SP ENERGY NETWORKS

Flexible Networks for a Low Carbon Future

Improved Use of Primary Substation Data

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Executive Summary

It is critical to develop improved network planning and operations tools and processes to facilitate a future flexible network and make best use of existing assets. These tools will provide a greater understanding of network behaviour and enable a more appropriate techno-economic response to load growth. In particular, the timing and rate of growth of new demand associated with increasing amounts of low carbon technology including PV, electric vehicles and heat pumps are uncertain and risks must be adequately managed, not least those of temporary overloading of the network, voltage excursions or severe overloading leading to demand disconnection. While network reinforcement can alleviate these risks, such an action introduces the risk of stranded assets in the event that forecasts of demand growth are inaccurate. Network monitoring data has traditionally been analysed consistent with a fit and forget network and satisfaction of simple standards associated with annual peak demand. This will be inadequate for management of the aforementioned uncertainties. More detailed and extensive monitoring of the network will certainly provide insights into underlying HV and LV network behaviour and trends. However, existing available data is often under-utilised in terms of the learning that can be extracted. This report aims to show how existing primary substation data can be used to better inform network reinforcement decisions.

Better use can be made of existing primary substation data based on new analysis tools and techniques.

Primary substation data analysis has conventionally been based on single value maximum and minimum demands and generation extracted from time series data. A more probabilistic approach to data analysis augmented by appropriate analytical tools provides a much fuller characterisation of network behaviour, sensitivities and trends. It also allows a less conservative forecast of network capacity headroom to be determined.

We have developed and tested our new methodology on the three Flexible Networks trial sites as well as a sample subset of other network groups. Our approach comprises the following interrelated innovations:

- An improved approach to identification and handling of data anomalies for better management of primary substation data uncertainty
- An enhanced load forecasting tool to more accurately forecast future network group load growth trends
- A risk-based methodology to identify additional capacity headroom based on characterisation of frequency and duration of high loading for the network group
- Recommendations to improve management of modelling uncertainty

Load growth uncertainty

The reduction of load forecasting uncertainty will support a more techno-economic response to the expected increase in low carbon technologies in future years through improved reinforcement prioritisation and planning. Data is already available to better

characterise primary asset loading behaviour and trends but has traditionally been underutilised.

Observations of the annual demand peak (P100 percentile) are subject to wide variation due, for example, to weather and unusual network conditions. Our enhanced load forecasting methodology has been developed to reduce the influence of peak demand outliers and thus reduce uncertainty, based on the following two suppositions;

1. Percentile half-hourly measured loads other than the P100 value are less prone to exceptional variation and are more representative of underlying conditions than the P100 value and, hence, are more indicative of underlying behaviour within the group than the P100 value; and
2. There is a consistent, fixed relationship between an observed percentile other than the observed P100 and the 'true' P100 value.

Because high demand periods are critical to reliability of supply, a percentile was selected that represents high demand periods. A simple linear regression based on a number of years of historical data then provides the forecast of 'true' P100 values for future years.

For the six sample primary network groups analysed, the enhanced load forecasting methodology is generally within 10% of the measured peak demand for 1 year-ahead forecasting, whereas the existing approach does not perform so well and is within about 20%. The enhanced methodology also performs better when forecasting load trends up to 4 years ahead.

To summarise, our findings suggest that use of this new methodology provides improvements over the existing forecasting approach through better characterisation of underlying asset loading behaviour and reduced impact of load outliers. The incorporation of local intelligence on new network connections will provide further enhancement. This will help to release available capacity headroom and improve network reinforcement strategy.

Implications for ER P2/6 – Security of Supply

Current methods for the calculation of network capacity headroom, which are based on a simplistic interpretation of ER P2/6, whilst easy to understand, can lead to potentially conservative estimates. This is because current methods do not assess the risks to security of supply directly, but rather apply the discrete P2/6 security levels according to deterministic rules. The techniques proposed here address the uncertainty of the data used in P2/6 assessments and treat it in manner that is consistent with the philosophy of P2/6 to reduce unduly conservative estimates but not add to risk in any material way.

A key consideration for planning of distribution networks is the ability to meet future demand. In the event that future demand is expected to exceed network capacity, appropriate reinforcement should be carried out in a timely manner that takes into account approval, procurement, construction and commissioning lead times. The heterogeneous uptake of low carbon technologies increases the uncertainty associated with network reinforcement timing and need. A key innovation that would permit improved management of the risk of, on the one hand, network overloads, disconnections or failure to facilitate new connections or, on the other, stranded assets, would be the articulation of network 'capacity headroom'.

From a customer perspective, there is no difference between a loss of supply due to a first circuit outage or a second circuit outage. A new design target which takes into account the ability to maintain supply during a second circuit outage, but may result in a small but insignificant increase in the probability of a first circuit outage leading to loss of supply under very high loading conditions, may result in reduced customer minutes lost and a more cost-effective service provision. For example, deployment of low-cost network automation schemes for supply restoration during a second circuit outage event may be better justified than investment in a major reinforcement triggered by P2/6 non-compliance for a first circuit outage event, for example.

The table below illustrates the potential additional capacity headroom that could be accessed for the three Flexible Networks trial sites based on application of our probabilistic risk based approach.

Primary Network Groups	Ruabon	Whitchurch	St Andrews
Firm Capacity MVA	**10**	**20**	**21**
Half-hour Maximum Demand MVA	7.12	14.21	19.84
Minimum of 4 Highest Half-hour Loads MVA	7.02	13.94	19.33
% Additional Capacity Headroom	1.1%	1.3%	2.4%

It is noted that a review is due to be undertaken soon of Engineering Recommendation P2/6 – Security of Supply. P2/6 does not currently define "maximum demand", but our methodology goes some way towards providing new insights into what this might be. It is our intention to feed our results into the upcoming review of P2/6.

This work has significant implications for ER P2/6 – Security of Supply

Reduced Data Uncertainty

If load transfers occur around the time of peak winter demand, this can lift the load duration curve and have implications for peak network loading and load forecasting for future years. Improved, automated algorithms based on robust rules have been developed to reduce the impact of outliers due to atypical load transfer or erroneous readings and zero measurements.

Trend-based techniques can better highlight periods of anomalous behaviour compared to detailed time-series based assessment of loading although informed review of load patterns may still be required to determine whether there is a genuine event of interest. Visualisation of historic behaviour and confidence bands permit the data to be evaluated more easily and changes in load can be shown without being unduly influenced by year-to-year weather variations.

Reduced Modelling Uncertainty

The improved identification, management and mitigation of modelling uncertainties will enhance network modelling for better informed business decisions. Considering the time-varying characteristics of load and generation connected directly to the 33kV network should be relatively simple to implement as part of network model validation process as this data is available and it does not require significant additional analysis time.

It will be particularly important for future voltage management and fault level modelling to better quantify the characteristics of increasing amounts of embedded generation on the HV and LV network and influence on network behaviour.

Glossary

BSP	Bulk Supply Point (Primary substation)
ER	Engineering Recommendation
FCO	First Circuit Outage
GSP	Grid Supply Point (supply point from the National Electricity Transmission System to DNOs)
LCT	Low Carbon Technology
LTDS	Long Term Development Statement
PI	Process Instrumentation – SPEN's Network Monitoring Data Historian System
SCO	Second Circuit Outage
SPD	Scottish Power Distribution
SPEN	Scottish Power Energy Networks
SPM	Scottish Power Manweb

1 Learning Outcomes

Innovative analytical techniques have been developed and applied for improved analysis of primary substation data to achieve the following principal learning outcomes:

- Better understanding of network asset loading behaviour and risk under high loading conditions resulting in release of capacity headroom.
- Improved forecasting of future load trends and enhanced management of measurement and modelling uncertainties facilitating more efficient network investment.
- Development and application from the outset of successful internal stakeholder engagement strategies to achieve user buy-in and fast-tracking of the improved processes into business-as-usual.

These learning outcomes have been supported through the development and application of better data error detection and correction techniques to raw measured data and the provision of simple, new spreadsheet based tools.

1.1 The Annual Network Review – Current Practice, Limitations and Improvements

An annual network review of primary substation loading is carried out to identify areas in which new connections might be expected or that are approaching capacity that may require reinforcement or additional infrastructure investment in the event of demand growth. SPEN current practice is to apply a base general, licensee area wide demand growth assumption that is refined in specific demand groups where there is local intelligence on future connections activity.

Primary substations identified as being close to capacity are examined in greater detail. Maximum demands for a number of previous years are analysed along with information on any new connections to determine trends in demand change which are then extrapolated forward to estimate the demand forecast for future years.

As maximum demand is sensitive to weather conditions and outlier events (for example due to a temporary network backfeed) historical network monitored data may not be representative of the actual maximum group demand. A manual investigation is currently carried out where group demands have significantly changed from the previous year and a correction is done if this change is identified as being due to temporary network reconfigurations. Further details of network planning tools utilised by SPEN are provided in Appendix A.

Limitations of the current load forecasting practice are illustrated below in Figure 1-1 and Figure 1-2 for a network group with particularly variable annual maximum demand. It can be clearly seen that a forecast based simply on the last three years' peak demand leads to very different forecasts depending on which three years are used.

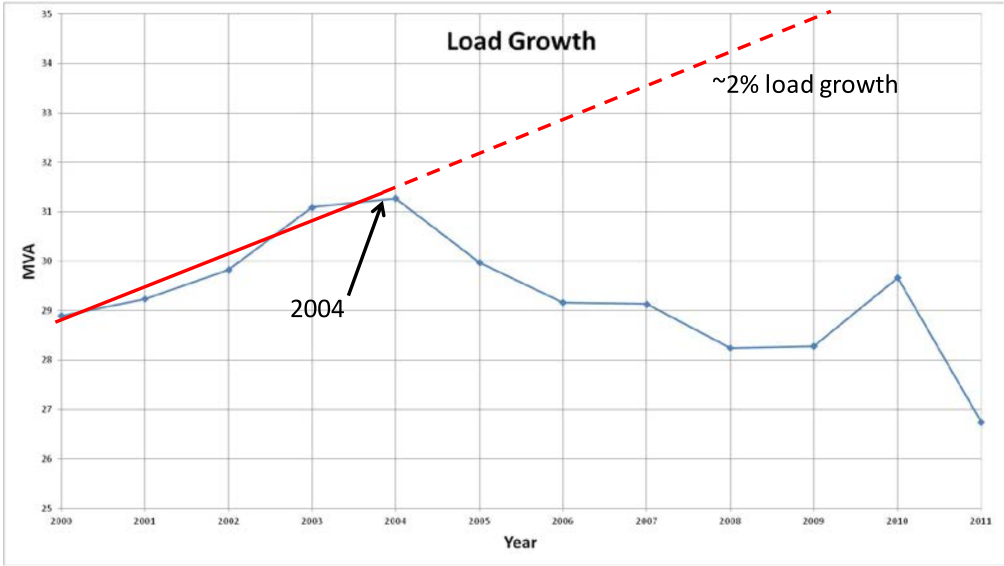

Figure 1-1 Forecast load growth based on 5 years of previous maximum demand values

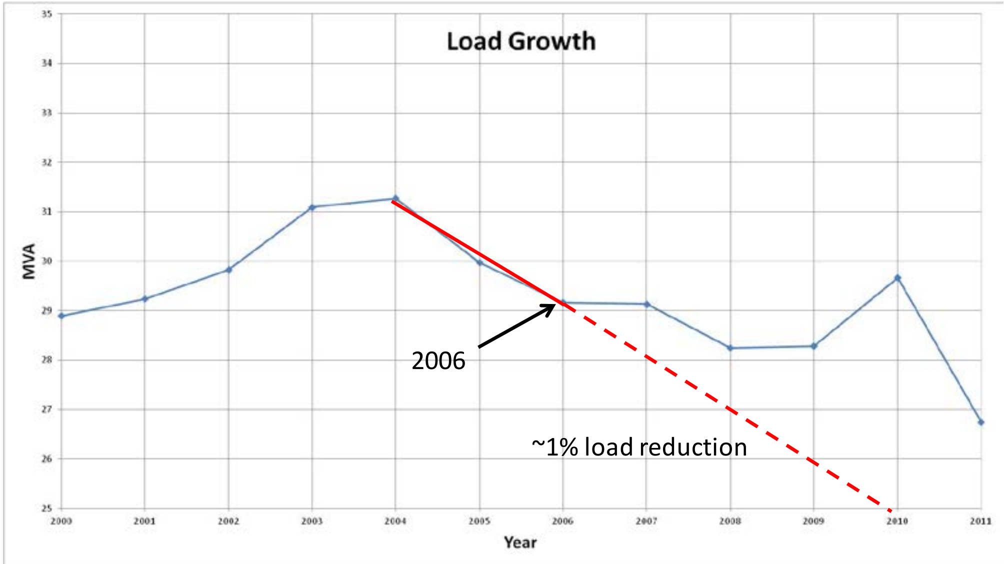

Figure 1-2 Forecast load growth based on 3 years of previous maximum demand values

An improved approach to load forecasting will incorporate annual load behaviour rather than just single annual peak demand values

1.2 Improved Data quality

Typically, raw primary transformer data are used directly in network studies, (e.g. the half-hour data from last year's maximum demand period to monitor load growth) and limited data analysis is carried out on the wider data set.

Data quality can be improved through the development and application of robust automated screening algorithms to the raw demand data.

Further details of planning and operational tools and processes that could benefit from improved primary substation data quality are described in Appendix A.

1.3 Potential Benefits

1.3.1 Network Planning

- Enhanced network reinforcement identification, prioritisation and proposal design
- More accurate and rapid assessment of capacity for new connections
- More accurate characterisation and modelling of the HV network and understanding of uncertainties

2 Background

2.1 Flexible Networks for a Low Carbon Future

'Flexible Networks for a Low Carbon Future' is a Scottish Power Energy Networks (SPEN) Tier 2 Low Carbon Network Fund (LCNF) trial project. LCNF Tier 2 projects are awarded annually on a competitive basis to UK Distribution Network Operators (DNO) and are administered through Ofgem.

Flexible Networks will provide the DNOs with economic, DNO-led solutions to enhance the capability of the networks as heat and transport are increasingly de-carbonised resulting in an increase in electricity use. Crucially, these solutions will be capable of being quickly implemented and will help to ensure that the networks do not impede the transition to a low carbon future.

Solutions are needed that can:

- Determine more accurately the capacity headroom while maintaining licence obligations,
- Allow that headroom to be exploited in a safe, reliable and cost-effective manner, and,
- Provide incremental increases in headroom in a timely and cost-effective manner.

Flexible Networks aims to provide a 20% increase in network capacity through a number of innovative measures. This will enable more customers to make the transition to new low carbon generation and demand technologies. The project involves enhanced monitoring and analysis to better understand and improve existing performance, and the deployment of novel technology for improved network operation and capacity - including dynamic asset rating, network automation, voltage regulation and energy efficiency measures.

To ensure representative and replicable outputs, the project involves three carefully selected trial areas across SP Distribution and SP Manweb licence areas, covering various network topology and customer demographics: St Andrews in Scotland, Wrexham in Wales and Whitchurch in England, see Figure 2-1.

The three trial areas have known capacity issues and consequently offer a real opportunity to analyse and implement alternative flexible solutions to network reinforcement. All three sites have different characteristics and customer demographics but, between them, are representative of types of site that can be found across the network. They are similar to each other in that they have near-term constraints due to increasing demand and an uptake of low carbon technology. The rapid nature of these changes both imposes a requirement, but also provides the opportunity to trial solutions that are faster and more cost-effective to implement than traditional reinforcement.

Figure 2-1 Trial Area Location Map

The specific issues facing these three locations are mirrored across the UK electricity distribution network, and this project will be able to provide generic solutions and recommendations to address these.

2.2 Improved Use of Primary Substation Data

The existing best practice for distribution network LV and 11kV network design and operation is based on a "fit and forget" philosophy where there is only a limited set of representative network metrics available e.g. the magnitude of peak loading on a feeder, which generally does not provide information on the dynamic interactions of the various system states over the course of a year of operation. Short term capacity overloads or voltage excursions are typically identified by customer complaints or investigations for new connections. Historically, it has been difficult to provide robust cost-benefit analysis in support of collection and analysis of time series data for large parts of the network.

The level of operating state uncertainty necessitated a number of assumptions which have inherent safety margins built in to minimise the risk of overloading equipment or failing to keep voltages within statutory limits. Also, existing load connections, i.e. customers, have generally been considered to be stable, i.e. load profiles and demand of existing connections do not change appreciably over time. At present, most load changes on the network are due to new connections, rather than changes to existing connections.

In the future, it is likely that customer consumption patterns could change radically, creating a significant impact on the distribution network over a short period of time. These changes could be localised and high-density due to rollout of electric vehicle charging points for example. This will necessitate an improved knowledge of the distribution network particularly at 11kV and LV and the ability to detect and extrapolate changes to implement the appropriate response. A key focus of Flexible Networks is to develop more knowledge of the characteristics and behaviour of the existing network, identify additional capacity headroom available and better understand the likely impact of future network changes. It will develop cost-effective tools to improve network performance and investment, and to flag network changes and trends. An important aspect will be engaging with network operations and planning staff to understand their viewpoint and needs with the objective of obtaining their buy-in to implement changes in techniques and behaviour.

The learning outcomes will allow existing inherent design and operational safety margins for capacity to be reduced, without placing the system at risk, or degrading quality of supply to customers. It will also enable the development of techno-economic strategies for management of the future low carbon network that are effective and easy to implement.

The analysis presented in this report explores the enhanced utilisation of primary substation data through development and testing of improved data analysis techniques. These investigate key network metrics including loading trends and risk to increase data value to network design and operation and reveal capacity headroom from existing power flow measurements available from primaries.

The characteristics and behaviour of the network at the primary substation level are being integrated with results from secondary substation monitoring deployed for Flexible Networks to provide an improved understanding of the network, possible gains in capacity headroom and the potential impact of low carbon technologies. This is presented in detail in a number of related Flexible Networks activities and reports such as the HV and LV Phase Imbalance report.

3 Experimental Design

Several new analysis techniques and tools have been developed and are described in this report: an enhanced load forecasting and network risk characterisation tool, based on peak loading duration and frequency, and a new data cleansing algorithm. In order to test and verify the performance of the load forecasting and network risk characterisation tool, the following criteria were used:

- The new analytical tool should be faster and more user friendly than the existing tool.
- The new analytical tool should reproduce maximum demand trends for the majority of networks analysed.
- The annual maximum demand forecast by the new analytical tool should generally agree more closely with the actual measured maximum demand, compared to the existing load forecasting approach.
- The analytical tool should provide peak load duration metrics (total number of hours, number of events etc) for a defined peak load and total number of hours, to support characterisation of additional network risk for peak loading above firm capacity.

It should be recognised, that typically, a network planner would have detailed local knowledge of the network and, thus, would be aware of any new blocks of demand or generation connecting or disconnecting. Therefore, the performance of the new load forecasting tool without incorporation of network specific knowledge may vary between individual networks but should show overall improvement.

Several linear regression techniques are available within the new load forecasting tool. Selection of the appropriate technique should be preceded by comparison of the various techniques for a range of representative networks.

Details of the new load forecasting tool algorithms and performance testing based on the above criteria are described below.

In order to test and verify the performance of the new data cleansing algorithm, the following criteria were used:

- The algorithm should reduce the impact of outliers such as those due to load transfer on characterisation of the network loading behaviour.
- The algorithm should reduce the impact of zero values on data trends.

4 Improved Characterisation of Network Behaviour and Trends

4.1 Introduction

We have identified that existing network planning processes for primary substation groups can benefit from an enhanced approach to load forecasting and risk characterisation. This will enable improved characterisation of primary asset loading characteristics, underlying demand changes and contribution to network capacity.

Evolution from a deterministic to a probabilistic approach will be required to plan and operate future networks effectively and manage the transient load patterns associated with embedded generation and low carbon loads (heat pumps, electric vehicles), demand side response, energy storage and dynamic thermal rating.

The enhanced load forecasting and risk characterisation tool presented in this report is based on applying a probabilistic approach to primary load data analysis and enables:

- Improved consideration of peak load outliers leading to better forecasting of future demand growth trends
- Improved characterisation and management of risk e.g. more detailed assessment of the load duration curve as well as the frequency and duration of high loading events
- Identification of network capacity headroom to help optimise network reinforcement requirements and prioritisation
- Ease of use and optimisation of load data import

The analysis methodology and key features of the risk characterisation and enhanced load forecasting tool are described below along with an assessment of its performance in relation to measured data and the existing load forecasting approach.

4.2 Sample Networks for Performance Testing

A subset of HV network groups was selected for detailed performance testing of the enhanced load forecasting and risk characterisation tool. These include the three Flexible Networks trial network sites, Whitchurch, St Andrews and Ruabon, as well as several network groups in SPM with varying locations and characteristics (Egerton, Hunts Cross and Boulevard). The location of the sample networks is shown in Figure 2-1. Further details of these network groups are provided in Appendix B.

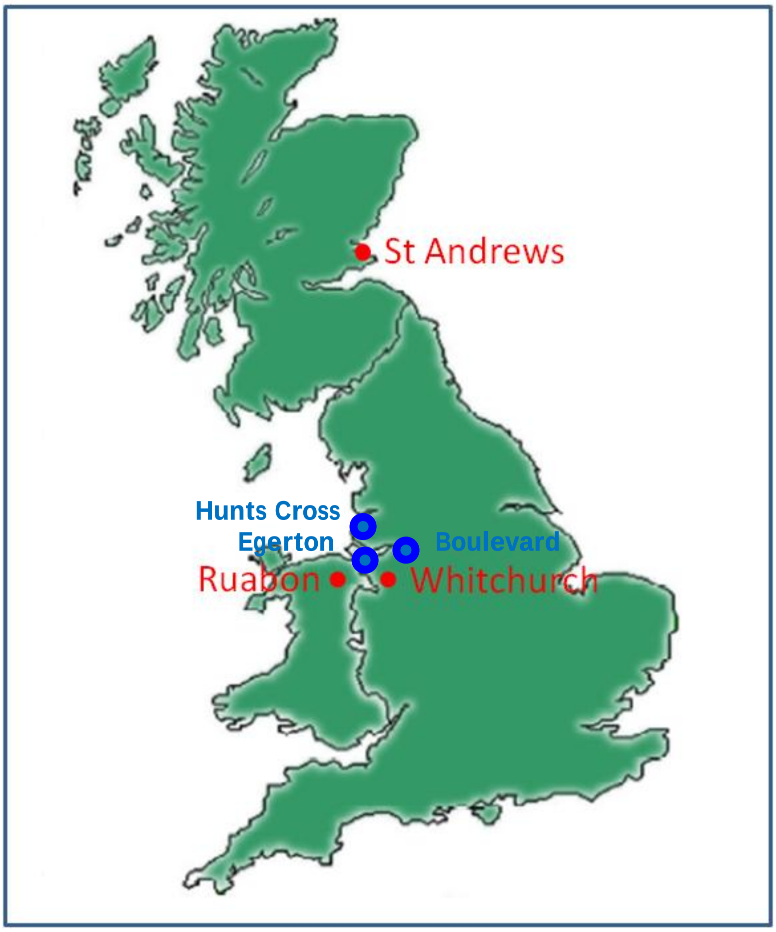

Figure 4-1 Sample Network Location Map (Flexible Networks Trial networks are shown in red)

4.3 Characterisation of Network Risk

There is inevitable uncertainty in forecasting network load years into the future, so there is always going to be an inherent element of risk associated with any network capacity headroom assessment. This network risk has generally been managed in the past by making conservative assumptions about the maximum demand: using the maximum half-hourly annual measured demand. This has worked well in recent years because, generally, annual load growth rates have been low and reasonably predictable (i.e. within a range of 0.5% +/- 0.5% per annum). However, in the future, the rate of load growth is expected to be much higher, combined with a much greater range in uncertainty if the electrification of transport and heating progresses rapidly. Given the uncertainty in load growth, the traditional conservative approach will lead to greater risk (either increased network risk if load growth is underestimated or increased financial risk if load growth is overestimated) and so alternative approaches need to be considered.

A move to a fully risked-based probabilistic approach to assessment of network security is outside the scope of this project. However, this project aims to examine some of the practical elements associated with such an approach and, in particular, to make better use of historic data. The key component examined here is characterisation of “Group Demand”.

Our proposed methodology is described below.

4.3.1 Definition of Network Risk

HV network groups typically fall within Engineering Recommendation P2/6 network Class C (i.e. maximum demand between 12MW and 60MW), where;

- First Circuit Outage (FCO) – i.e. unplanned (fault) outage - results in no loss of supply
- Second Circuit Outage (SCO) – i.e. unplanned (fault) outage occurring during a planned outage - can result in 100% loss of supply

Network capacity is generally based on a summation of the continuous ratings of network branches (referred to in ER P2/6 as ‘circuits’) connecting a group to the rest of the network and over which power continuously flows in order to meet demand in the group. ‘Firm’ capacity is that after an outage of one of the connecting circuits.

According to conventional interpretations of ER P2/6, the limiting factor for the network’s capacity to meet demand in a group is often transformer continuous ratings. For example, for a network group connected via three 10MVA transformers, the firm capacity will be 20MVA (i.e. 3x10MVA – 10MVA), which would be the maximum peak demand that could be supported in compliance with P2/6 for a Class C group.

ER P2/6 requires that network capacity – comprised of, in conventional interpretations, summations of continuous ratings of circuits connecting a group – should be sufficient to meet both a given demand under an FCO condition and another given demand under an SCO condition. The implication is that insufficiency of network capacity should be addressed by investment in primary assets[1] to enhance network capacity.

The specifications in ER P2/6 of the levels of demand to be met are based on probabilistic assessments of failures to meet the full demand. The results of these assessments were published in 1979 in “ACE Report No. 51 – Report on the Application of Engineering Recommendation P2/5 Security of Supply”. The ER P2/5 and, subsequently, P2/6 requirements represent crisp, ‘deterministic’ characterisations of the probabilistic assessments and the boundaries between acceptable and unacceptable conditions given an assumed value of lost load and assumed costs of network reinforcement.

[1] The term ‘primary’ is used here to mean assets that carry load serving current as distinct from ‘secondary’ assets that are concerned with network monitoring and control.

One of the dimensions that would have been taken into account is the likelihood of a particular network outage condition. In particular, it would have been recognised that

1. the probability of a single outage leading to an inability to meet the full demand is highest when the level of demand is highest, i.e. at annual peak demand. Maintenance or construction outages should not normally be scheduled to take place at such times; hence, the critical single outage condition representing a risk to demand is an unplanned outage, i.e. a forced outage, which could occur at any time of the year;
2. a situation in which two circuits are out of service is most likely to occur when there is already a planned outage (for maintenance or construction) and a forced outage happens, such as due to a network fault. Planned outages are normally scheduled to take place during the summer period when the peak demand is low relative to the annual peak; the probability of an SCO leading to a failure to meet the full demand is thus related to the peak demand during the summer period.

The stipulations written into ER P2/6 were also based on an assumption that the magnitude of impact of a failure to meet demand is proportional not only to its probability but also the size of an affected demand group and the duration of a failure. The latter factors led to rules being written for different sizes of demand group concerning the maximum time within which some given amount of demand should be restored.

At the time at which the analysis on which the requirements written into ER P2/6 was done, a distribution operator would have had

- limited access to network data;
- little or no access to adequate analysis tools to make efficient use of extensive network data;
- little or no experience with means of meeting demand other than through additional primary assets.

A more sophisticated approach should be possible now that recognises that (a) ‘continuous’ ratings are dependent on ambient conditions, (b) by virtue of the time variation of demand, excessive circuit conductor or transformer oil temperatures can be avoided even when continuous ratings are exceeded and (c) network remote control can permit reconfiguration of the network and the restoration of demand more quickly than was assumed in the analysis underpinning ER P2/6.

The work reported here does not claim to address all the issues but offers practical, simple improvements. In particular, it should be noted that compliance with ER P2/6 does not guarantee perfectly reliable supply. In other words, failure to meet the full demand in a group at any time in a year of operation can still occur.

Custom and practice in the quantification of 'group demand' and maintenance period demand varies among DNOs and is made difficult either by (a) lack of data, e.g. the dependency of demand on weather; (b) atypical network conditions leading to measured peak demands that are unlikely to reproduced in the next year or two; or (c) simplistic or inconsistent interpretations of ER P2/6.

A readily accessible improvement is suggested here. DNOs typically do already have access to half-hourly measure demands at primary (11kV) substations even if *explanation* of observations is much more difficult and, often, impossible. As noted above, there is already a finite probability of any given demand value being exceeded albeit that probability diminishes as the given demand level increases. Nonetheless, a typical, simple approach used by DNOs in network planning is to assume that the observed peak demand from the previous year had a 0% chance of being exceeded, i.e. was representative of the 'true', underlying 'peak demand'. Instead, here, formation of a full year's load-duration curve based on the observed values has been used to estimate a particular level of demand that has a given probability of being exceeded, i.e. a particular percentile of demand. Statistical theory indicates that percentiles nearer to the 50th can be estimated with increasing confidence and that estimates of the 100th or zeroeth percentiles are most prone to error. It is shown below that a percentile other than the 100th provides a much better basis for forecasting of peak demand than the 100th from previous years' observations.

4.3.2 Increase in risk associated with marginal increases in demand

From a customer perspective, there is no difference between a loss of supply due to a FCO or a SCO – to the customer it is still a loss of supply. So, there may well be a better design target which takes into account the ability to maintain supply during a SCO, but may result in loss of supply during a FCO, resulting in an improved supply security from a customer perspective. This new design target would need a full probabilistic assessment to determine properly, but as a first order approximation, it is likely to be where the probability that the load will exceed the network capacity during an unplanned fault is typically an order of magnitude less than the probability of an unplanned fault occurring during a maintenance outage. This is a "small" (but non-zero) number. The implication of this is that it may be better from a customer security of supply perspective for DNOs to invest in low-cost network automation schemes for supply restoration during an SCO event than it is for a DNO to invest in a major reinforcement triggered by P2/6 compliance for an FCO event. Additionally, it may be that plant dynamic ratings could be applied to extend plant operating capability for short durations during periods of network overload.

More formally, given that the probability of two independent outages is small enough to be neglected, the probability of a particular firm capacity being exceeded may be estimated as follows:

$$P(L > C \cap FCO) \simeq$$
$$P(L > C)xP(fault|no\ planned\ outage) + P(L > C)xP(planned\ outage|no\ fault)$$

where L is the level of load and C is the firm capacity.

It should be noted, however, that the probability of the loading exceeding the firm capacity at the same time as a planned outage is minimised by scheduling maintenance outages to coincide with periods where the network is typically not highly loaded.

Assuming that the probability of two, concurrent fault outages is negligible, the probability of a SCO, resulting in up to 100% of loss of supply, can be considered as the probability of a fault occurring during a planned outage, as per ER P2/6 definition.

$$P(SCO) = P(planned\ outage) x\ P(fault)$$

For example in SPEN, primary transformer outages are typically taken for five days every three years during which the opportunity is taken not just to maintain the transformer but to carry out other maintenance during the outage e.g. for protection equipment. This gives a probability of planned outage of 1.67 days/year (or 80 half-hours, or 0.9%) although this would be most likely to occur during seasonal periods of low load.

If the total probability of loading events above network firm capacity is much less than the probability of a planned outage, then the additional risk of (partial) loss of supply is relatively minimal. The total acceptable number of half-hours that a network is loaded above network firm capacity throughout the course of a year can be defined as an order of magnitude less than the duration of a planned outage. For the example given above, this would give a total of 8 half-hour periods in a year or P99.95, the 99.95 % percentile load in probability notation. These may be consecutive or occur independently of one another e.g on separate days.

If the probability of peak loading above network firm capacity is much less than the probability of a planned outage, then additional risk of loss of supply is relatively minimal.

4.3.3 Identification of Additional Capacity Headroom

A theoretical test case is provided below in Figure 4-2 to illustrate application of our risk based methodology for a network where load is slightly exceeding firm capacity. Based on a total acceptable number of half-hours for peak loading events above firm capacity of 8 half-hourly periods in a year, 4 short duration loading events (of between 0.5 hours to 1.5 hours duration) above firm capacity are accepted.

The single highest half-hourly annual reading is also indicated in Figure 4-2 which is currently used for characterisation of the annual group maximum demand. This shows that an increase in load of approximately 0.8MVA is facilitated before network reinforcement is triggered, based on application of our risk based approach. This gives additional capacity headroom of 4%.

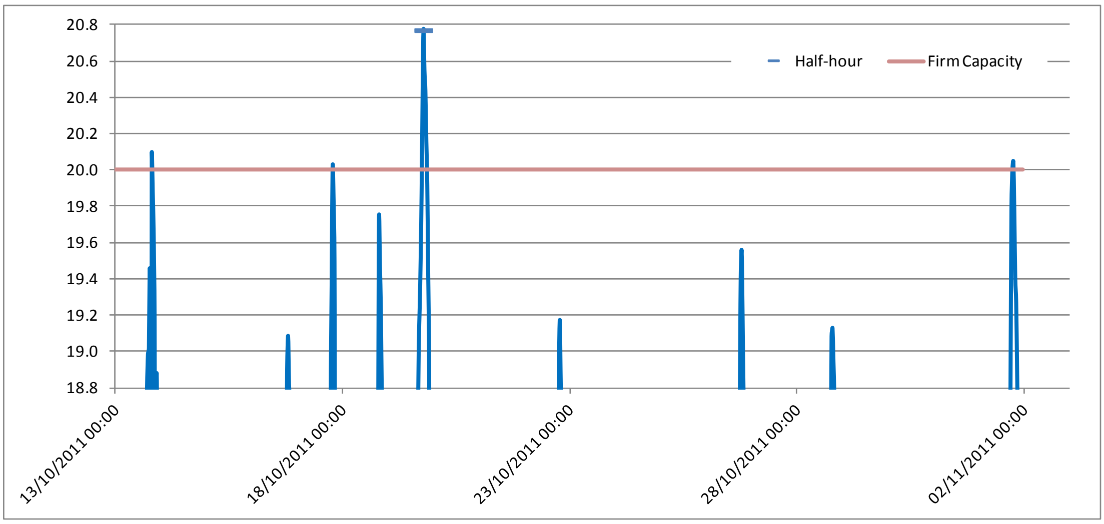

Figure 4-2 Illustration of peak loading above network firm capacity

It is recognised that this approach is based on the use of limited measurements at peak demand and transient load characteristics which can vary from year to year. This is investigated in Figure 4-3 and Figure 4-4 for St Andrews and Ruabon primary substations. The analysis indicates that the annual peak loading behaviour is relatively consistent in terms of the relationship between the maximum demand and the P99.95 demand. However, this should be evaluated alongside the increase in LCT technology uptake to determine whether changing load type alters the probabilistic behaviour of peak loading significantly.

Thus, once maximum demand is forecast to exceed firm capacity, the capacity headroom then available by accepting 8 half-hourly load values above firm capacity should be reasonably well represented by the capacity headroom calculated from previous years (based on the previous year's P99.95 demand and the maximum demand for example). The use of a total acceptable number of hours above network firm capacity that is an order of magnitude less than the duration of a planned outage should also mitigate the impact of uncertainty in forecasting future load behaviour on additional risk, to an extent.

An idealised network group is shown in Figure 4-5 with consistent 4% capacity "headroom" between the historic P100 'maximum demand' and P99.95 demand. Also illustrated is reinforcement deferral for a 2% annual load growth, assuming that the reinforcement is completed before headroom is completely exhausted.

This methodology does also raise the question as to whether there is a more optimal design goal than currently encompassed in P2/6, with more emphasis placed on reducing the impact of SCOs, whilst allowing the impact of FCOs to increase marginally.

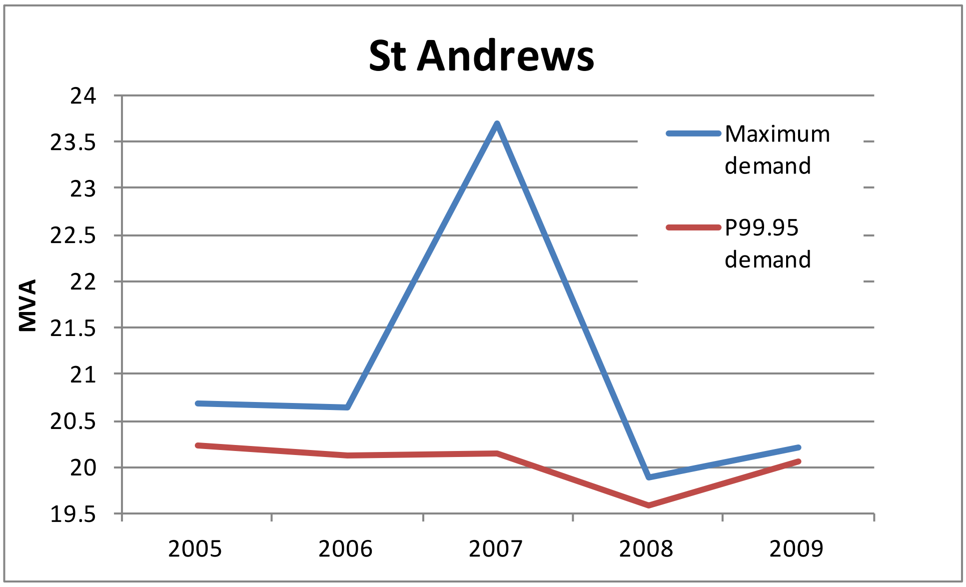

Figure 4-3 St Andrews primary substation annual load characteristics

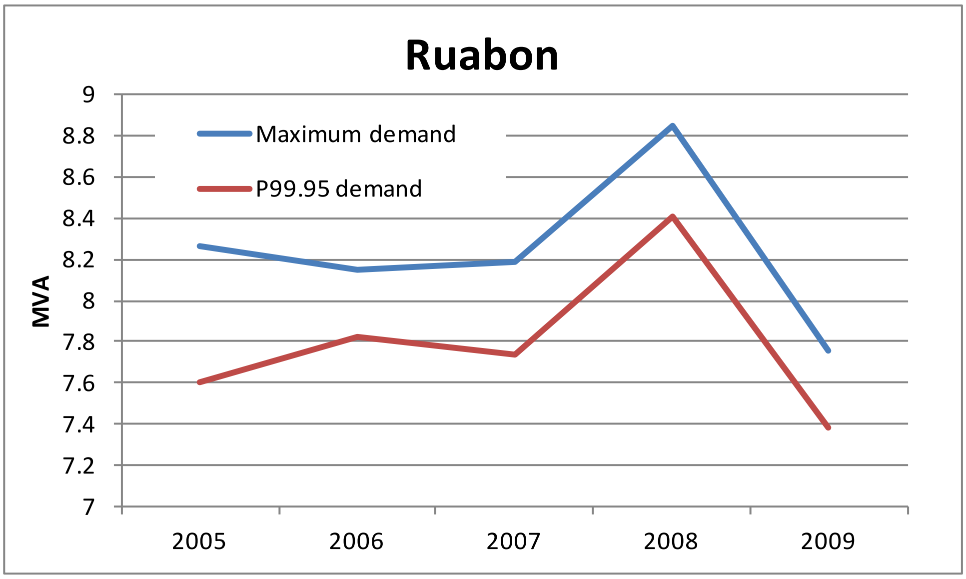

Figure 4-4 Ruabon primary substation annual load characteristics

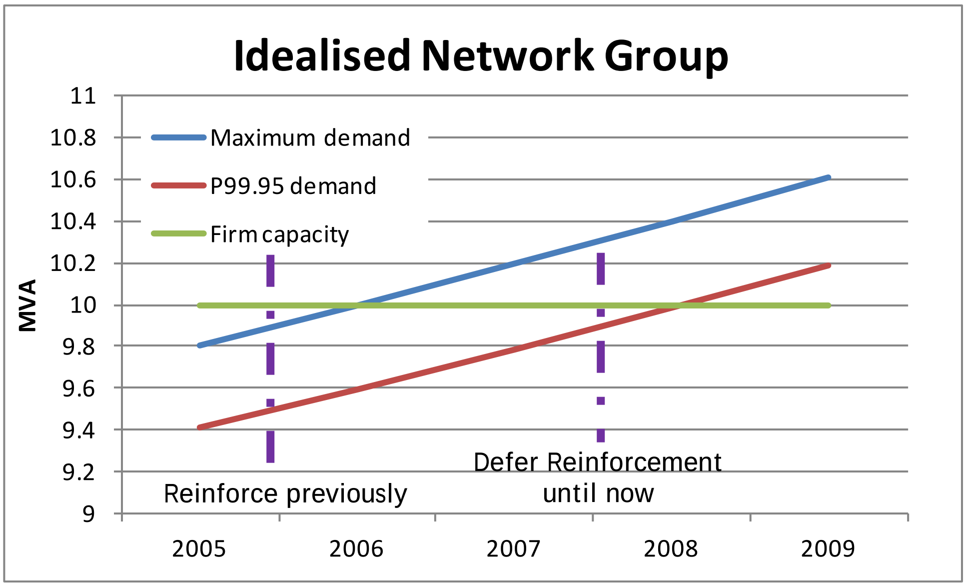

Figure 4-5 Idealised primary network group annual load characteristics (based on a capacity headroom of 4% between max demand and P99.95 demand)

The analytical tool developed contains algorithms to calculate the metrics required for application of this risk based approach e.g. number of loading events above a defined value of load and the total number of half-hours of those events.

4.3.4 Results

The additional capacity headroom that is available based on application of our risk based methodology has been calculated and is shown in Table 4-1 for a number of representative sample primary network groups. It has been assumed that year-on-year, peak loading behaviour is broadly similar as the load approaches (and exceeds) network firm capacity. The minimum of 8 highest half-hour loads for example, refers to the lowest load occurring within the most highly loaded eight half-hourly periods, i.e. the P99.95 value based in the previous year's observations, and similarly for the other defined minimum peak loads. Load events are defined as occurrences of high loading above the given percentile based threshold. The duration of each event is also noted and is defined as the number of consecutive half-hours in each event in which the loading is above the given threshold. Events that have durations of more than one half-hour mean that the total number of acceptable threshold exceedance events can be less than the total number of acceptable half hours. An event that has a duration greater than a given duration limit, here taken as 2 hours, is not regarded as acceptable and the half-hours in that event are not counted in the total number of acceptable exceedances. (The 2 hour duration is limit is chosen as a conservative limit having regard to the rate of rise of critical temperatures of network branches).

Whilst peak loading for some network groups is well below firm capacity, this analysis provides a useful illustration of the potential benefits of the proposed technique.

Table 4-1 Additional capacity headroom for risk based methodology

Primary Network Groups	Ruabon	Whitchurch	St Andrews	Egerton	Hunts Cross	Boulevard
Firm Capacity MVA	**10**	**20**	**21**	**20**	**30**	**40**
Half-hour Maximum Demand MVA	7.12	14.21	19.84	15.14	20.52	29.71
Minimum of 2 Highest Half-hour Loads MVA (no. of load events)	7.06 (1)	14.03 (2)	19.77 (1)	14.92 (1)	20.44 (2)	29.70 (2)
% Additional Capacity Headroom	0.6%	0.9%	0.3%	1.1%	0.3%	0.0%
Minimum of 4 Highest Half-hour Loads MVA (no. of load events)	7.02 (3)	13.94 (2)	19.33 (1)	14.74 (1)	20.31 (2)	29.53 (3)
% Additional Capacity Headroom	1.1%	1.3%	2.4%	2.0%	0.7%	0.4%
Minimum of 8 Highest Half-hour Loads MVA (no. of load events) (P99.95)	6.87 (5)	13.83 (6)	19.17 (3)	14.38 (4)	20.19 (5)	29.35 (5)
% Additional Capacity Headroom	2.5%	1.9%	3.2%	3.8%	1.1%	0.9%

From this preliminary analysis on sample primary network groups, it can be seen that application of the risk based approach based on the 2 highest loaded half-hour periods observed in the previous year, the 4 highest loaded half-hours or the 8 highest loaded half-hours can provide up to 1.1.%, 2.4% or 3.8% additional demand capacity headroom respectively, whilst not having a significant impact on the probability of the full demand not being met. This is illustrated further in Figure 4-6. This analysis provides an excellent foundation for further work to more extensively verify the methodology.

Figure 4-7 shows the total number of high loading events and corresponding number of half-hour load values to achieve additional capacity headroom of 2% for the sample primary network sites assessed. For each of St Andrews and Egerton, the 4 half-hours (2 hour) threshold is reached in one high loading event but provides 2.4% and 2% capacity headroom respectively. This can be contrasted with Boulevard and Hunts Cross where many more high loading events and crucially, more half hours above a certain loading must be accepted in order to achieve an additional 2% capacity headroom. This shows that the risk based approach will be more effectively applied to primary substations with loading characteristics similar to St Andrews and Egerton.

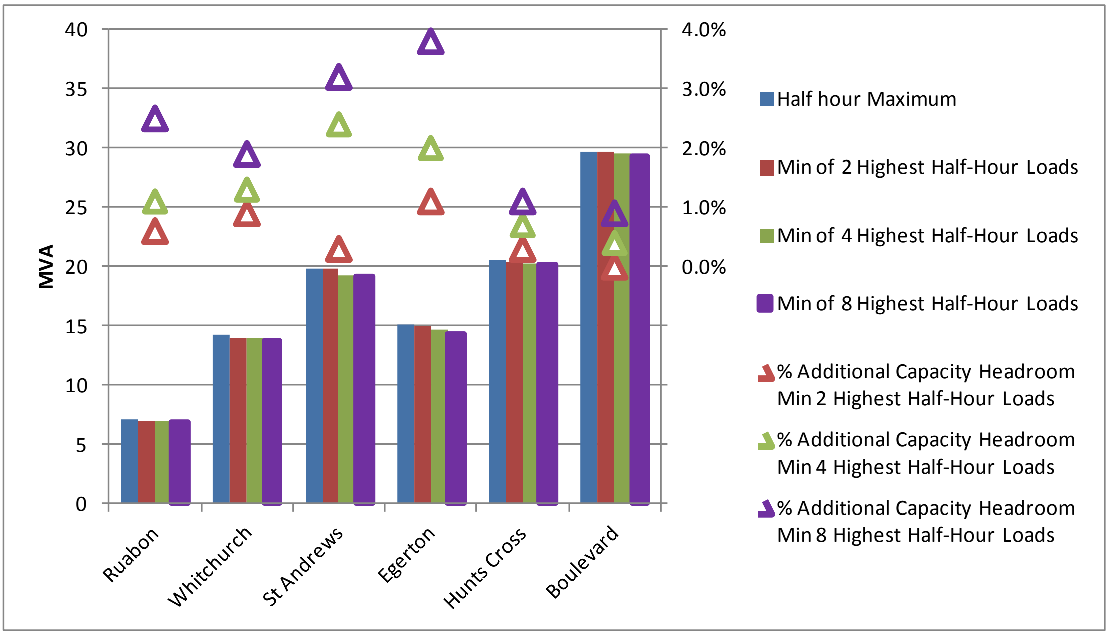

Figure 4-6 Additional capacity headroom for minimum of 2, 4 and 8 highest half-hour loads

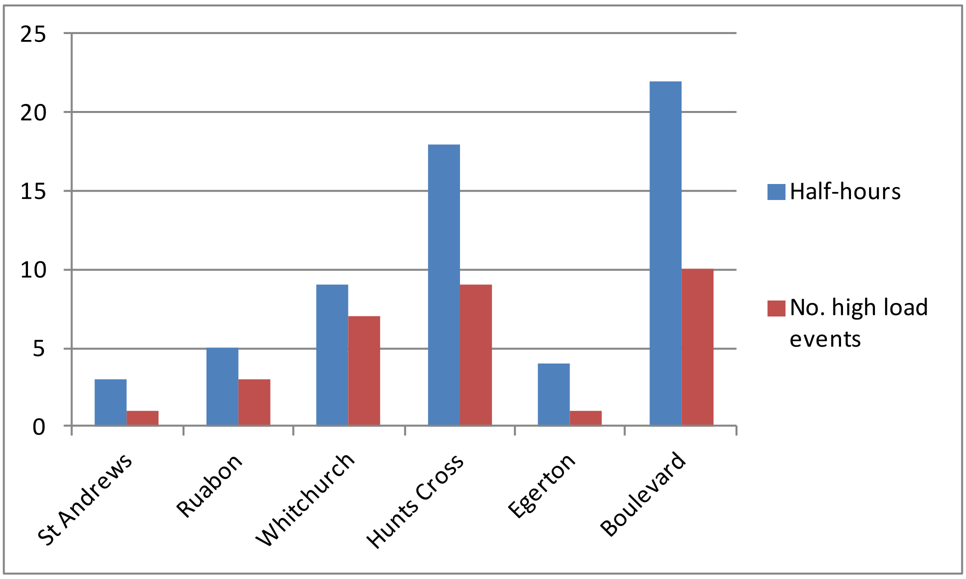

Figure 4-7 Total number of half-hour load values and independent high loading events for an additional capacity headroom of 2%

4.3.5 Recommendations

The new term "capacity headroom" should be included in ER P2/6 alongside a probability of demand exceeding a given level based on historic observations, such a probability being expressed in terms of number of half-hours or hours per year. The "capacity headroom" describes the margin between network capacity and a given level of network demand. Together with a demand exceedance probability, this will enable a more probabilistic, risk based approach as detailed above to be taken in determining remaining network capacity headroom rather than the simplistic and deterministic maximum demand/minimum generation and minimum demand/maximum generation scenarios currently used.

This has the added benefit of avoiding the difficulty, for instance, in deciding whether or not new smart grid techniques like “network automation”, “voltage regulation” and “dynamic ratings” increase network capacity or reduce demand, since it is only the margin that really matters.

This should facilitate a more efficient approach to network design, releasing capacity headroom and reducing network reinforcement costs.

4.4 Enhanced Load Forecasting Tool

4.4.1 Introduction

As was noted above, the ‘true’, underlying value of a peak demand can be estimated only with considerable uncertainty and observations of the annual peak are subject to wide variation due, for example, to weather and unusual network conditions. This section describes and demonstrates an approach that has been developed that allows the annual peak demand in a demand group to be forecast without any dependency on complex models of demand but with greater accuracy than a through simple extrapolation of historic, observed peak values. The underlying principles are:

1. that percentile half-hourly measured loads other than the P100 value are less prone to exceptional variation and more representative of underlying conditions than the P100 value and, hence, are more indicative of underlying behaviour within the group than the P100 value; and
2. that there is a consistent, fixed relationship between an observed percentile other than the observed P100 and the ‘true’ P100 value.

4.4.2 Input Load Data

A number of years of half-hourly (time series) MW and MVar data for a selected network group were automatically downloaded from the SPEN PI database. The number of historical years to be considered is defined by the user.

4.4.3 Algorithm for Enhanced Load Forecasting

An algorithm was developed, implemented and tested for enhanced load forecasting in Microsoft Excel. This enables load data to be rapidly imported in the appropriate format from the SPEN PI database. It is also consistent with the format and structure of other network planning tools (as detailed in Appendix A) to aid usability and maintainability.

The annual load data was screened for erroneous and null values (a robust methodology for detection of these is described in Section 5.2) which are removed. As maximum demand is of key interest, any invalid data spike can introduce errors to the calculated load growth trend. Data errors due to zero values are not a major issue for load growth analysis unless these occur at the time of typical high demand i.e. winter.

It is postulated that a high percentile load other than the observed P100 value would be a better predictor of demand growth than the P100 that was calculated for each year of historical load data. However, because high demand periods are critical to reliability of supply, a percentile should be chosen that represents high demand periods. This approach is intended to reduce the influence of outliers due, for example, to load transfer to other networks under FCO conditions and to provide an improved characterisation of underlying load behaviour. It also provides some degree of smoothing of temperature effects due to an unusually cold or mild winter.

Probabilistic values for the 98th, 95th and 90th percentile demand as shown in Figure 4-8 were tested and the 98th percentile demand was found to provide sufficient year-to-year smoothing of peak load for all network groups tested (37) whilst still retaining a reasonable representation of underlying load trends. Sample results are provided in Appendix C. Further analysis should be performed in future on a larger sample of network sites to verify the appropriate probabilistic value/s.

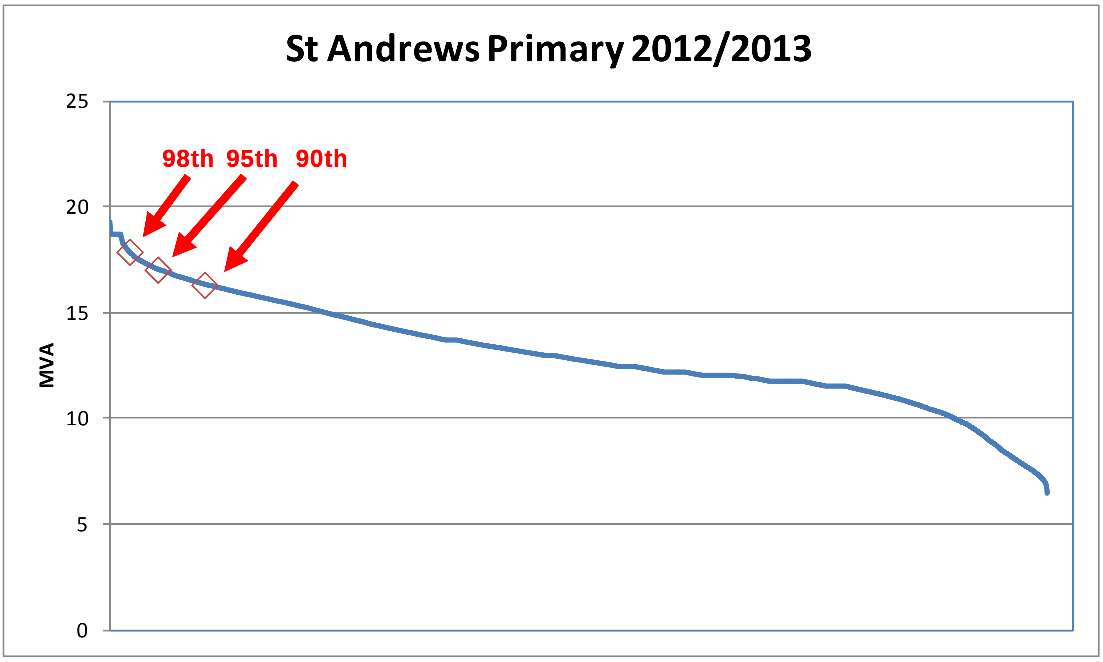

Figure 4-8 Annual load duration curve for St Andrews primary group 2012/2013

A synthesised historical maximum demand value was calculated based on a linear scaling factor. The linear scaling factor is determined from the average scalar between the 98th percentile and the maximum demand for the years considered, smoothing the effect of outliers. It is calculated automatically on a case by case basis for each network group or can be user defined. The synthesised maximum demand is compared to the actual maximum demand in Figure 4-9 and Figure 4-10.

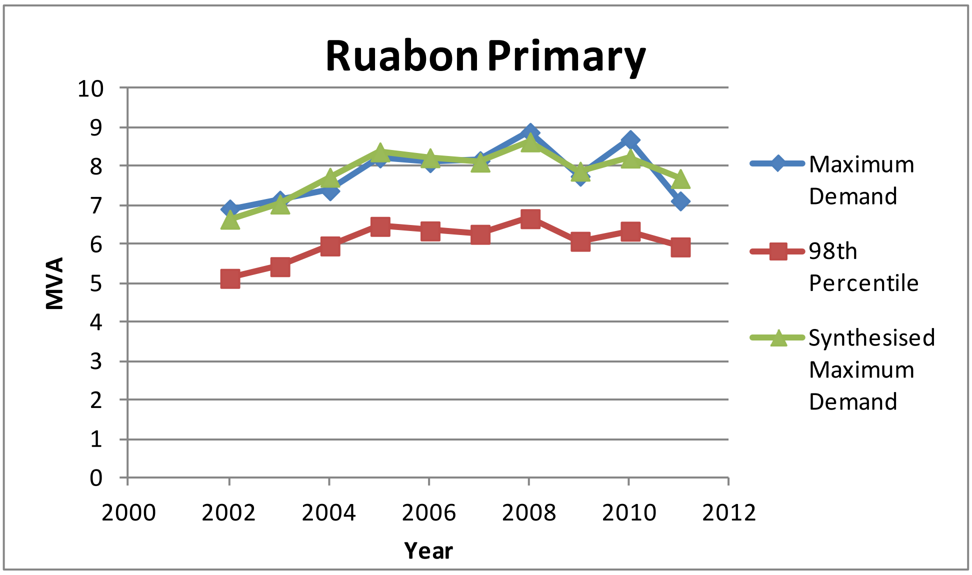

Figure 4-9 Ruabon primary network group load analysis

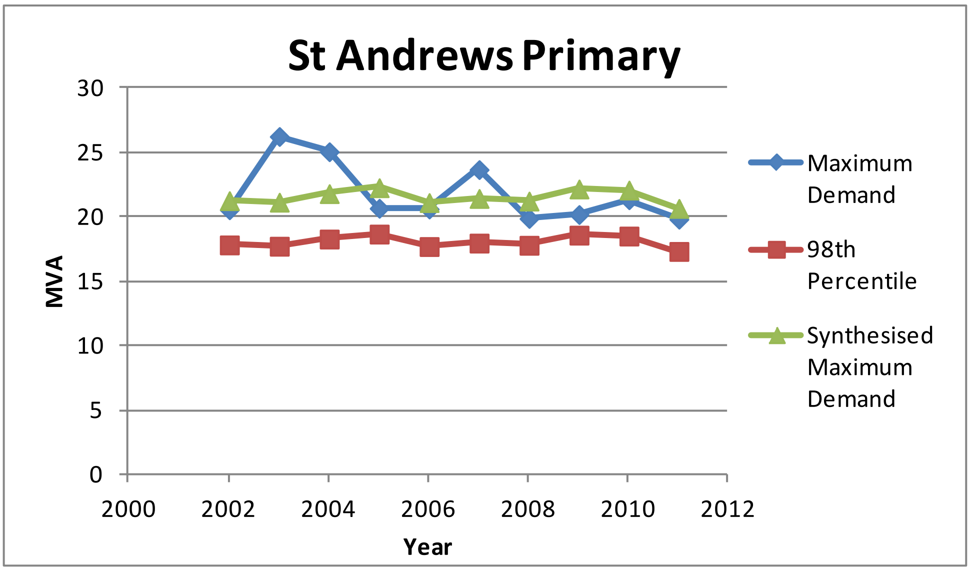

Figure 4-10 St Andrews primary network group load analysis

The synthesised historical maximum demand data was then used to forecast future maximum demand. A load trend is provided for up to the next five years.

This can be based on:

- Linear regression over N historical years of maximum demand
- Several weighted linear regression methods over N historical years of maximum demand (evenly weighted, decreasing weighted)

The linear regression approach has been evaluated and found to be more effective at reproducing maximum demand trends than extrapolation of observed maximum demand values.

A fully operational SPEN user interface has been developed for the enhanced load forecasting analytical tool and is shown in Figure 4-11.

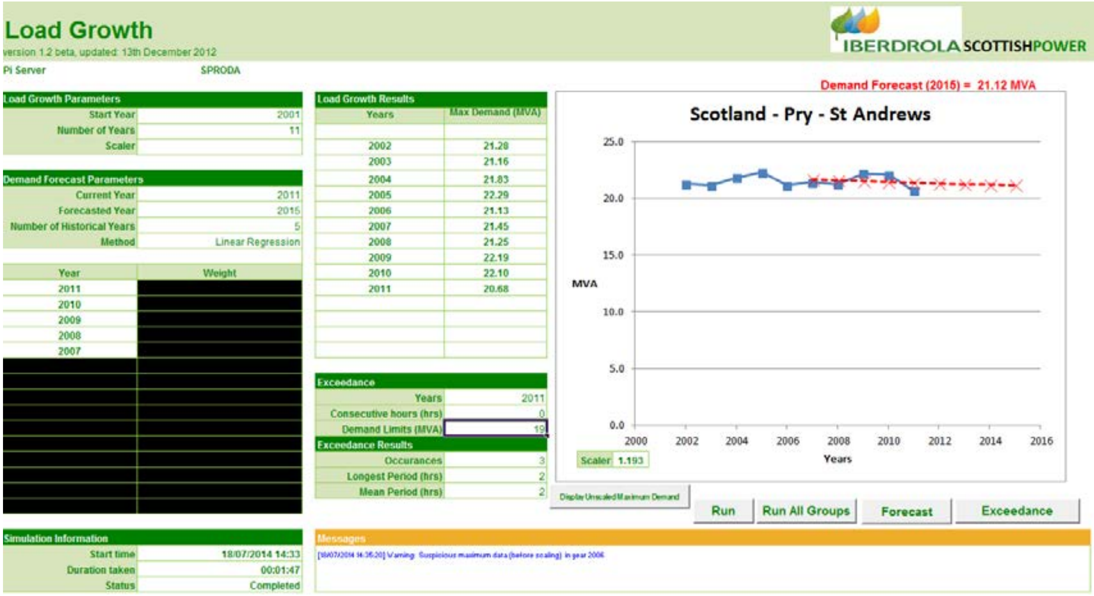

Figure 4-11 User interface for enhanced load forecasting and risk characterisation tool

4.4.4 Performance Evaluation

Load forecast results from the existing and enhanced load forecasting approaches were compared to actual measured annual maximum demand. A simple linear regression was applied for the enhanced load forecasting approach to produce 1-year ahead forecasts of peak load for each successive year, predicted based on 5 previous years of synthesised maximum demands derived from historical load data (e.g. 2011 was based on 2006-2010).

From Figure 4-12 and Figure 4-13, it can be seen that for the six sample primary network groups analysed, the enhanced load forecasting approach is generally within 10% of the measured peak demand, whereas the existing approach does not perform so well and is within about 20%. The root-mean-square error for each approach is compared in Figure 4-14 and it can be seen that this is generally lower for the enhanced load forecasting approach, based on all six sample network groups.

Prior to the 2009 SPM LTDS, the previous year's maximum demand and future load forecasts were reported for individual transformers rather than HV network groups for SPM. As maximum demand may not occur simultaneously on all transformers in a group (where there is more than one transformer) it is not possible to summate the published LTDS load forecasts to determine the overall HV group future load trends that were estimated using the existing approach. This is why there are no results in Figure 4-13 prior to 2009 for SPM HV groups with more than one transformer.

It can be seen from Figure 4-12 that the 1-year ahead load forecast is generally over-estimated for the sample network groups analysed. An underestimation of maximum demand in 2010 shown in both Figure 4-12 and Figure 4-13 can be correlated to a particularly cold winter.

It is anticipated that the forecast could be improved further with some local knowledge of network connections and generation. It should be recognised that the existing approach already incorporates this local knowledge.

It is recognised that forecasting will contain some inherent error particularly when assessed on a site by site basis however use of the enhanced load forecasting approach should provide an overall improvement in accuracy compared to the existing approach as shown in Figure 4-14. This is realised through improved representation of underlying network loading trends and reduced influence of maximum demand outliers.

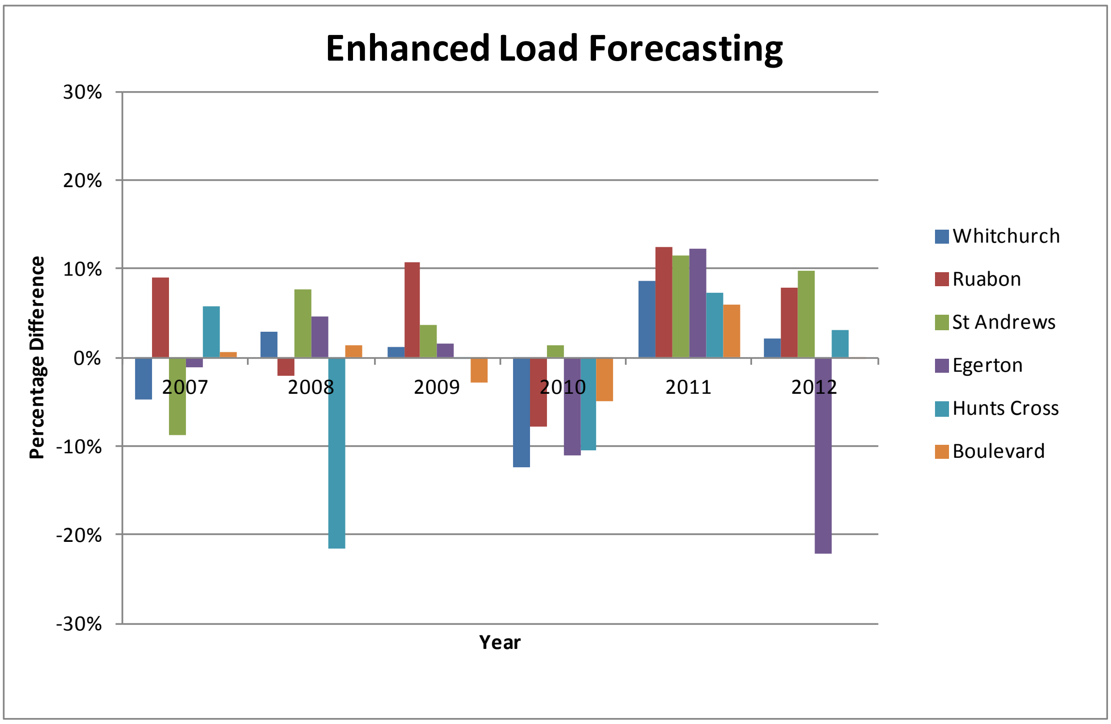

Figure 4-12 Percentage difference between actual and 1-year ahead forecast maximum demand for enhanced load forecasting method

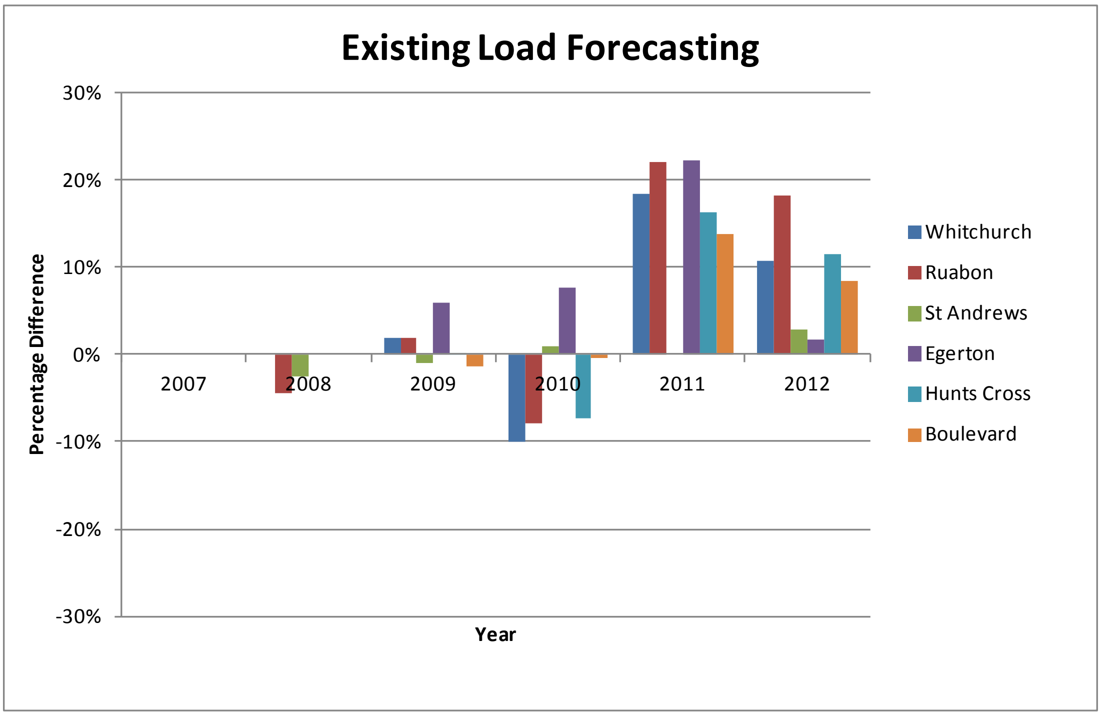

Figure 4-13 Percentage difference between actual and 1-year ahead forecast load for existing load forecasting method

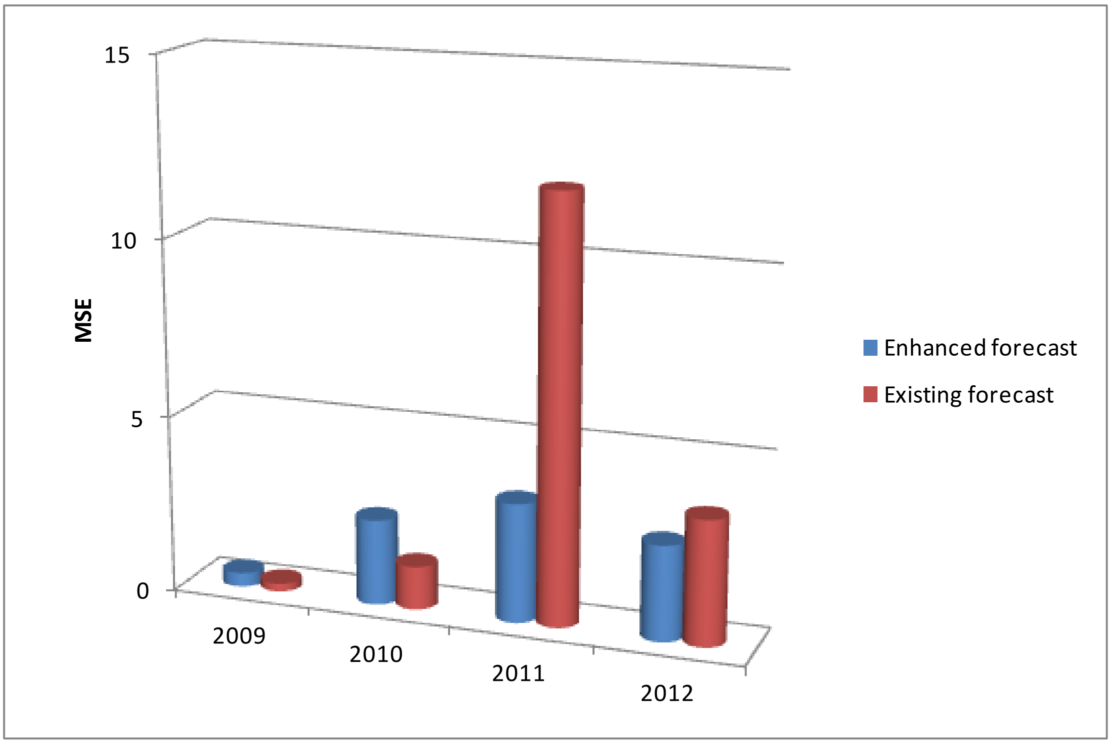

Figure 4-14 Mean-square error comparison for 1 year ahead actual and forecast load for enhanced and existing load forecasting methods (based on analysis of 6 sample sites)

A more general assessment of the forecast of load growth trends was undertaken. Results are shown in Figure 4-15 to explore whether the use of larger amounts of historical data improves the forecasting of 1 year ahead load trends. It can be seen that for this case using linear regression, the use of up to 7 years of historical data compared to 5 years of historical data does not significantly improve the 1 year ahead load forecast although this may not be the case for other network groups. If rapid changes to network demand/generation due, for example, to future LCT uptake alter the underlying load characteristics, then the use of more historical data is unlikely to improve load forecasting and it may be more prudent to use a reduced set of historical data or increase the weighting of the linear regression equation to more recent years.

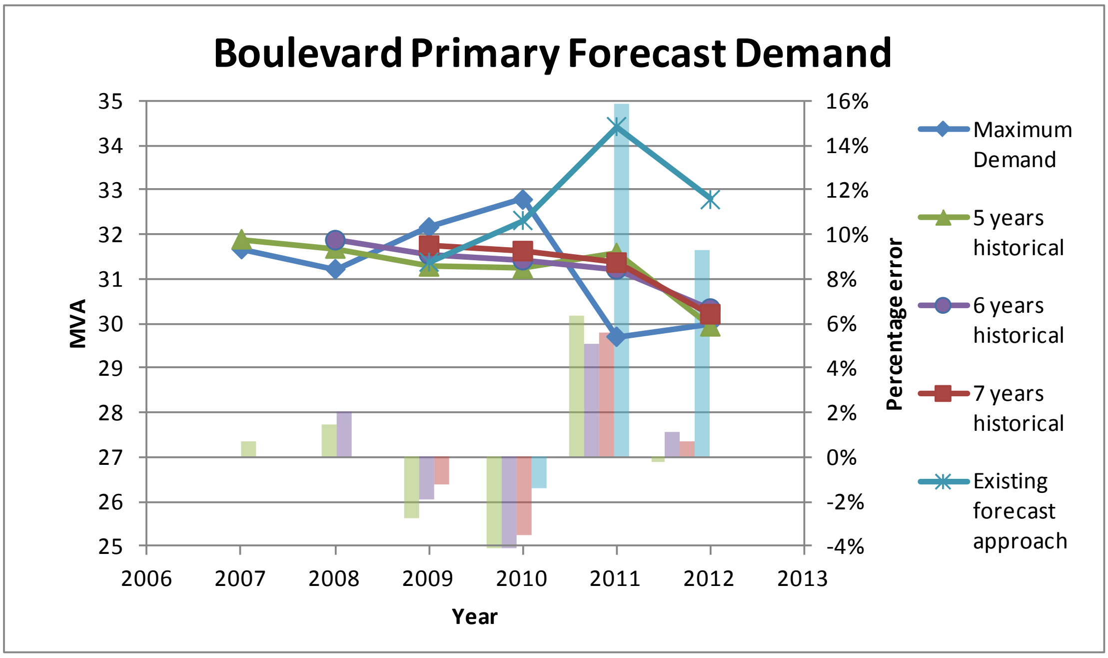

Figure 4-15 Boulevard primary group 1 year ahead load forecasting

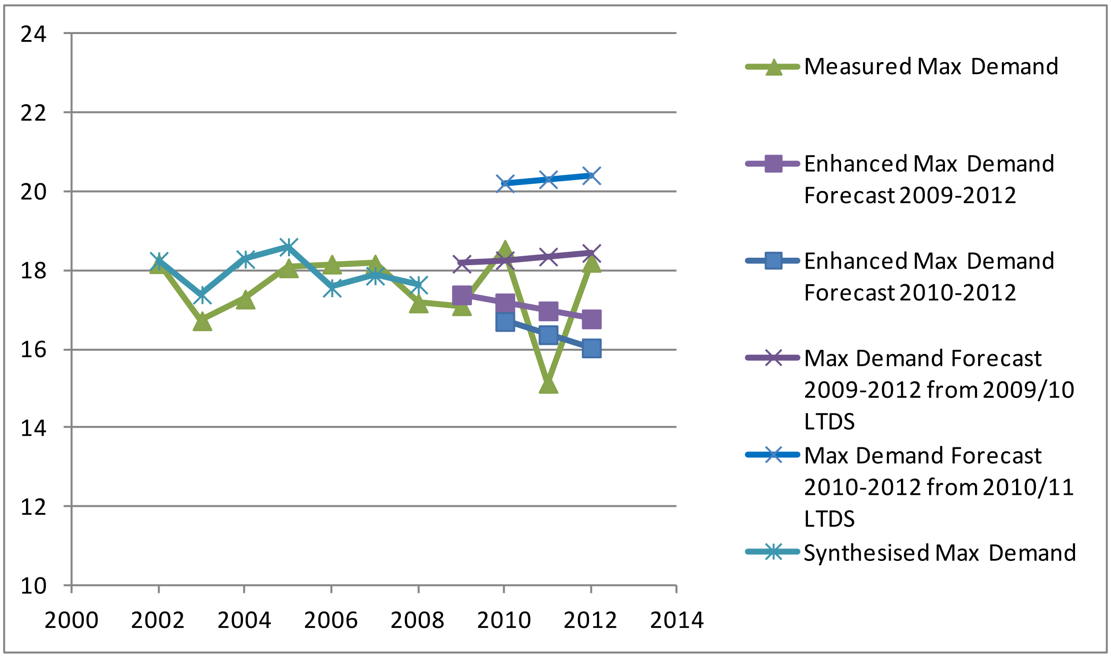

Figure 4-16 Egerton primary group load forecasting comparison for 1 to 4 years ahead

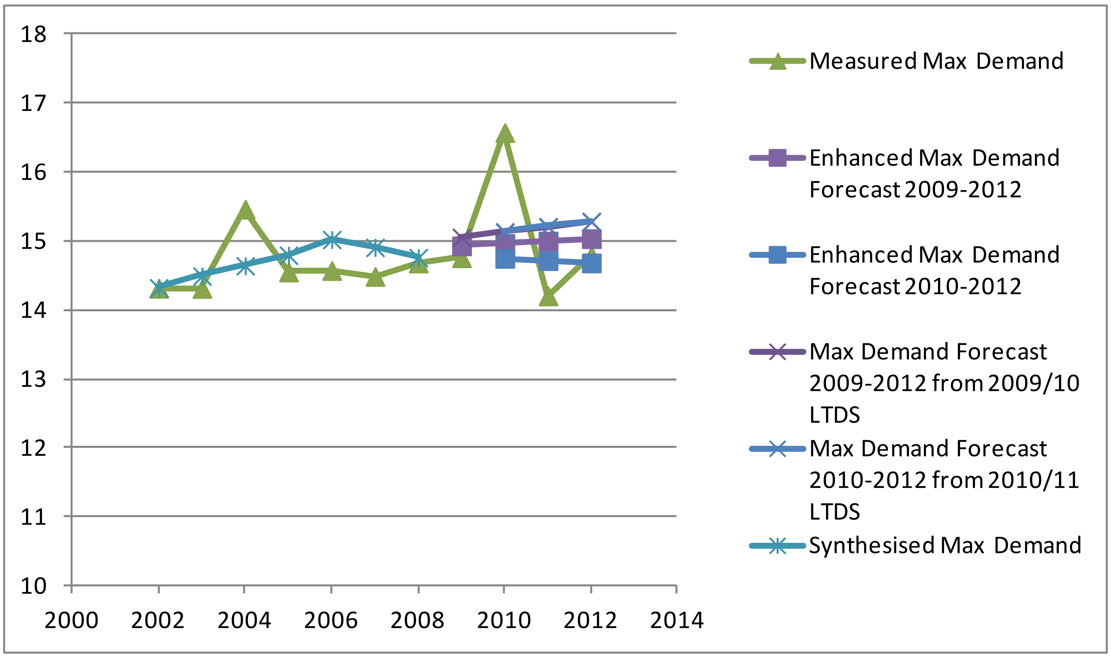

Figure 4-17 Whitchurch primary group load forecasting comparison for 1 to 4 years ahead

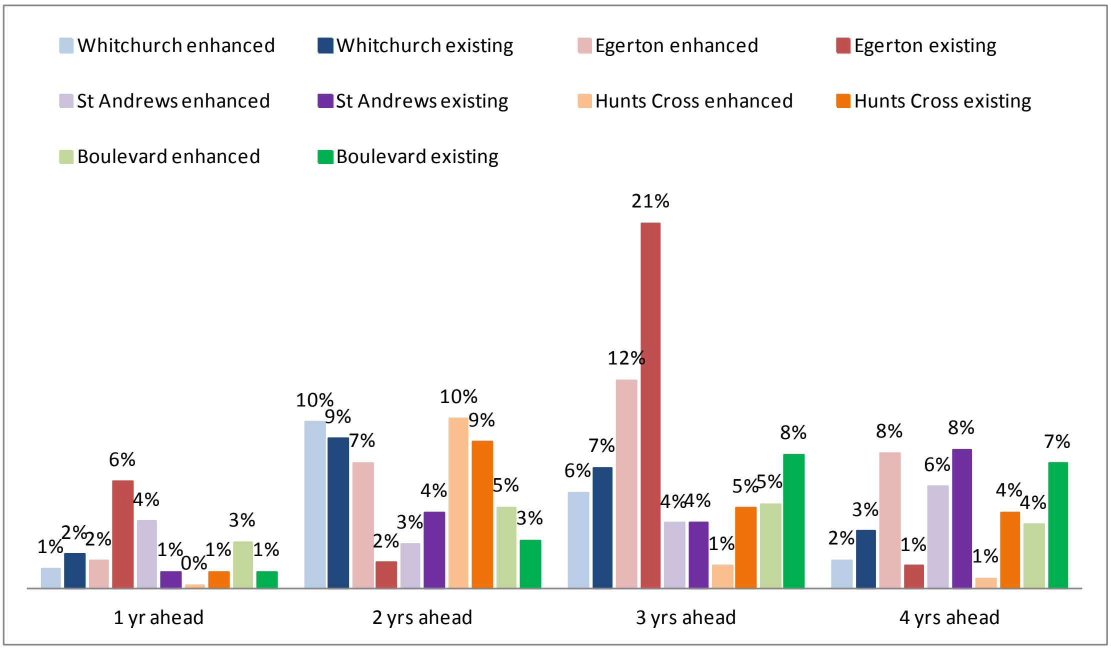

Figure 4-18 SPM and SPD primary group enhanced and existing load forecasting percentage error for 1 (2009) to 4 (2012) years ahead compared to measured maximum demand

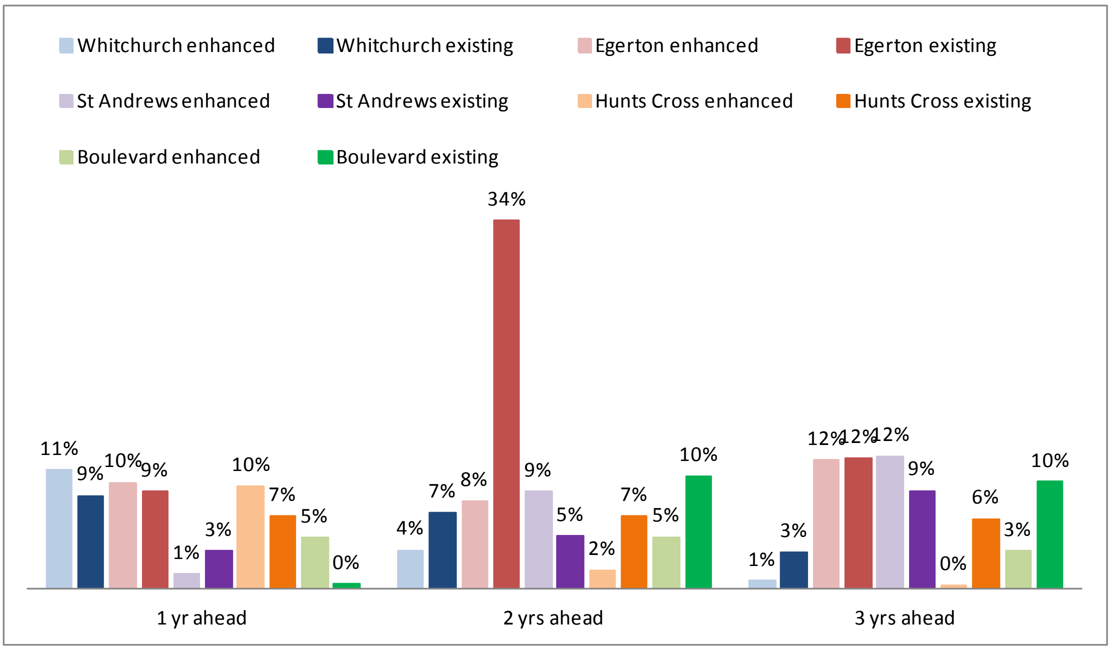

Figure 4-19 SPM and SPD primary group enhanced and existing load forecasting percentage error for 1 (2010) to 3 (2012) years ahead compared to measured maximum demand

Figure 4-16 and Figure 4-17 show load forecasting trends using the enhanced method based on five years of historical data and forecasting one to four years ahead compared to actual measured maximum demand for the Egerton and Whitchurch HV groups. The corresponding demand forecasts from the 2009/2010 and 2010/2011 LTDS' are also plotted for comparison. The values reported in the

LTDS were in MW so were converted to MVA using power factors calculated from measured MW and MVar values reported for individual primary transformers within the corresponding HV network groups which were available over several years. It is not valid to use LTDS primary load forecasts from earlier than 2009 for SPM as these are reported at individual transformer level rather than HV group. Aggregation of these load forecasts would lead to overestimating future load if peak loading on transformers within the HV group do not occur concurrently.

Figure 4-18 and Figure 4-19 illustrate the percentage error between forecast and measured demands for a number of the primary groups when using the enhanced load forecasting approach and the existing approach for up to four years ahead. Overall, the enhanced forecasting approach performs better in comparison to the existing load forecasting approach.

4.4.5 Capacity Headroom Forecast

The network capacity headroom that is predicted by the enhanced load forecasting approach for 1 year ahead has been compared to the existing load forecasting approach[2]. This does not test how accurate each approach is in predicting the actual measured maximum demand but rather provides a side-by-side comparison.

Capacity headroom is calculated as the network group firm capacity less the forecast demand level, divided by the firm capacity. The Flexible Networks project is exploring the improved management of network capacity (and demand) through use of innovative technologies such as dynamic thermal ratings, flexible network control, energy efficiency and voltage regulation.

It can be seen in Figure 4-20 that the enhanced load forecasting approach generally identifies additional capacity headroom for the sample networks assessed apart from St Andrews network group and Ruabon network group in 2008 and 2009 where less headroom is identified.

[2] The Flexible Networks "Network Capacity Headroom Positioning Paper" benchmarks existing capacity headroom for each of the three network trial areas using a business as usual approach.

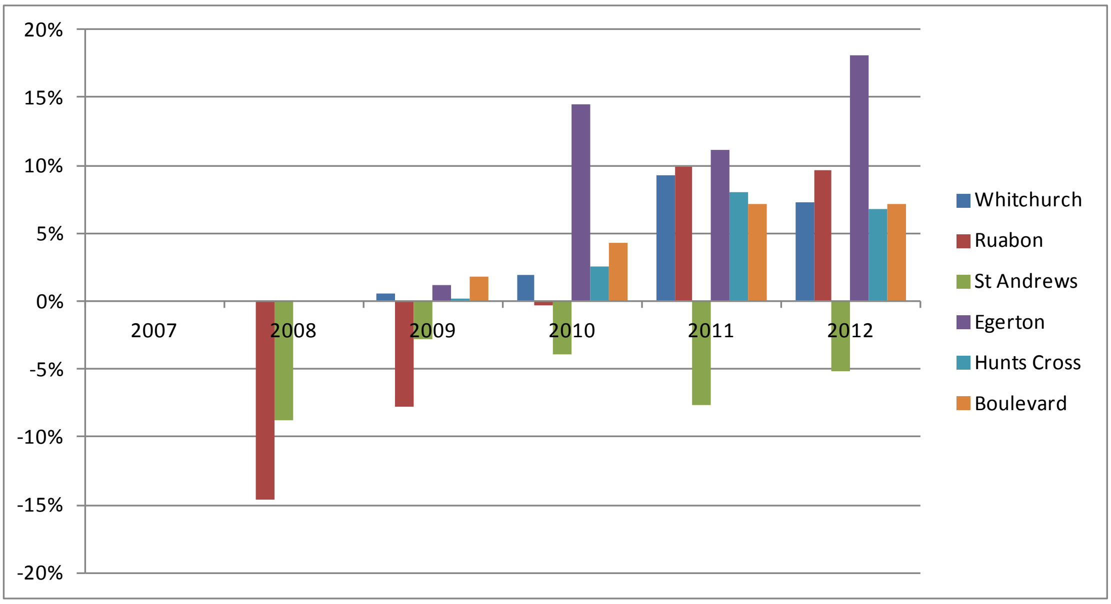

Figure 4-20 Additional network capacity headroom identified through use of enhanced forecasting of the 1 year ahead maximum demand

5 Management of Measurement and Modelling Uncertainties

5.1 Introduction

There are various sources of uncertainty in both measured data from the network and within network models. For measurements, this may be due to data resolution, instrumentation accuracy and calibration, interference and time syncing. The accuracy of network models is influenced by the quality of input data such as aggregated load and generation profiles, correct definition of asset parameters such as cable length and modifications to network topology, for example. Details of legacy assets in particular, can be problematic to source.

Algorithms have been developed to enable improved identification, management and mitigation of measurement uncertainties.

The improved identification, management and mitigation of modelling uncertainties is also explored.

5.2 Improved Data Cleansing Algorithms

The improved identification and management of poor quality primary substation data was investigated.

Two items of concern in relation to primary substation load measurements are anomalously high values of measured demand, and erroneous zero values. Anomalously low values of measured demand are of less immediate concern, but their identification may still be of value. Anomalously high values appear to arise for two reasons:

1. Measurement errors
2. Transfers of load onto a primary substation as a result of reconfiguration of the 11kV network. These could be corroborated by reductions in measured demand elsewhere.

Such errors can result in excessive estimates of peak substation demand, which might give an unnecessarily urgent impression of the need to reinforce or (in operational planning) to restrict the load on the substation or the ability to transfer load to it under outage conditions.

Gross measurement errors can be identified through the application of a filter at a small multiple of either the transformer rating in question, or of a 'typical' primary transformer network. Ideally, load transfers would be identified by reference to records of switching activity, but these are generally not available in relation to historical load data. Furthermore, such an approach would not identify small measurement errors. A statistical approach based on short-term forecasting techniques published in the academic literature[3] has therefore been adopted. In the forecasting approach, the forecast was constructed from an average load profile for each week of the year, an average profile of the deviation of each measurement point during the day from the daily profile (calculated over the preceding few weeks, with different profiles for different days of the week) and a stochastic element which is forecast based on the error in previously forecast points.

In the approach adopted here, the annual profile is calculated from measurements for the preceding five years, or such smaller number of years as is available. The daily profile is calculated from the deviation of the measured load from the annual profile for corresponding measurement points over the previous eight weeks (e.g. all of the points relation to 08:00 on Sundays). Individual daily profiles are calculated for weekdays, Saturdays and Sundays. The combination of the weekly averaged load from the annual profile and the daily profile gives an 'expected value' for the measured quantity at a particular time, based on the typical annual shape of the load, and its recent behaviour.

Clearly, the actual measured load will vary somewhat from the expected load, and this variation will depend on the nature of the load supplied from the substation. Each measured value can be thought of as being composed of the expected value plus a residual difference. Since the typical annual and daily variations in load have been accounted for, these residuals would be expected to correspond to a statistical distribution centred at (or close to zero). The standard deviation (usually shown by the symbol σ) of the residuals provides a measure of the extent to which the actual load varies from the expected value, and can be compared to a new measurement in order to determine how well it corresponds to the historical behaviour of the load.

Figure 5-1 shows the construction of the expected value and calculation of residuals for a sample of measured load.

[3] D.C. Hill and D.G. Infield, "Modelled operation of the Shetland Islands Power System comparing computational and human operators' load forecasts", IEE Proceedings: Generation, Transmission and Distribution, Vol. 142, No. 6, 1995, pp555-559.

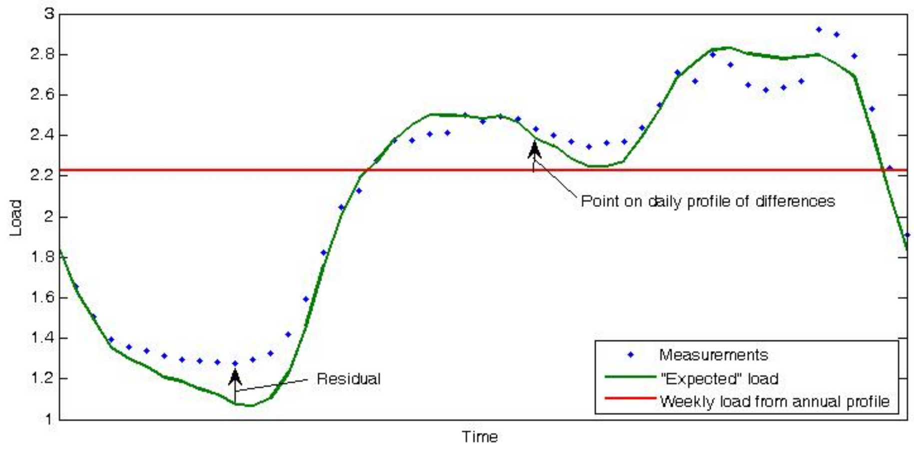

Figure 5-1 Calculation of expected load and residuals

The magnitude of the residual associated with any measurement in relation to the standard deviation of the residuals gives an estimate of how 'unexpected' the measurement is. For measurements following a normal distribution, 99% of randomly selected samples from that distribution would be 2.57 or fewer standard deviations above or below the mean. This value has therefore been selected as a comparator to determine whether a point should be regarded as anomalous. The application of a 99% (2.57σ) band around the historically expected load profile for the measurements is shown in Figure 5-2.

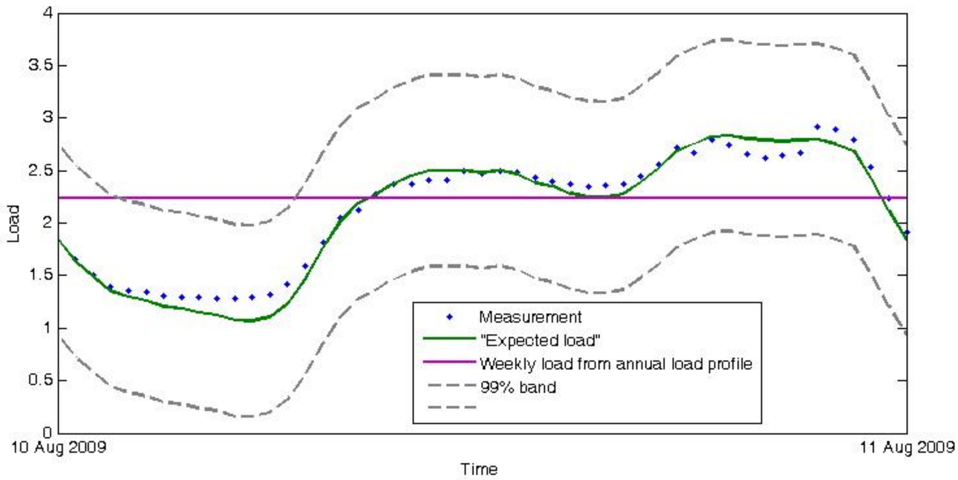

Figure 5-2 Application of confidence bounds based on residuals

In this case, from summer 2009, it is clear that the measured values are very similar indeed to the pattern of load expected from historical behaviour. Figure 5-3, however, shows the effect of a change in behaviour in the load over the evening peak which had taken place by the autumn of that year.

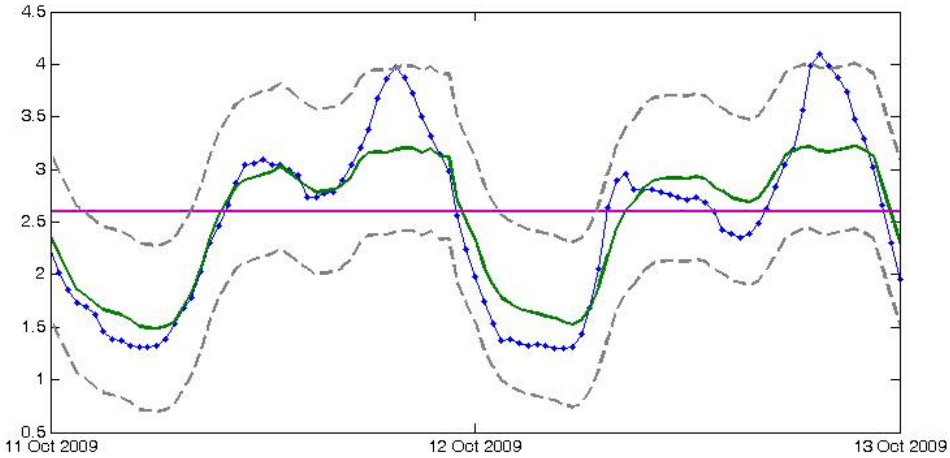

Figure 5-3 Change in load behaviour

Although the overall load has grown in comparison to the summer, the load at the evening peak has increased in comparison to the daytime load, to the extent that one or two measurements are now outside the 99% confidence band. Small numbers of points outside the band, such as in this case, are not unexpected because of the statistical nature of the method. Within-week changes in load shape such as this are modelled by the moving average process used to calculate the point-by-point deviation from the forecast weekly average represented by the green line. As such there is an inevitable lag is responding to changes in daily load shape.

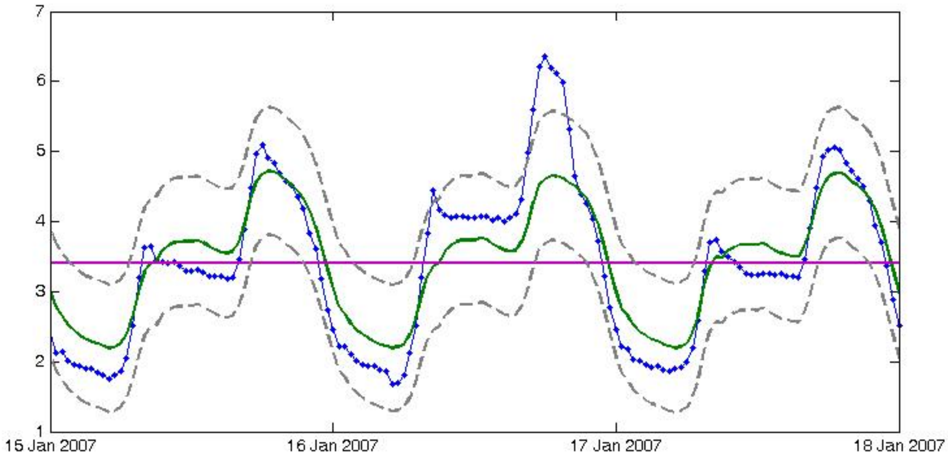

Figure 5-4 Load transfer produces sustained load outside expected limits

Figure 5-4 shows an apparent short-term load transfer in January 2007. Based on the patterns of load on 15 and 17 January, it appears that load is transferred onto the primary substation on the morning of 16 January, and is removed as the load begins to decline from the evening peak. Although the daytime load is only fleetingly outside the 99% confidence band, the peak (which would be of interest to network planners and operators) is outside this limit for a sustained period. This sustained exceedence would identify this peak as anomalous and worthy of further scrutiny in identifying the system peak.

Over time, this line will change shape to reflect the changed behaviour of the load. In addition, should a significant number of points begin to lie outside the 99% confidence band, as a result of a change in load behaviour, the confidence band itself will widen so that, over the moving average period, approximately 99% of points lie within in. In this way, the process will adapt to long-term or permanent changes in behaviour as a result of changes in load patterns or to network configuration.

It should be noted that the speed with which the algorithm adapts to changes in the behaviour of loads is controlled by the length of the moving average window used to generate the annual and daily load profiles. Shorter windows will tend to give faster adaptation to medium-to-long-term changes in measurement behaviour, either as a result of seasonal changes in load shape or because of changes in the nature of the load or network configuration. A shorter moving average window can be of benefit, particularly where there are seasonal changes in daily load shape, as shown in Figure 5-3 and Figure 5-4 above; the longer the moving average window, the more chance there is of daily peaks being misidentified as anomalous.

However, reduction of this window will also reduce the period over which the 99% confidence interval is calculated, with the result that the true variability of the measurement is not properly characterised. It is likely that the trade-off between these two considerations will vary from substation to substation, and statistical model identification techniques may be helpful, as would methods of modelling seasonal load shapes. Additionally the length of the moving average window for the annual profile must be tailored to respond to changes in load without giving undue weight to unusually warm or cool years or other external factors. Methods of correcting for these factors (such as Average Cold Spell) techniques may be of use.

Figure 5-6 also shows that the rate of change of load may be high close to the peak. This brings a chance that a small temporal shift in the load pattern may lead to points being considered anomalous. Although consideration of the rate of change of measured and expected load may be of assistance here, given that the period of high rate of change of load is short, few points would be so identified, and the effect on the assessment of the load pattern would be small. The assessment of the validity of the load peak would be unlikely to change.

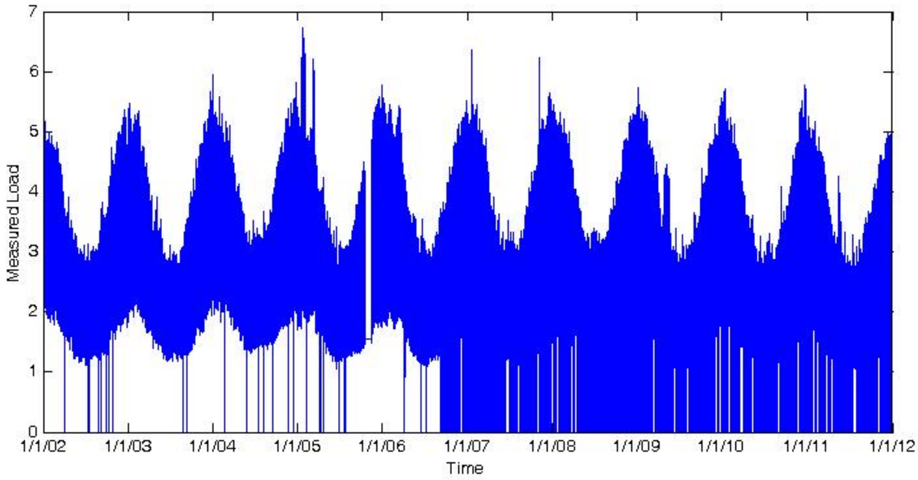

Figure 5-5 Ten year pattern of measurements

Finally, Figure 5-5 shows that (particularly since mid-2006), there are a very large number of "zero" measurements. Some of these, such as that shown in Figure 5-6 may be a result of genuine transformer outages. In passing, it should be noted that, since the half-hourly measurements available are an average of higher-frequency measurements (and for real power are effectively half-hour energy throughput) lower measurements are obtained for the half-hour in which switching takes place. Furthermore, as also shown in Figure 5-6, load may gradually reduce and increase as circuits are switched away from and onto the outaged substation.

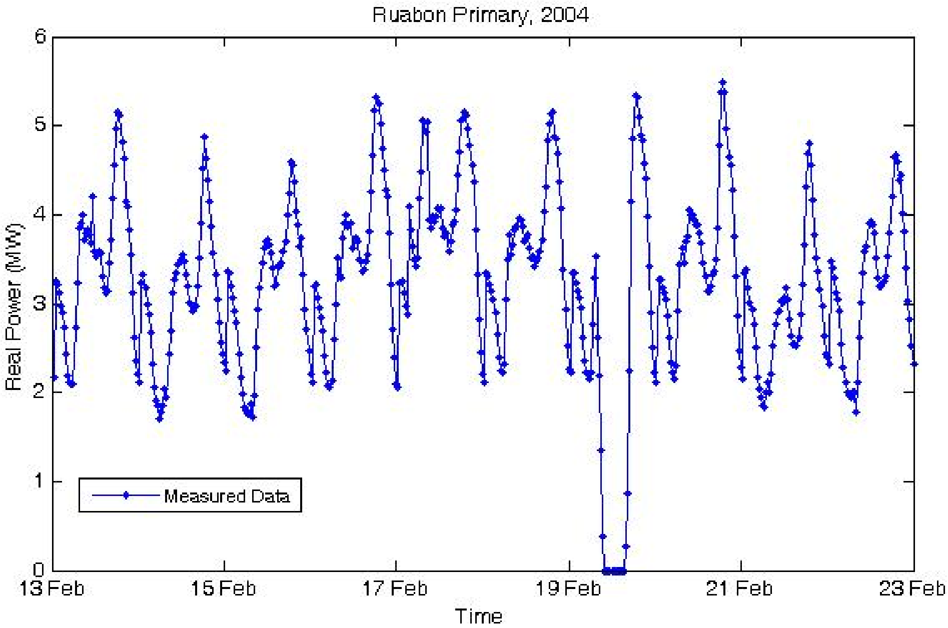

Figure 5-6 Apparent primary transformer outage

The number of observed "zero" measurements, however, makes it implausible that all of these correspond to "genuine" outages. Furthermore, as shown in Figure 5-7, most of these show a sudden, sharp descent to zero immediately followed by an equally sharp recovery. Given the averaging process outlined above, it is concluded that these represent an error in the measurement recording and archiving process. Although such measurements would often be excluded by the lower bound of the seasonal filtering process, a specific filter step should be added to remove zero measurements. This will cater for any substations with low mean load in comparison to load variability such that the lower filter limit is below zero – which may be more likely in summer.

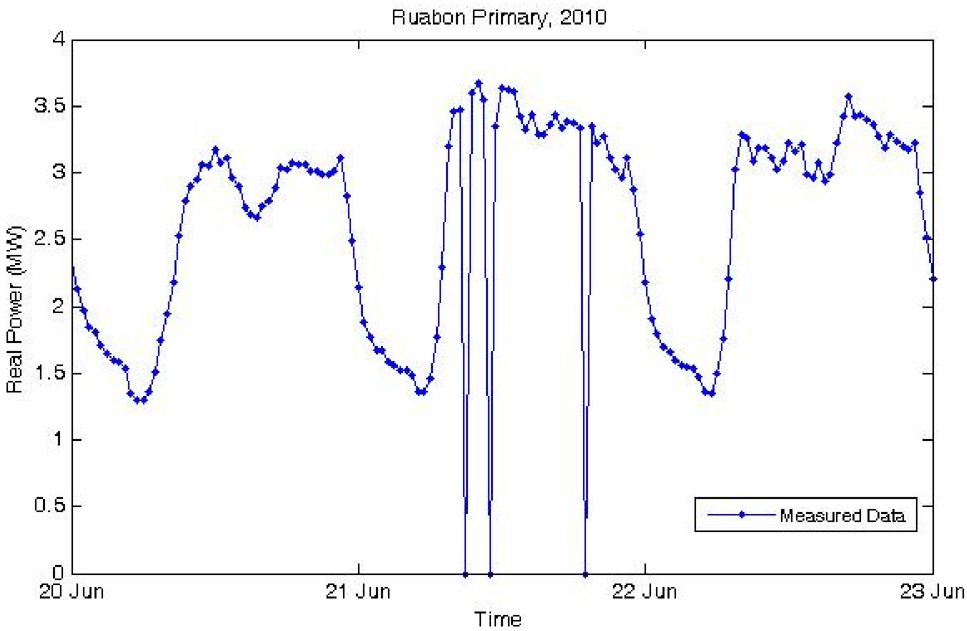

Figure 5-7 Erroneous "zero" measurements

5.3 Improved Management of Modelling Uncertainties

Load flow models are created and maintained for the SPM and SPD 132kV and 33kV networks. Typically, several Grid Supply Points (GSPs) are modelled with underlying EHV circuits and BSPs with aggregate loads. Network models at 11kV (and LV) are not built or maintained as standard practice at present.

SPEN are notified by National Grid of the time of GB peak demand; SPEN can then identify the demands at each GSP at that particular time as well as the highest demand experienced at each individual GSP at any time in a year of operation. These figures along with measured loading data at individual Bulk Supply Points (BSPs) are used to validate the network load flow models before running fault level analysis. The validation process aims to reproduce the network load for two specific events e.g. GB peak demand, GSP peak demand. The network models are updated and re-validated annually with model loads being automatically populated from the 'PI to IPSA' spreadsheet.

Often, there are issues when validating the models and reactive power in particular is associated with increased levels of uncertainty. It is possible to achieve an agreement in general to within 2-5%. Real power on average is within 2% and reactive power is on average to within 5% of measured values. It is important to achieve a well-validated model because for network planning under contingency conditions and fault level analysis, there are very limited to no measurements available for verification.

Some likely sources for divergence include:

- Generation connected at 33kV is typically modelled at rated capacity or an appropriate value. When this is taken away from the total demand in a GSP group, the resultant net GSP demand may not match the net GSP demand at GB peak demand or GSP peak demand.
- 33kV connected customers are typically modelled at agreed supply capacity. When this is added to the assumed or measured generation output and the measured primary demand, the resultant net GSP demand may not match the observed net GSP demand at GB peak demand or GSP peak demand. Non-embedded customers are required to supply their own profile demand directly to National Grid and therefore the Network Operator submission should exclude any non-embedded customer demand however it needs to be included to first validate the network models.
- Generation embedded within smaller demand customers' sites is not modelled but should be reflected through the measured loading at the BSP although for the purpose of fault level calculations, it is becoming increasingly important to better quantify embedded generation.
- There may be flows between GSPs where there are parallel paths with SPD or SPM (this may lead to quite complex flows on the SPM meshed network).
- Differing measurement resolution of load data between National Grid and SPEN.
- In addition to demand and generation uncertainty, there are generally uncertainties associated with network parameters such as impedance and exact length of overhead lines or underground cables.

5.4 Recommendations

It is likely that, to some extent, informed assessment of patterns of load will still be required to determine whether there is a genuine event of interest. However, trend-based techniques can valuably focus the attention of users of measurement data on periods of anomalous behaviour, and through the visualisation of historic behaviour and confidence bands, permit the data to be assessed more easily. These can be refined to respond to changes in load without being unduly influenced by year-to-year weather variations. Also, a specific filter should be added to remove zero measurements.

The improved identification, management and mitigation of modelling uncertainties will enhance network modelling for better informed business decisions. Including the load characteristics of demand and generation connected directly to the 33kV network for the scenarios (timestamps) under consideration should be a relatively simple implementation to improve model validation. This data is available to the DNO.

The improved quantification of embedded generation operation and characteristics on the HV and LV networks will also be required for voltage management and fault level modelling as uptake increases.

6 Further Work

Work conducted in this work package has proved extremely valuable in revealing some simple and effective new practices in use of primary data to inform planning. Many of these are recommended for adoption as business-as-usual. However, it has become apparent during the work that the same simple and effective measures could also be further improved.

A number of areas are identified below which merit ongoing further investigation to extend the learning gained from the techniques proposed and tested in this study. Whilst we consider these to be of value, the work is beyond the scope of Flexible Networks.

- Weather correction of loads to better quantify underlying trends associated with use of electricity by existing customers and allow trends associated with changed use or growing customer numbers to be better identified
- Understanding of correlations between demand for electricity, real-time ratings of distribution branches and output from wind and PV generation such that the network capacity headroom relative to real-time, dynamic ratings can quantified with greater confidence.
- Quantification of typical loading 'rates of change' and step changes associated with network outages for both radial and meshed networks in order to aid the identification of bad data in network measurements.
- Detailed review of available data on the probabilities of planned and unplanned outage events and analysis of the implications for network risk.
- Given a future forecast of network capacity headroom along with the application of appropriate smart solutions and typical transformer, cable or OHL sanctioning, procurement and commissioning times, an assessment of timescales required for triggering works.
- More comprehensive assessment and quantification of demand forecast uncertainties and more extensive testing of the enhanced method for forecasting of future demand over different time horizons, e.g. 2-5 years ahead, not only 1 year ahead.
- Provision of forecasts not only of peak or near peak demands for the winter period but also of peaks that might be expected during the planned outage season.
- Quantification of daily and seasonal trends for demand at different locations so as to allow more effective identification of bad data. (Measured values could be seen to be significantly different from historically observed averages for particular hours of the day on particular days of the week in particular seasons).

Appendix A – Existing Primary Substation Data Analysis

Available primary data

The following real-time data is currently measured and collected on the SCADA system for primary substations.

- Transformer MW/MVAR
- 11kV feeder currents (these are not available for older, urban sites)

The substations are polled continuously and real-time data is displayed in the NMS. This data is then stored to the load database for half-hourly periods as a half-hourly average for transformer MW/MVar and as a half-hourly snapshot for feeder currents. This data requires manual extraction from the load database and interpretation on a case-by-case basis when analysis is required.

Data quality

Typically, primary transformer data is used directly in network studies, (e.g. the half-hour data from last year's maximum demand period to monitor load growth) and limited data analysis is carried out on the wider data set.

The time series data typically contains single value data drop-outs, along with longer periods (hours, days, or up to weeks) where the data is missing. Figure A-1 provides an example of raw time series data aggregated for a Grid transformer group showing data drop-outs. Figure A-2 provides an example of raw current data for an HV feeder indicating data dropout for a significant proportion of the year.

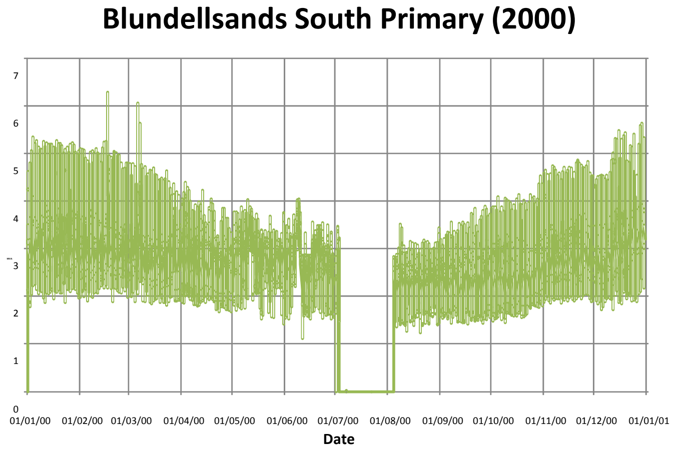

Figure A-1 Typical transformer load data export from load database

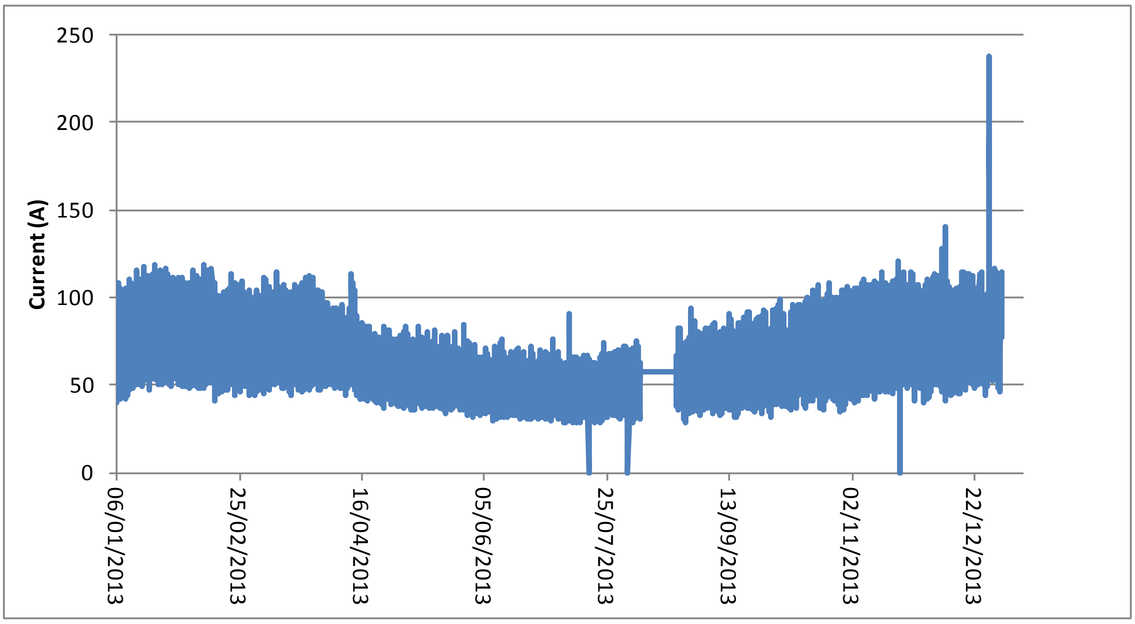

Figure A-2 Typical HV feeder current data export from load database

Data extraction

Excel-Based Tool - "PI Max/Min"

The extraction of the data held in the load database can be done by several methods, one frequently used approach is to populate an excel prepared report. The PI Max/Min report gives the maximum and minimum demands over a pre-set time usually twelve months, of a single primary transformer or the demands for a group of transformers as well as their individual demands at the group maximum demand.

Excel-Based Tool "PI-to-IPSA"

This is used when populating primary demands on 33kV and 132kV models taking data directly from the load database.

Excel Based Tool 'IPSA Ratings Spreadsheet'

SPEN have an excel based tool that calculates seasonal ratings for 132kV and 33kV circuits to populate power systems models in IPSA. These take into consideration seasonal temperatures and P2/6 network security i.e. system intact rating, first circuit and second circuit outage ratings.

Existing Analysis Processes

A number of analysis processes have been developed by SPEN to utilise existing primary substation measurements to inform asset ratings, planning and operational decisions. These comprise the following for network planning:

- Load forecasting

- Connection studies
- Network review
- Network planning
- Load index (for regulatory reporting)

SPEN network operators use primary substation data in the following functions:

- Outage Planning
- Fault response

Load forecasting

Recorded primary substation transformer power flows are used as part of the annual network review to monitor load growth and identify areas approaching capacity limits that may require reinforcement or additional infrastructure investment, or for new connections. The current SPEN practice for load forecasting is to use a base general load growth assumption and modify this assumption (up or down) for areas where there is additional local intelligence on future new connections activity. Using the PI Max/Min spreadsheet, the maximum demands for a number of previous years can be obtained, these values are then analysed to determine trends in demand change which are then extrapolated forward to estimate the demand forecast for future years.

Maximum demand is sensitive to weather conditions and outlier events which introduce uncertainty. For example, the highest recorded primary transformer loading may have been caused by a temporary network backfeed, which is not representative of the group demand. These types of rare events need to be identified and removed from consideration so that projections of demand growth are not unduly distorted. As part of the regulatory review of network demands and forecasting, a manual investigation is currently carried out where group demands have significantly changed from the previous year and a correction is done if this change is due to temporary network reconfigurations.

Whereas individual group demands are not corrected for a temperature, the overall network demand trending network done as part of the annual review does attempt to take account of minimum temperature to suggest to designers the validity of the last year's maximum demands.

Limitations of the current load forecasting practice are illustrated below in Figure A-4 and A-5 for a network group with particularly variable annual maximum demand.

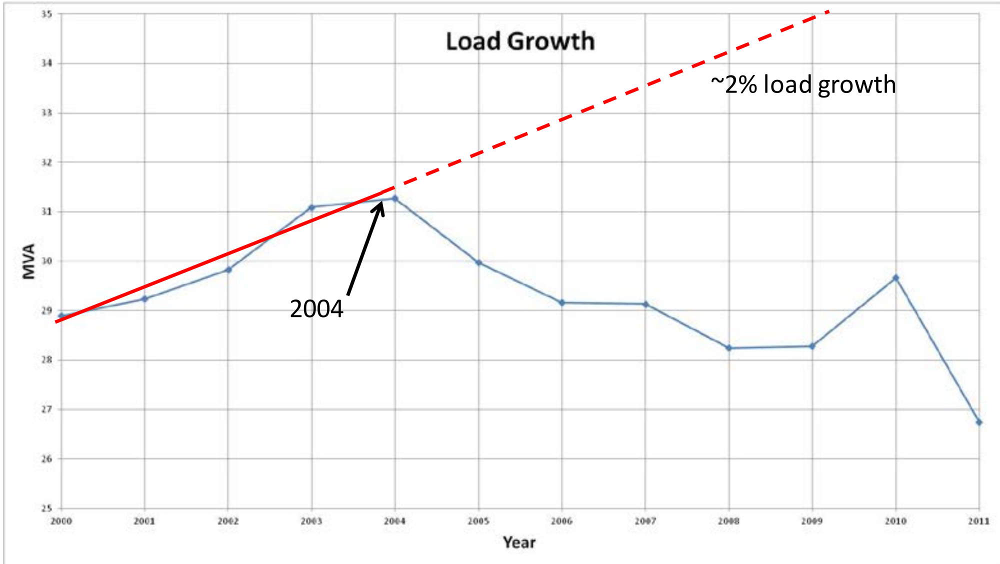

Figure A-4 Forecast load growth based on 5 years of previous maximum demand values

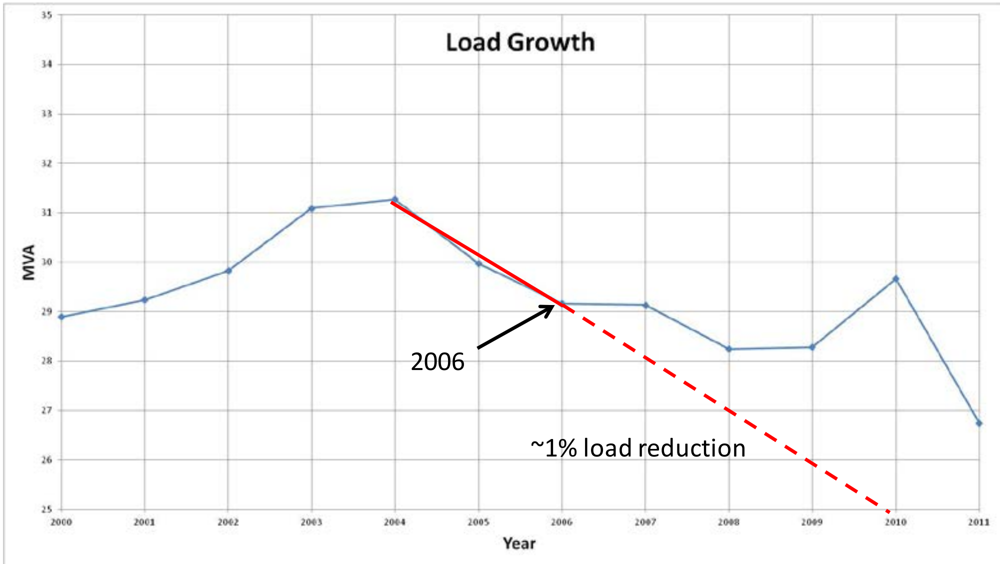

Figure A-5 Forecast load growth based on 3 years of previous maximum demand values

Connection Studies

For assessment of connection of new loads or generation to the 33kV or 11kV network, the characteristics of the new connection are first established as this may dictate where on the network the connection is to be made. Network investigations are then carried out to establish the available headroom. The initial investigation is analysis of load data using the Max/Min spreadsheet followed by the population of a power systems model (IPSA) using load data. Load flow analysis is then carried out to ascertain if the new connection can be accommodated and if required the minimum network reinforcement needed to enable the connection to be made.

When producing a network study to investigate the effect of a new connection, it is usual to extract demands from April of one year to March of the following year to include the winter season in one extract. This is usually done for the previous year and former years to investigate previous demand variations as part of the considerations when deciding the proposed new connection arrangement. Maximum demands as presented by the load database are typically used, without any correction for temperature or network anomalies.

At LV the process is similar to HV but the tools available to the designer are not as robust. The maximum demands on the secondary transformers are available but the only way to obtain feeder loads is to do direct measurement at the secondary substation at the time of the investigation. Time constraints normally do not enable useful information to be obtained by this method. The designer has to rely on network maps and making estimates of the demands to the existing properties connected, the circuit demands and resulting voltage to establish if the new connection can be accepted and any reinforcement required.

Network Review

Network loading is compared to asset ratings to ensure compliance with Engineering Recommendation P2/6 – Security of Supply, typically during FCO and SCO contingency conditions on the 132kV and 33kV networks, including 33/11kV transformers. This may be carried out to assess the impact of a new connection or to analyse a network reaching capacity through underlying load growth in more detail.

Seasonal loads are extracted from the load database for winter, summer and spring/autumn and the following network scenarios are assessed;

- Group Demand, corresponds to winter max demand (FCO)
- Summer/winter load ratio, to give summer max demand (SCO)

33kV Network Modelling

The 33kV network is modelled and maintained across the extents of the SPD and SPM licence areas. Network groups are defined for assessment of compliance with P2/6. Load flows are compared with MW and MVar measurements at GSPs and primary transformers for model validation.

11kV Network Modelling

To analyse an HV group supported by a number of primary substations (in a meshed network such as SPM), a network model is built incorporating the HV feeders and secondary substations. To determine the load profile of the group, the ground-mounted secondary substations are populated with their recorded maximum demands, based on the manual reading from the Maximum Demand Indicator (MDI). As no timestamp is recorded for the maximum demands and they are not necessarily concurrent i.e. the sum of these demands would exceed the recorded primary transformer maximum demands, a correction factor is applied.

For example, for HV feeder 15 connected to the St Andrews primary substation, the total aggregated MDI record for late 2011 was 2.545MVA for 13 ground mounted secondary substations. Peak loading conditions on this feeder in the second half of 2011 occurred on the 4th of December 2011 with a recording of 91.2A. A voltage of 11.1kV was assumed at the primary substation as per SPD standard primary transformer configuration which gives a peak load of 1.75MVA. No pole mounted substations are connected to this HV feeder.

Table A-1 Comparison of peak feeder loading to aggregated secondary substation MDI

	Loading (MVA)
HV Feeder 15	**1.753**
Secondary substations	**2.545**
Cannongate Primary School	0.25
Priory Acres	0.1725
Newpark S/Andrews	0.125
Lawpark St A	0.235
Cannongate	0.1125
Gordon Lodge	0.25
Carron Lodge	0.15
Lawhead School	0.2
Maynard Road	0.11
Broomfauld Avenue	0.15
Observatory St Andrews	0.05
Wester Langlands	0.5775
Strathkinness High Raod	0.1625

It should also be noted that the HV feeder current is measured only on the yellow phase and there may also be some phase imbalance present however, analysis of a number of HV feeders has shown that this is not significant.

To correct the model loading to match the group infeeds, i.e. the recorded primary transformer demands, a diversity factor is applied to the secondary substation demands. This can be done as a global factor applied to all the secondary demands to reduce their combined total to match the recorded primary transformers demands and or on sections of the network to also reflect the recorded feeder maximum currents. For a HV group fed by only one substation, this process is also applied. For example, for the example above in Table 1, a diversity factor of 69% would be applied to reduce the secondary substation demands to match the feeder peak loading.

HV network models for load flow analysis are constructed as follows:

- ArcView/GIS provides data for cable lengths, conductor types, transformer location and rating, the SAP database provides data for transformer impedances (available for ground mounted substations)
- Cable ratings can be extracted from a database of cable ratings based on conductor types in "Equipment Ratings and Assessment of EHV/HV systems"
- Ground-mounted secondary transformer loading is based on MDI data from the SAP database. MDI data is generally read six-monthly with three phase current measurements. Some network planners base their models on the highest phase, others on the total power/average. The new database now adds the recorded currents to calculate the total transformer load.
- Half-hourly settlement metering data for HV connected customers can be requested from SPEN's Distribution Use of System Admin group in Scotland. Stated connection capacity may be higher than actual consumption in which case the planner uses their judgement to select the appropriate loading. New 11kV loads/ generators are connected across the three phases.
- The primary transformer maximum loadings and corresponding 11kV feeder currents are sourced from the load database which contains half-hourly data for the 33kV/11kV primary transformers as well as 11kV feeder currents.
- Diversity factors are then applied to scale the secondary substation and HV connected loads so that they add to the maximum primary transformer load (because the MDI readings don't all occur simultaneously). This is an iterative process based on the planner's best judgement.
    - A diversity factor of 80% of MDI is typically applied to ground-mounted secondary substations and a 20% diversity factor (20% of total rated transformer capacity) is typically applied to pole mounted substations. Some additional scaling may then be applied to fine tune the values to match the total primary transformer and feeder loads obtained from the load database.
    - The PI Max/Min spreadsheet is used to extract data from the load database to use when validating a network model that is being built using secondary substation demands.
- Network configuration is confirmed from the NMS and represented in the model.

Current Limitations

- Analysis is based on maximum loads and does not take into account the daily load profile. However, the size of a new connection may be reduced in the model if the designer is satisfied that the connection maximum demand will occur outside the network peak.
- Some HV network models may be simplified and aggregate a number of similar and nearby secondary substation loads to speed up model build. However, this is typically done for overhead networks, radial feeders or to represent sections of network required for transformer demands that do not affect the HV network being studied.

Network Planning

Network planning includes network reinforcement identification and prioritisation activities.

HV Network

At the higher voltages, reinforcement is identified by several means. Firstly the annual review of the network, done by using PI Max/Min spreadsheets to extract data from the load database, identifies any areas which potentially will require reinforcement in the next few years by adding on estimated generic demand growth to the recorded maximum demand of the HV group. This also forms the basis of regulatory reporting for network reinforcement activities. Local knowledge through stakeholder engagement may result in this forecast being adjusted to match future load increase (or decrease) due to anticipated new connections (or closures). Areas of the HV network which will require reinforcement can also be flagged up by designers carrying out network investigations, e.g. designing new connections. This may identify problems adjacent to the network area being investigated which cannot be resolved as part of the proposal under consideration or the proposal does not proceed beyond the design stage.

Areas of network concern are also reported by the Network Control Centre and the local network operational staff. These are usually areas where the network is shown to be or anticipated to be stressed under outage conditions due to faults or planned outages, or a large number of customers cannot be restored until a fault is repaired.

When a potential reinforcement requirement is identified and initial investigations have been completed, each reinforcement request is ranked against a pre-approved set of criteria and added to the reinforcement programme for resolving at the appropriate time.

LV Network

At low voltage, the only reinforcement identified by available network data is the peak loading of secondary ground mounted transformers. These values are extracted from SAP and used to populate an Access database. This then allows reports to be generated which list the transformers which have a recorded value above a pre-set value i.e. 110% of rating. These values are confirmed by onsite investigations to confirm their accuracy and if the demands are likely to be repeated regularly before any design work is undertaken. This process may also involve the HV design section.

LV network constraints are often identified by customers when the voltage is approaching the statutory limits. Network investigations are then completed to assess network performance in more detail and to confirm the network arrangement. Where a potential reinforcement requirement is identified, an appropriate network solution is then found to resolve the issue.

Network problems can also be identified by the local operation staff who flag up such problems as blowing fuses due to high loads or areas where the network cannot be secured under outage conditions as anticipated. Following investigation if a reinforcement proposal is confirmed, a proposal is prepared.

Load Index

Load index is worked out for each group as part of the annual network review process and gives an indication of when reinforcement to the group will be required. It can also be used to provide a general health assessment of the network. There are five load index levels defined by Ofgem[4], as shown in Table A-2.

Table A-2 Load Index

LI Banding	Loading Percentage	Duration factor
LI1	0 - 80	n/a
LI2	80-95	n/a
LI3	95-99	n/a
LI4	100	<9 hours
LI5	100	>9 hours

[4] Ofgem, Strategy decision for the RIIO-ED1 electricity distribution price control Reliability and safety Supplementary annex to RIIO-ED1 overview paper, 2013. https://www.ofgem.gov.uk/ofgem-publications/47073/riioed1decreliabilitysafety.pdf

The number of LI5 transformers should be decreasing over time as reinforcement activity is focussed on the parts of the network that need it most.

Outage planning

The control engineer has access to real-time primary transformer loading and 11kV feeder currents with the current network running arrangement visible in the NMS.

For outage planning, primary substation data is used in several capacities;

- Outage planning – generally 1 to 4 weeks ahead based on historical and forecast demand profile and historical outages where available
- Outage management – generally now to 24 hours ahead based on historical and forecast demand profile and historical outages where available

The backfeed configuration for outage planning is typically done using the planner's experience of the network along with data taken directly from load database. Excel based tools are used to access and summate the load data.

Unplanned outages

In general, network reconfiguration for fault restoration due to unplanned outages will be selected based on experience and understanding of the network. Plans may be prepared (by operational planners) for specific situations of concern, and may be used once restoration is under way. These plans would typically be prepared for the peak load case; off-peak cases are dealt with from experience.

Appendix B – Selected Network Group Details

St Andrews

St Andrews is a large town in the rural location of Fife, Scotland, with a population of approximately 17,000. St Andrews is a tourist area and is also home to the well-known St Andrews University. The primary network group of St Andrews consists of 2No 33/11kV primary transformers of 12/21MVA rating that supply the 11kV distribution network. The two transformers are located at St Andrews Primary Substation and operate in parallel. The 11kV circuits from this primary substation are operated radially but with the facility to be interconnected to neighbouring networks following a system outage.

Ruabon

Ruabon is a small village located in the borough of Wrexham, Wales, with a population of approximately 2500. The Ruabon 33/11kV system consists of one 10MVA 33/11kV primary transformer which supplies the 11kV distribution network. The 11kV circuits from this primary substation are operated radially but with the facility to be interconnected to neighbouring networks supplied from Llangollen, Johnstown, Monsanto and Maelor Creamery following a system outage.

Whitchurch

Whitchurch is a market town in Shropshire with a population of approximately 9000. The 33/11kV system, in Whitchurch, consists of three 33/11kV primary transformers that supply the 11kV distribution network, Whitchurch, Liverpool Road and Yockings Gate.

Egerton

Egerton is located in Birkenhead on the Wirral Peninsula and is an industrial/semi-suburban area. The Egerton 33/11kV system consists of three 10MVA 33/11kV primary transformers Egerton, Shell Tranmere and Rock Ferry which supply the 11kV distribution network.

Hunts Cross

Hunts Cross is a suburb of Liverpool, England located on the southern edge of the city and is an urban area. The Hunts Cross 33/11kV system consists of four 10MVA 33/11kV primary transformers Hunts Cross, Kenton Rd, Woodend Ave and Woolton which supply the 11kV distribution network.

Boulevard

The Boulevard area is located in urban Warrington. The Boulevard 33/11kV system consists of six 10MVA 33/11kV primary transformers Boulevard, Hawleys Lane, NWW Campus T1 and T2, Westbrook and Winwick Quay which supply the 11kV distribution network.

Appendix C – Peak Load Trend Representation Sample Results

Peak load trend representation testing results are shown below for a sample of HV network groups. Daily peak maximum refers to the annual maximum demand.

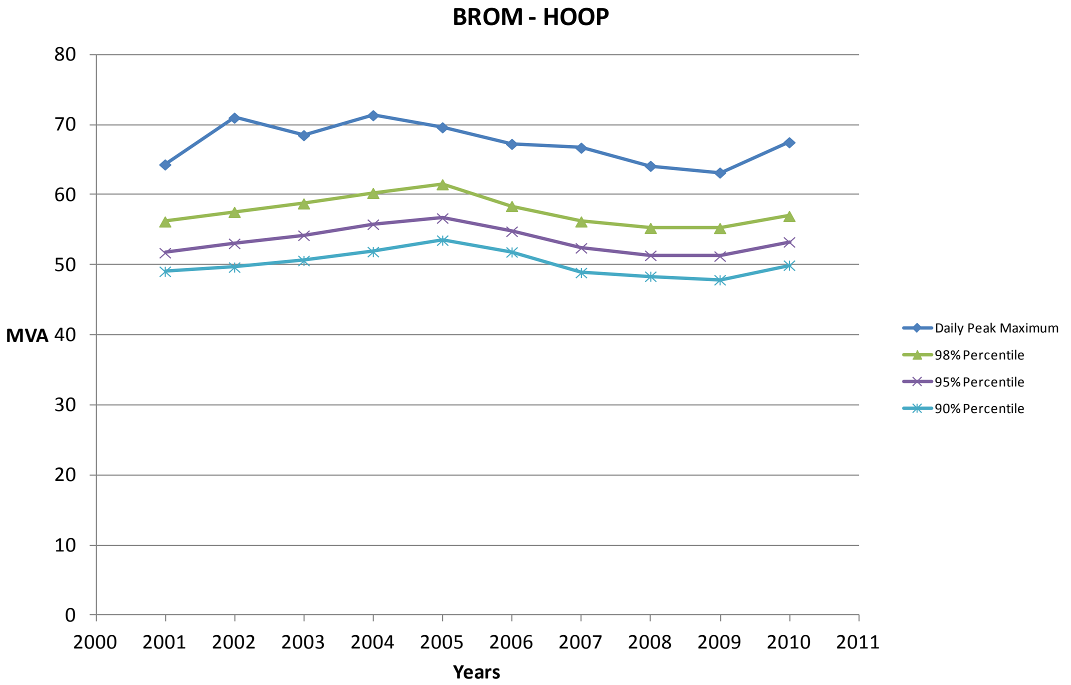

Figure C-1 Annual maximum demand and selected percentile demands for SPM HV group BROM-HOOP

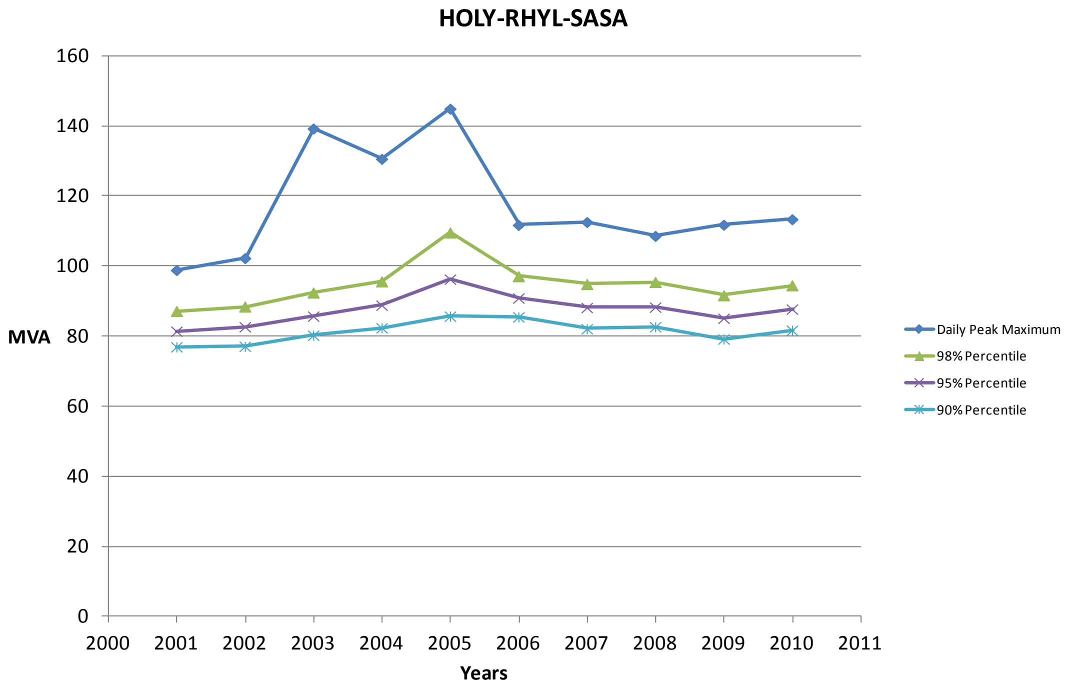

Figure C-2 Annual maximum demand and selected percentile demands for SPM HV group HOLY-RHYL-SASA

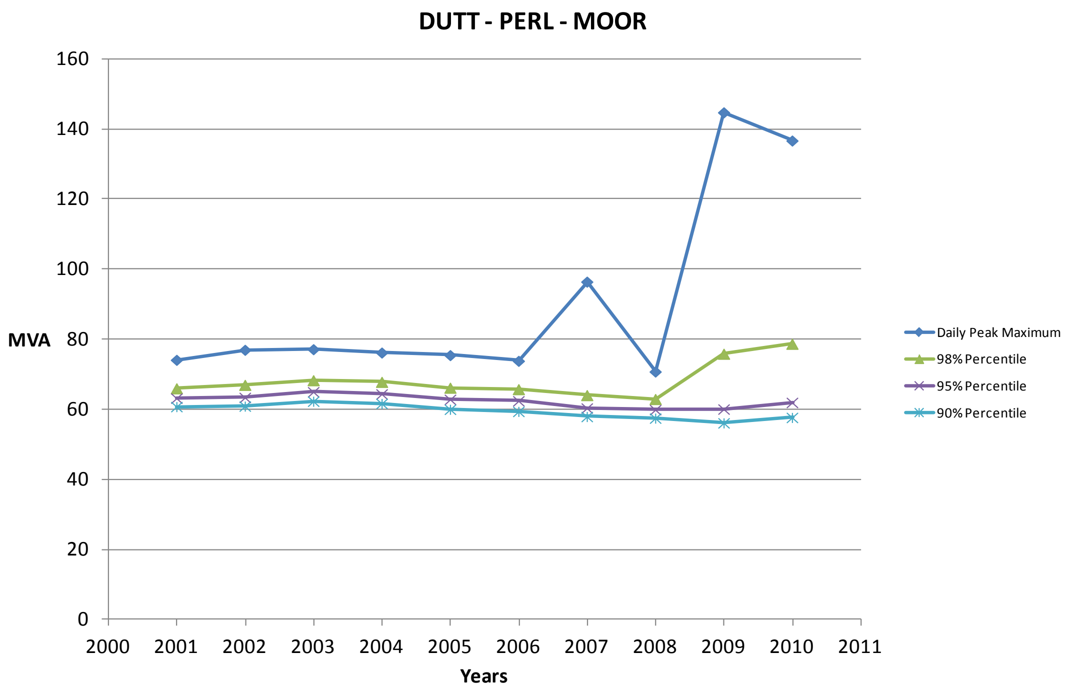

Figure C-3 Annual maximum demand and selected percentile demands for SPM HV group DUTT-PERL-MOOR