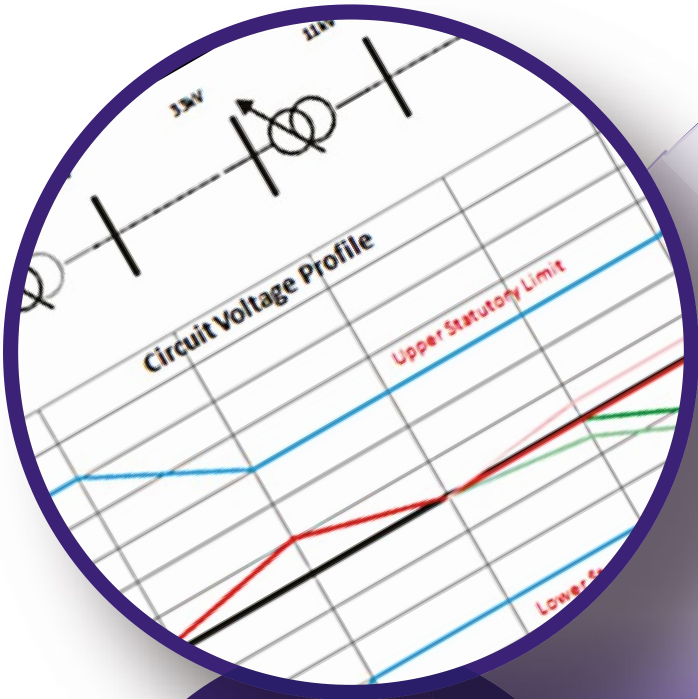
SP ENERGY NETWORKS

Flexible Networks for a Low Carbon Future



Recommendations on Operational Policy and Practice

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Executive Summary

Success for a network innovation project is adoption into business-as-usual. Integration of the innovative technology, operating or commercial arrangement requires a review and update of network operation policy and code of practice as well as extensive stakeholder engagement to ensure user buy-in. This provides the network control engineer with an established and approved procedure to follow when considering the behaviour, management and control of an innovation deployed in the network.

Increasing amounts of low carbon technology including PV, electric vehicles, heat pumps and energy storage are likely to connect to the distribution network in the near future along with the growth of demand side response and generation ancillary services. Scottish Power Energy Networks (SPEN) is developing strategies for a more techno-economic response to load growth through the application of innovative technologies. This also encompasses updating network planning and operations policy and codes of practice to enable these technologies to be suitably designed, deployed, operated and managed.

This paper provides recommendations for enhancements and considerations for network operations policy and code of practice to help facilitate integration of the innovations being trialled within SPEN's "Flexible Networks" network innovation project into business-as-usual (BAU). These include the following;

- Use of enhanced seasonal ratings for primary transformers in network groups approaching firm capacity consistent with an appropriate level of risk.
- Use of real-time thermal ratings (RTTR) for 33kV overhead lines to enable increased wind generation connection with minimal additional risk.
- Flexible network control (FNC) to switch load automatically to other HV network groups when high loading approaches the firm capacity of the network group to enable additional demand growth or connections beyond the existing firm capacity.
- Strategies for distribution network voltage control through several innovative approaches;
    - Customised voltage management at primary and secondary substation transformers through seasonal tap settings to meet high load conditions in winter and increased embedded generation activity in summer, or through line drop compensation techniques.
    - The deployment of an automatic voltage regulator (AVR) to facilitate flexible network control schemes, where load transfer to long interconnectors is constrained due to voltage issues. Whilst SPEN already have a number of AVRs installed on the network, these are to enable generation connections.

Maximising the Value of Internal Stakeholder Engagement

It is critical to involve staff from the concept design stage during trials to gain user buy-in and maximise the likelihood of integration into BAU. As an increasing level of network automation is adopted, control engineers will be managing a distribution network that has a greater degree of self-control and distributed intelligence but also a greater number of potential modes of failure. Network reconfiguration coupled with automated thermal and voltage control systems can create a large number of possible configurations and behavioural characteristics (current, voltage, fault level) for the network at any one time. Resultant increased network risk requires improved risk management tools and techniques.

From our internal stakeholder engagement activities with network control engineers for Flexible Networks, key learning outcomes on the integration of network innovations are as follows;

- Changes to operational practice are best implemented through policy.
- The introduction of innovations should avoid extensive actions or decisions from the operator although the operator should always have the option of taking manual control.
- Network control engineers should be equipped with the knowledge, suitable information in the NMS and appropriate level of control of innovations under both normal running conditions and contingency conditions.

Changes to operational practice are best implemented through policy.

Recommendations for network operations policy and codes of practice

Dynamic Thermal Ratings

Enhanced thermal ratings for primary transformers will be automatically populated in the NMS (and any power system analysis software) to replace nameplate ratings. This would be initiated as part of network planning practice for selected HV groups approaching capacity where enhanced ratings can be cost-effectively applied to increase capacity headroom.

Top oil temperature monitoring will be implemented for transformers where enhanced thermal ratings are deployed and these measurements will be accessible to the network control engineers in real-time with appropriate temperature warning alarms as transformer thermal loading approaches the acceptable maximum.

Enhanced thermal ratings for primary transformers will replace name-plate ratings in the NMS, where applied.

An overhead line RTTR information dashboard hosted in the NMS providing both RTTR values i.e. dynamic ratings of the circuits, and all other monitored data will be available to the control engineer. This will be utilised as per a code of practice to inform network operations primarily during outage planning and fault response to maintain network security, replacing previous seasonal overhead line ratings. A graceful degradation algorithm has also been developed allowing the system to be robust if measurement data is missing.

For future full adoption of RTTR systems, an automated forecasting methodology should be added to the RTTR calculation process. Development of an interface between RTTR systems and active network management (ANM) systems for controlling the outputs of generators would enable further network automation and risk management. Real-time conductor temperature estimation and comparison with the monitored conductor temperature can be an additional feature to indicate, in real-time, the accuracy of RTTR values and provide some further risk metrics to the control engineer.

An overhead line RTTR dashboard is hosted in the NMS to inform network operations.

Flexible Network Control (FNC)

The rollout automated FNC scheme will be fully integrated with the NMS and requires no input or action from network control engineers. Key information will be displayed such as location, status, and voltage and power flow at key control points. An operational code of practice will describe the control hierarchy and procedure for interacting with FNC schemes during unplanned outages, maintenance and construction, including deactivation if required and manual restoration. Any AVRs operating within the scheme will also be considered.

An operational code of practice will describe how to interact with automated FNC schemes during planned and unplanned outages.

New policies and procedures are being developed by SPEN to manage the design and operation of communications for increasingly complex network automation systems and remote monitoring to maximise security and resilience to faults.

Voltage Management

A degree of voltage control relay functionality is currently possible from the control room for a number of primary substations. This will be extended to all primary substations during RIIO-ED1 along with improved visibility of voltage control schemes across the HV and LV networks.

Future voltage management may be deployed as a fixed seasonal voltage set point, a voltage set point determined by line drop compensation or a voltage set point determined from real-time evaluation of measurements. At present, a fixed seasonal voltage set point is a simple solution that can be applied to all primary transformers however, voltage management through line drop compensation where the relay functionality is (increasingly) available is often a more responsive and flexible solution.

> Future voltage management can be achieved through fixed seasonal voltage set-points or line drop compensation.

For all these solutions, the tap positions of all transformers in a network group will need to be adjusted to prevent current circulation and any backfeeding or meshing arrangements should be carefully considered by the control engineer along with corresponding switching sequences.

> The voltage control strategy should be consistent within an HV group and appropriate for any backfeeding or meshing arrangements.

A future, more dynamic voltage control scheme would need to be supported by wider network monitoring and a probabilistic characterisation of a dynamically shifting optimal voltage point and associated risk. This could interface with an Active Network Management approach that integrates automated switching operations, HV and LV network voltage control and control of larger distributed generators such as hydro plants, CHPs or wind farms.

Voltage policy and operational codes of practice to enable improved, more flexible voltage management will also address acceptable target voltage range with voltage control, interactions between voltage control schemes at primary substations, secondary substations and AVRs, and HV demand and generation customers.

AVRs are currently used in limited numbers at 11kV in SPD and SPM to mitigate voltage rise on spur lines due to generation connections. Flexible Network Control (FNC) schemes which shift load between HV network groups can result in a voltage drop at the end of long feeders below statutory limits. An AVR placed in series on a long feeder can boost voltage and enable FNC. As part of the Flexible Networks project, SPEN has installed and tested a three tank telecontrolled AVR in the St Andrews 11kV network to facilitate FNC.

In order to monitor operation and condition as well as control basic functionality, telecontrolled AVR units are integrated with the NMS. An operational code of practice regarding the control of AVRs has been developed by SPEN control engineers to enable safe and secure operation. In particular, tap to neutral and switching out of automatic mode during network paralleling are very important controls from a safety perspective.

An operational code of practice for control of AVRs has been developed including critical safety actions during network paralleling.

SPEN voltage policy is being updated to reflect learning outcomes on AVRs from Flexible Networks. Some of the key elements in the policy are that only one regulator is to be installed on a main feeder although multiple devices may also be installed on spur lines i.e. no sequential devices, and that AVRs on interconnector or ring circuits will be able to accommodate reverse power flow and have capacity for bypass. Appropriate control modes are also addressed with the default control mechanism being 'Co-Generation' apart from when the AVR is being established to resolve load related voltage issues, the default control mechanism for the units should be 'Bi-Directional'. Other considerations include use of an AVR in a meshed network and the "load-bonus" feature of the AVR available by constraining voltage tap range.

SPEN voltage policy does not allow sequential AVR devices and provides guidance on appropriate AVR control modes.

In future, AVRs may be integrated into an autonomous voltage control scheme at the local level. This would require clear definition and verification of AVR response to various network events and actions, and the capability for manual control as required.

Increased Network Monitoring

Increased HV and LV network monitoring will provide improved characterisation of demand/generation load and voltage profiles and should support the development of improved voltage management strategies, outage plans and response to network faults.

Glossary

ANM	Active Network Management
ARC	Accelerating Renewable Connections LCN Fund
AVR	Series (Automatic) voltage regulator
BAU	Business-As-Usual
CI	Customer Interruptions
CML	Customer Minutes Lost
DNO	Distribution Network Operator
EV	Electric Vehicle
FCO	First Circuit Outage
FNC	Flexible Network Control
HP	Heat Pump
LCT	Low Carbon Technology
LDC	Line Drop Compensation
MDI	Maximum Demand Indicator
NMS	Network Management System
NOP	Normally open point (a normal point of isolation part way along a feeder)
PI	Process Instrumentation – SPEN's Network Monitoring Data Historian System
PNDC	Power Networks Demonstration Centre
PV	Photo-voltaic generation
RTTR	Real-Time-Thermal-Ratings
SCO	Second Circuit Outage
SPEN	Scottish Power Energy Networks

1 Learning outcomes

Recommendations for changes to current SPEN operational policy and practice have been developed in order to integrate Flexible Networks innovations. The following learning outcomes have been achieved through this process;

- Improvement in the characterisation and management of existing network risk and any additional network risk due to deployment of innovative network solutions and low carbon technology e.g. embedded PV generation.
- More efficient path into future business-as-usual rollout through policy changes for example for both Flexible Networks innovations as well as future innovations.
- Improved understanding of effective internal stakeholder engagement strategies specifically with network control engineers and in general to achieve user buy-in.

1.1 Facilitating Integration into BAU

SPEN have a number of policies and design standards that provide network control engineers with approved practices and procedures to use when carrying out their day to day activities. For example, control engineers can refer to approved practices whilst planning maintenance outages and responding to unplanned outages. This also forms the basis for any audits required by the Regulator (Ofgem) in the occurrence of exceptional network events.

As innovative solutions to growth of low carbon demand and generation are increasingly deployed and network management and control become more sophisticated and decentralised, control engineers require new tools and processes that allow them to ensure quality and security of supply.

Flexible Networks is trialling use of the following technology innovations;

- Enhanced thermal ratings for primary transformers and real-time thermal ratings for 33kV overhead lines.
- Flexible network control (FNC) for HV networks through automated load shifting.
- Automatic series voltage regulators to enable the application of FNC to networks constrained by voltage limits.
- Voltage management through automated voltage control at primary substations.
- Increased network monitoring at HV and LV.

In order to integrate the innovations being trialled in Flexible Networks into BAU, changes to operational policy and practice are required to implement new tools and processes. This will also provide general learning on how best to implement other network innovations in the future.

Changes to operational policy and practice are required for innovative network solutions to be applied as BaU.

These changes are often facilitated through changes to network planning and design policy and practice first. For example, an innovative network solution is selected by network planning to solve a network issue. This will require some approved guidelines on how to analyse the solution and understand its behaviour on the network. These will have implications for monitoring, loading, control and protection, and maintenance of the solution and interdependencies with other assets on the network. Learning from network operation under normal and contingency conditions can then also be integrated into consequential system design processes including techno-economic appraisals.

1.2 Improved management of network risk

HV and LV network design has traditionally been consistent with a fit and forget approach. Consistent with this more deterministic approach, network risk is typically not characterised. With the increase in embedded generation, energy storage clustering of HPs and EVs and demand side response, a more probabilistic approach is required to improve management of network demand, generation and capacity. This is a key component in the transition from Distribution Network Operator towards Distribution System Operator. An improved understanding of how to integrate greater characterisation and management of risk into network operation is required. This can be facilitated to an extent through changes to policy and codes of practice.

However, it should not introduce a real or perceived additional workload burden or uncertainty/risk. Also, training should be provided to increase confidence in applying this approach.

Improved strategies for network risk management are required whilst not impacting on control room workload.

1.3 Effective Engagement Strategies with Staff

Flexible Networks provides the opportunity to engage with staff across a number of areas of the business to understand their concerns for future network and asset design and operation. In fact, it is critical to involve staff from the concept design stage during trials to gain user buy-in and maximise the likelihood of success.

This should enable some optimisation of the innovation roadmap towards BAU i.e. improving engagement strategy during trials, then network wide roll out and integration with the control room, and maintenance.

In future, the network will contain significantly more automation than at present. It is critical to understand how the control engineer and the network will interact with and respond to both centralised and decentralised automation during normal and contingency conditions.

Buy-in from control room staff is crucial to enable successful rollout of an innovative network technology solution.

1.4 Potential Benefits

- Improved development of strategies for planned and unplanned outages with full consideration of network innovation behaviour/response.
- Better characterisation of individual network risk profiles.
- Improved understanding of how to manage network risk for more dynamic future networks.

2 Integration of Network Innovations into Business as Usual

Control engineers have a responsibility to maintain the safe and secure operation of the network as the 'gate-keepers' of the network. They need to have the appropriate tools and procedures to confidently take any decisions and actions required to manage the network particularly during planned and unplanned outage events.

The introduction of innovative technology, commercial or operating arrangements will require changes to the way the distribution network is operated. In order to implement these efficiently, it is important to both develop and trial any changes to policy and practice as well as to carefully consider how to facilitate user adoption.

Changes to an area of the business that has been governed by long-standing policy and practice has raised concerns that this will result in additional uncertainty and/or risk for critical network activities as well as increasing workload. These concerns have been considered and addressed through extensive stakeholder engagement on proposed policy and practice changes.

As an increased level of network automation is adopted, operations policies and procedures will need to be developed to define how they will be implemented and managed. Control engineers will be managing a distribution network that has a greater degree of self-control and distributed intelligence. Network reconfiguration coupled with automated thermal and voltage control systems can create a large number of possible configurations and behavioural characteristics (current, voltage, fault level) for the network at any one time.

2.1 Current Operational Policy and Practice

A review of current control room tools, policy and practice was undertaken to help identify any barriers or limitations for deployment of Flexible Networks innovations. This involved discussions with both control engineers and other Operations staff to incorporate their views on integration challenges.

A summary of current operational policy and practice is given below, further details are provided in Appendix B.

- SCADA measurements are mapped to the NMS which provides a continuous report on;
  - Real-time current and voltage on primary transformers
  - Real-time current on 33kV circuits at EHV substations
  - Real-time yellow phase current on 11kV feeders
  - Network configuration
  - Status of network control and protection devices
- Network operators are responsible for a number of key activities including;
  - Outage planning
  - Unplanned outage response
- Network reconfiguration for restoration due to unplanned outages is generally based on experience and understanding of the network. Plans may be prepared by operations staff for specific situations of concern, and may be used once restoration is under way.
- Designated asset ratings are documented in SPEN Design manuals and policy. For primary transformers, these are the nameplate ratings.

2 Integration of Network Innovations into Business as Usual [continued]

2.1 Current Operational Policy and Practice [continued]

- Network operators have some control over generation connected at 11kV and above and large customer loads. Where constraint of generation constraint or load shedding is required for network restoration for example, a phone call is made to the owner/operator requesting a generation or load reduction for a certain time period.
- Voltage control including AVRs is governed by a specific policy relating to management of voltage on the network. AVRs currently installed at 11kV do not have the communications facility to map to PowerOn.

Learning outcomes from our internal stakeholder engagement on integration of network innovations are as follows;

- Changes to operational practice are best implemented through policy.
- The introduction of innovations should avoid extensive actions or decisions from the operator although the operator should always have the option of taking manual control.
- Control engineers need to have a clear understanding of the operational characteristics and behaviour of innovations under both normal running conditions and contingency conditions.

2.1.1 Network Security Requirements

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 theoretical 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.

2.2 Challenges for User Adoption

The introduction of innovations to the network that require control engineers to continually monitor and respond e.g. by reconfiguring the network, are unlikely to be welcome. Increasing control engineer workload particularly during time critical activities such as during network unplanned outages, increases the risk that sub-optimal decisions will be made due to information overload.

The following recommendations for achieving successful integration of new policy/practice into network operation have developed through extensive stakeholder engagement as tabulated in Appendix D with SPEN control room engineers, operations policy team, network design and connections and asset management;

- New operational policy or practice should first be tested and implemented in network planning and analysis as a solution in the planners 'toolbox' e.g. use of enhanced seasonal thermal ratings for assets, FNC schemes. Once an approval policy/process has been developed by the planning team for the innovation, it can then be integrated into operational practice.
- Learning from operations should also then provide input back into the network design process and reinforcement solution selection and design.
- For time critical activities such as unplanned outage response, it is crucial that all required network information is available and fully integrated into the NMS.
- Automation of new network operational tools e.g. FNC schemes, is acceptable as long as the appropriate fail safe and deactivation controls are designed in to enable the control engineer to take manual control if required.
- Control engineers should be provided with training to develop a good understanding of the general principles, rules and behaviour of any innovation deployed on the network whether automated or manual. This should include how network risk should be considered and guidance on risk management where required.
- Any new operational tool/software that is not able to be integrated into the NMS should be relatively straightforward and quick to use and have an official owner from within the team who is going to use the new tool/software. Otherwise it is unlikely to be used or maintained.
- Network innovations should be given the full "business as usual" treatment e.g. clearly defined responsibilities within the business for maintenance, the provision of spares, preparation of procurement specifications.

2.3 Dynamic thermal ratings

The use of dynamic thermal ratings for primary transformers and 33kV overhead lines is being trialled in Flexible Networks. Dynamic thermal ratings can provide a real-time transformer or feeder rating through calculation of thermal loading based on measured current, ambient weather conditions (real-time or forecast temperature and wind speed and direction) and acceptable insulation/conductor temperature limits. Measurements of transformer top oil temperature and overhead line conductor temperature have been used to validate thermal models. With typically an inverse dependency between load and ambient temperature e.g. high demand in winter, dynamic thermal ratings can enable an increase in the firm capacity of the primary network through an increased asset rating, thus deferring reinforcement requirements. Also, as windy conditions are required for high wind generation, dynamic thermal ratings on overhead lines can enable increased connection of wind farms.

From discussions with SPEN control room engineers, very short-term ratings (in the order of 5-10 minutes) are of limited use at primary network level due to the time required for control engineers to identify and understand the implications of any unplanned outages and form a considered plan of action. Short-term ratings requiring a response less than these timescales could only be considered if the network response was automated.

2.3.1 Transformer Enhanced Thermal Ratings

For primary transformers, a fixed nameplate rating is defined in Poweron with alarms set at 80% and 90% of maximum top oil temperature (?? degC). Ratings are based on the SPEN policy document ESDD-02-007 "Equipment Ratings and Assessment of EHV//HV Systems" and TRAN-01-004 "Manweb Primary Transformer Application and Rating Policy".

For most effective use in network planning and operations, dynamic thermal ratings for transformers will be implemented as "enhanced" seasonal thermal ratings. From Flexible Networks analysis, it should be possible to achieve a ratings uplift of at least 10% for most primary transformers for minimal additional risk.

As part of the project, a methodology and software tool for calculation of enhanced transformer thermal ratings has been developed, tested and validated. This considers the thermal behaviour of transformers in detail as well as site-specific factors such as load profiles, forecast load growth and ambient temperature conditions to determine an enhanced seasonal rating.

For HV network groups approaching firm capacity, a detailed analysis will be carried out using the enhanced thermal ratings software tool as part of the network planning process to identify additional incremental capacity headroom available though this method. This will include consideration of the following key aspects;

- Site assessment to check condition of transformer and connecting assets and review of current transformer age to determine whether the transformer is approaching the end of its mechanical life.
- Whether the transformer/s are located indoors or is relatively sheltered from weather conditions. In this case, ambient temperature (in the substation) is likely to be higher and the inverse dependency of transformer load on ambient temperature is reduced so there is limited applicability of enhanced thermal ratings.
- Limitations due to the ratings of connecting assets e.g. cable tails, 33kV circuits etc. and assessment of cost-benefit case to uprate if required.

2.3.1 Transformer Enhanced Thermal Ratings [continued]

The impact of enhanced ratings on transformer aging has also been considered and one of the key learning outcomes from Flexible Networks is that using an enhanced thermal rating will have minimal impact on transformer aging as long as the maximum transformer insulation temperature does not approach the insulation breakdown limit.

Based on stakeholder engagement, enhanced thermal ratings must be available through the NMS if network operators are to use them. In future, all enhanced seasonal primary transformer ratings will be automatically populated in the NMS (and any power system analysis software). The SPEN network analysis team would initiate this action as part of network planning practice and identification of HV groups approaching capacity.

Top oil temperature monitoring will be implemented for transformers where enhanced thermal ratings are deployed to minimise risk. These measurements will be accessible to the network control engineers in real-time with appropriate setting of warning alarms as the transformer thermal loading approaches the enhanced rating. Alarms are only likely to operate during first circuit outage conditions when loading is highest. This will also help to verify thermal model parameters for a range of transformer types compared to the standard IEC thermal model parameter values which are known to be conservative.

An Application Guide for the enhanced transformer rating software tool has been provided including case studies and sensitivity analysis to give network operators confidence in the thermal modelling approach. Existing technical manuals and policy documents for primary transformer ratings will also be updated to reflect the application of enhanced seasonal thermal ratings in network planning and operations codes of practice, on selected primary transformers.

2.3.2 Overhead Line Dynamic Ratings

Seasonal ratings (winter and summer) for 33kV overhead lines are currently defined in the NMS. These are based on SPEN policy ESDD-02-007 "Equipment Ratings and Assessment of EHV/HV Systems" as informed by manufacturers data.

Circuit design ratings conform to Engineering Recommendation (ER) P27 (Current Rating Guide for High Voltage Overhead Lines Operating in the UK Distribution System) which is based on a statistical domain analysis considering the risk of full load and overload conditions simultaneously with conductor design and operational temperatures.

Multi-circuit primary supply systems (33kV) must have the capability to supply maximum load in the event of a circuit outage e.g. duplicate transformer feeders at 33kV according to ER P2/6. A derating factor of 0.96 is applied to 33kV circuits intended to supply intensive industrial or commercial centre loads due to the less variable demand profile and thus reduced conductor cooling periods. However, it should be noted that overhead lines have a very small thermal inertia. Minimum ground clearances for overhead lines are defined in current legislation as per ENA's Technical Specification 43-8 "Overhead Line Clearances.

2.3.2 Overhead Line Dynamic Ratings [continued]

The thermal loading of an overhead line is influenced by the conductor load, wind speed and direction to a lesser extent, the ambient temperature. Overhead line ratings assume the following conditions;

- Minimum Wind Speed 0.5m/s
- Ambient Temperature (Winter) 2°C
- Ambient Temperature (Summer) 20°C
- Solar Radiation Nil
- Maximum Conductor Temperature 50°C
- Overhead line summer ratings generally have a derating factor of 0.8 of the corresponding winter rating due to the reduced cooling. For an overhead line rating, winter is defined as between October and April.

Flexible Networks has trialled the deployment of Real-Time-Thermal-Rating (RTTR) systems for 33kV overhead line networks in Scotland to increase network generation capacity. This builds on the learning outcomes and outputs of a 132kV overhead line dynamic thermal rating scheme located in North Wales trialled as part of a LCNF Tier 1 project, to release network capacity for additional wind generation.

Weather monitoring and conductor current and temperature monitoring was installed for Flexible Networks to enable thermal model validation and to investigate how asset ratings can be optimised by considering real-time environmental conditions. A graceful degradation algorithm has also been developed allowing the system to be robust if measurement data is missing.

The RTTR calculation module is hosted in a stand-alone NMS server with RTTR values i.e. dynamic ratings of the circuits, and all monitored data is available through a dashboard to the control engineer. This can be used to inform network operations outage planning and fault response decisions to maintain network security.

The following developments have been identified[1] in order to fully adopt the RTTR system applications into network operations as business as usual:

- RTTR forecasting is an essential feature for full adoption of RTTR systems. A forecasting methodology should be added to the RTTR calculation process to boost the confidence on any planning decisions that are made based on RTTR. This will be automated so will not create any additional workload for the control engineer whilst reducing risk. SPEN is now conducting "Enhanced Weather Modelling for Dynamic Line Rating" project under the Network Innovation Allowance (NIA) funding mechanism, with the University of Strathclyde as a partner.
- Real-time conductor temperature estimation and comparison with the monitored conductor temperature can be an additional feature of an RTTR system to indicate, in real-time, the accuracy of RTTR values. This will provide some further risk metrics to the control engineer.
- Establish interface between RTTR system and active network management (ANM) system for controlling outputs of generators. SPEN has held a workshop with "Accelerating Renewable Connections" (ARC) LCN Fund and RTTR project partners to explore the way forward for integrating the RTTR system within an ANM system.

[1] *Flexible Networks Final report Work package 2.1: Dynamic thermal rating of assets – Cupar St Andrews RTTR system.*

2.3.2 Overhead Line Dynamic Ratings [continued]

Limitations on 33kV circuit ratings due to the ratings of connecting assets e.g. transformers, cable tails, should be considered before deploying RTTR.

Existing technical manuals and policy documents for 33kV overhead lines will be updated to incorporate the application of RTTR for overhead lines in generation connection offers, network planning and operations codes of practice.

2.4 Flexible Network Control

The flexible network control (FNC) scheme that has been trialled as part of Flexible Networks performs the following primary function; switching load automatically to other HV network groups when high loading approaches the firm capacity of the network group. This enables additional demand growth or connections beyond the existing firm capacity limit.

No cost-effective opportunities have been found to apply a FNC scheme to switch load automatically between HV network groups under normal conditions, taking advantage of differing diurnal load profiles to reduce loading and losses at peak times. This was also an original aim.

2.4.1 Requirements for Network Operations

The rollout FNC scheme will be an automated system that is fully integrated with the NMS and requires no input or action from network control engineers. The NMS will clearly indicate where FNC schemes are deployed and whether they are currently active. This will also be displayed in the NMS through visualisation of the real-time network configuration and status of switching points. Key network metrics at control points including power flow, voltage and phase unbalance (if above any stipulated deadband levels) will also be accessible.

FNC schemes will need to be considered when developing response plans for unplanned and planned outages. An operational code of practice will be produced describing the control hierarchy and procedure for interacting with FNC schemes including during unplanned outages, maintenance and construction.

The control engineer will be able to deactivate a FNC scheme if required and manually restore the network either to its standard running configuration or an alternative configuration. The code of practice will provide a methodology for determining any settings when under manual operation and will also include consideration of any AVRs operating within the scheme.

2.4.2 Communications requirements

As the network becomes more complex in terms of automation systems and remote monitoring, a communications network will develop that is robust and resilient to faults. New policies and procedures are being developed to manage the design and operation of this new communications system including procedures for collating, analysing and distributing data to the relevant design and operations functions.

The growth of two way communications nodes in the network will also require policy and procedure to maintain network security.

2.5 Voltage Control

Increasing embedded generation, typically wind and PV, has resulted in the need to manage voltage rise on both the HV network and the LV network. Also, demand growth from low carbon technologies and the deployment of innovative technologies to provide incremental capacity headroom gains results in an increased need to manage voltage drop on network circuits, for example;

- Use of enhanced thermal ratings for primary transformers enabling further demand to connect. This will result in increased voltage drop towards the ends of HV feeders and the possibility that some voltages may drop below statutory limits.
- FNC schemes using load switching between HV network groups to reduce demand on a network group where peak loading exceeds firm capacity (or potentially generation under high generation output conditions). Load switching is carried out by moving network normally open points (NOPs) so that an adjacent network group picks up load from the constrained network group via an interconnecting feeder. These interconnecting feeders may sometimes be overhead lines in rural locations, particularly susceptible to voltage drop.

Flexible Networks has trialled several innovative voltage control techniques to increase generation and demand capacity headroom;

- Voltage management at primary substations
- Automatic series voltage regulators (AVRs)

The trial deployment of an AVR solution is specifically to facilitate FNC schemes, where load transfer to long interconnectors is constrained due to voltage issues. Whilst SPEN already have a number of AVRs installed on their network to enable generation connections, the deployment of an AVR for this purpose represents the use of the technology for a novel application: voltage support to enable load transfer during conditions of high demand.

2.5.1 Primary Substation Voltage Management

The selection of an appropriate target voltage is critical to the ability to manage, system voltages and the voltage limits at customer's premises. Many SPEN primary transformers are equipped with automatic on-load tap changing equipment that can be operated remotely to achieve voltage control normally within +1% and -1% of the nominal voltage. The nominal target voltage for SPM is 11.0kV and for SPD is 11.2kV.

The on-load tap-change control scheme most frequently deployed is of the SuperTapp arrangement based on a modified Negative Reactance principle. This allows a number of transformers to be operated in parallel at the same site without the need for complex control circuits. Some control of voltage control relay functionality is possible from the control room for a number of primary substations. Line drop compensating equipment (LDC) may also be installed which causes the tap changing equipment to increase the secondary voltage by an amount which can be varied and which is in proportion to the load carried by the transformer.

2.5.1 Primary Substation Voltage Management [continued]

Reduction of network voltage at primary will enable the connection of increased embedded generation. However periods of high demand, usually occurring in winter when PV generation will be lower, may result in the voltage dropping below statutory limits at the ends of feeders. Several possible network voltage management solutions that address both increasing generation and demand include;

- A fixed seasonal voltage set point that is lower in summer and higher in winter to respond to seasonal changes in load and demand. This can be more easily integrated into the control system than an automated scheme.
- A voltage set point determined by line drop compensation. This causes the tap changing equipment to increase the secondary voltage by an (variable) amount which is in proportion to the load carried by the transformer. This requires the transformer group to have the appropriate voltage relay functionality and communications. Line drop compensation also enables adjustment to the settings for the off-load tap setting on the secondary distribution transformers which may be changed to facilitate greater connection of embedded generation.
- A voltage set point determined from real-time evaluation of measurements of voltage towards the ends of critical feeders.

The tap positions of all transformers in a network group will need to be adjusted to prevent current circulation. In addition, any backfeeding or meshing arrangements along with corresponding switching sequences should be considered to ensure that voltage set points remain consistent within a group and transformer voltage relays do not hunt against one another. It should also be noted that a short duration change to voltage set-point may not be appropriate depending on the relay technology and bandwidth. This is due to the time required for the transformer/transformer group to stabilise at a new voltage set point (hours to days to reach steady state for large changes circa 2-3% where there are multiple remote transformers).

Where large commercial/industrial loads are connected to HV or LV feeders, or customers connected directly to 11kV where there is little or no embedded generation, reducing the voltage set-point at the primary substation may cause voltage to drop below the statutory limit. This could be mitigated by installing voltage regulators on the affected 11kV feeder or directly at the customer's premises and/or working with the customer on energy efficiency measures and updating the power purchase agreement. This is also conversely the case for generation connected to HV that is masked by high demand, this can be addressed through deployment of a series voltage regulator on the spur line that tees in the generation.

Power systems analysis of a section of the Ruabon LV network has been undertaken to specifically explore the potential benefits of voltage management to enable increased embedded PV generation connection. It has been found that a 3% reduction in primary transformer voltage can be applied to accommodate high levels of embedded PV whilst minimising risk. This will inform an updated PV generation connection planning code of practice and voltage policy. Further details are available in "Flexible Networks Improved Characterisation of PV Capacity at LV" report.

2.5.1.1 Voltage Reduction Test Case

As part of Flexible Networks, the reduction of network voltage specifically to reduce thermal loading has been investigated. This was based on a review of various approaches to load modelling and practical UK and international experience of the response of load to controlled changes in network voltage. Several experiments have also been carried out in the Ruabon network trial area where the primary transformer voltage was reduced by 3% for several weeks during winter.

From this assessment, it has been found that;

- A reduction in voltage will generally result in a reduction in active power demand however this will be larger over the short term than in the long term.
- The reduction achieved will depend on the types of load present, and therefore:
  - can vary between different parts of the distribution network
  - can vary between different seasons, and different times of day
  - can vary according to the ambient temperature
- In the absence of local knowledge of experimental results, a reduction of 1% in active power demand in response to a 1% voltage reduction is a reasonable estimate. Note that this assumption implies that whilst power consumption is reduced, the current remains constant, so rating issues associated with I2R heating affects will remain unaffected by the voltage reduction. Reactive power demand will generally be reduced by a larger factor than active power demand.

This voltage reduction could be applied from the primary or secondary substation.

2.5.1.2 Future Voltage Control

The Voltage Control Relay Enhancement Programme in SPENs RIIO-ED1 Business Plan will further enhance the functionality of the existing voltage control regime by extending the controllability of the voltage control relays at all Primary substation sites via the Control Room.

At present, a fixed seasonal voltage set point is a simple solution that can be applied to all primary transformers however, voltage management through line drop compensation where the relay functionality is (increasingly) available is a more responsive and flexible solution.

A future, more dynamic voltage control scheme would need to be supported by a probabilistic characterisation of voltage drop/rise conditions due to varying demand and embedded generation, and associated risk. Variations in power flow on the network will affect the location of maximum voltage rise (or maximum voltage drop), thus dynamically shifting the optimal point/s of voltage measurement for defining the voltage set point. A scheme based on real-time network area measurements will need to include the use of more extensive HV and LV network monitoring (as feedback as part of an open or closed loop), where cost-effective in key areas e.g. with high PV penetration, key HV customers, feeders with high summer loading, along with real-time network configuration information. Control actions to adjust the voltage set point in a network group or area should be co-ordinated and kept to a minimum. Future smart meters will also provide some voltage metrics and could be referenced in key LV network locations e.g. mid feeder, end of feeder.

2.5.1.2 Future Voltage Control [continued]

This could interface with a wider Active Network Management approach that integrates automated switching operations, HV and LV network voltage control and control of larger distributed generators such as hydro plants, CHPs or wind farms.

In future, with the evolution towards a more active, automated distribution network, the control engineer may also have more controllability of some types of embedded generation including voltage control through improved power factor set point control.

2.5.1.3 Primary Substation Voltage Policy

SPEN ESDD-02-008 "Quality of supply, system voltages and voltage regulation" provides system planning guidance relating to standard phase relationships, statutory voltage limits and allowed voltage regulation across the system. The objective of this voltage control policy is to ensure that the voltage at customer terminals is maintained to within statutory requirements and facilitate the future development of the system in an economic and coordinated manner.

The following recommendations are made for updating voltage policy and practice to enable improved, more flexible voltage management to respond to increasing embedded generation and demand;

- Voltage remains within statutory limits in the HV (and LV) networks under the range of loading conditions likely to be experienced during any applied seasonal tap change period. Acceptable target voltages and voltage ranges with voltage control should be defined in policy.
- All primary transformers in an HV group will be at the same HV target voltage and/or using the same voltage control scheme to prevent circulating currents.
- If a network group with a voltage control scheme is connected (temporarily) to an adjacent network group with no voltage control or with a different voltage set-point, there may be resultant through flows and voltage gradients. This should be managed through preparation of an appropriate switching sequence for planned or unplanned outages.
- The impact of voltage control actions on HV connected customers or feeders with high demand in summer will be quantified through network modelling and analysis of measurements.
- The impact of voltage control actions on HV connected generation will be quantified through network modelling and analysis of measurements.
- Interactions between primary transformer voltage control schemes and any AVRs connected on HV feeders or secondary transformer voltage control schemes in the network will be quantified through network modelling and derisked through co-ordination of voltage control schemes for example.
- Consideration of transient stability for the network during large voltage step changes if required.

2.5.2 Secondary Substation Voltage Management

Whilst secondary substation voltage management is not being trialled as part of Flexible Networks, it is worth considering the implications for operational policy and practice.

Ground mounted equipment generally has off-load devices with five tap steps giving a range of -5%, -2.5%, 0, +2.5%, +5%. Pole mounted equipment can have a similar range available (-5%, -2.5%, 0, +2.5%, +5%) but this is sometimes restricted to three tap positions: -5%, 0, +5%. These are generally selected by means of internal connections or more frequently for modern equipment, by selection of appropriate combination of bushing terminals.

Tap adjustment of ground mounted transformers to reduce LV voltage by 2.5% or 5% will enable more embedded generation to be connected. This should be fairly straightforward as transformers can be manually tapped and backfeeds are generally readily available. However, unless changed seasonally, this tap adjustment may introduce (or bring forward) undervoltage issues experienced during peak demand times. In rural areas, the adjustment of taps on a secondary transformer, which tend to be of lower rating and pole mounted, is potentially more problematic (lack of backfeeds and may require the transformer to be re-wired to select full range of tap positions).

For deployment of voltage control at secondary substations, voltage policy and network planning and operations codes of practice will need to consider the following issues;

- Voltage remains within statutory limits in the LV network under the range of loading conditions likely to be experienced during the seasonal tap change period.
- All transformers in an LV group need to be at the same LV voltage to avoid a voltage gradient and prevent current circulation. This also has implications when back-feeding an LV network from an adjacent network group with a different voltage set point.
- There should be negligible impact on the HV network voltage.
- If it is not possible to ensure a continuous LV supply for the duration of the tap adjustment operation, then customers would need to be contacted and warned of the potential loss of supply unless it is possible to use a mobile generator.
- In areas where the demand is high, during the scheduled day of tap adjustment, prior MDI assessments may be required to fully risk assess the procedure.
- Phase imbalance resulting in voltage differences across phases will be specific to each network and should be considered prior to applying a tap adjustment. This imbalance is normally kept within 2% of the nominal voltage. The typical level of LV current phase imbalance has been assessed in Flexible Networks with the monitoring and analysis of a range of LV feeders. Large volumes of secondary substation LV voltage phase measurements are also available for analysis and characterisation.
- Might need to re-wire some older transformers (remove transformer from pole and replace with pre-adjusted one, some poles might also be replaced in process).
- Any secondary substation voltage control scheme should be applied with consideration of primary substation voltage control schemes that exists or are likely to be applied in the future.

2.5.2 Secondary Substation Voltage Management [continued]

The control engineer will need to be aware of any wide-scale LV voltage control schemes applied, through the NMS. Although at LV, there is limited visibility and control of the network in the NMS. However, it is anticipated that any future secondary substation voltage control scheme will be either a fixed seasonal setting or fully automated, requiring no input from network operations apart from de/activation in limited circumstances.

In the future as pressure on the network increases, automated on-load tap adjustment of secondary substations may become more wide-spread however, this will be costly and complex to deploy.

2.5.3 Series Voltage Regulation

Automatic Voltage Controllers (AVRs) are not new technology but have not been used widely in the UK. In the past, they have been occasionally used to provide voltage support in rural areas but they are increasingly being installed to mitigate voltage rise issues caused by generation connected to the 11kV network and by doing so avoid the need for costly network upgrades.

AVRs are currently used in limited numbers at 11kV in SPD and SPM to mitigate voltage issues caused by individual larger scale generation connections on long spur lines in radial circuits. These are normally two tank and are set to regulate freely with no SCADA integration. AVRs on main feeders are required to be three tank AVRs with telecontrol installed and are managed remotely through the NMS.

Reconfiguring networks in order to implement Flexible Network Control (FNC) by shifting load between HV network groups can result in a voltage drop at the end of long feeders below statutory limits. An alternative application for AVRs is being placed in series on long feeders to cost-effectively boost voltage and enable FNC.

As part of the Flexible Networks project, SPEN has installed and tested a three tank telecontrolled AVR in the St Andrews 11kV network to facilitate FNC. A range of performance tests at the PNDC have also been carried out. The device is located on the St Andrews to Anstruther circuit in the vicinity of the St Andrews Bay Hotel, adjacent to West New Hall secondary substation, where there are known voltage issues during backfeeding conditions.

An operational code of practice regarding the control of AVRs has been developed by SPEN control engineers and includes the following;

- Units are not connected to a parallel network unless they are tapped to neutral.
- A Technical Limitation Record (TLR) is attached to any normally open point to warn if an AVR needs to be tapped to neutral prior to switching. This system will be adopted for the St Andrews regulators and the other regulators coming under telecontrol. Telecontrol is required for all AVR installations on a main line.

2.5.3 Series Voltage Regulation [continued]

In order to monitor operation and condition as well as control basic functionality, three tank AVR units are integrated with the NMS. The network control engineer has access to the following information in the NMS;

- AVR rating and tap setting range
- Unit status – indication of selector switch position(s)
- Indication of control mode
- Tap setting of all AVR tanks (including alarms for top tap and bottom tap positions)
- Target voltage
- Load current and direction

The network control engineer has remote control of the following settings in the NMS;

- Select to Manual Operation
- Select Auto Operation
- Tap setting (particularly for tap to neutral during network paralleling)
- Time delay settings
- Control mode
- Line Drop Compensation (LDC) values

Tap to neutral and switching out of automatic mode during network paralleling required for FNC schemes are very important controls from a safety standpoint. It is highly dangerous to connect an AVR to two parallel networks with differing voltages if it is not tapped to neutral as this could result in circulating currents with the AVR and catastrophic failure. Also, the unit must be switched out of automatic operation mode so once the unit is set to neutral it does not start to operate the tap changer.

It should be noted that the majority of AVRs already on the network are not under telecontrol, being two-tank devices on spur lines, and it is necessary for a technician to attend site to ensure the unit is in neutral during times when the network needs to be reconfigured. The roll out of the new telecontrol design as part of Flexible Networks will result in less operation needing to be carried out in future however manual operation will still occasionally be required.

ESDD-02-008 “Quality of supply, system voltages and voltage regulation” addresses the use of AVRs for system voltage correction and provides a description of open and closed delta configurations as well as policy on design and operation. This document is currently under review and update.

The voltage policy states that once the need case for an AVR is clearly established, the optimal AVR location will be derived from exhaustive network modelling taking into consideration loading and likely tap positions on interconnectable circuits under network normal and abnormal conditions. The voltage profile along the circuit should be considered under the extreme scenarios of (where appropriate) maximum / minimum generation and maximum / minimum load. The recommended target voltage of the regulator should ensure that the network is fully compliant with respect to voltage performance under all credible scenarios. This will ensure that the AVR will provide the expected benefits without compromising network security or power quality.

2 Integration of Network Innovations into Business as Usual [continued]

2.5.3 Series Voltage Regulation [continued]

As per the voltage policy, only one regulator is to be installed on a main feeder although multiple devices may also be installed on spur lines i.e. no sequential devices. AVRs on interconnector or ring circuits will be able to accommodate reverse power flow and have capacity for bypass. It is unlikely that an AVR installed on a main feeder to control voltage during backfeeding conditions will interact with an AVR situated on a spur line to control a generator's contribution to voltage rise, as the main line AVR will only be required during high load and thus low voltage conditions. However, definition of tap settings on the main feeder AVR should take this into consideration.

Guidance is provided in the voltage policy on the appropriate AVR control mode as follows;

- For AVR's installed on spur lines, the default control mechanism of the units should be 'Co-Generation'.
- For a main line where there is no feasible alternative network connection, the default control mechanism of the AVR should be 'Co-Generation'.
- For a main line where there is an alternative network connection, backfeed or change in the direction of power flow, the default control mechanism of the AVR should be 'Co-Generation'.
- Where the regulator is being established to resolve load related voltage issues, the default control mechanism for the units should be 'Bi-Directional'.
- AVR response can be optimised through use of the Line Drop Compensation feature.

Other considerations for inclusion in the voltage policy and network planning and operation codes of practice include;

- The interactions of an AVR operating on an HV network with dynamic voltage control at the primary or secondary substations will be carefully considered to ensure that there will be no tap hunting between the two voltage control systems.When used in a meshed network, AVRs may locally change the voltage angle which could result in adverse power flows through the network. This should be carefully assessed through modelling during concept design.
- Consideration of the fault level at the proposed point of regulator deployment shall consider also any future potential for increase in that fault level as the network evolves (e.g. from the connection of generation).

In future, AVRs may be integrated into an autonomous voltage control scheme at the local level. This would require clear definition and verification of an algorithm to determine the control mode and settings that the AVR will automatically apply under extreme network conditions e.g. maximum demand/minimum generation, for normal and abnormal running conditions.

Training schemes are in development for control engineers including guidance on consideration of AVRs during switching procedures, AVR manual control when required and any by-pass isolators to enable maintenance to take place.

As part of stakeholder engagement it was found that unlike SPEN, many other UK DNO's do not allow for the connection of AVRs to facilitate intermittent generation connections. The issues surrounding installation of AVRs for generation connections have been found to be more complex than previously thought and future policy in this area is under active discussion.

2.5.3.1 ADD-AMP Feature

By constraining the allowable tapping range of the AVR, the "load bonus" function of an AVR (referred to by Cooper Power Systems as the "ADD-AMP" capability) can also be considered. The "ADD-AMP" function permits an increase in the maximum current rating of the AVR to be achieved provided that the tapping range of the AVR (and therefore the extent of voltage control that it is able to provide) is correspondingly limited.

However, permitting a higher rated current to flow in the regulator's series windings could lead to localised winding hotspots that, in turn, could induce premature insulation ageing. Whilst IEEE C57.15:2009 goes some way to addressing this issue, it is felt that the lack of a methodology in that standard for calculating the localised steady-state hot spot temperature rise from measurements of top oil temperature similar to that set out in IEC 60076-7:2005, gives some grounds for caution.

In cases where it is deemed acceptable to take benefit from the ADD-AMP feature, then consideration should be given to the provision of additional in service monitoring of the regulator to determine the extent and duration of any operation beyond the nameplate rated current.

2.6 Improved network monitoring

The value of increased granularity of network monitoring on both the HV and LV network is being investigated as part of Flexible Networks. From our analysis, monitoring at HV and LV can provide some significant benefits such as;

- Improved characterisation of embedded generation on the LV network and corresponding voltage profiles, particularly in areas of high clustering.
- Improved characterisation of demand and corresponding voltage profiles. As part of SPEN's RIIO-ED1 business plan, a 'smart' secondary substation monitor will be deployed to increase data resolution in key locations across the wider network and ultimately improve understanding of asset utilisation and network reinforcement prioritisation.
- Better understanding of levels of HV and LV phase imbalance and correlation with network 'types' e.g. suburban rural. Findings can provide some general guidance to control engineers when considering suitable backfeed configurations.

Learning points above and the availability of additional network metrics will all aid in the development of improved voltage management strategies, outage planning and response plans for network faults.

Appendix A – Flexible Networks for a Low Carbon Future Background

'Flexible Networks for a Low Carbon Future' (Flexible Networks) is a Scottish Power Energy Networks (SPEN) Tier 2 Low Carbon Network Fund (LCNF) trial project. Flexible Networks will provide 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 Error! Reference source not found.. Further details of the trial areas are provided in Appendix A.

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 but representative characteristics and customer demographics, and are similar 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 A-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.

Improved Operational Tools

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 transformer, which generally does not provide information on the dynamic interactions of the various systems 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 and keeping 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. Presently, 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. The focus of the work carried out has been 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. A key aspect has been the engagement with network operations and planning staff to understand their viewpoint and needs with the objective of obtaining buy-in accept change.

The 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 availability of higher resolution network data from enhanced network monitoring can be utilised in the control room to improve risk management capability through real-time analysis of the data or improved 'rules of thumb' to provide information that corresponds more closely to the planning methodology and equipment capability.

As network planning methodologies and network technology become increasingly sophisticated, network control staff also need to be provided with more information to help them manage and control the network in compliance with the planned and technical limits. Simply increasing the level of information is in itself not the answer, control staff need to be provided with useful interpretation of situations to aid with their decision making processes.

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 12/24MVA 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.

In the NMS, a network diagram shows the current network configuration and all items of plant down to LV with linkage to the asset database which provides asset ratings. Real time current and voltage is displayed for primary transformers and the EHV network. Real time current is shown for the yellow phase of the HV feeders.

There are a number of alarms in the NMS that can be set by the control engineer for exceedance of various displayed parameter values permanently or for a specific duration. Alarms/event indicators may relate to temperature, current, voltage, protection operation and switchgear open/close.

Network operators are responsible for a number of key activities including;

- Outage planning
- Unplanned outage response

This includes network reconfiguration and requires consideration of network loading, asset ratings and embedded generation to maintain quality and security of supply. These activities and considerations are described in further detail below.

Outage planning

Outage planning and management is carried out to secure the network during periods of asset maintenance or network reinforcement (typically during the summer) or possibly other reasons such as to install monitoring equipment.

- Outage planning is for 1 to 4 weeks ahead based on historical and forecast demand profiles and historical outages where available.
- Outage management is generally up to 24 hours ahead based on historical and forecast demand profiles and historical outages where available.

The backfeed configuration for outage planning is typically determined using the outage planner's experience of the network area along with historical load data taken directly from the load database. Spreadsheet based tools are used to access and summate the load data. The level of scrutiny applied to a particular outage plan will depend on the perceived level of risk. For example, significant outages (e.g. switchgear/ switchboard replacement after the autumn clock change) would receive more detailed consideration.

Power systems studies are generally not currently run for outage planning. Asset ratings are based on nameplate ratings for transformers and seasonal ratings for overhead lines and cables, as defined in SPEN policy. The presence of generation at 11kV and above and large customer loads is also considered.

Network planners complete a schedule of works when maintenance or reinforcement is required for a certain part of the network. Once accepted, this is displayed in the NMS so control engineers can manage this area of the network appropriately.

Unplanned outage response

Unplanned outages are identified through alarms in the NMS for EHV and HV or customers phoning in. If a circuit trips then it will be switched back in several times, to check whether the fault has cleared. If the fault does not clear, then the section of circuit where the fault is located needs to be determined. Sometimes this can be identified from the type of alarm or event. If not, then switching sections of the circuit out and switching the remaining circuit back in may help to isolate the fault. If the circuit no longer trips then the fault has occurred in the section that was switched out. The trace feature within the NMS allows the operator to trace the path of all connected circuits to determine which substations are supplying the network of interest.

In general, network reconfiguration for restoration due to unplanned outages will be selected based on experience and understanding of the network. Plans may be prepared by operations staff 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 load cases are dealt with from experience.

Asset Ratings

NMS network diagrams are linked to the asset database to display asset ratings. These are also documented in SPEN Design manuals and policy. For transformers, these are the nameplate ratings which can be defined as continuous or cyclic. The use of cyclic ratings is described in TRAN-01-004 "Manweb primary transformer application and rating policy".

Network Restoration

The 33kV and 132kV network are managed by a small team of control engineers as the EHV network is relatively small compared to the 11kV and LV networks. These engineers have an excellent understanding of reconfiguration options and associated network behaviour. In SPM, due to the nature of a meshed network, there are a larger number of possible reconfiguration options compared to a radial network, with asset ratings fairly standardised to enable this.

For the 132kV and 33kV networks, power systems analysis is carried out on network models to assess the reconfiguration power flows, due to the higher criticality of the EHV network and associated increased network security requirements. Historical load data is obtained from the load database to populate the network model.

The 11kV network operations team is larger due to the volume of the HV network and varies depending on the workload. Control engineers may not have the same expert knowledge of the network as network areas are assessed as required on a case by case basis. Calculations are done in spreadsheets using historical load data is obtained from the load database or real time data from the NMS to select the most suitable backfeed option is there are multiple options. CI and CML are a key consideration when defining the restoration sequence.

When planning network restoration, generation is not considered below 11kV. Generation is assumed to be unavailable to support the network.

Once the restoration plan is complete, network control devices carry out the required switching actions. Network reconfiguration is carried out by remote switching via the NMS or sending engineers to site to manually switch. Remote switching in the NMS is available for most circuits at 33kV and above, with some remote switching at 11kV. If a device requires manual switching then a flag will be set within the NMS.

Following remote switching, the network diagram will automatically be updated in the NMS. For manual switching the network update must be updated manually once confirmation is received from site that the switching has taken place.

The new configuration will be recorded manually in a switching schedule for network planners, which can be viewed in the NMS.

Embedded Generation

Generation is considered for direct connections at 11kV and above. In the event of a significant demand outage, potential voltage rise due to generation is assessed. This is based on rated capacity as real time generation outputs are not visible to the SPEN control rooms.

During a planned or unplanned outage, the contribution of embedded generation to demand supply is assumed to be negligible to minimise risk due to potential variability e.g. wind, PV.

Generation and also large loads at 11kV and above can be curtailed by SPEN during an unplanned outage if required, for restoration purposes for example. This is currently carried out by direct (phone) contact with the generation owner/operator or demand load customer.

Appendix D – Stakeholder Engagement

The following SPEN staff were consulted during the development of this document. A number of business units were involved including Network Operations, Network Planning and Design and Asset Management both from SPD and SPM.

Table: SPM circuit voltage profile

Department	Name	Role
SPEN – Future Networks	Alan Collinson	Engineering Specialist
SPEN – Future Networks	Kevin Smith	Lead Engineer
SPEN – Future Networks	Watson Peat	Lead Engineer
SPEN – Future Networks	Clive Poole	Seconded from TNEI
SPD -	Graeme Vincent	Asset Management
SPEN - Design	Cornel Brozio	Analysis Manager
SPEN - Design	Elena Chalmers	
SPD – Network Operations	Graham Denton	Control Engineer
SPD – Network Operations	Grant McBeath	Control Engineer
SPD – Network Operations	Trevor Hurry	
SPM – Network Planning	Miles Buckley	Senior Design Engineer
SPM – Network Operations	John Knott	Control Engineer
	Geoff Wood	Asset Management - Transformers

System design voltage requirements

The Electricity Safety, Quality and Continuity Regulations 2002 require that the voltage at a customer's supply terminals be maintained within 230V +10%/-6% which is equivalent to 216V to 253V respectively.

Table B-1 quotes the voltage control policy regarding the maximum expected voltage drop/rise across the different network levels. Please note that the following are provided on a 230V customer base.

Table E-1 Maximum expected voltage rise/drop

	Full Load (Max Vdrop)	Min Load (Min Vdrop)
33/11kV transformer tap range	-1.0%	+1.0%
HV Circuits	-3.5%	0.0%
HV/LV transformer	-1.7%	0.0%
HV/LV transformer ratio gain	+8.7%	+8.7%
LV mains	-5.5%	0.0%
LV services	-3.0%	0.0%

SPM present control scheme

The primary target voltage was previously +1%, a programme is in place to reduce this to 0%.

SPD present control scheme

The primary target voltage is 11.2kV.