each transformer (which are generally warmer due to its housing and the running of the transformer). The second graph shows the predicted rating for each month derived from the day ahead forecast (similar to the second graph in Appendix E).

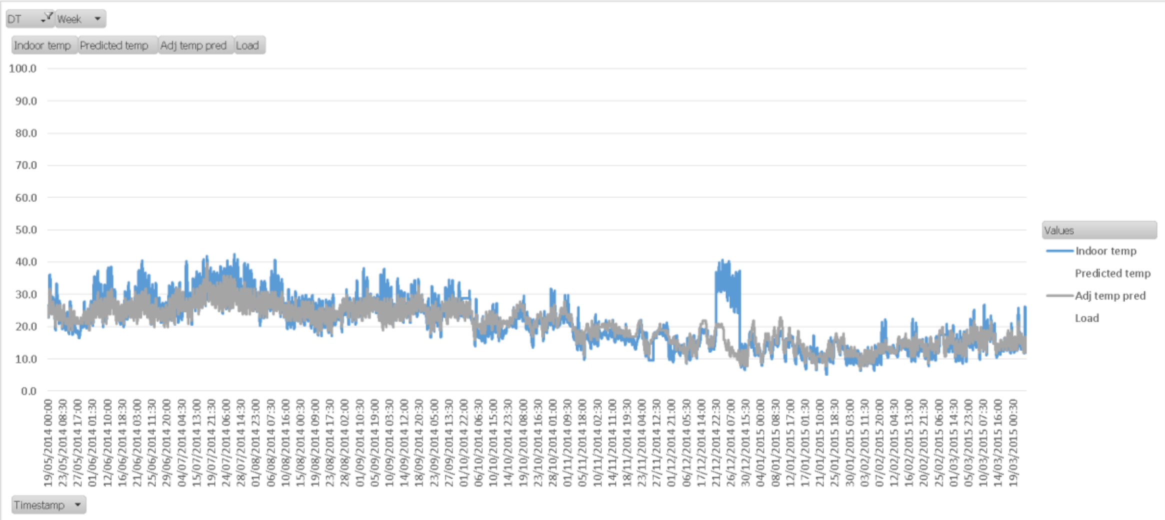


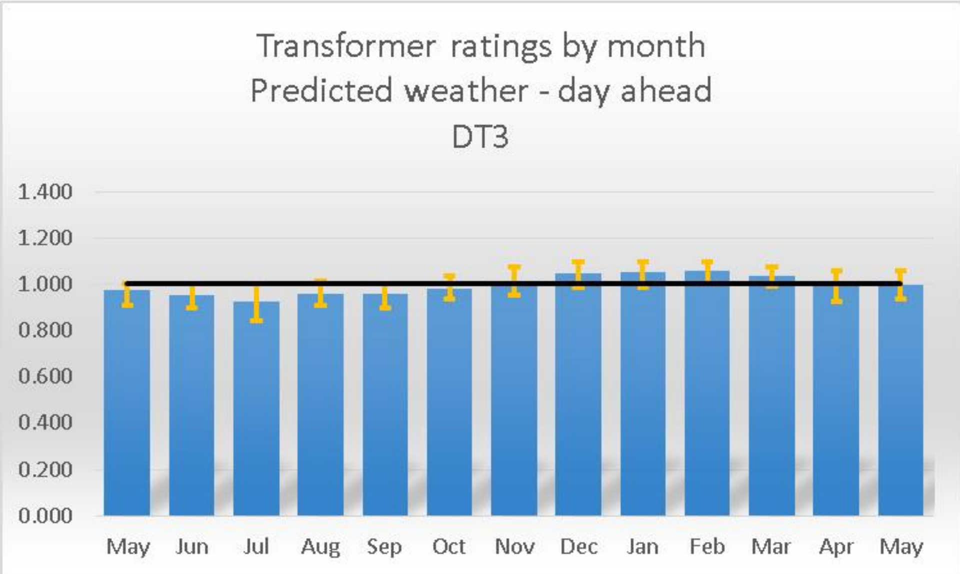
Transformer 1 : Predicted ambient temperature and predicted benefits



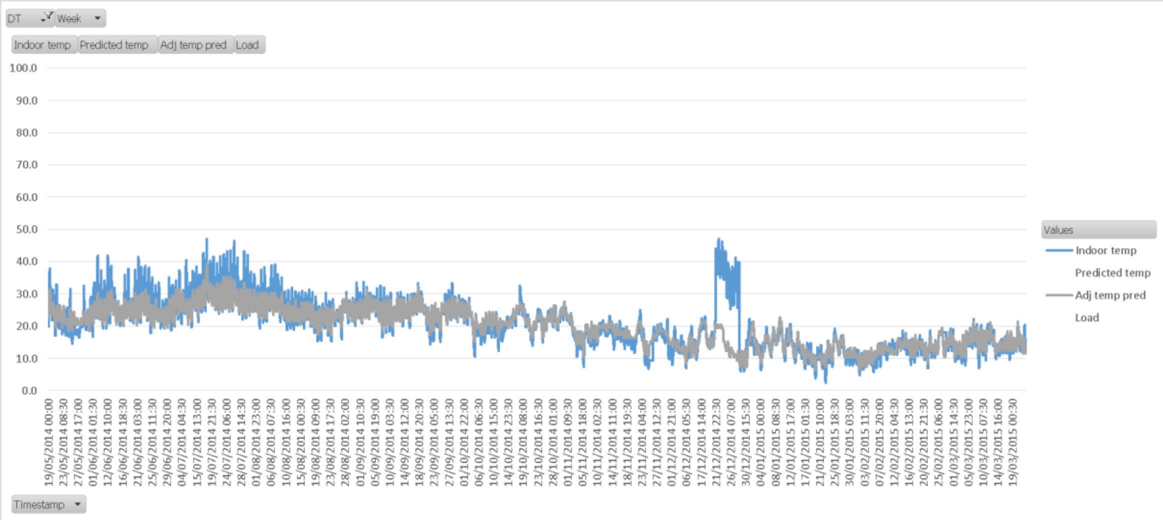


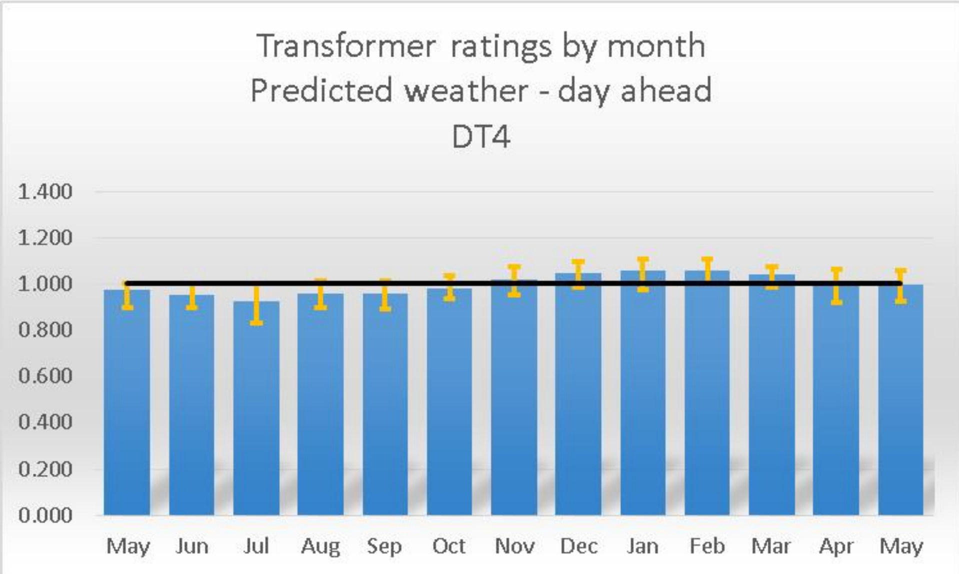
Transformer 2 : Predicted ambient temperature and predicted benefits



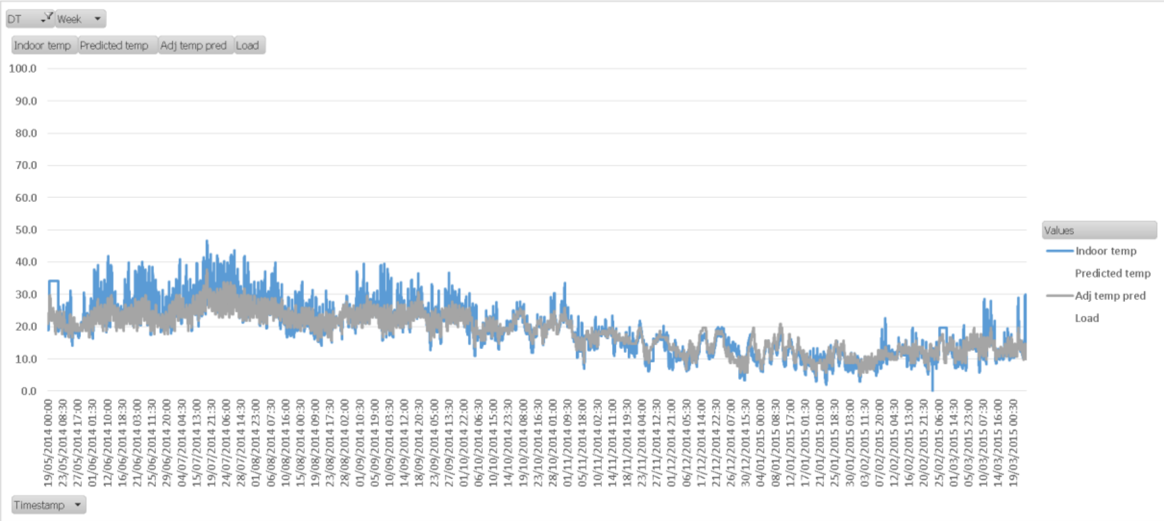


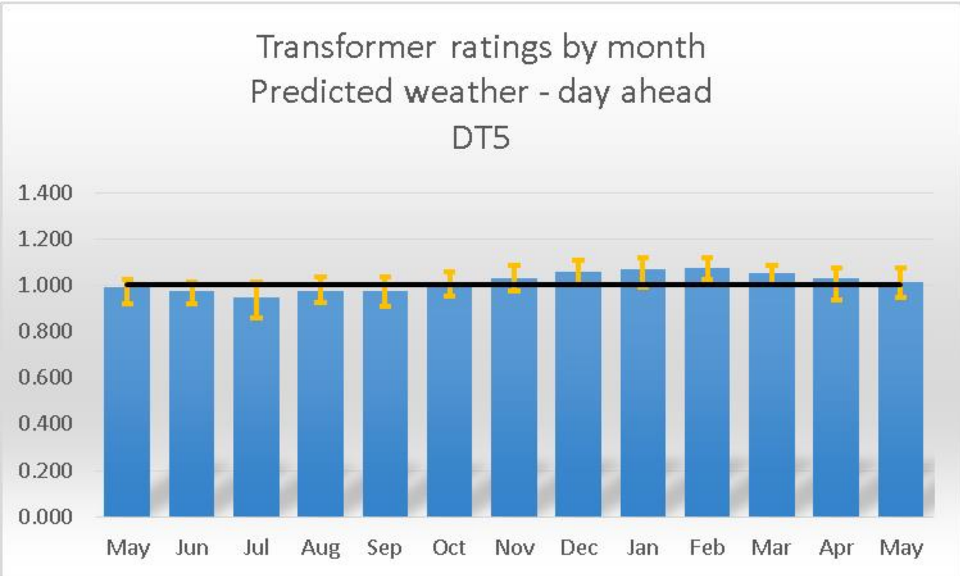
Transformer 3 : Predicted ambient temperature and predicted benefits



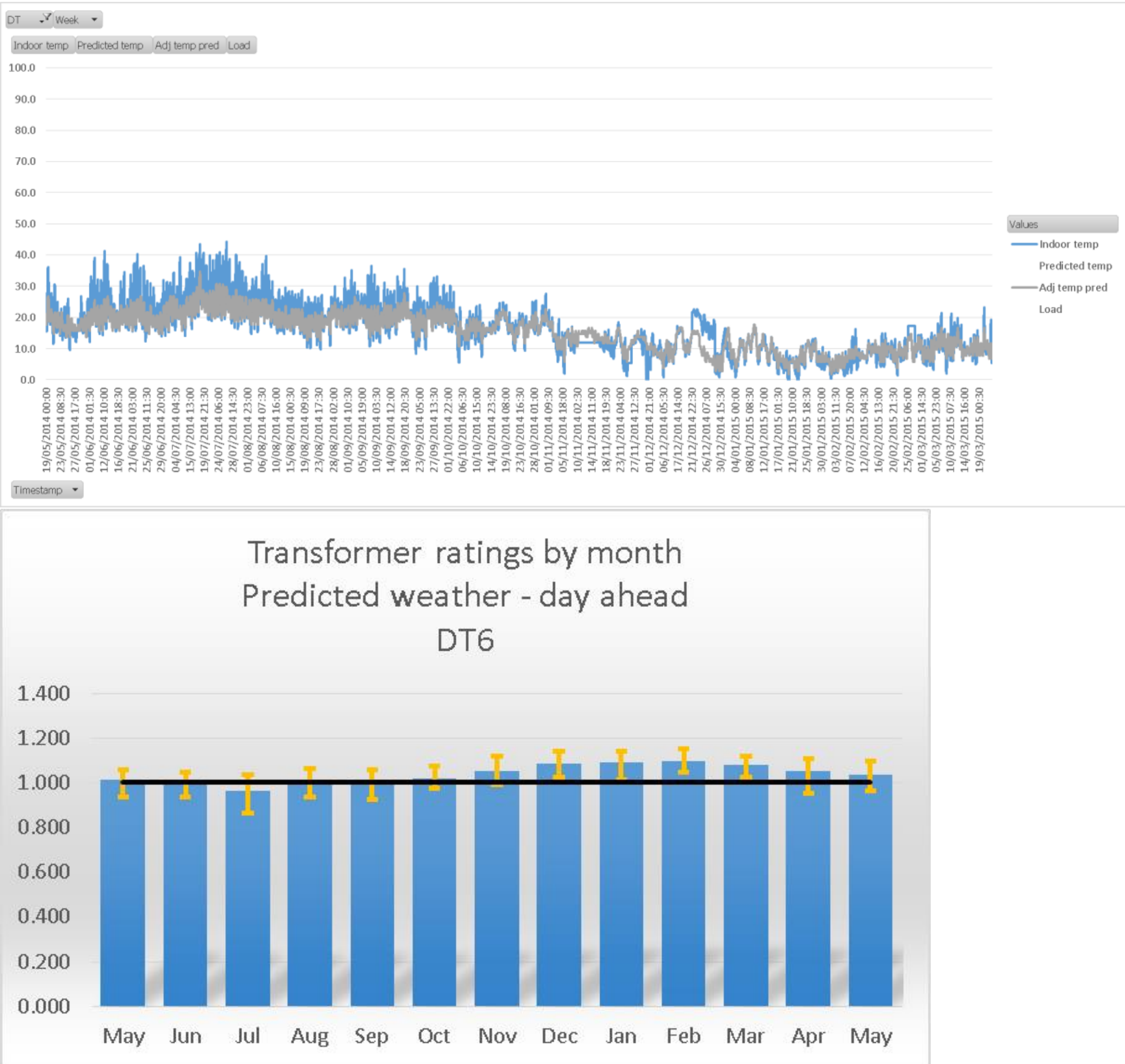


Transformer 4 : Predicted ambient temperature and predicted benefits

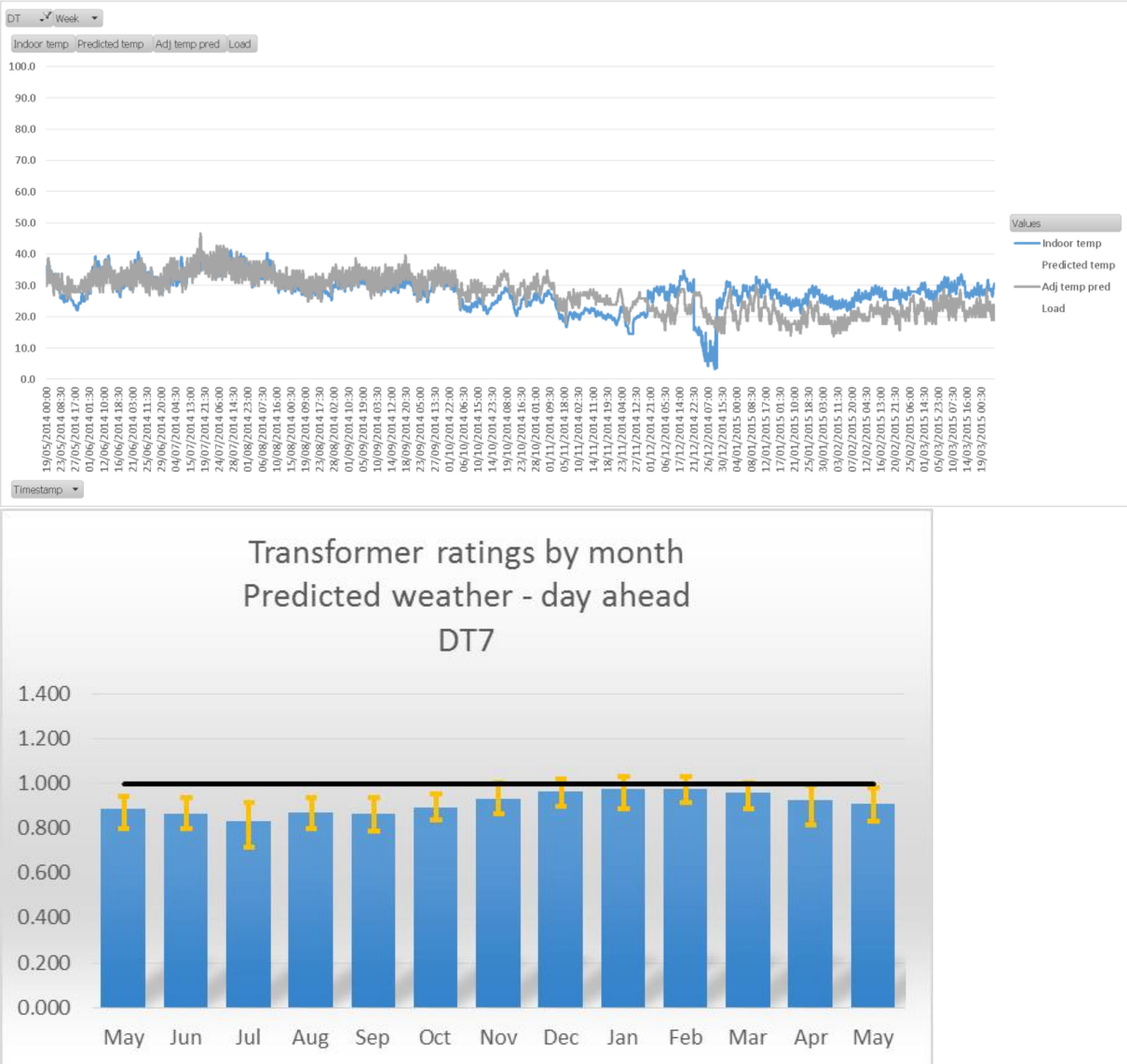




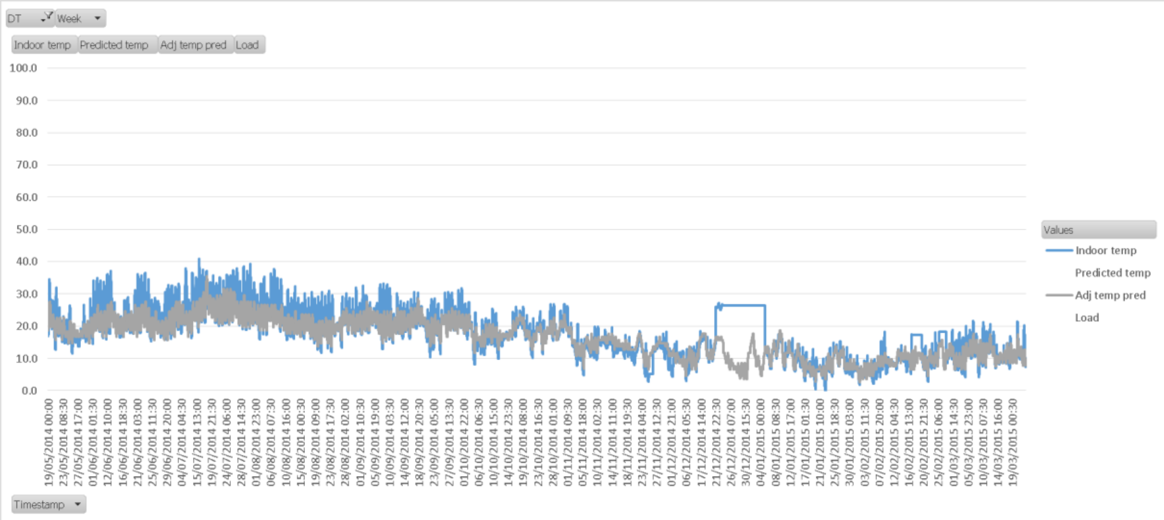
Transformer 5 : Predicted ambient temperature and predicted benefits

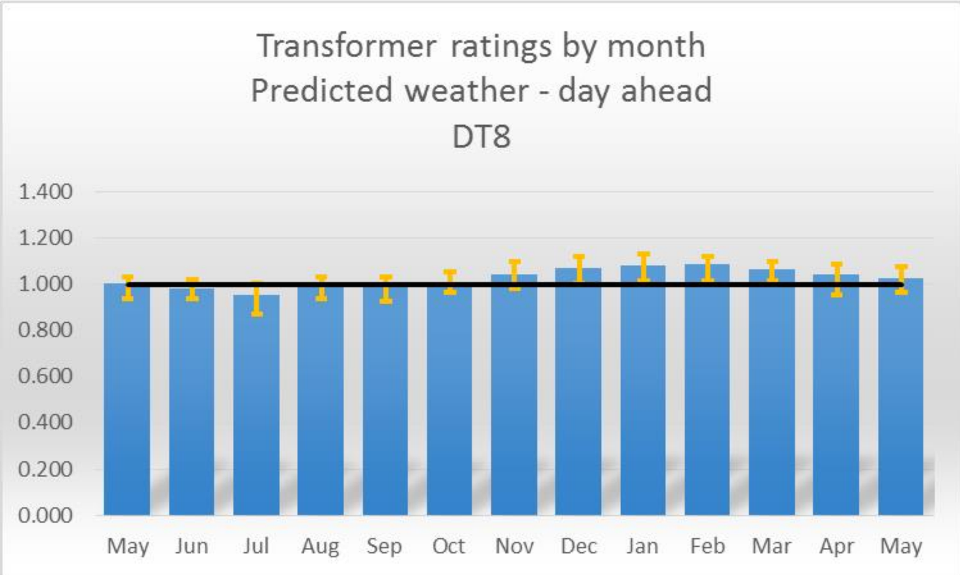


Transformer 6 : Predicted ambient temperature and predicted benefits

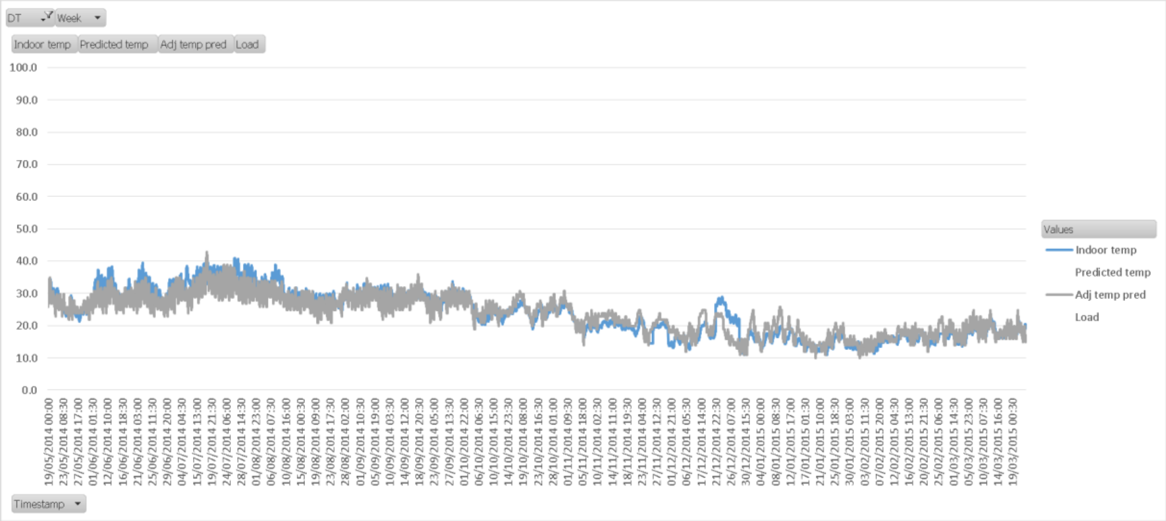


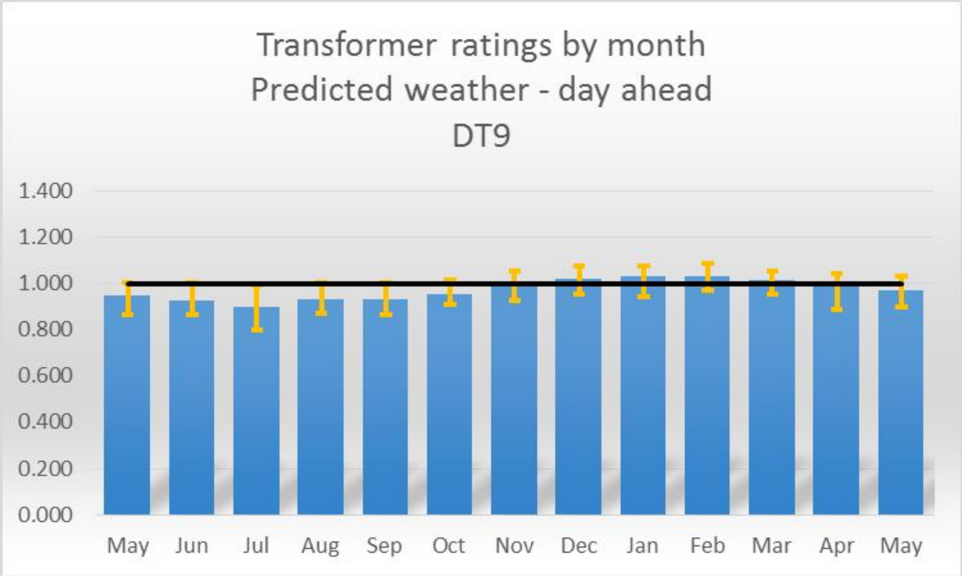
Transformer 7 : Predicted ambient temperature and predicted benefits



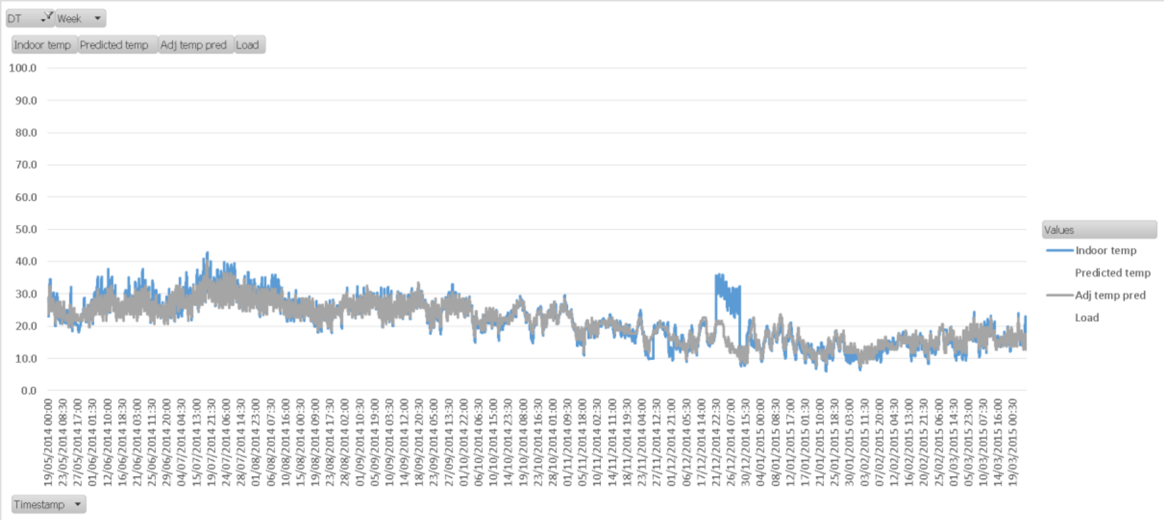


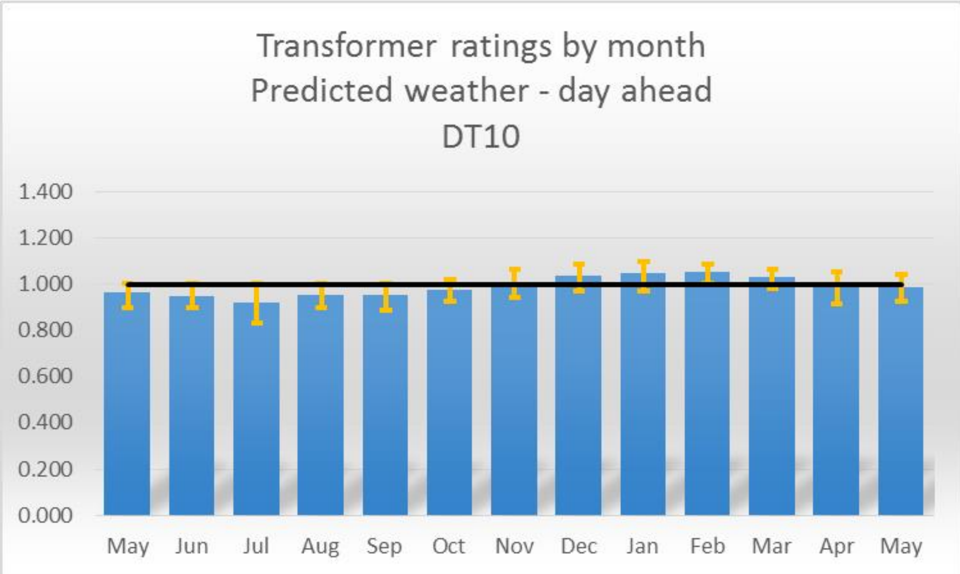
Transformer 8 : Predicted ambient temperature and predicted benefits



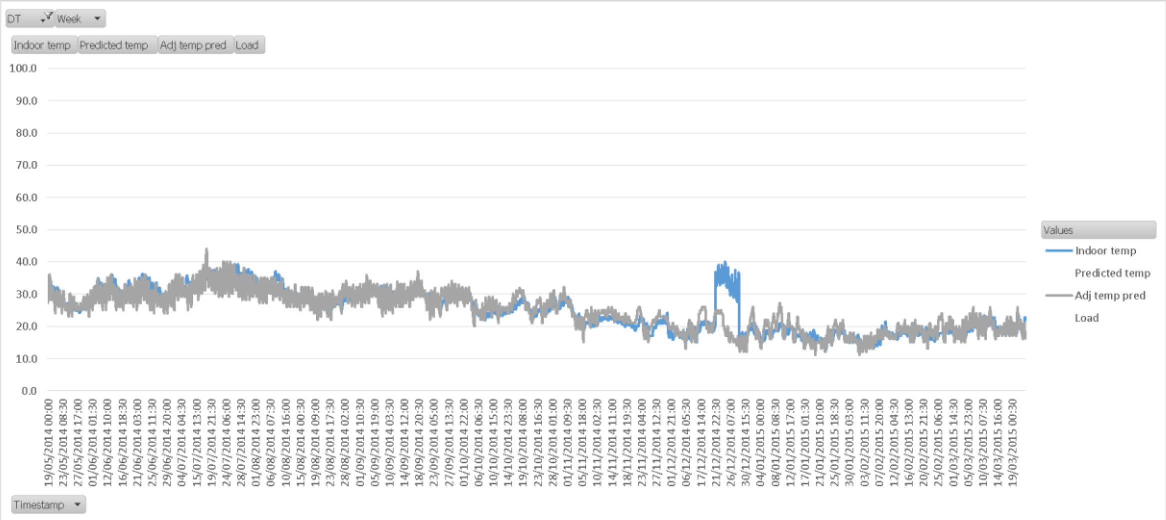


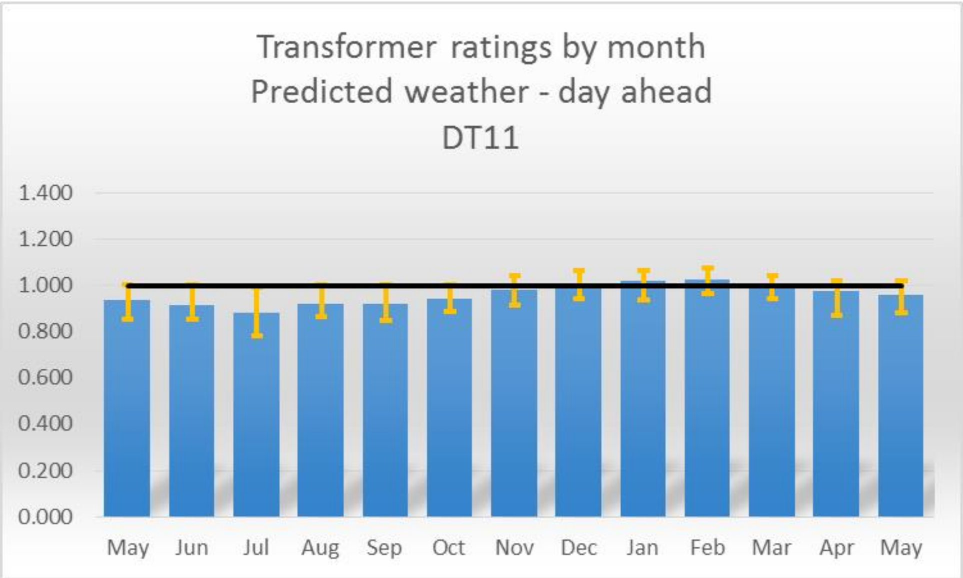
Transformer 9 : Predicted ambient temperature and predicted benefits



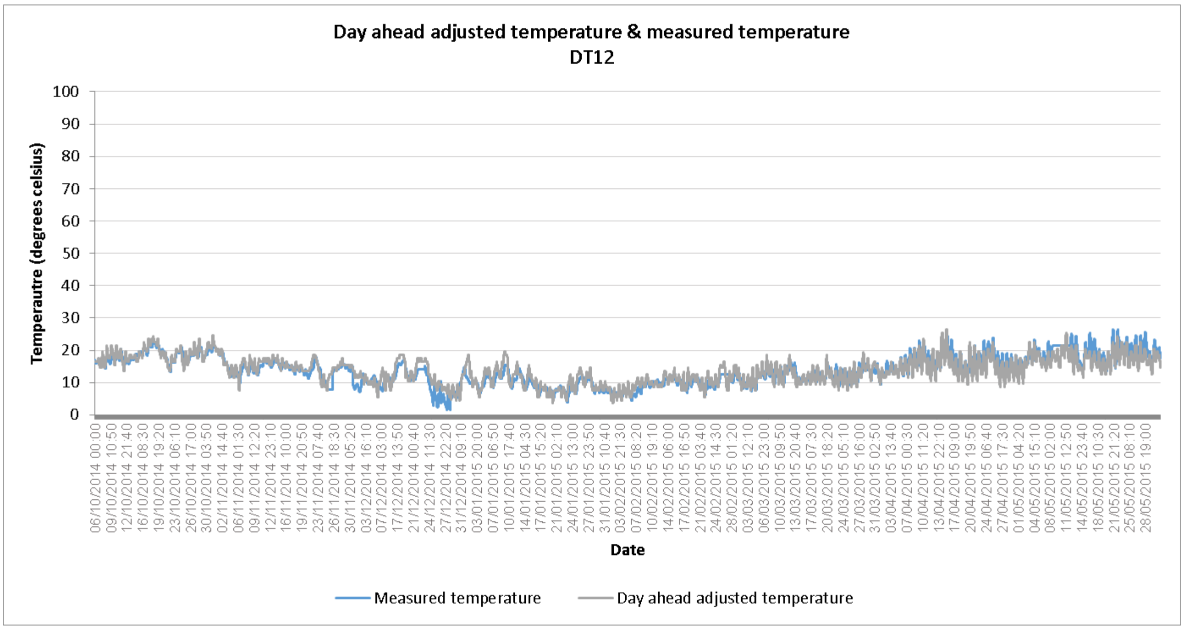


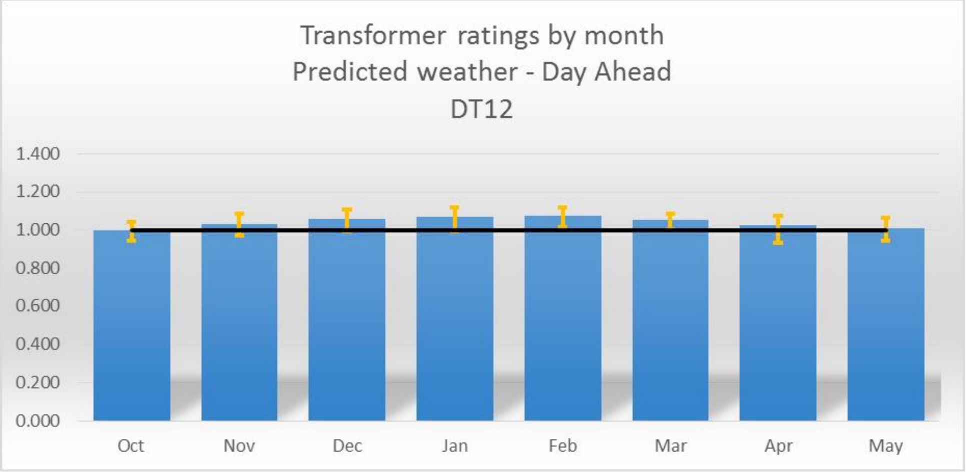
Transformer 10 : Predicted ambient temperature and predicted benefits



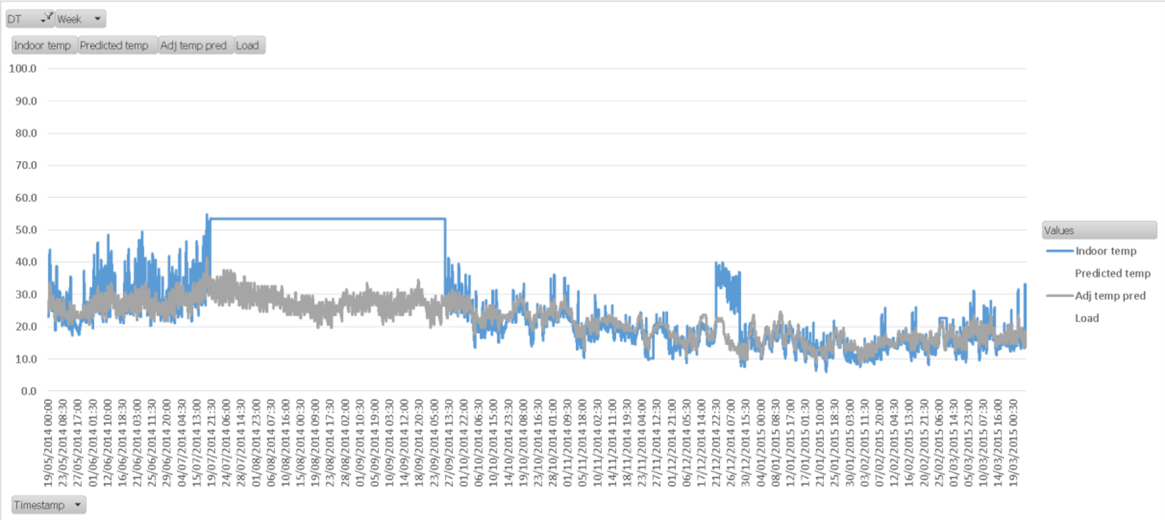


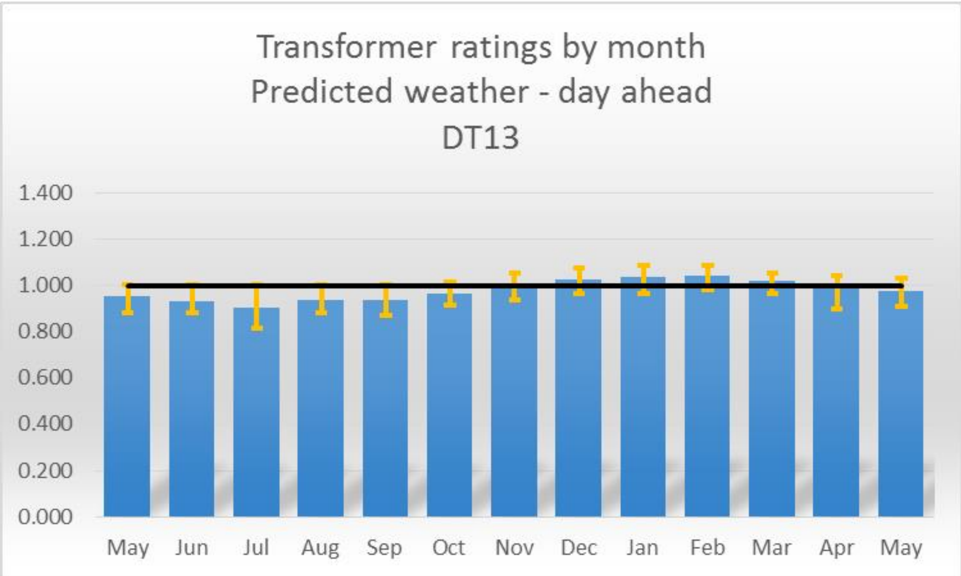
Transformer 11 : Predicted ambient temperature and predicted benefits



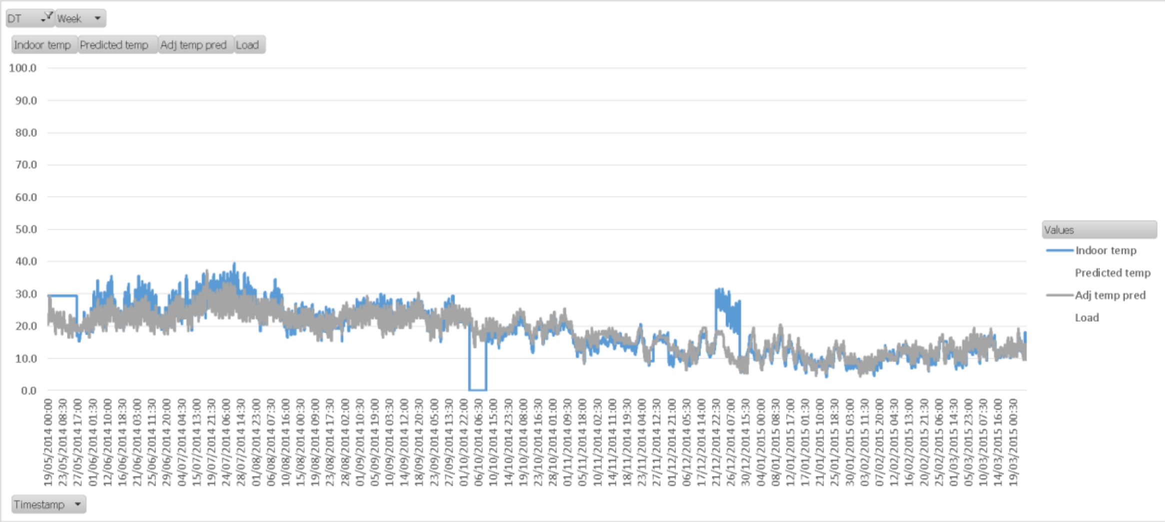


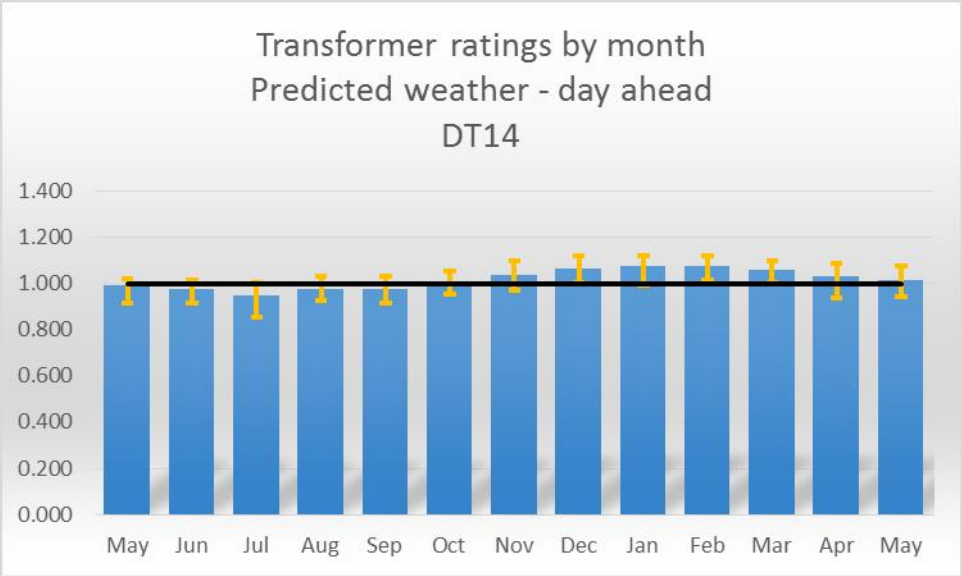
Transformer 12 : Predicted ambient temperature and predicted benefits (data for Transformer 12 only valid from Oct 2014 onwards)



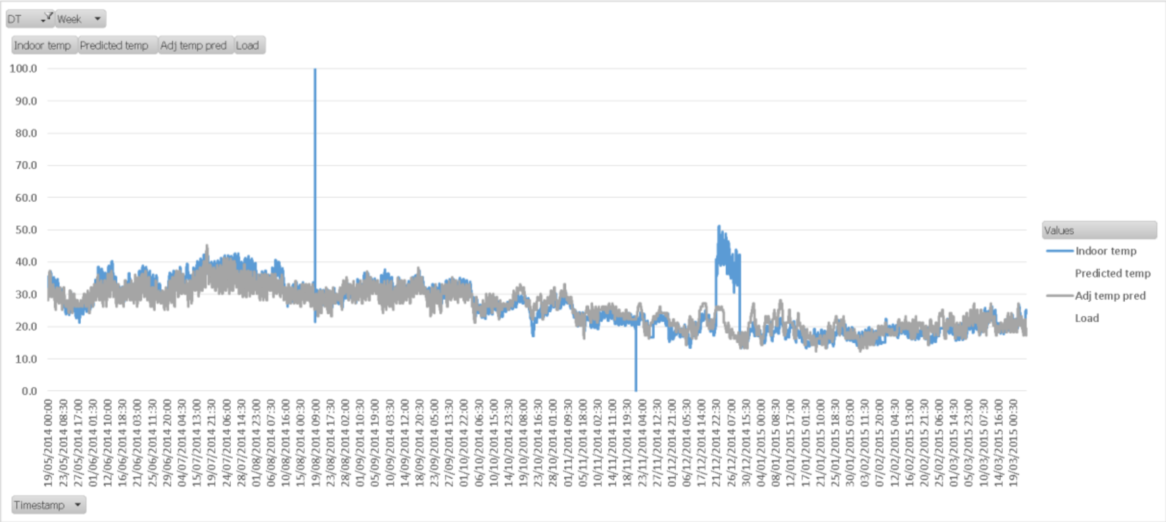


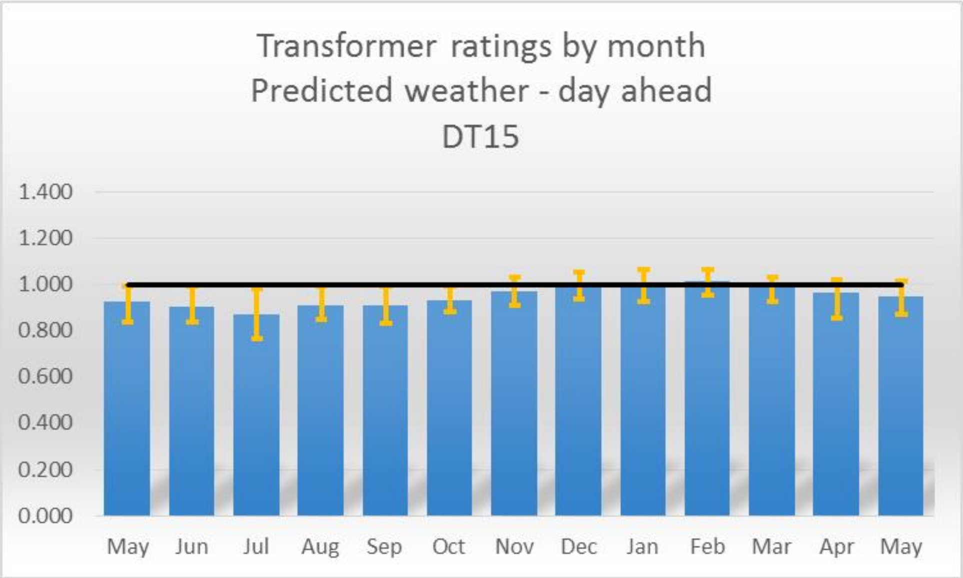
Transformer 13 : Predicted ambient temperature and predicted benefits



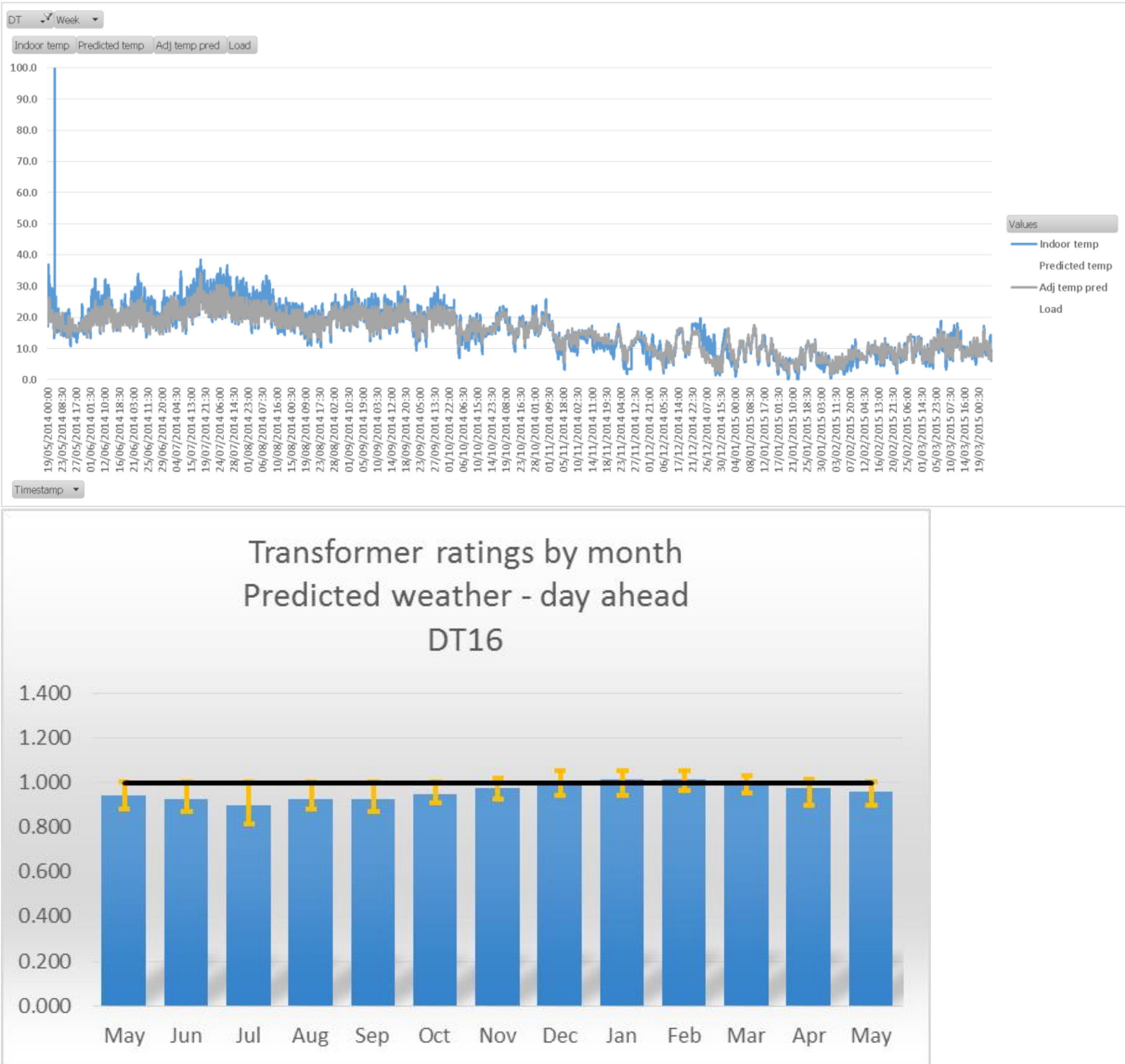


Transformer 14 : Predicted ambient temperature and predicted benefits





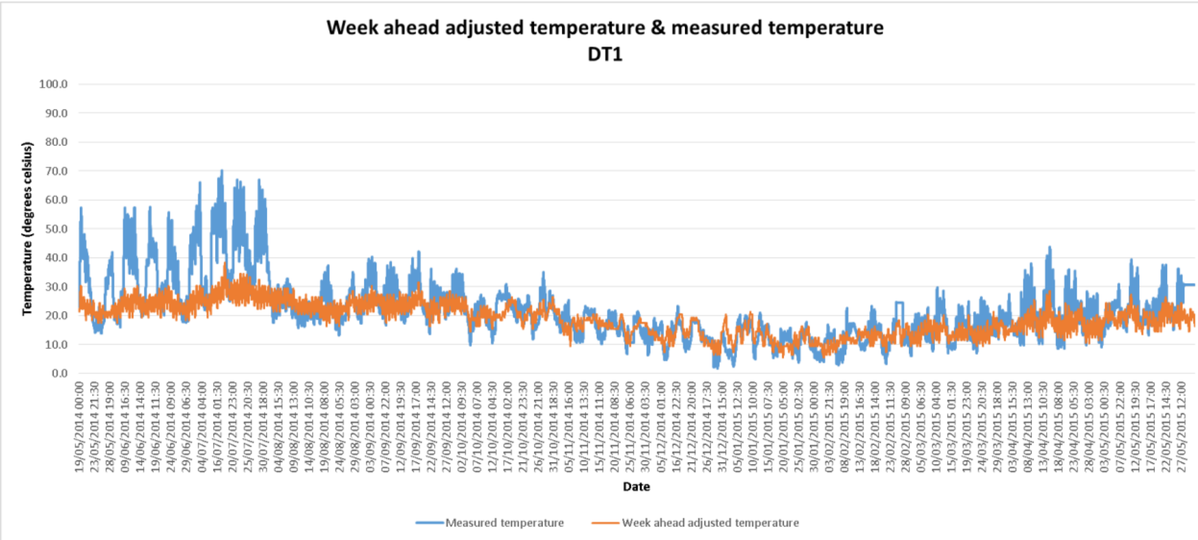
Transformer 15 : Predicted ambient temperature and predicted benefits

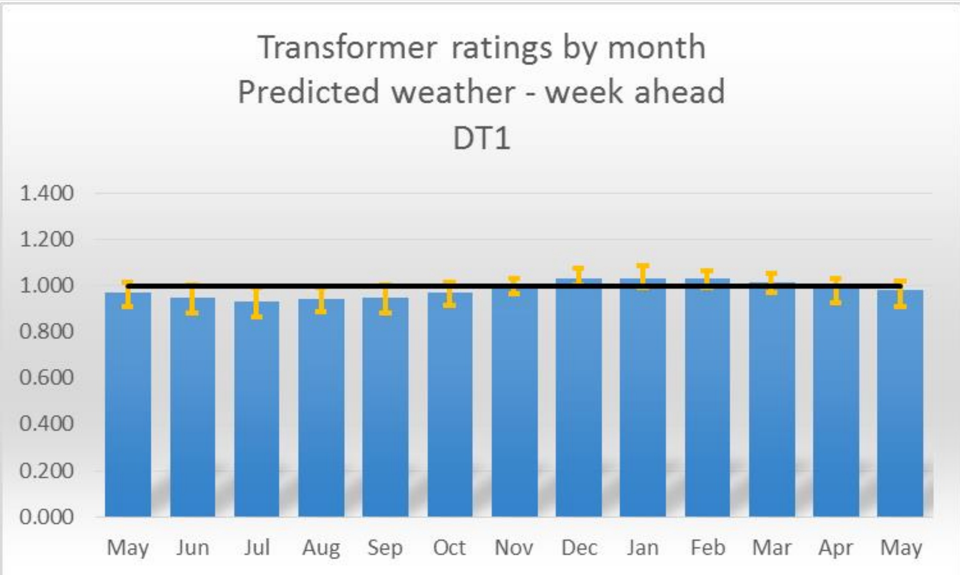


Transformer 16 : Predicted ambient temperature and predicted benefits

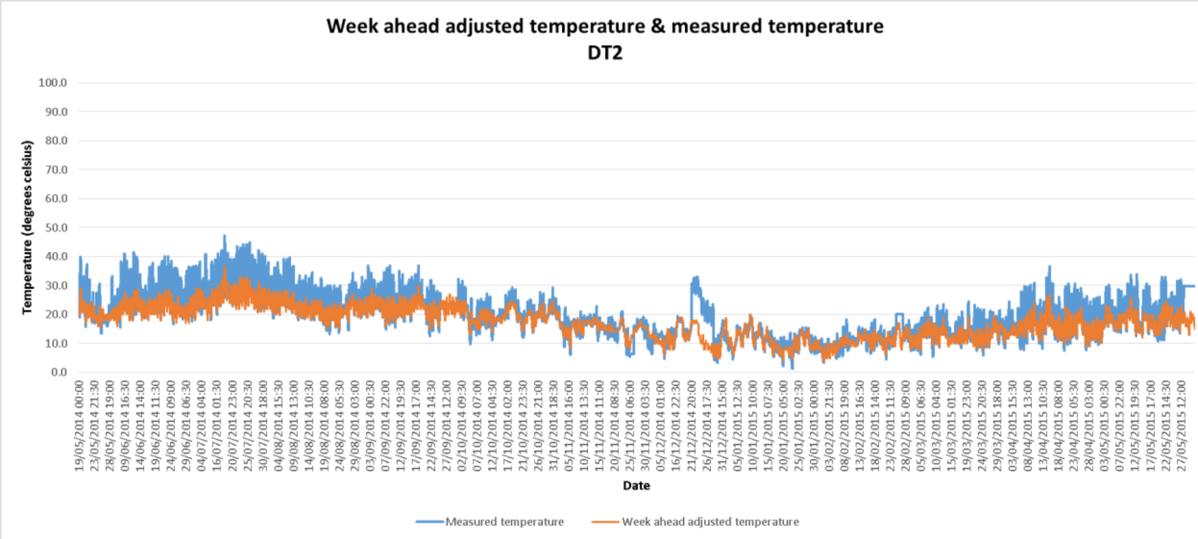
G Week Ahead Forecast Temperature and Ampacity

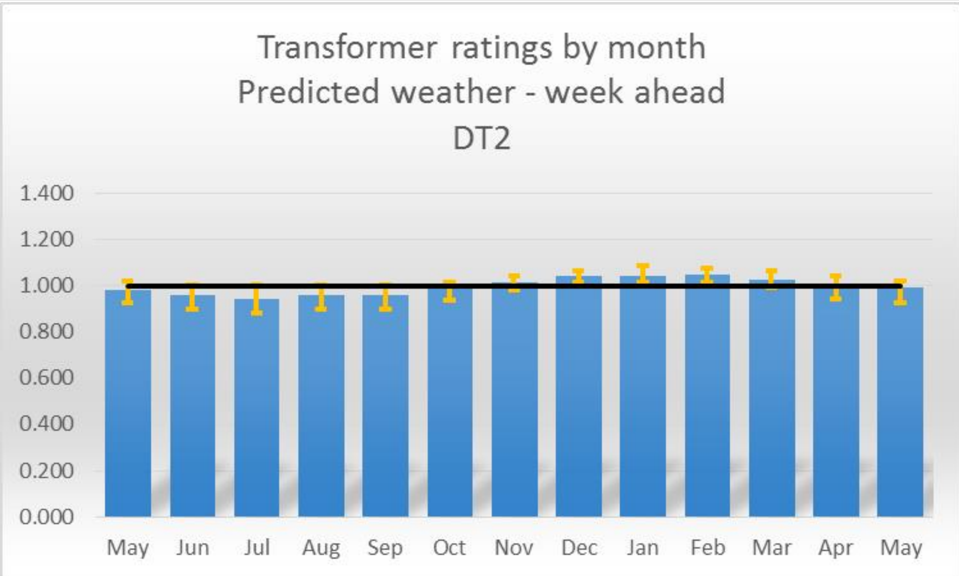
This Appendix shows the forecasted week ahead temperatures compared to the measured ambient temperatures for each transformer (graph 1). The blue line represents the 10 minute ambient temperature recorded at each site, and the orange line represents the adjusted forecast temperature. This adjustment takes into account the typical temperature difference for each transformer (which are generally warmer due to its housing and the running of the transformer). The second graph shows the predicted rating for each month derived from the week ahead forecast (similar to the second graph in Appendix E).



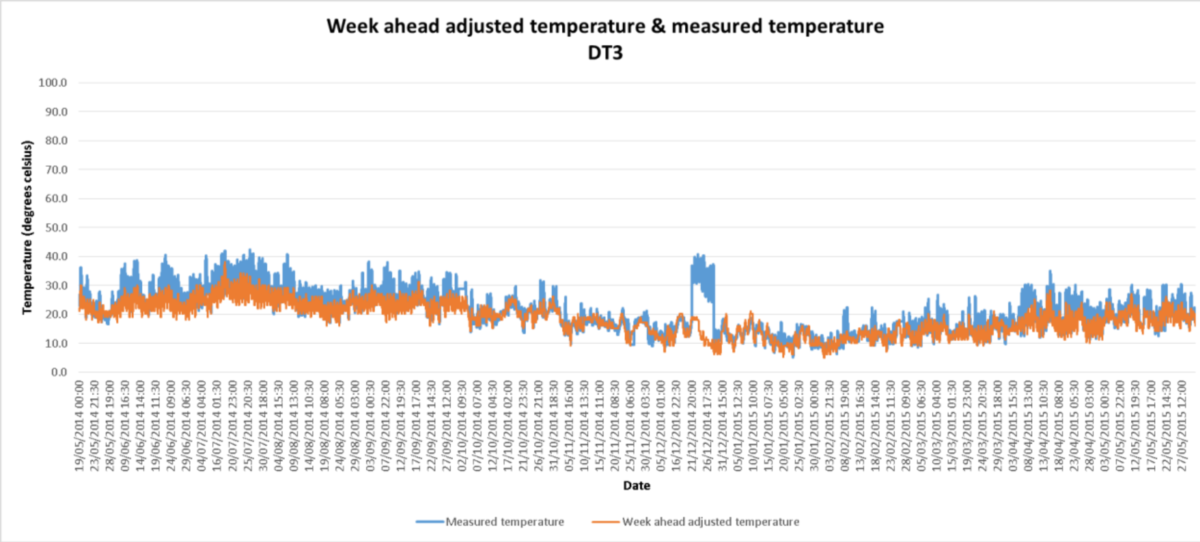


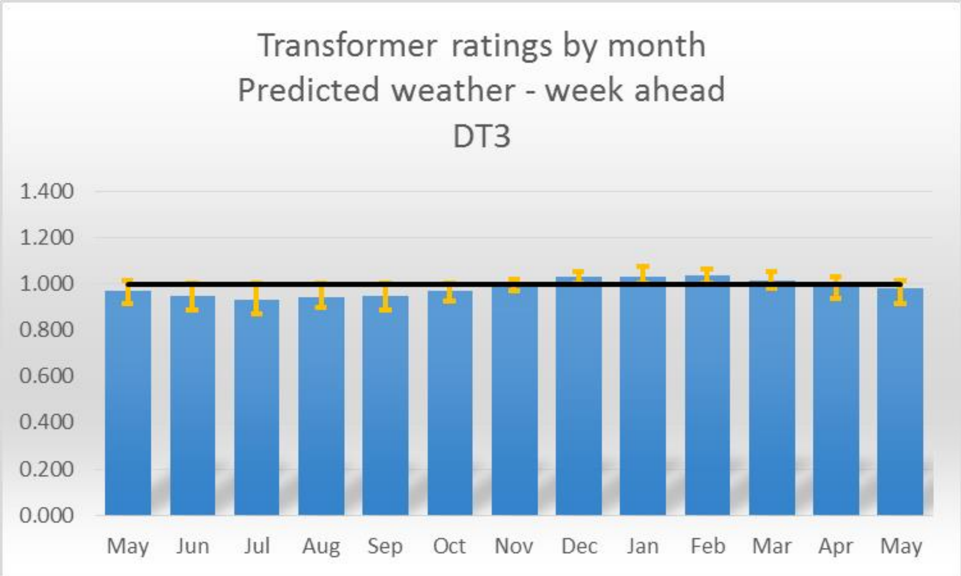
Transformer 1 : Predicted ambient temperature and predicted benefits



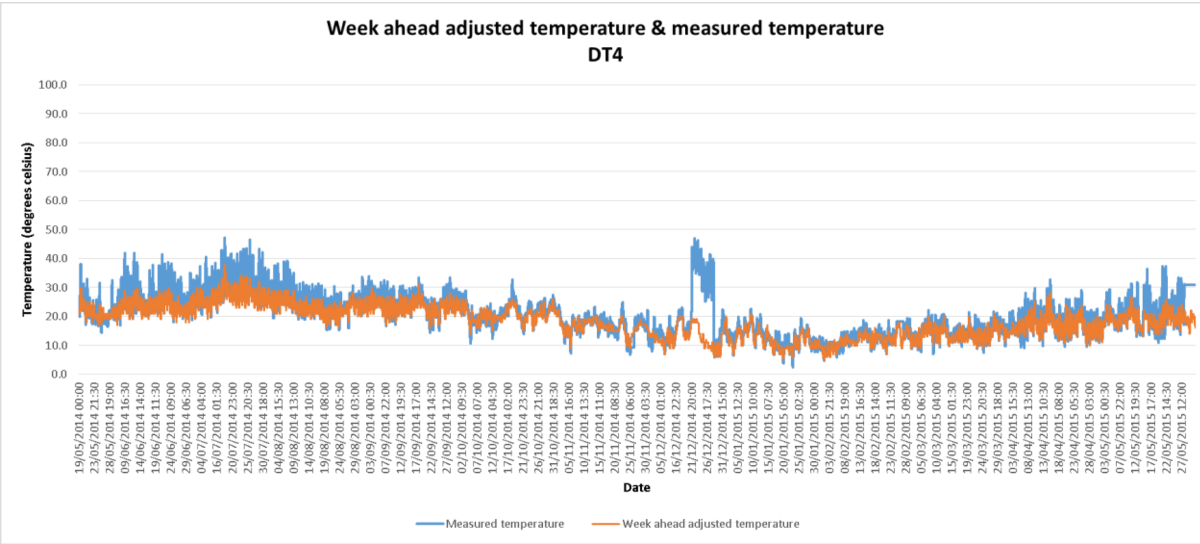


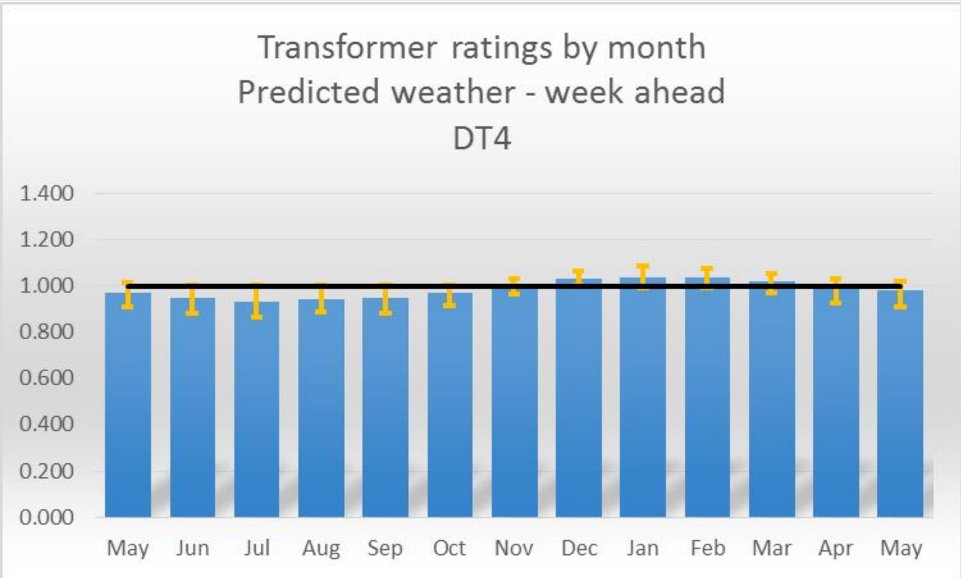
Transformer 2 : Predicted ambient temperature and predicted benefits



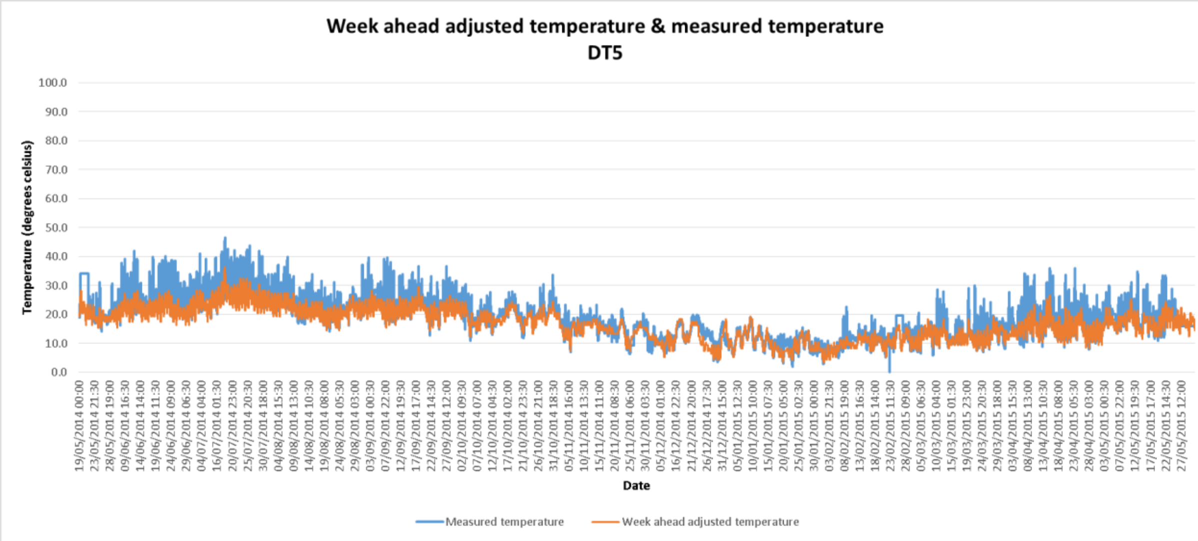


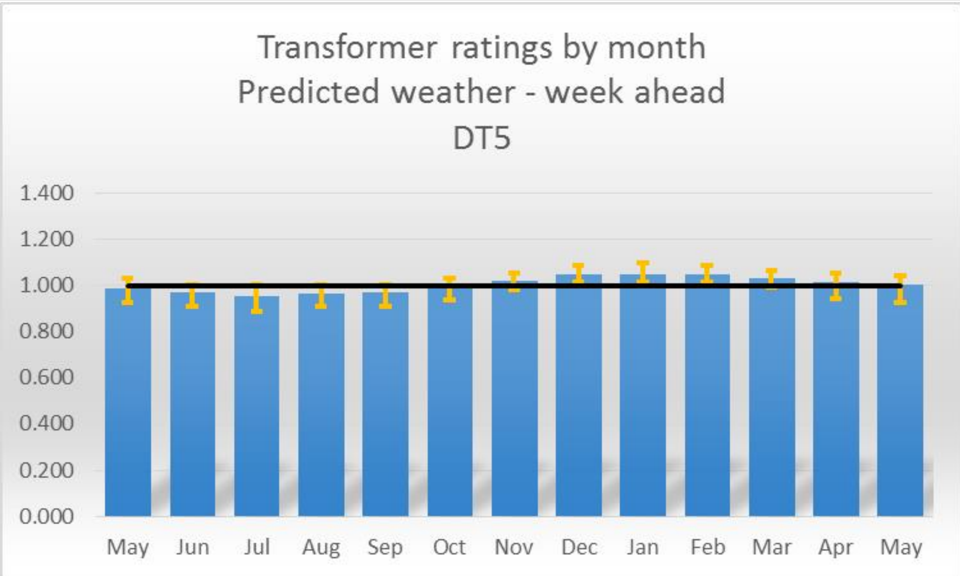
Transformer 3 : Predicted ambient temperature and predicted benefits



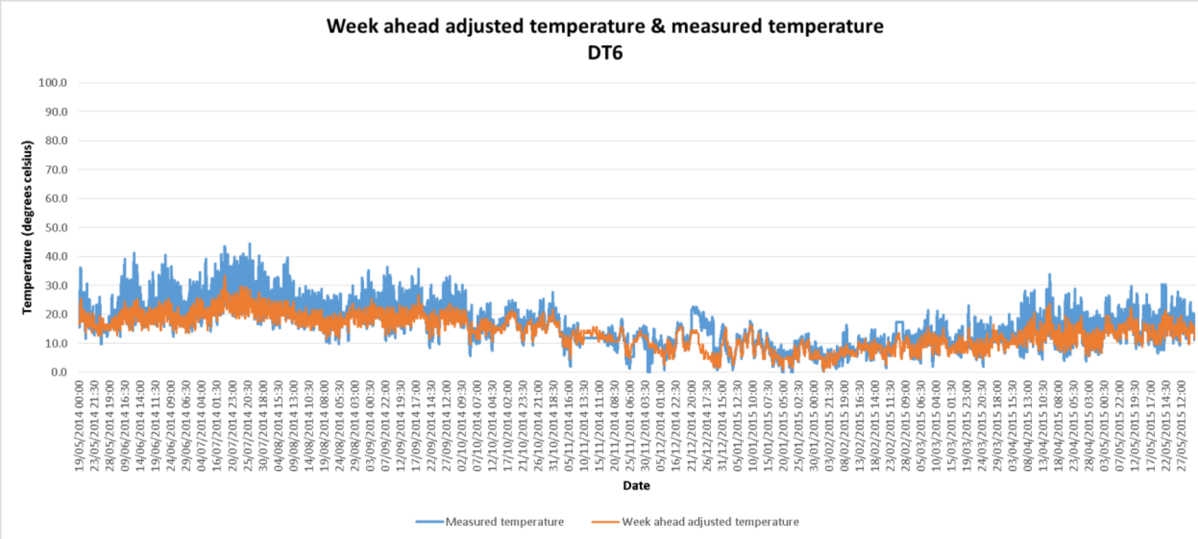


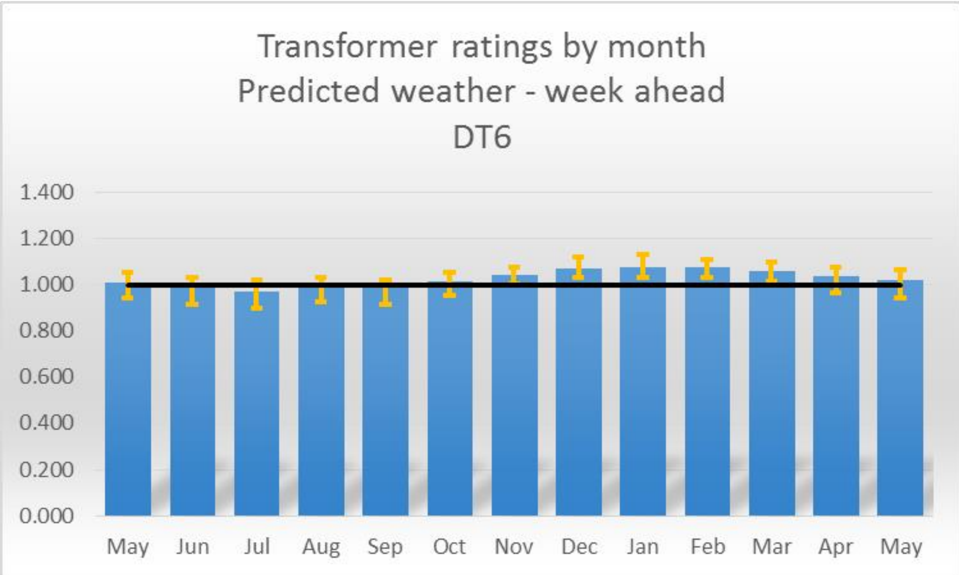
Transformer 4 : Predicted ambient temperature and predicted benefits



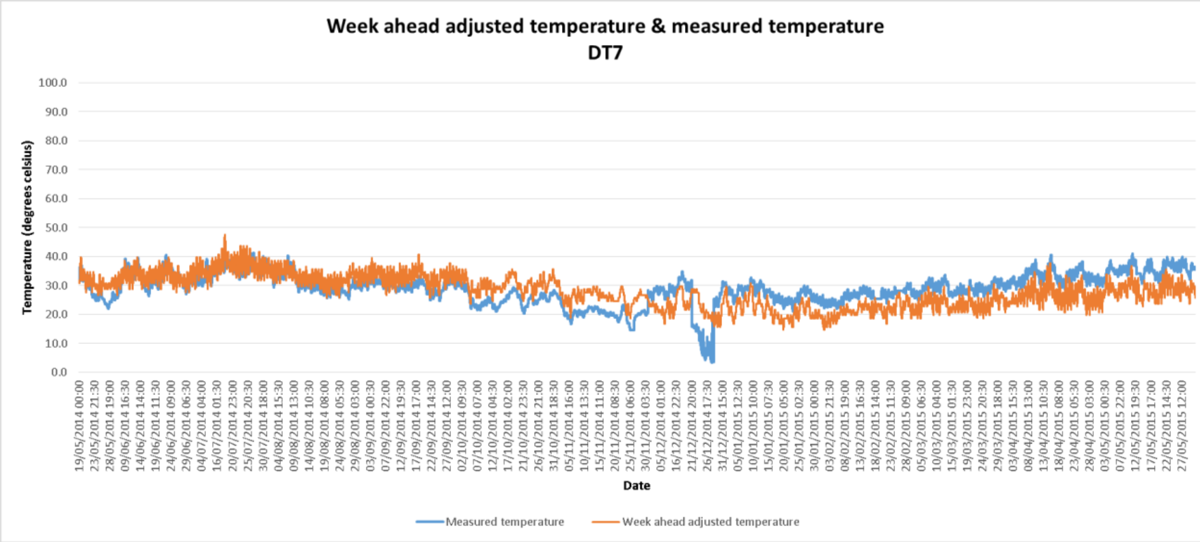


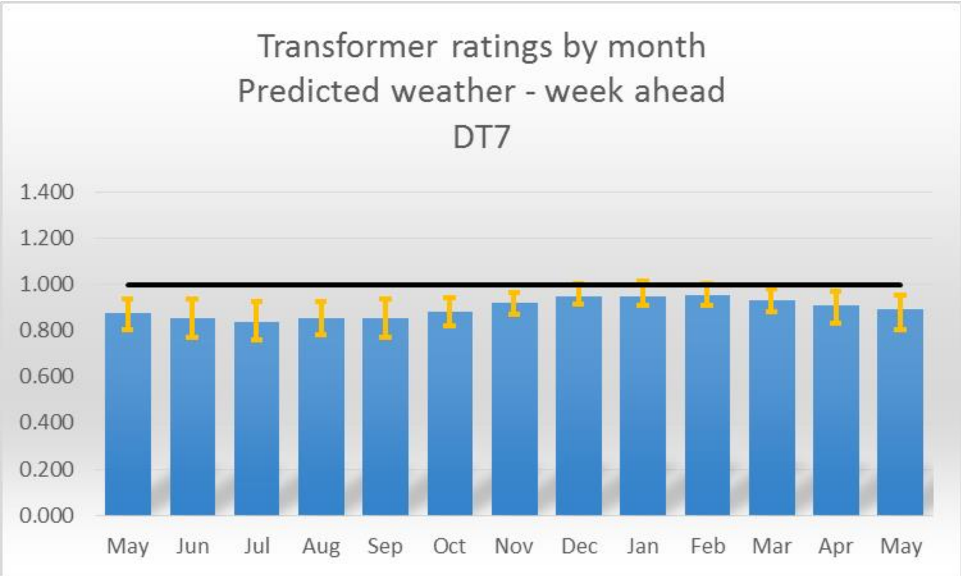
Transformer 5 : Predicted ambient temperature and predicted benefits



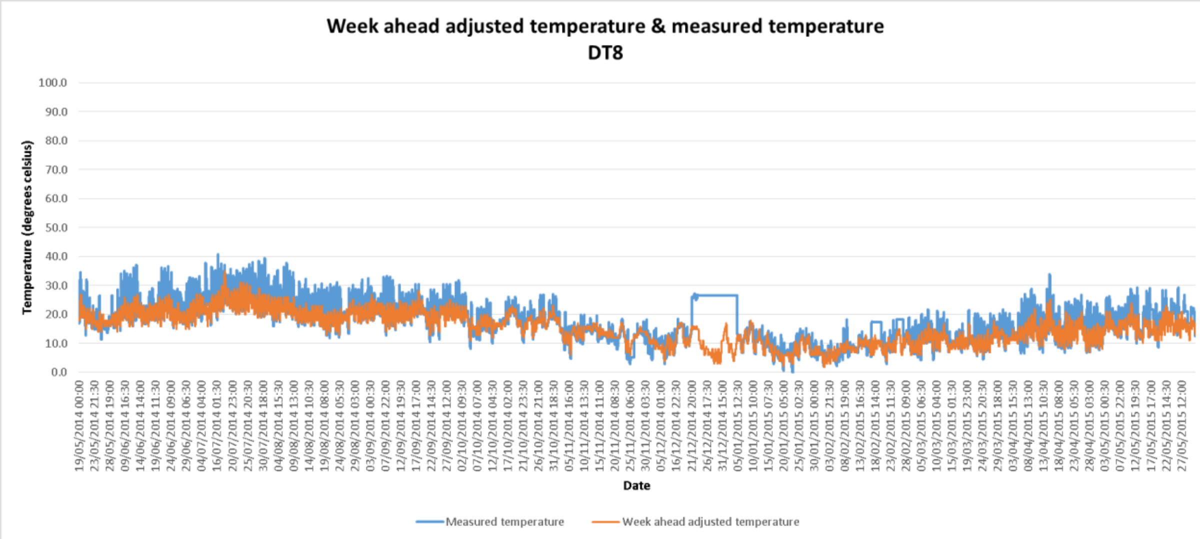


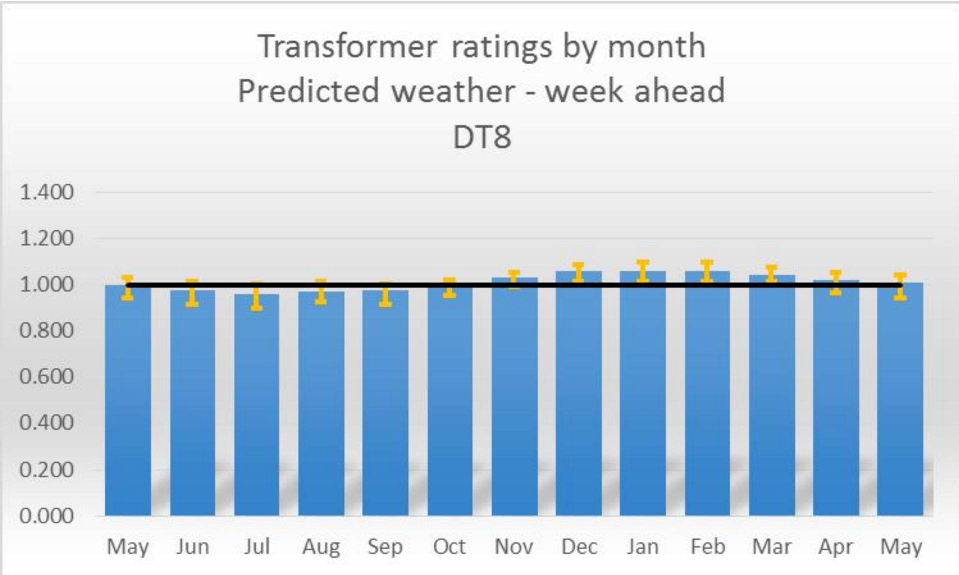
Transformer 6 : Predicted ambient temperature and predicted benefits



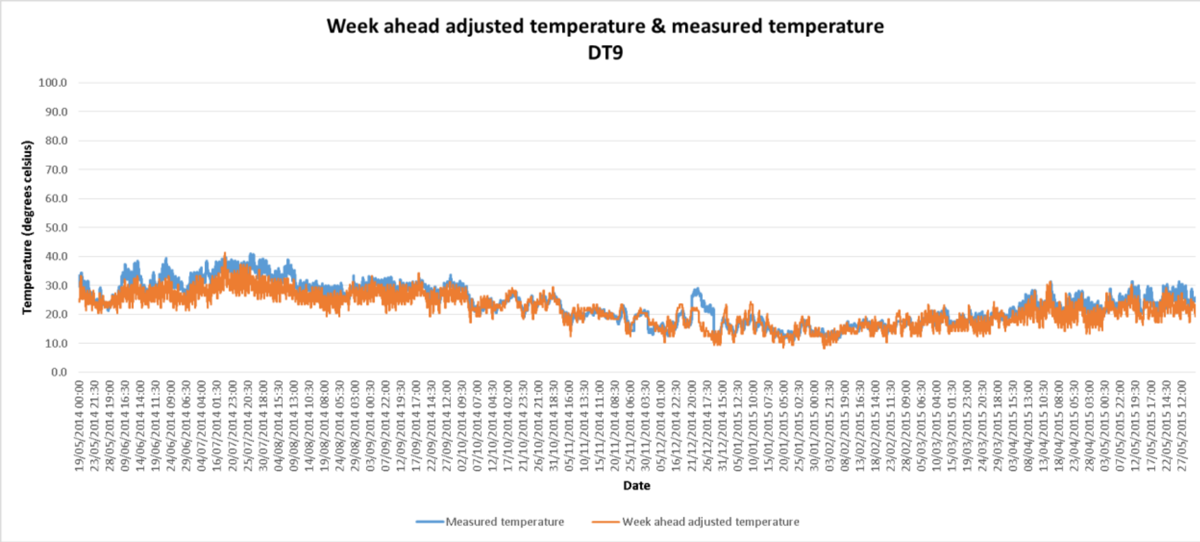


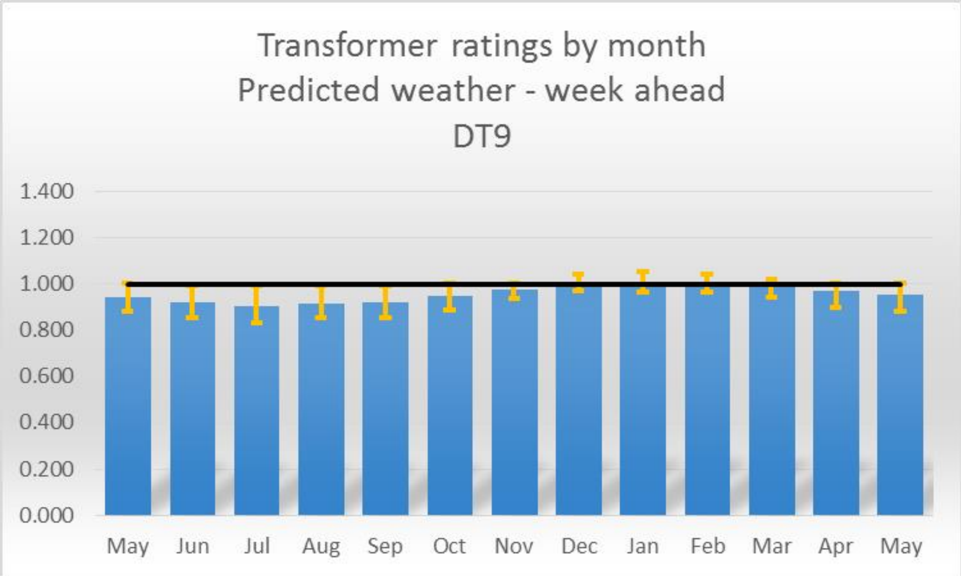
Transformer 7 : Predicted ambient temperature and predicted benefits



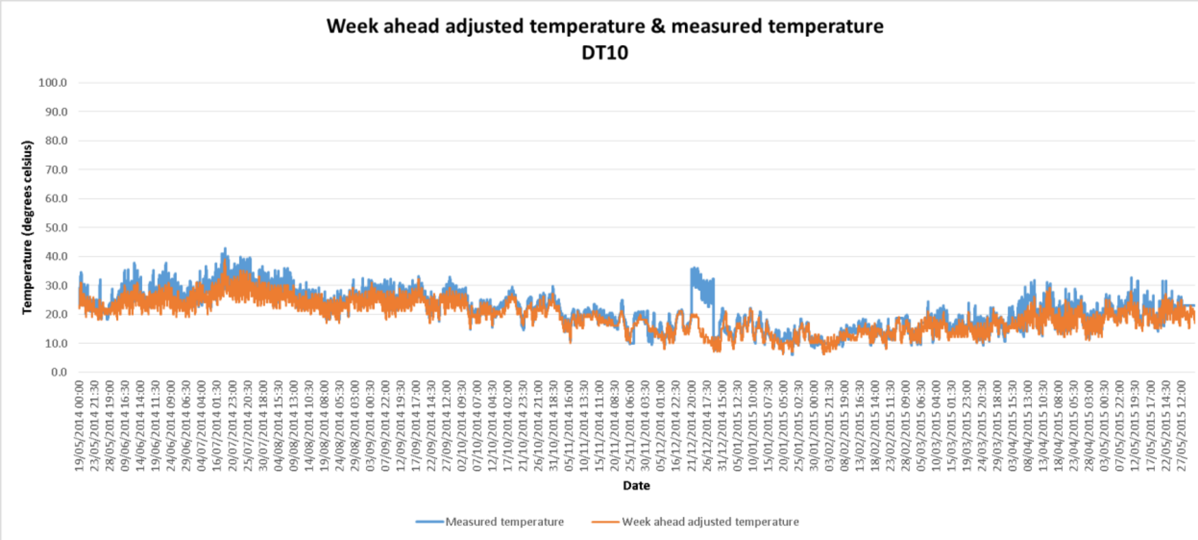


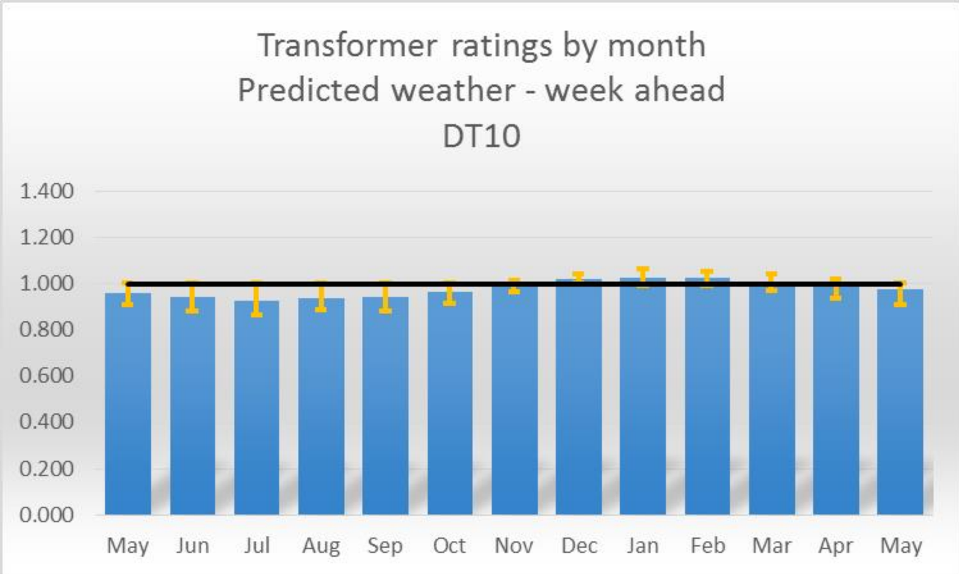
Transformer 8 : Predicted ambient temperature and predicted benefits



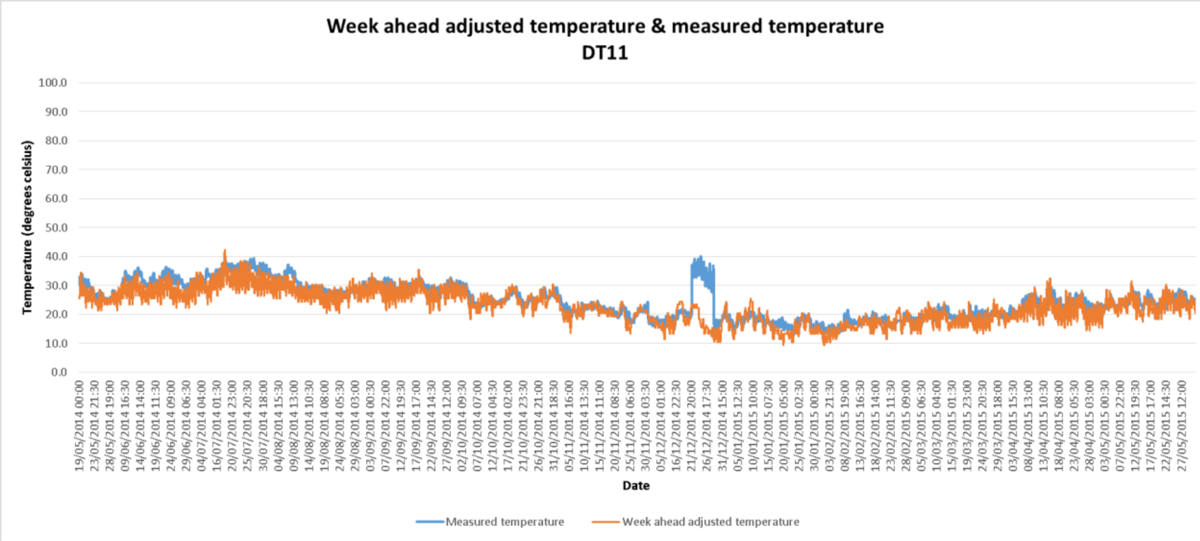


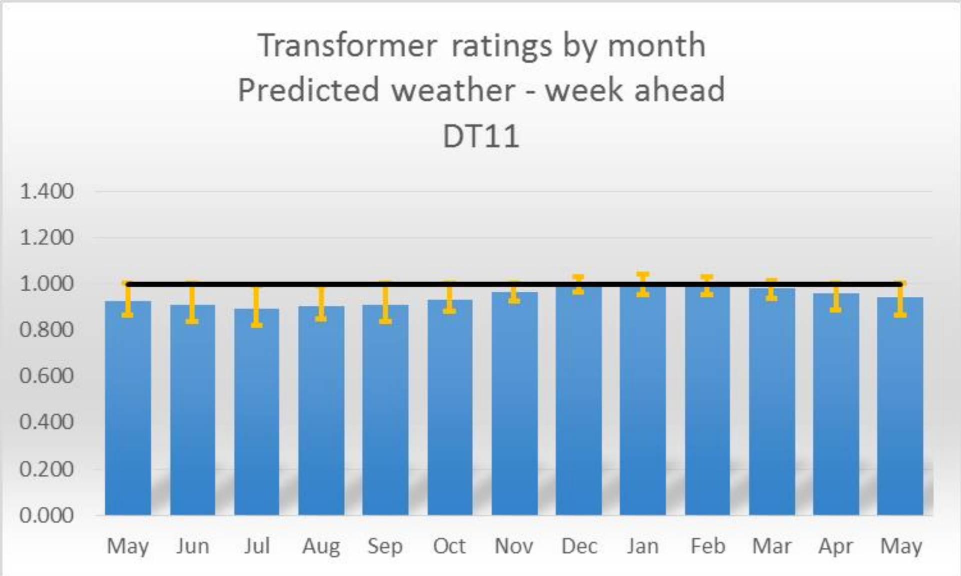
Transformer 9 : Predicted ambient temperature and predicted benefits



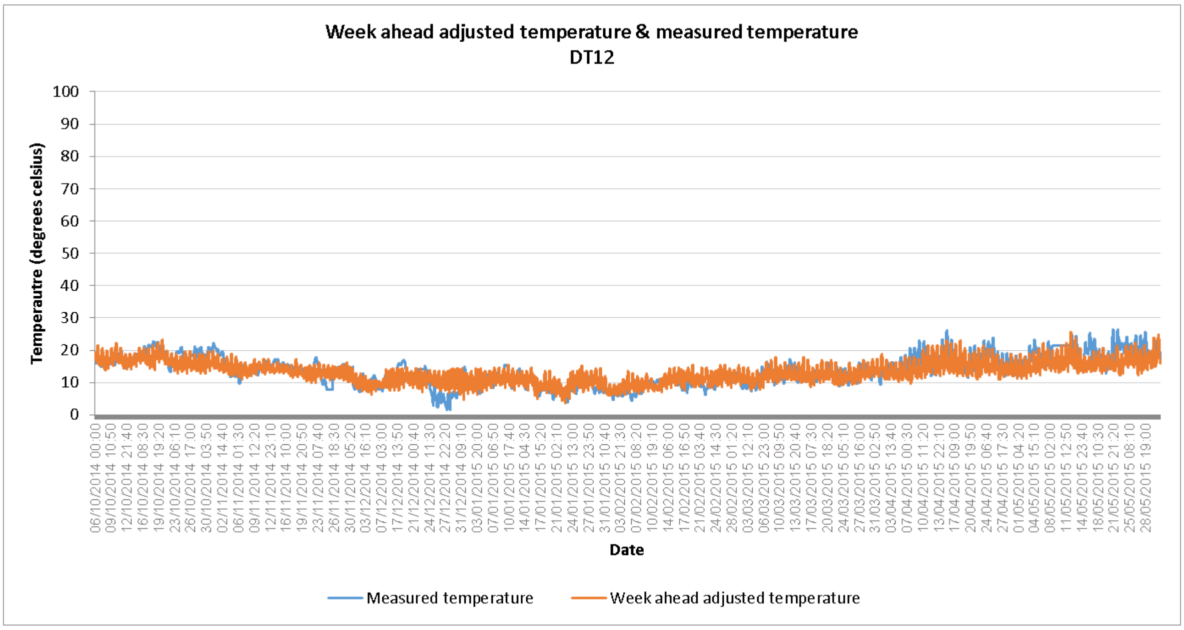


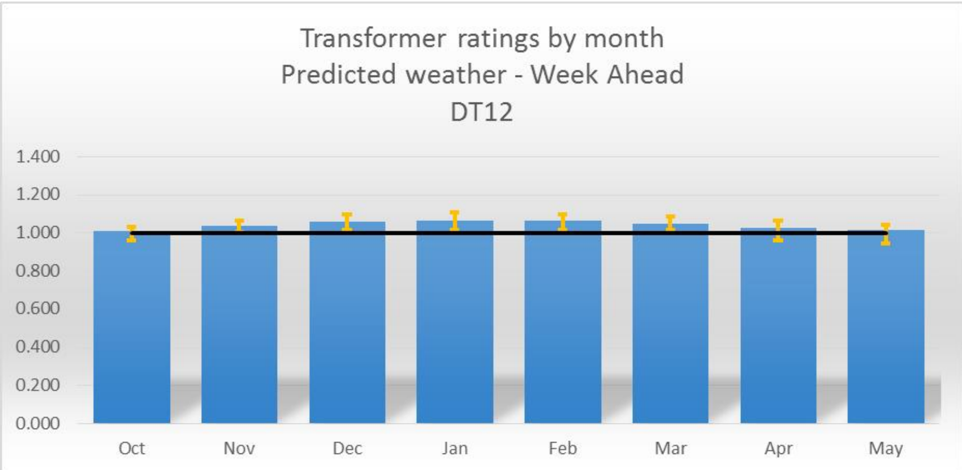
Transformer 10 : Predicted ambient temperature and predicted benefits



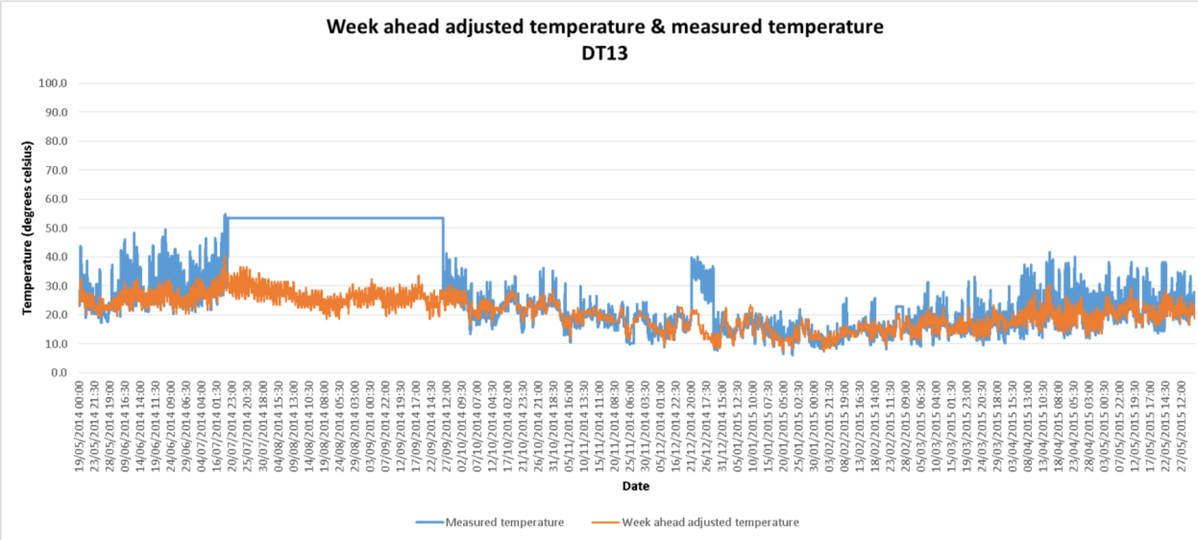


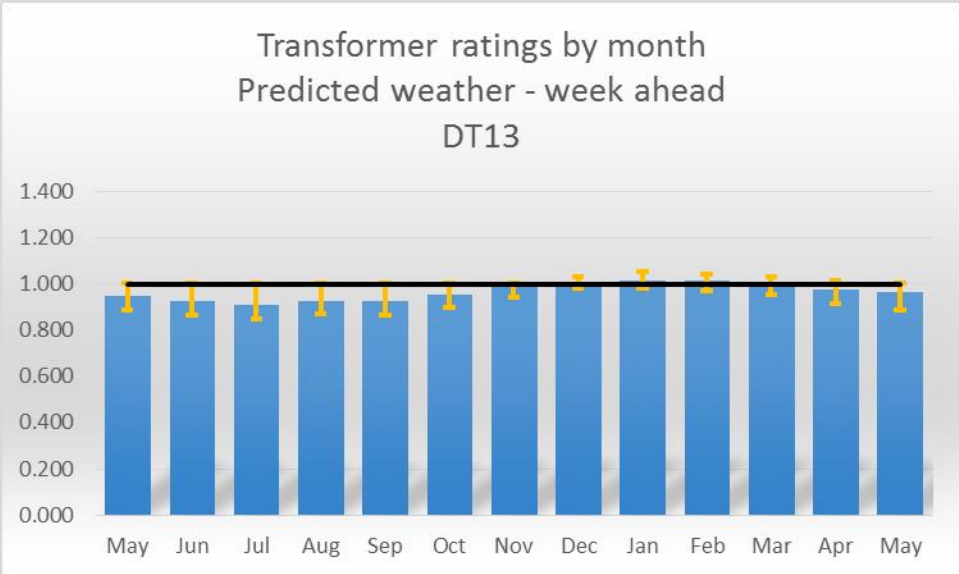
Transformer 11 : Predicted ambient temperature and predicted benefits



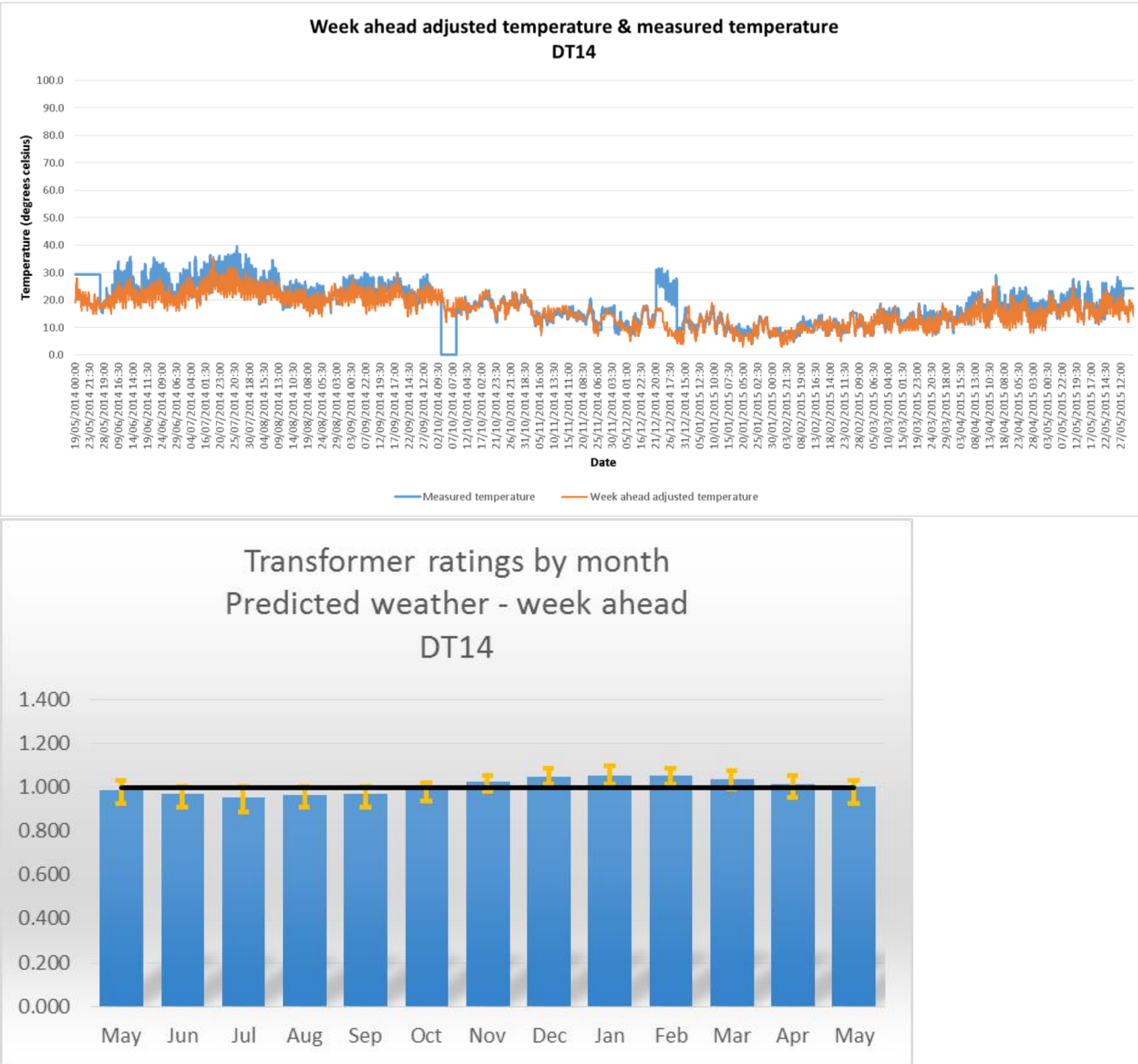


Transformer 12 : Predicted ambient temperature and predicted benefits (data for Transformer 12 only valid from Oct 2014 onwards)

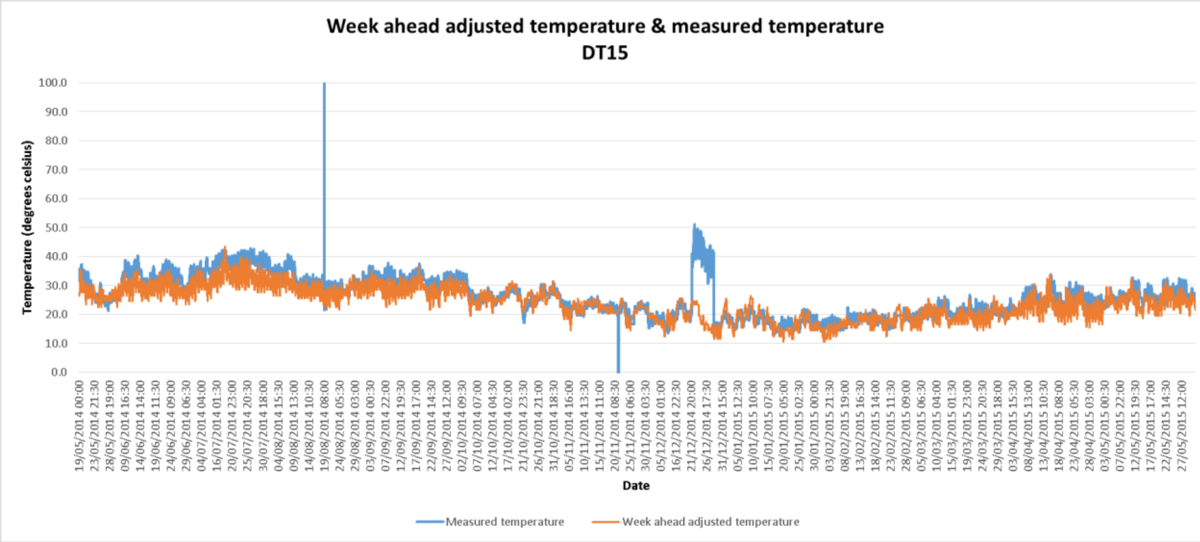


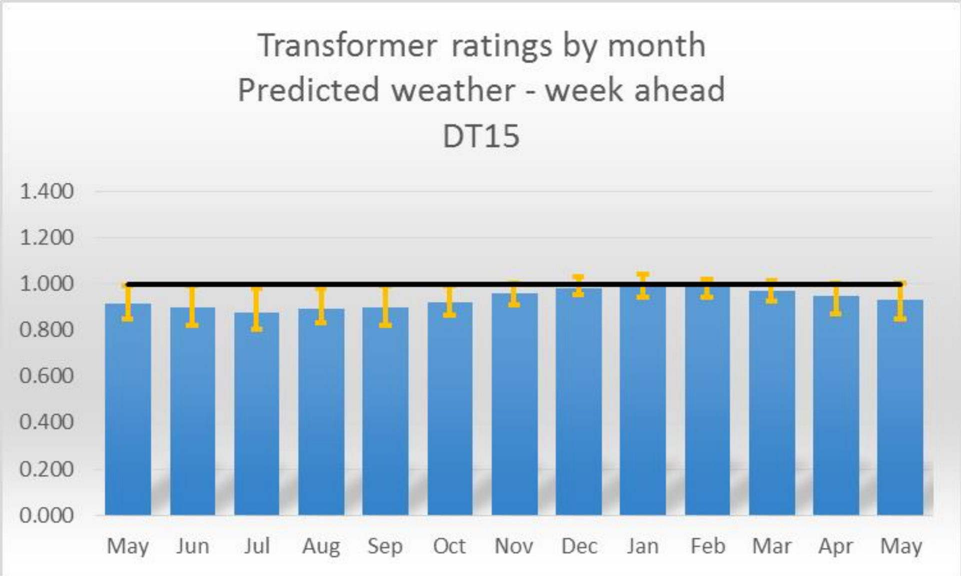


Transformer 13 : Predicted ambient temperature and predicted benefits

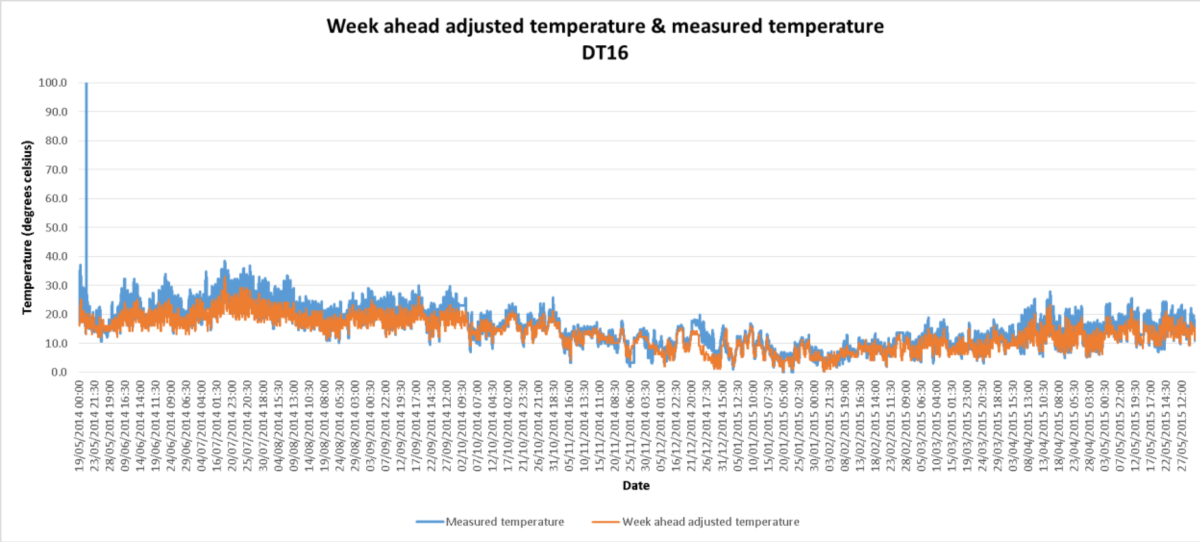


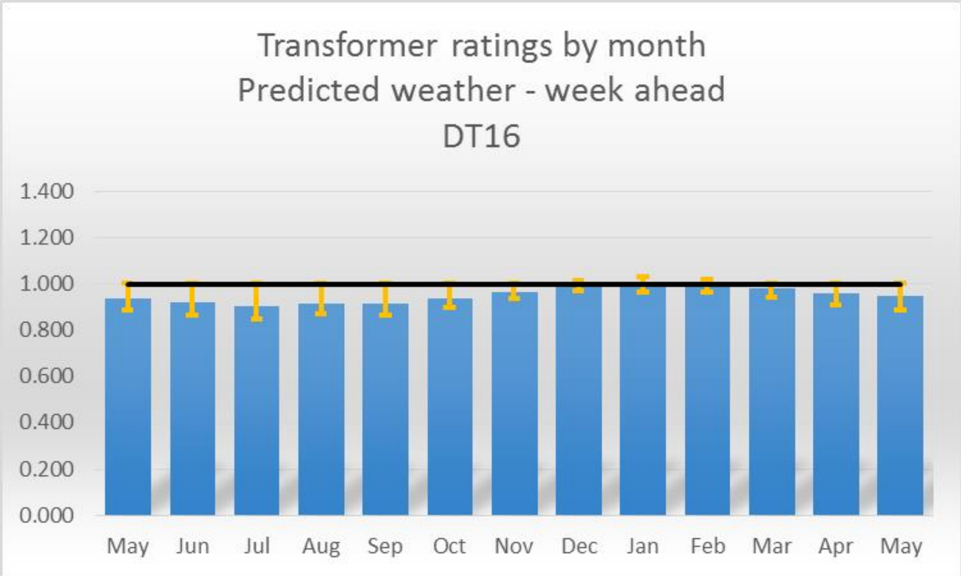
Transformer 14 : Predicted ambient temperature and predicted benefits





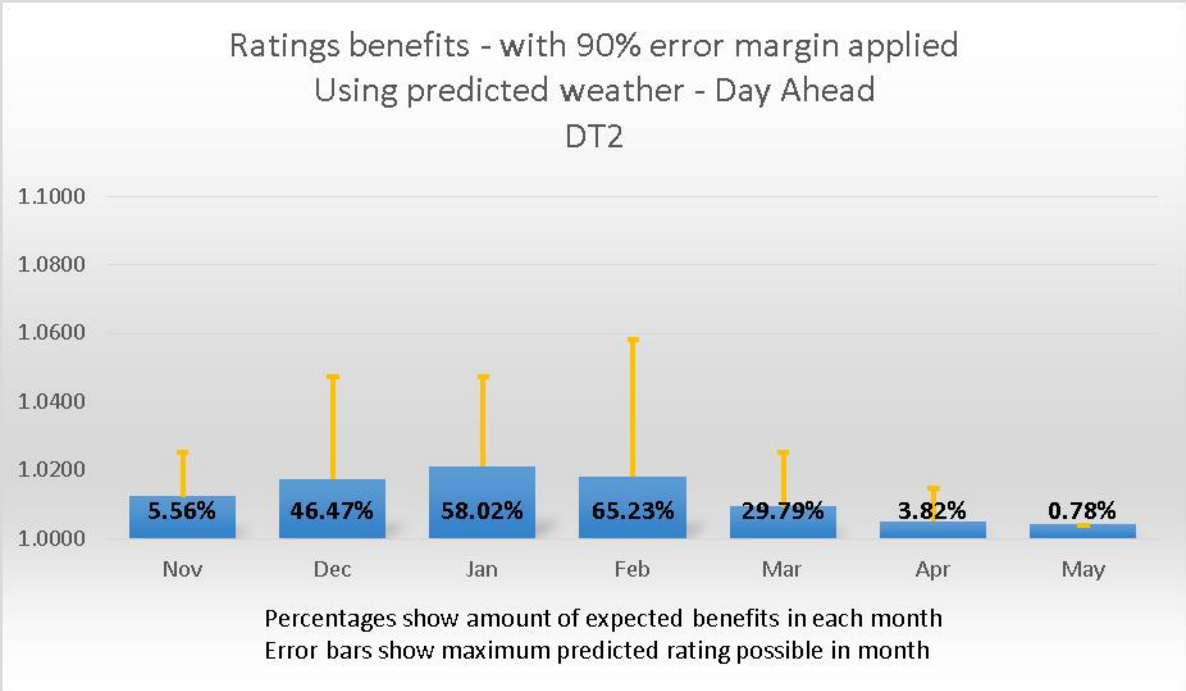
Transformer 15 : Predicted ambient temperature and predicted benefits

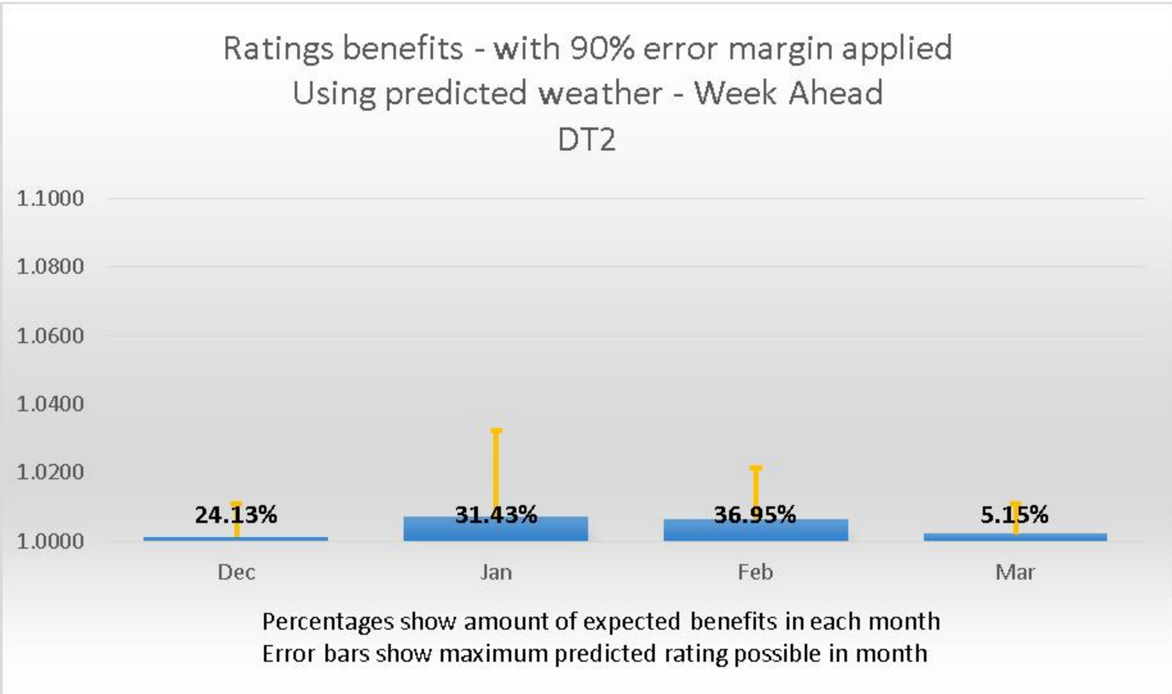


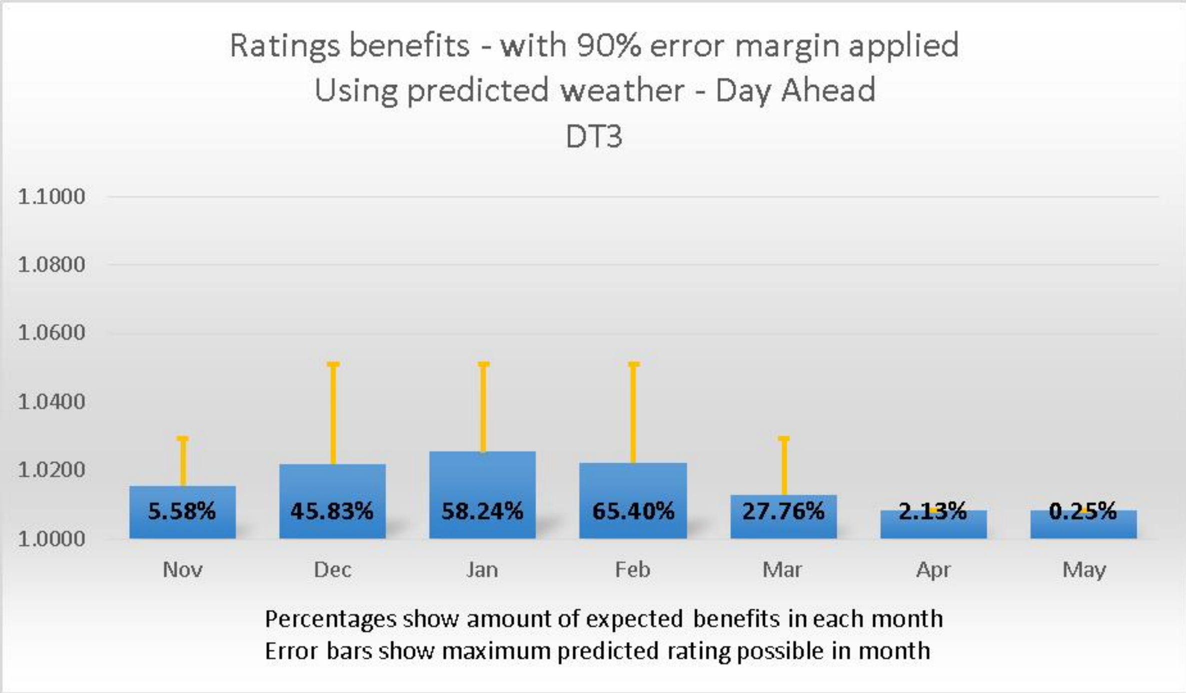


Transformer 16 : Predicted ambient temperature and predicted benefits

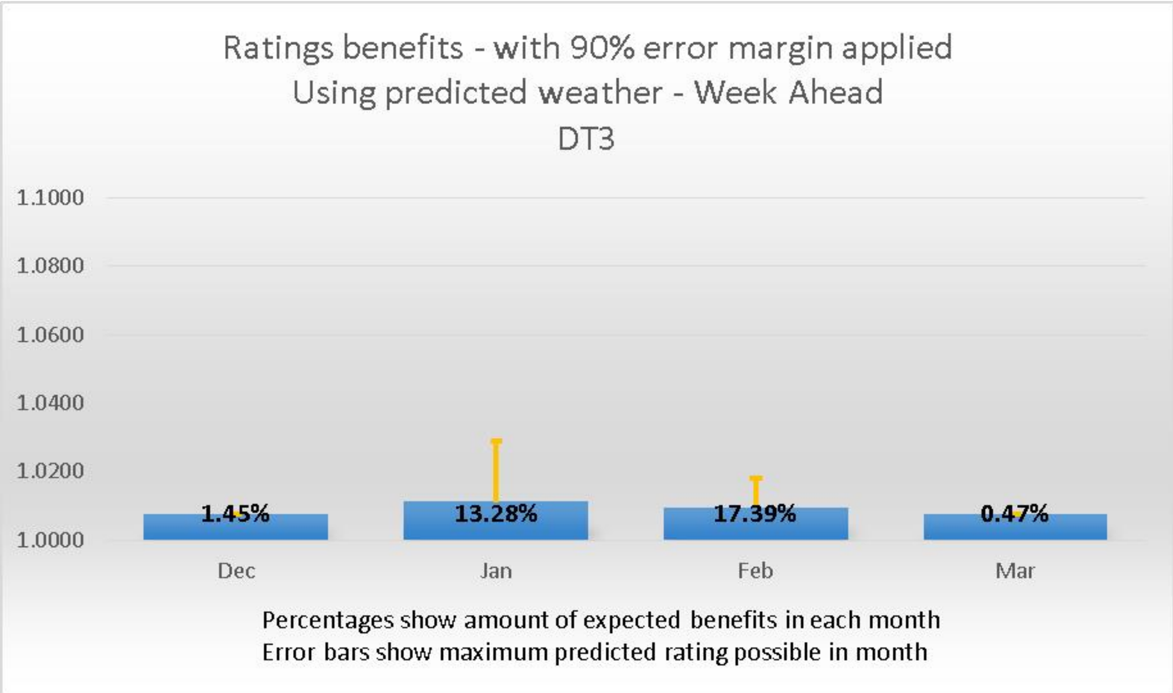
H Ratings with Error Margins



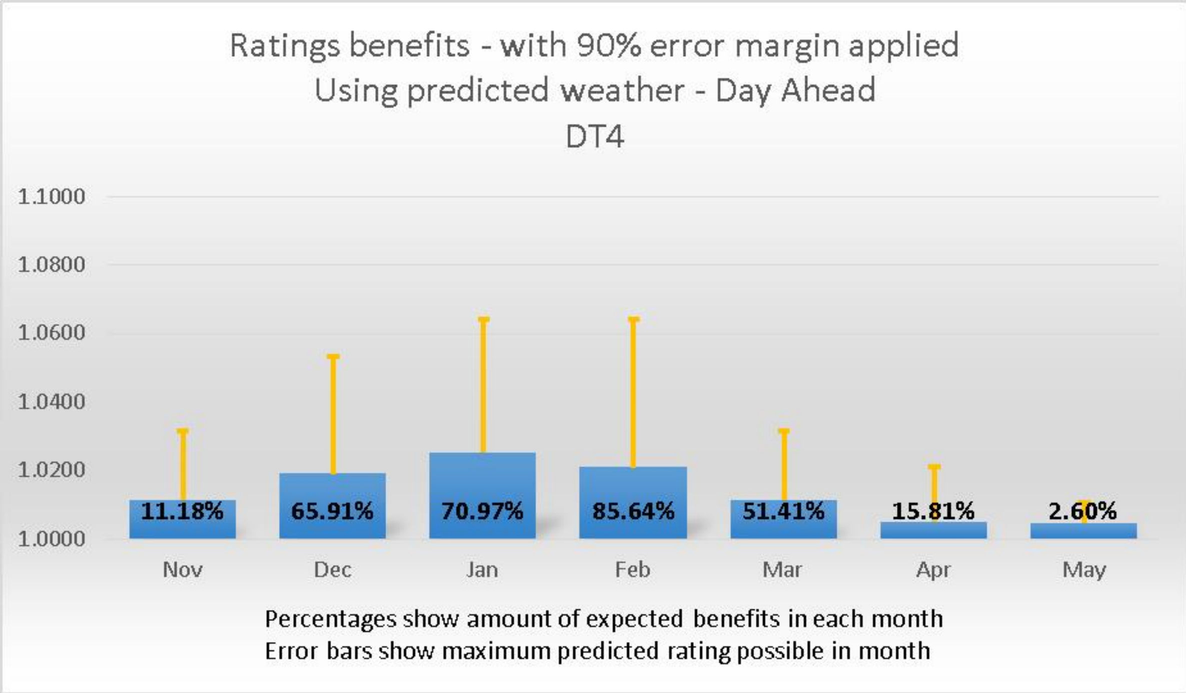


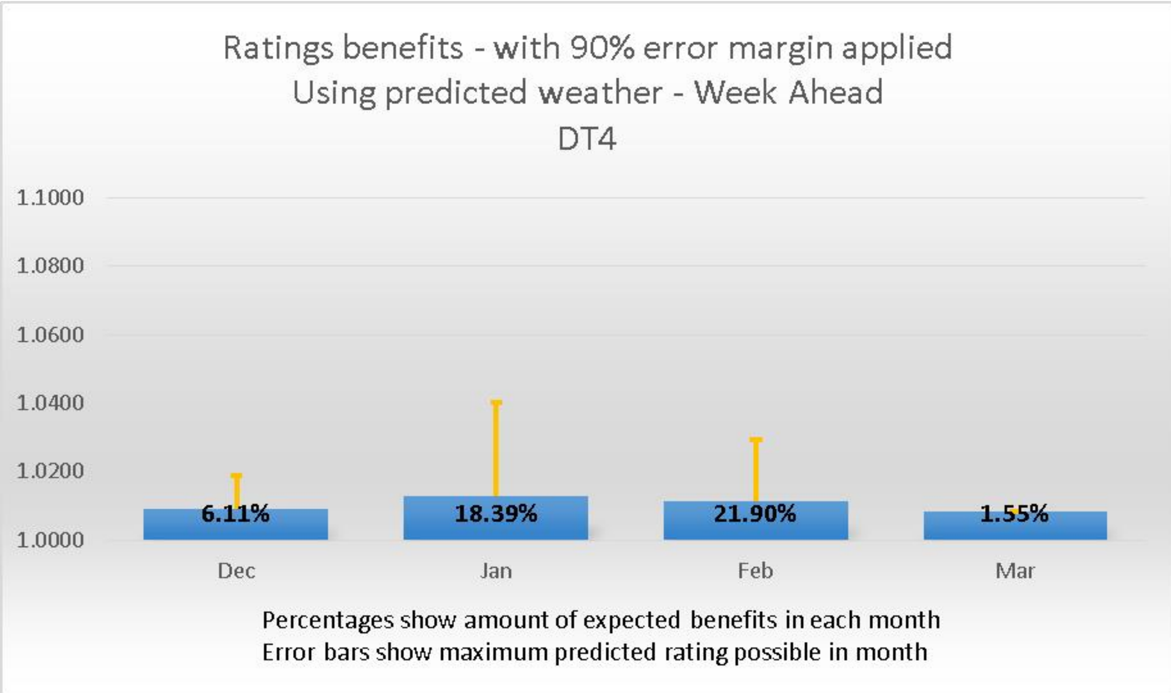


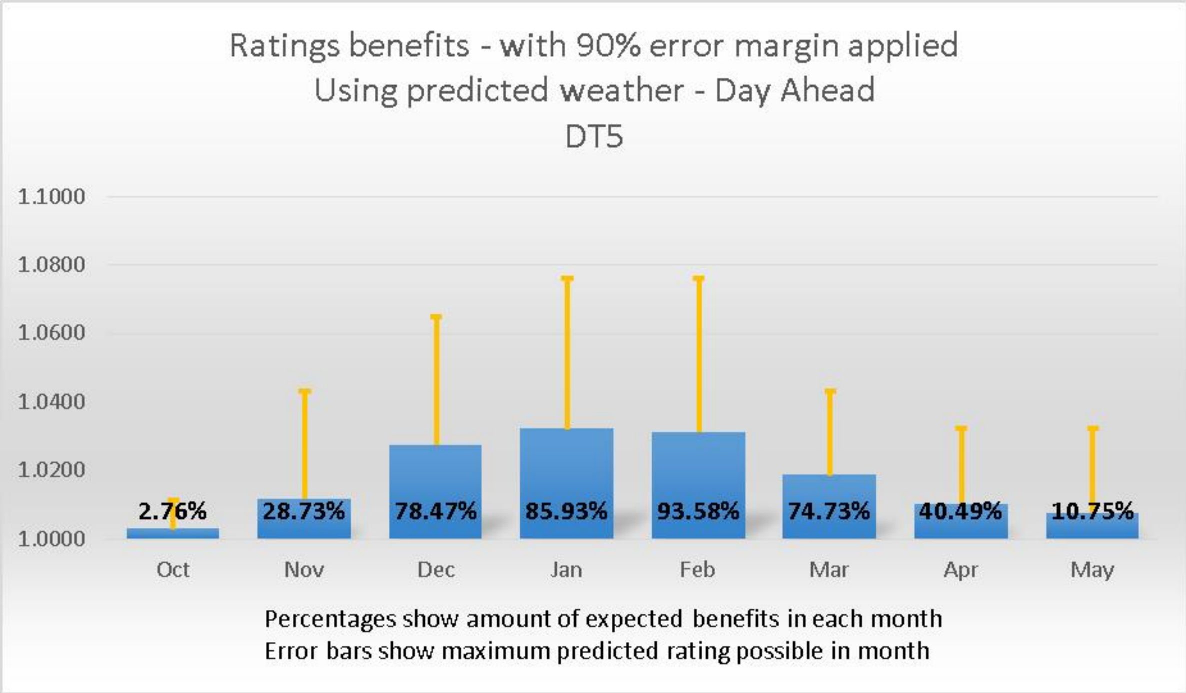
Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT3
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
5.58%
45.83%
58.24%
65.40%
27.76%
2.13%
0.25%
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

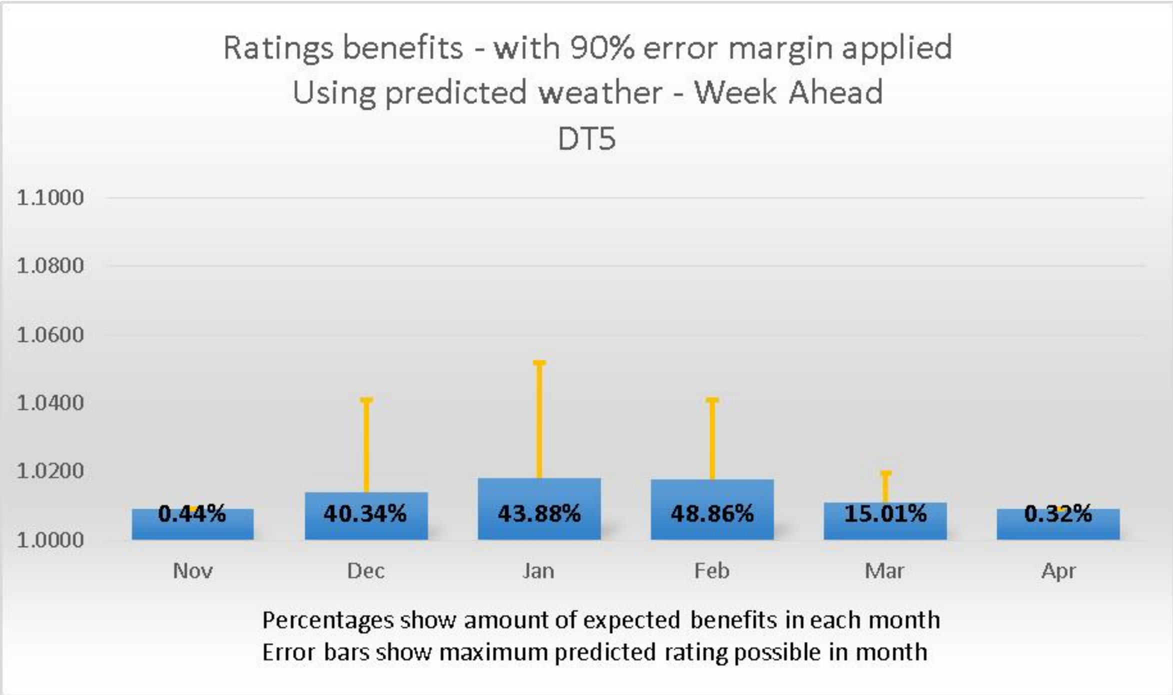


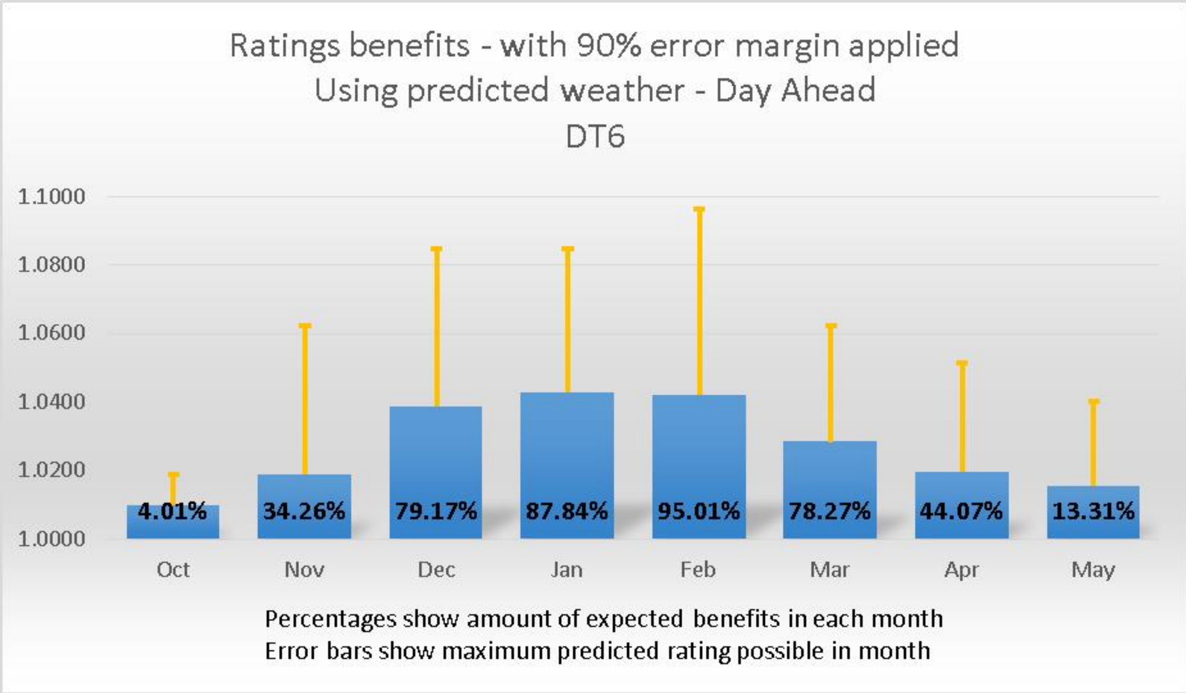
Ratings benefits - with 90% error margin applied
Using predicted weather - Week Ahead
DT3
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
1.45%
13.28%
17.39%
0.47%
Dec
Jan
Feb
Mar
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

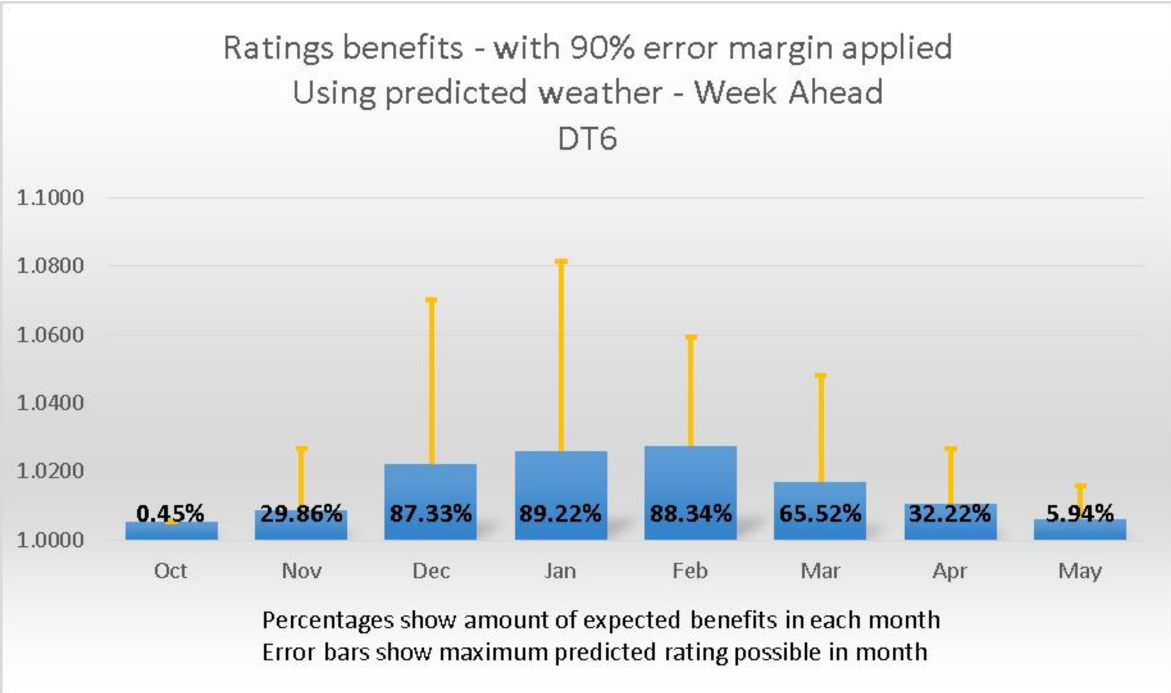

Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT4
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
11.18%
65.91%
70.97%
85.64%
51.41%
15.81%
2.60%
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

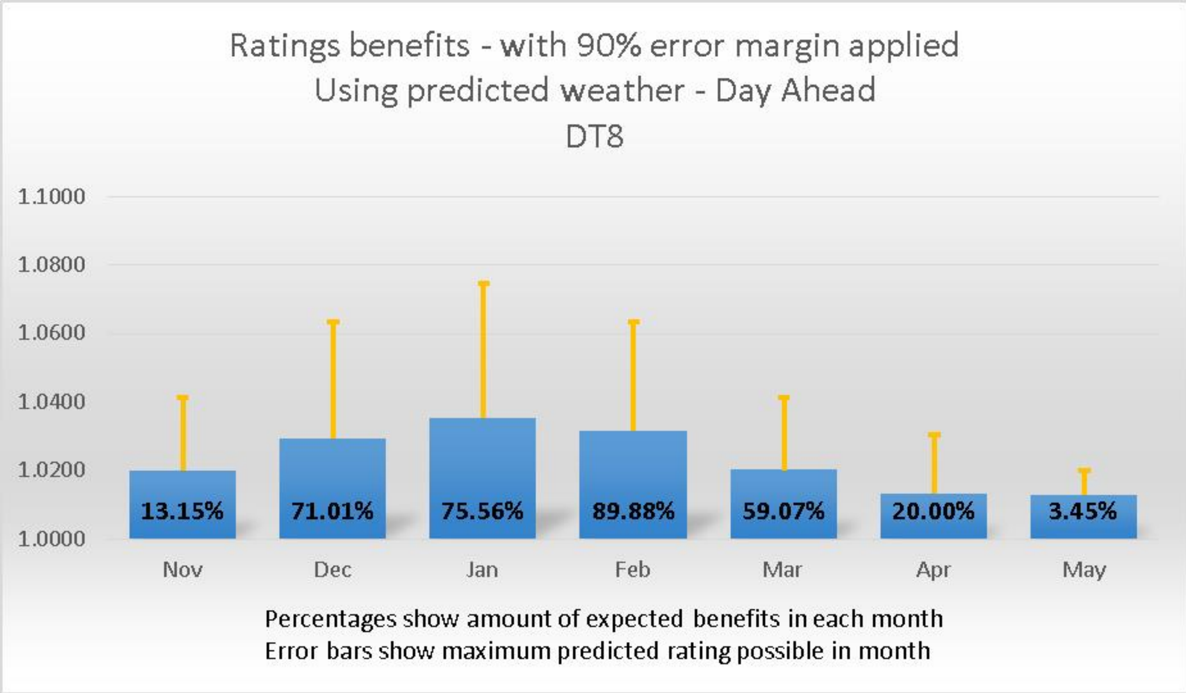

Ratings benefits - with 90% error margin applied
Using predicted weather - Week Ahead
DT4
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
6.11%
18.39%
21.90%
1.55%
Dec
Jan
Feb
Mar
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

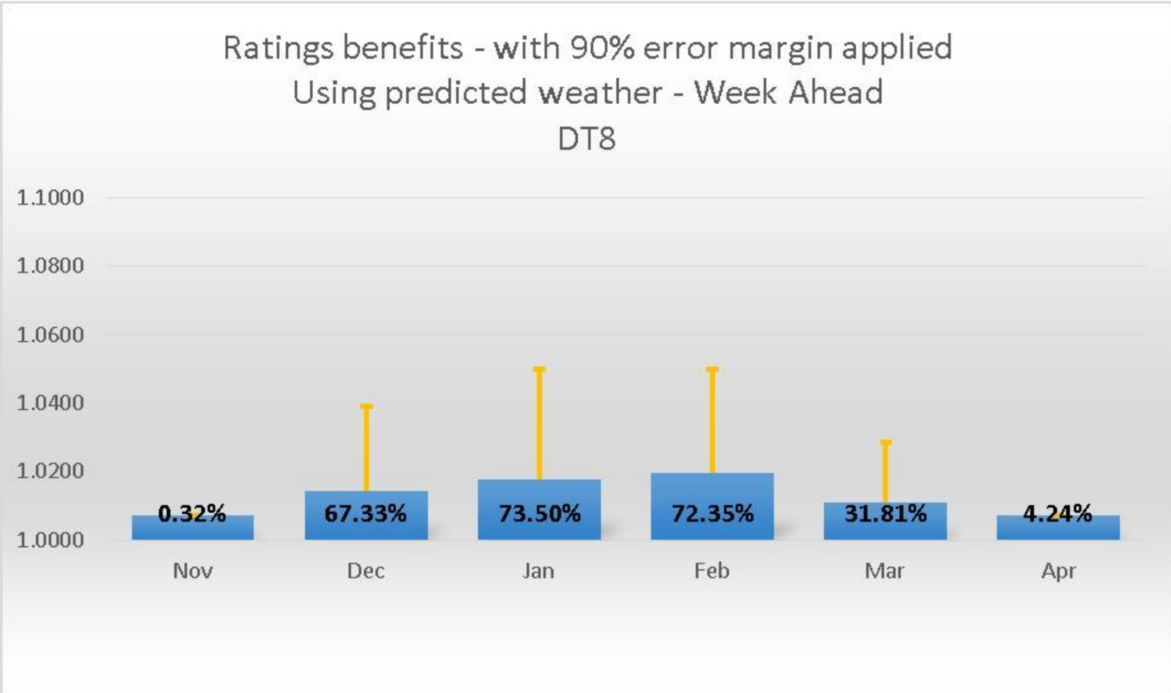

Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT5
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
2.76%
28.73%
78.47%
85.93%
93.58%
74.73%
40.49%
10.75%
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

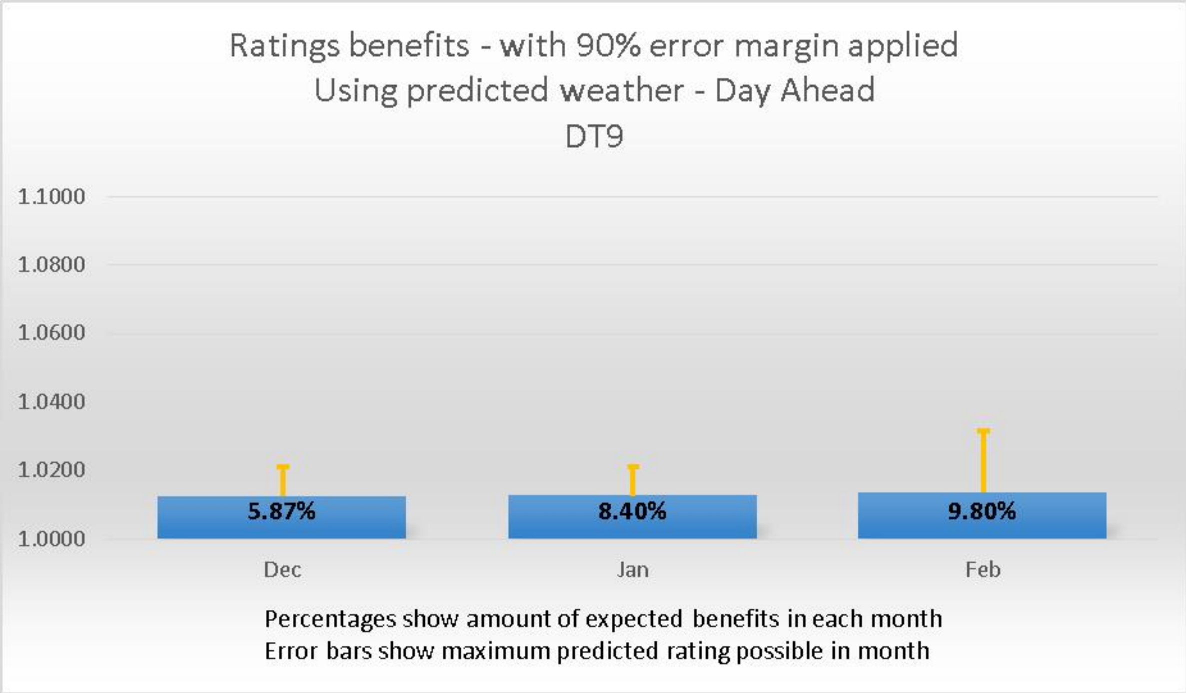

Ratings benefits - with 90% error margin applied
Using predicted weather - Week Ahead
DT5
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
0.44%
40.34%
43.88%
48.86%
15.01%
0.32%
Nov
Dec
Jan
Feb
Mar
Apr
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

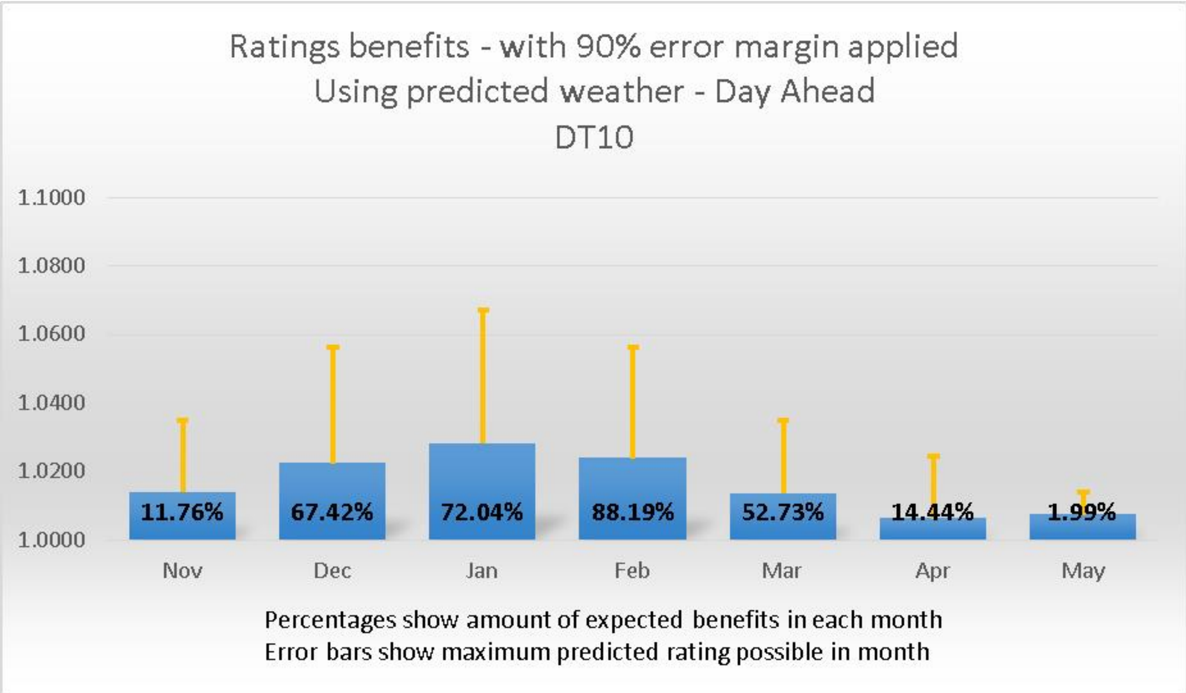

Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT6
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
4.01%
34.26%
79.17%
87.84%
95.01%
78.27%
44.07%
13.31%
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

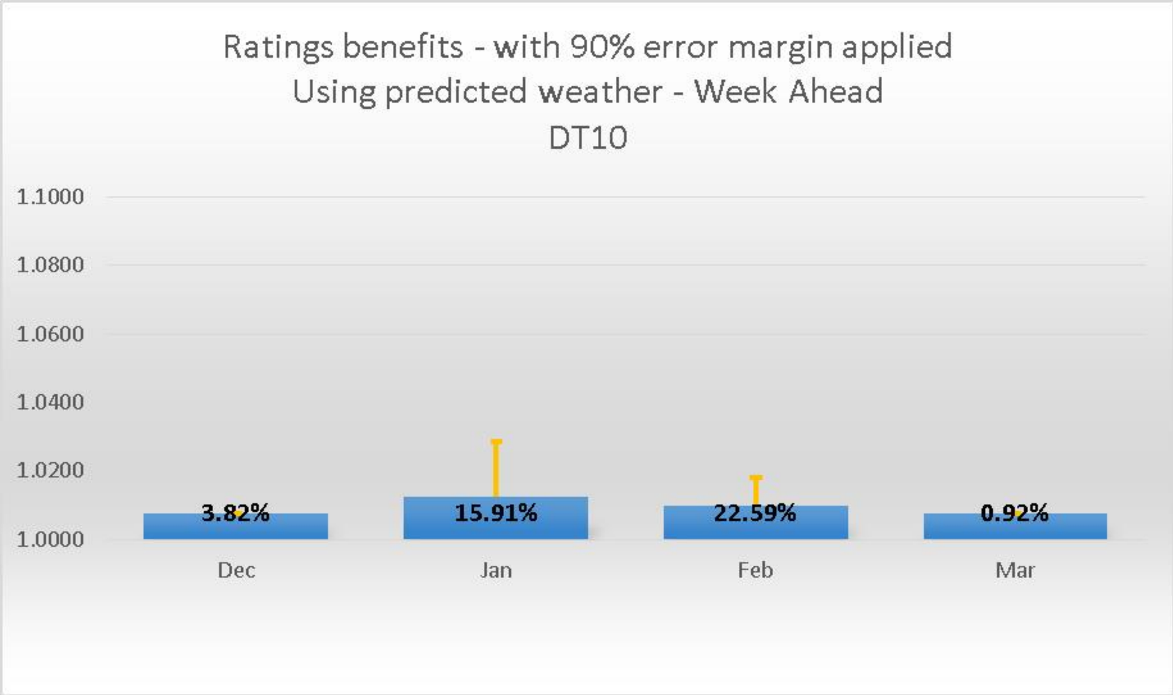

Ratings benefits - with 90% error margin applied
Using predicted weather - Week Ahead
DT6
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
0.45%
29.86%
87.33%
89.22%
88.34%
65.52%
32.22%
5.94%
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

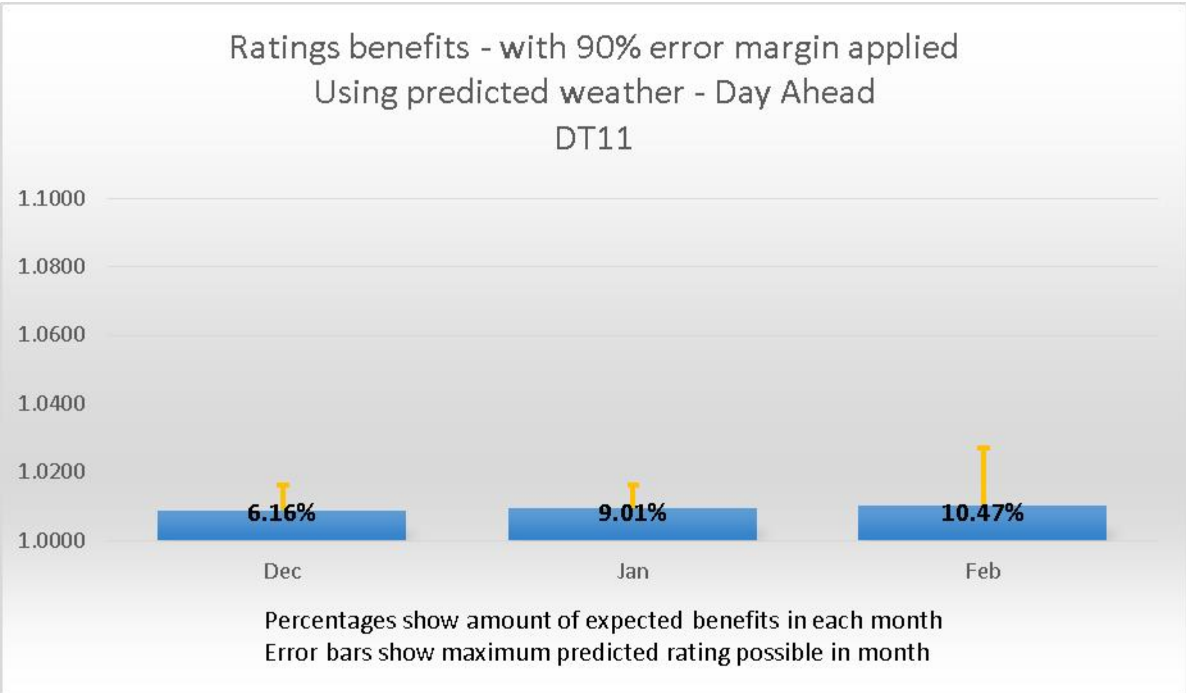

Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT8
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
13.15%
71.01%
75.56%
89.88%
59.07%
20.00%
3.45%
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

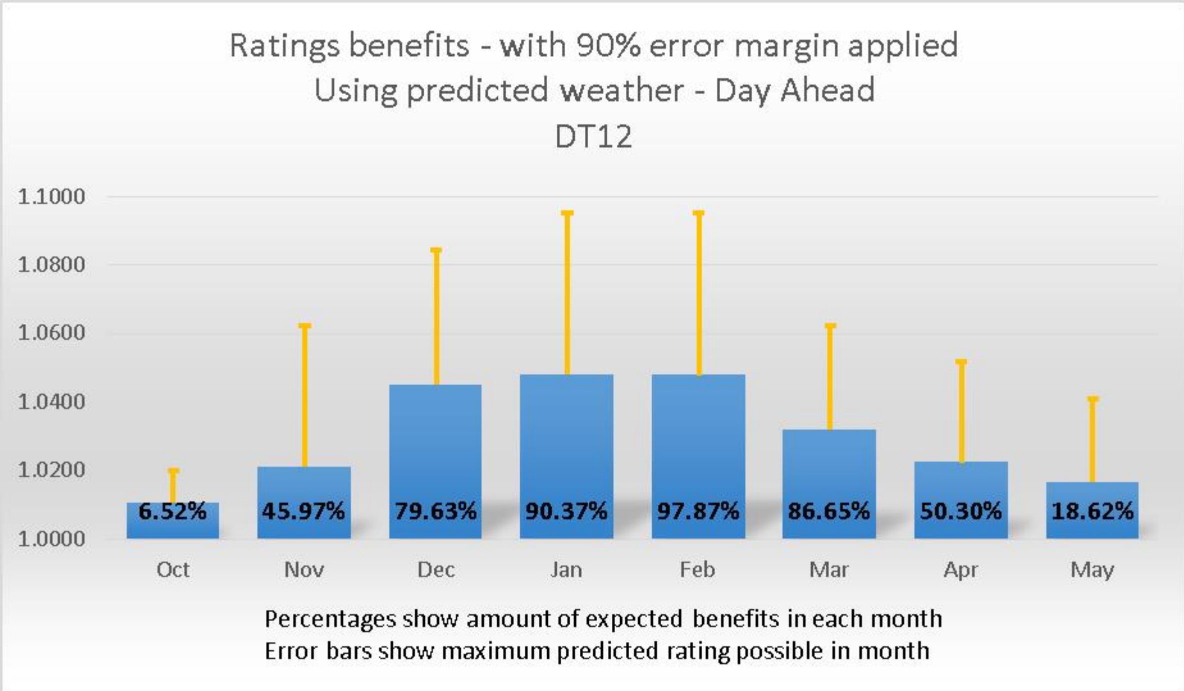

Ratings benefits - with 90% error margin applied
Using predicted weather - Week Ahead
DT8
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
0.32%
67.33%
73.50%
72.35%
31.81%
4.24%
Nov
Dec
Jan
Feb
Mar
Apr

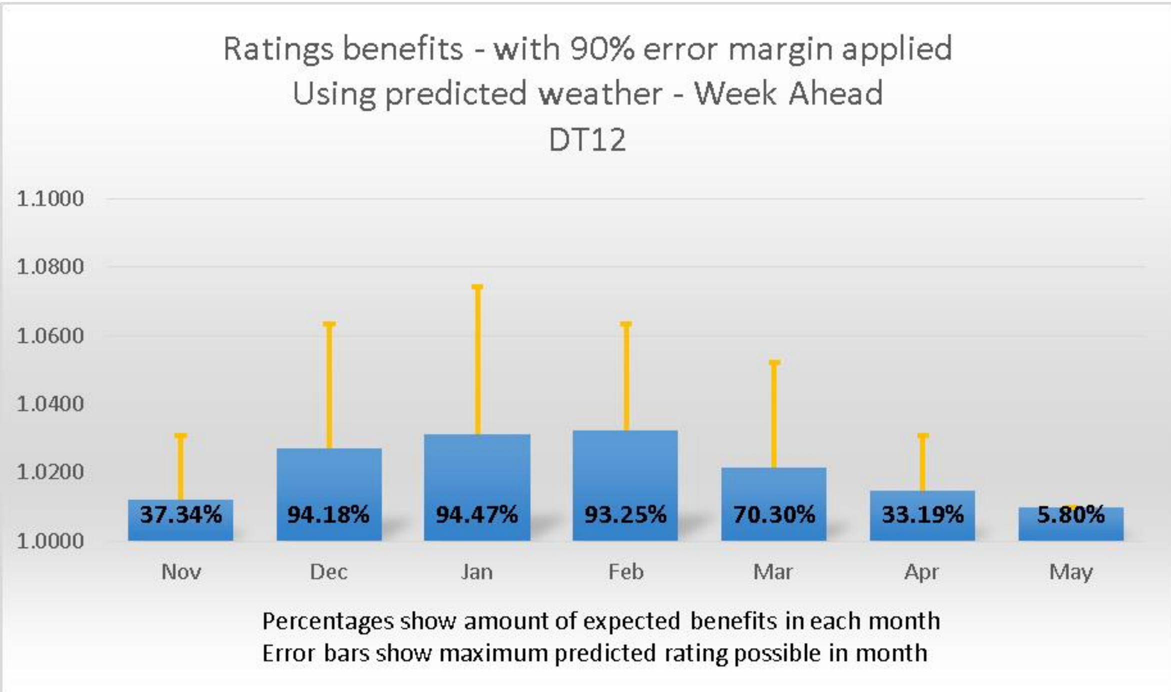

Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT9
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
5.87%
8.40%
9.80%
Dec
Jan
Feb
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

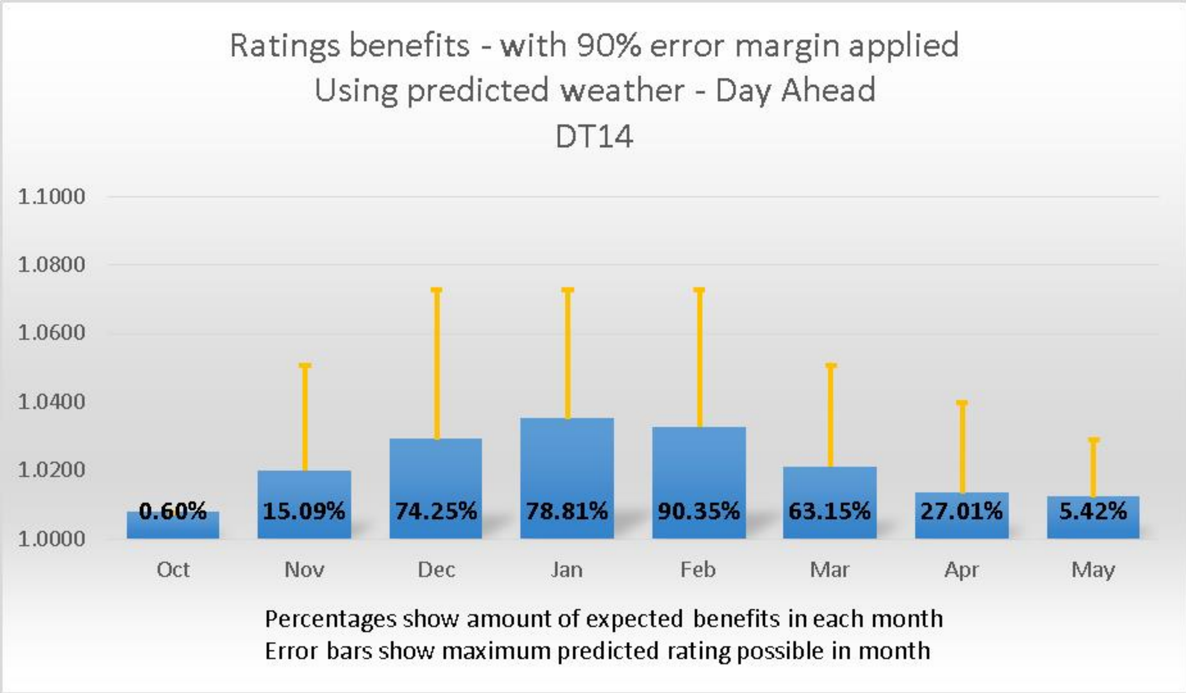

Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT10
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
11.76%
67.42%
72.04%
88.19%
52.73%
14.44%
1.99%
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

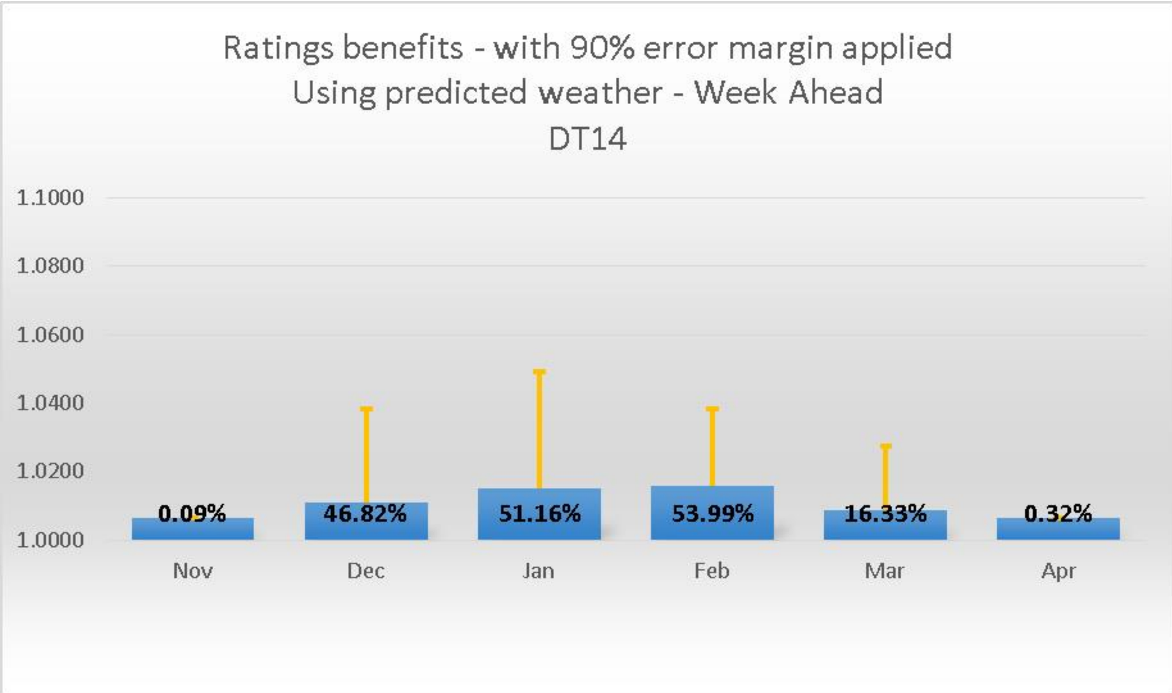

Ratings benefits - with 90% error margin applied
Using predicted weather - Week Ahead
DT10
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
3.82%
15.91%
22.59%
0.92%
Dec
Jan
Feb
Mar

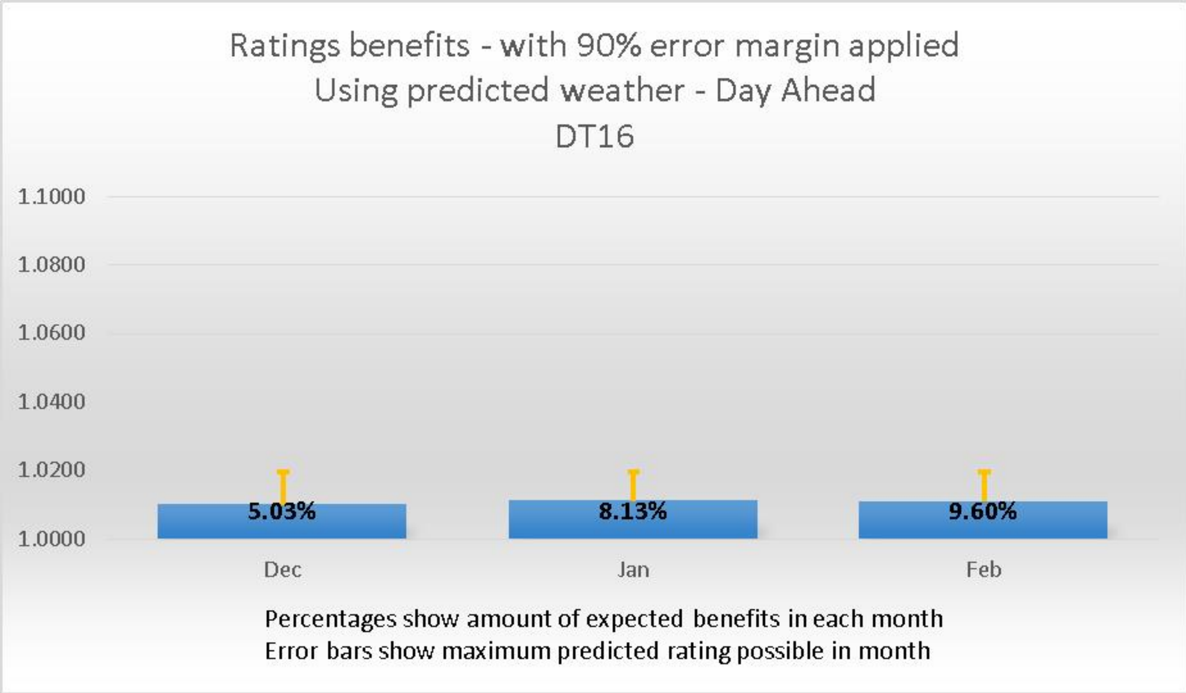

Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT11
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
6.16%
9.01%
10.47%
Dec
Jan
Feb
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month


Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT12
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
6.52%
45.97%
79.63%
90.37%
97.87%
86.65%
50.30%
18.62%
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month


Ratings benefits - with 90% error margin applied
Using predicted weather - Week Ahead
DT12
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
37.34%
94.18%
94.47%
93.25%
70.30%
33.19%
5.80%
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month


Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT14
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
0.60%
15.09%
74.25%
78.81%
90.35%
63.15%
27.01%
5.42%
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month


Ratings benefits - with 90% error margin applied
Using predicted weather - Week Ahead
DT14
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
0.09%
46.82%
51.16%
53.99%
16.33%
0.32%
Nov
Dec
Jan
Feb
Mar
Apr


Ratings benefits - with 90% error margin applied
Using predicted weather - Day Ahead
DT16
1.1000
1.0800
1.0600
1.0400
1.0200
1.0000
5.03%
8.13%
9.60%
Dec
Jan
Feb
Percentages show amount of expected benefits in each month
Error bars show maximum predicted rating possible in month

Western Power Distribution (East Midlands) plc
Registered in England and Wales No. 2366923
Registered Office: Avonbank, Feeder Road, Bristol BS2 0TB

Western Power Distribution (West Midlands) plc
Registered in England and Wales No. 3600574
Registered Office: Avonbank, Feeder Road, Bristol BS2 0TB

Western Power Distribution (South West) plc
Registered in England and Wales No. 2366894
Registered Office: Avonbank, Feeder Road, Bristol BS2 0TB

Western Power Distribution (South Wales) plc
Registered in Wales No. 2366985
Registered Office: Avonbank, Feeder Road, Bristol BS2 0TB