SP Energy Networks 2015–2023 Business Plan

Updated March 2014

Annex

Load Related Investment Strategy

SP Energy Networks

March 2014

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1. Scope

This annex provides a summary of the business processes and draws on design guidance documentation. It provides an overview of the methodologies and interfaces but replicates only the procedural details that are relevant at a higher level.

The annex solely considers the drivers and decision processes associated with investments required by load related activities. The load related workstream is independent of the asset replacement (Non-Load) programme but there is close cooperation and coordination of activities and timelines in order to optimise delivery efficiencies and minimise risk to the system and continuity of customer supplies.

The Load Related Investment Strategy identifies areas where investment is (or may be) required, it does not seek to propose solutions. The conversion of system issues or new connection requirements to economic and efficient projects is addressed by other guidance and therefore out with the scope of this strategy review. However, a high level summary is included in order to place the strategy in the context of the portfolio of projects.

2. Table of linkages

This strategy supports our ED1 Business Plan. For ease of navigation, the following table links this strategy to other relevant parts of our plan.

Document	Chapter / Section
SP Energy Networks Business Plan 2015-2023	Chapter C6 - Expenditure
SP Energy Networks Business Plan 2015-2023 Annexes	Annex C6 – Expenditure Supplementary Annex – SPEN
SP Energy Networks Business Plan 2015-2023 Annexes	Annex C6 – SP Manweb Company Specific Factors – SPEN
SP Energy Networks Business Plan 2015-2023 Annexes	Annex C6 – Transform Model Analysis and Support – EATL
SP Energy Networks Business Plan 2015-2023 Annexes	Annex C6 – RIIO-ED1 HV and LV Network Investment Analysis - Phase 2 – TNEI
SP Energy Networks Business Plan 2015-2023 Annexes	Annex C6 – SP Manweb Company Specific Factors – SPEN
SP Energy Networks Business Plan 2015-2023 Annexes	Annex C6 – LCT Network Monitoring Strategy – SPEN
SP Energy Networks Business Plan 2015-2023 Annexes	Annex C7 – Smart Grid Strategy - Creating a Network for the Future – SPEN
SP Energy Networks Business Plan 2015-2023 Annexes	Annex C7 – Smart Meter Strategy – SPEN

3. Introduction

This annex is provided to offer better transparency of the strategy, policy and processes that Scottish Power Energy Networks employ in determining Load Related Investment Programmes. Ofgem feedback to the 2013 submission concluded that further information in regard to our strategy would be helpful.

By clarifying and publishing the rationale, decision-making process and community engagement which inform and shape the development of the load related investment programme, we intend that Ofgem and our customer base in general will have greater confidence in the drivers and component projects of the Load Related Programme.

4. Objectives

4.1. Objective of the Load Related Strategy

Application of the Load Related Strategy is intended to remove all unacceptable capacity, voltage and fault level issues from the distribution systems of SPD and SPM and the programme of projects will result in significant progress towards that goal by the end of the RIIO-ED1 period. This aspiration however is based on current estimates of economic growth and it is acknowledged that, in the event of significant demand growth driven by the uptake of Low Carbon Technologies or electrification of transport, triggered events are likely to occur within the review periods, necessitating a re-appraisal of the programme and associated timeline.

4.2. Principles for Load Related Investment

The purpose of the Load Related Investment Strategy is to ensure that the system is fit for purpose, both now and for the foreseeable future.

The system therefore must operate robustly, meet statutory and licence obligations and satisfactorily meet customer expectations for:

- *Current system conditions,*
- *Anticipated system changes and loads,*
- *Changes to the system arising from Asset Replacement or Non-Load programmes.*

Therefore, in high level terms, the system must be capable of meeting the requirements imposed on it by customers without exceeding equipment ratings and while satisfying statutory obligations such as system security, system voltage and overhead line ground clearances. This requires that present and all reasonably predictable future scenarios of load flows, fault levels and voltage issues can be accommodated by the system configuration and component capabilities.

Measures of System Utilisation

A measure of the system capability or utilisation is provided by its Load Index rating. The Load Index (LI) is a key regulatory measure for primary (33kV) and 132kV network substations. Each substation is assigned an LI rating between LI1 (low) and LI5 (high) and provides a measure of how well those assets are utilised. This measure was introduced in 2010 as a regulatory output measure of comparative network loading and risk across different companies and has been further refined for ED1 to derive a consistent methodology of reporting across all distribution network companies. The LI values are essentially loading percentages based on the substation maximum demand during the year and are structured as follows:

Load Index (LI) Banding	Loading Percentage	Duration Factor
LI-1	0%-80%	N/A
LI-2	80%-95%	N/A
LI-3	95%-99%	N/A
LI-4	>99%	Less than 9 hours above 100%
LI-5	>99%	More than 9 hours above 100%

Table 1: Load Index Bands

The maximum demand at a substation, a key element in the calculation of LI rating, is largely driven by our customers' usage at a particular point in time and this profile will vary across our franchise area. As a result, performance against the LI deliverable is not directly within our control, and the investment schemes we deliver will reflect the actual changes in our customers' power needs.

The Load Index methodology is an excellent method of achieving consistency of reporting across the industry although it does not necessarily trigger reinforcement if the overload is marginal or for particular reasons such as tourism areas imposing short term loads during spring or autumn breaks.

Reasons for Investment

Load Related Investment is a high level term which covers all investment projects or programmes which do not arise from asset condition requirements. Therefore, Load Related Investment can be separated into five broad categories:

1. *Customer Connections*
2. *System Reinforcements triggered by general load growth*
3. *Fault Levels*
4. *System Reinforcements required for Voltage or Voltage Step Considerations*
5. *System Reinforcements triggered by embedded generation*

Customer connections are a specific subset of activity which is driven by customer requirements and therefore any triggered reinforcements are reactionary in nature with project scope and cost apportionment being specific to that application, although there may be a wider system benefit.

Similarly, system reinforcements triggered by specific embedded generation are deemed customer driven reinforcements and addressed by methodology similar to load customers.

At a high level, the relationship between project drivers and the development of a load related investment solution is indicated in Figure 1

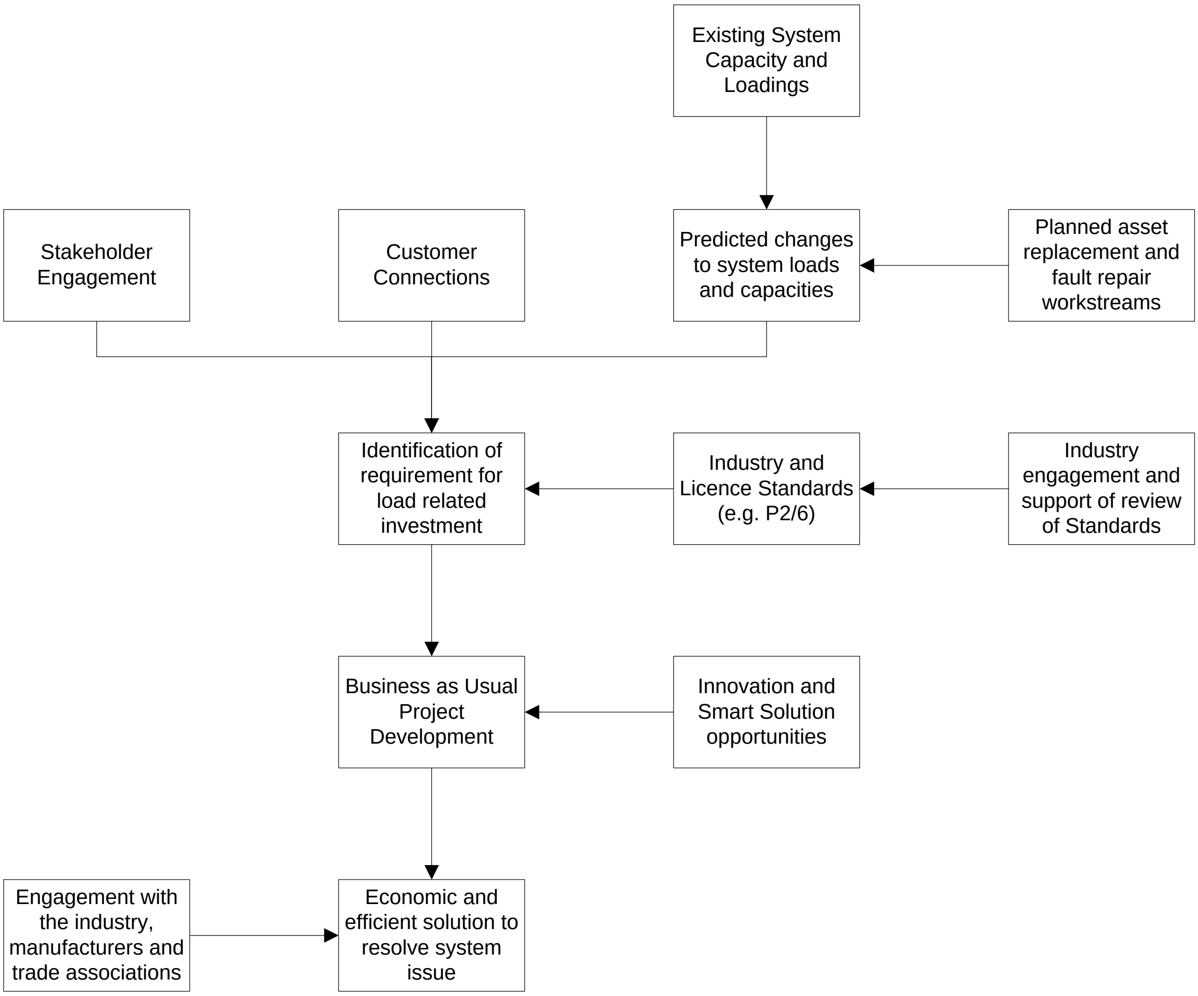


Figure 1: Load Related Investment Drivers and Investment Solution

5. Overview

Higher voltage networks such as Primary substations and above have long lead times to construct, replace or reinforce and therefore planning some years in advance is crucial. In order that we can therefore identify, in good time, areas of our network which require load related investment, we need visibility and a clear understanding of three aspects of system utilisation:

Load – the demand placed on the system from domestic, commercial and industrial customers. This requires taking account of anticipated changes arising from societal ‘background’ load changes and predicted changes from the uptake of emerging technologies such as heat pumps, electric vehicles and local generation. At Primary substation level and above, it is also possible to include known developments which will increase or decrease the demand on that location.

Capacity – the term capacity relates to the ability of the local system to supply the load imposed on it. The available capacity will reflect the combination of all the components (such as cables, overhead lines, transformers etc.) in the connection chains. Larger substations such as Primary substations (or groups of primary substations) will have two (or more) supplies into the local system and the declared capacity is effectively the capacity which is available with the largest connection(s) being unavailable due to outages. This required capacity will be in accordance with the P2/6 industry planning standards as a minimum.

Customer Activity - we engage with stakeholders in order to identify future additional demands on the system such that informed investment plans can be developed. The objective is to ensure that stakeholder ambitions are realised without supply constraints or reinforcement timescales imposing barriers to their developments.

Assessment of Load

System load data is critical to many of the business processes - understanding, documenting, validating and tracking the demand on the network and the network components is critical to safe and efficient operation of the network and compliance with licence obligations. Efficient and accurate preparation of system load data facilitates:

- *The customer connection process*
- *Timely identification of system reinforcement requirements*
- *Demonstration of compliance with system security obligations*
- *Development of the 'Week 24' data requirement for submission to the System Operator (SO)*
- *Derivation of system load data required for publication in the distribution Long Term Development Statement (LTDS)*

In order to execute these requirements and satisfy the business processes, an understanding of the historical performance is required as well as an understanding of the influencing factors which enable an estimate of future load to be made. The future demand estimation is therefore constructed from four components:

- *Historical performance of both real (MW) and reactive (MVAr) power*
- *Basic background demand movement*

This will include known or anticipated load step changes (at Primary Substation level and above) arising from potential future new connections or market intelligence via stakeholder engagement. More details on this aspect are contained within Appendix F.

- *Impact of emerging technologies (e.g. heat pumps, electric vehicles etc.) and*
- *Local step changes arising from known or contracted developments (acquisition or disconnection etc.)*

As the system capability is generally expressed in MVA (or kVA), it is important that the identification of system load takes account of reactive demand (or power factor) and is similarly expressed in MVA or kVA.

How we go about identifying system loads is discussed in more detail in Appendix A of this document. Arising from that assessment, the resultant load growth factors for both SPD and SPM over the ED1 period, including the apportionment of background and LCT driven load growth is indicated in Figure 2 and Figure 3 respectively.

It is clear from the figures that the anticipated LCT is a major factor in the future demand growth scenarios for both SPD and SPM and this is discussed in Appendix A at a high level and in more detail in **Annex C7 – Smart Grid Strategy - Creating a Network for the Future – SPEN.**

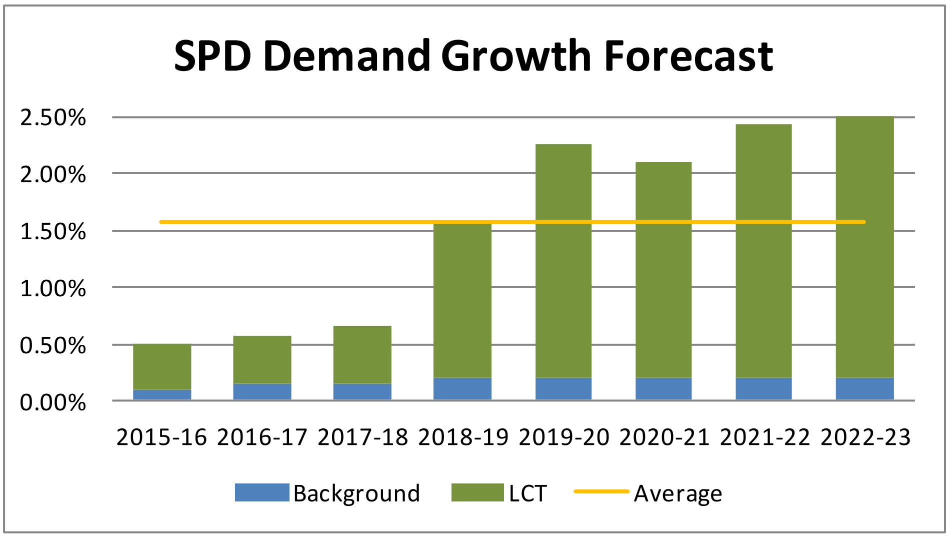


Figure 2: Demand Growth Forecast for SPD over the ED1 Period

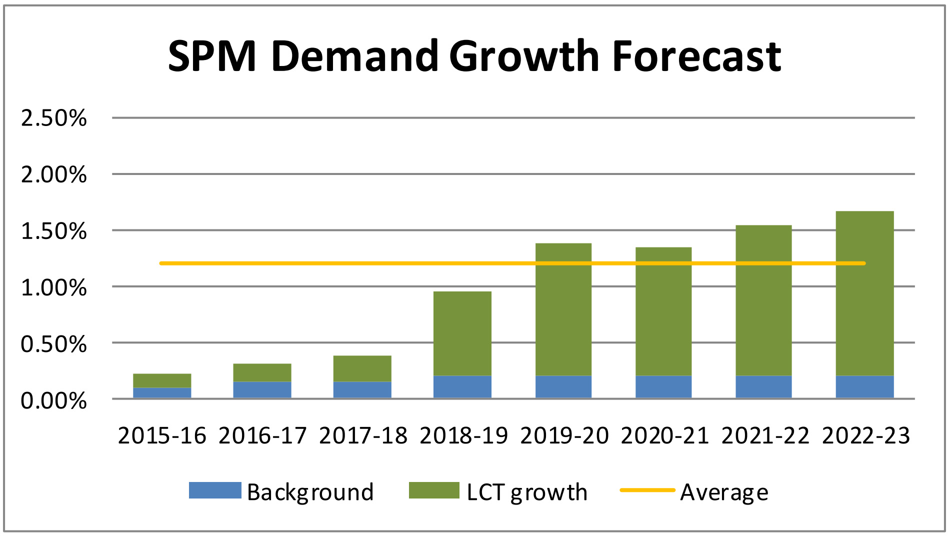


Figure 3: Demand Growth Forecast for SPM over the ED1 Period

Equipment Capability

The Electricity Safety, Quality and Continuity Regulations 2002 (ESQCR) requires that we ensure that our equipment is sufficient for the purposes (and the circumstances) in which it is used. It also requires that it be constructed, installed, protected (both electrically and mechanically), used and maintained to prevent danger, interference with or interruption of supply, so far as is reasonably practicable.

In essence, this requires that all equipment and components of the distribution systems have a capability to meet their duty. The components which make up the system have duties imposed from two different operating environments – steady state and fault conditions.

The steady state (or thermal) condition includes the normal operating conditions of a fully intact system or a system where equipment is out of service for maintenance. Equipment capability varies with a wide range of factors such as wind and temperature (for overhead lines) and ground conditions (for underground cables).

A system experiencing fault conditions has much higher power flows for a short period of time before automatic protective equipment disconnects the fault from the system. Therefore, as well as coping with the normal load current situations (i.e. thermal assessments), system components must be able to handle those short circuit fault events. The fault level capability falls into two broad categories:

- *Inactive components (such as cables and overhead lines) which are only required to withstand the fault currents for a defined time period without failing mechanically and*

- *Active components such as circuit breakers which are required to actively disconnect the fault from the system, again without catastrophic failure of the device.*

More detail on Equipment Capability is included in Appendix B of this document

Load Related Investment Policy

Implementation of this Strategy into normal business processes and practices is achieved by application of the SP Energy Networks Load Related Investment Policy on which this annex document is based.

As stated in the Objectives section of this annex, the purpose of the Load Related Investment Policy is to ensure that the power network is fit for purpose, both now and for the foreseeable future. Therefore, in simple terms, the capacity or capability of the system and its components must be such that they can meet the needs and duties imposed on it from normal and anticipated conditions.

The Load Related Investment Policy sets out the processes for assessment of the system and identification of requirements to invest to resolve potential issues.

The Policy, and integral processes, relies on the underlying building blocks provided by the estimation of system loads and the assessment of equipment capability. On a simple level, the policy enables a comparison of burden with ability and facilitates the identification of possible deficits.

The Load Related Investment Policy identifies areas where investment is (or may be) required, it does not seek to propose detailed solutions. The Business as Usual (BAU) conversion of system issues or new connection requirements to economic and efficient projects is out with the scope of the Policy.

The Scottish Power Energy Networks policy document 'Load Related Investment Policy' provides more details on the philosophy and background to assessing reinforcement requirements.

New Customer Connections

Customer connections fall into one of two categories – Demand Developments or Generation Developments (although there can be a third hybrid category where demand customers are also commissioning generation plant as a composite load). Both types of connection will superimpose additional thermal loads on the existing system with generation developments also increasing system fault levels and system voltage. The voltage rise aspect of generation connections is a particularly significant factor for the 11kV and LV networks where the connection of a generator may result in an unacceptable impact on the voltage of the connecting circuit.

Customer connection developments which require system extension or reinforcement can be classified as:

- *Generic - Areas where developments are not yet known / identified or projects where clustering is not evident and which therefore require ad-hoc system extensions.*

- *Specific - Those projects, developments or areas which are currently known or identified and which are sufficiently grouped geographically to enable them to be treated as a cluster. By definition, these will be reasonably large developments (typically EHV or EHV/HV) as the more common scenarios of multiple LV or HV connections are generally business-as-usual and dealt with by normal business processes.*

- *Emerging – Areas where clustering has yet to be identified but where indicators to increasing levels of activity are evident. This is the transitional stage between Generic and Specific categories. Failure to identify or manage this could result in uneconomic investment with multiple single customer connections where load or generation connections are trunked to points on the system that facilitate the connection, rather than a single homogeneous and holistic solution.*

Connection activity and engagement with stakeholders provides indications of potential system reinforcement requirements and appropriate solutions by tracking connection hotspots, frustrated developments, technically sub-optimal connections and network constraints. This enables the development of a view of connection activity which informs and influences reinforcement requirements and solutions to best facilitate customer connection. It is anticipated that this 'tool' or methodology will enable the consideration of options to undertake system reinforcement as a reflection of multiple enquiries that, in themselves, are uneconomic. The funding and apportionment (if appropriate) would be in accordance with the commercial charging rules applicable at that time.

As the penetration of smart metering increases with time, the additional data and greater levels of visibility of customer behaviours that will become apparent will aid the early identification of hot spots or LCT clustering, together with advanced warning of emerging system issues such as overloads and voltage concerns.

Customer connection projects are designed and developed to ensure that all equipment is operating within its respective capability. The methodology and policy contained within this strategy which permits managed and risk-assessed overloads as a mechanism of ensuring appropriate and timely reinforcement projects is a reinforcement deferral mechanism only and therefore not a deployable solution as part of a customer connection or system reconfiguration project.

Stakeholder Input

New developments being undertaken by cities, regions and development agencies are potentially some considerable time in the concept and planning stages as they progress to a point where they would support or inform a detailed and formal application for connection. However, if these developments trigger additional infrastructure or reinforcements or have a dependency on wider reinforcement works, then there is a danger that the reinforcement timescales may not support the customer’s delivery aspirations.

It is critical that SPEN engage with customers and key stakeholders in order to inform and support developer decisions to ensure that their development ambitions can be realised. Therefore, in addition to the guidance material (such as the system 'heat maps' and Long Term Development Statements) provided through a variety of platforms to inform and assist stakeholders with site specific developments or plans, we proactively engage with stakeholders to enable mutual understanding of requirements and to better inform investment decisions.

More details on Stakeholder Engagement are contained within Appendix F of this document.

Smart Grid Enablers

Within our load related investment, we have identified the need for a number of enabling technologies to be deployed. These are considered as no-regrets investments which require to be deployed in a top-down manner and are an essential component for the efficient development of the network. Having the enabling technology in place will allow us to flex between different future scenarios. These are key smart grid components, and allow other smart grid applications to be deployed and are vital to enable and inform future reinforcement activity.

- *Voltage control upgrades – This investment will help to facilitate additional Distributed Generation to connect to the network through improved control of the voltage across our HV and EHV network.*
- *Network Monitoring – we will create a foundation of LV network monitoring to facilitate an improved understanding of the network. This will better inform future reinforcement requirements by providing more granular information.*

These investments do not, in themselves, create capacity, but provide more information on the existing capacity, how we can make better use of it, optimise utilisation and potentially defer reinforcements. The costs for these enablers are detailed below and are included within the Reinforcement costs.

	Enabler Costs per network (£m)	
Enabler	SPD	SPM
Voltage control	4.0	3.9
Network Monitoring	4.0	3.0

Table 2: Expenditure on Smart Grid Enablers during RIIO-ED1 Period

We have also included other enablers within our plan including IT upgrades to process the new streams of data that will become available from network monitoring and smart metering. These other enablers are embedded across our plan within business as usual and not specifically identified.

The network monitoring strategy is covered in detail in **Annex C6 – LCT Network Monitoring Strategy – SPEN**.

6. Our Strategy

6.1. Strategy for Thermal Assessment

When considering system condition and consequential requirements for reinforcement, the fundamental philosophy is that there is a clear understanding of what the system or equipment is being required to do and its inherent capability to perform that function. This can be summarised as Equipment Duty and Equipment Capability:

Equipment Duty is the load imposed on the equipment under a variety of scenarios such as intact or a depleted system. This duty also takes account of the reactive demands imposed on the equipment.

Equipment Capability is the capacity (expressed in MVA or kVA terms to take account of reactive demand) that the equipment (or collection of components) has to perform the required duty. While, under normal conditions, a site or group can be loaded beyond its firm capacity limit without overloading any equipment, there is an inherent risk that equipment will overload in the event that an outage occurs at a time when the site or group demand is close to, or at, peak. The actual duty of the site must therefore be assessed against the site capability to determine the time based level of exposure to risk. This is generally achieved by identifying the number of hours (together with their incidence) within a year where the load exceeds the firm capacity. Therefore, when the historical site/group demand exceeds capability, the duration and profile of any excursions require to be identified so that the risk and project initiation is triggered in accordance with this policy.

The Assessment Process

At a high level, the methodology for the assessment of system thermal issues enables an evaluation of the ability of the network to meet the demands imposed on it from a load flow perspective.

From a demand perspective, the load assessment process as described in Appendix A provides the baseline requirements for the system by identifying:

- *A current year normalised maximum demand*
- *Predicted maximum demands for the next 10 years*

This enables a comparison with the equipment capacities, taking account of any known equipment changes over the period. Equipment ratings, for a typical collection of components such as overhead lines, cables and transformers forming a substation or group, can be reduced to two primary parameters:

- *Firm Capacity and*
- *Cyclic Rating.*

Dynamic rating systems, if present, are generally considered real time systems which provide rating enhancement in operational timeframes. However, in future, as more historical monitoring data is gathered from the system, this will permit modification of the firm and cyclic rating factors to reflect the additional capacity available. The revised values will, by definition, be greater than the firm and cyclic values but less than the absolute maximum ‘ampacity’ available from the system under completely ideal and favourable conditions.

The process then tests decision points to expand on some aspects of the equipment duty versus capability balance to identify whether an overload risk exists, or is material. This clarification is centred on the magnitude and duration of any overload and considers it from three aspects:

- *Exposure to extreme overloads, i.e. loaded beyond cyclic capability*
- *Time exposure where the cumulative time in a year, when loading exceeds firm capacity, is considered excessive*
- *High equipment utilisation where there is insufficient or inadequate cool back period*

The process test point values will periodically be reviewed to embed experience and factor equipment changes. The methodology and process flow chart for the assessment of thermal issues is covered in more detail in Appendix C.

6.2. Strategy for Fault Level Assessment

Health & Safety requirements dictate that all equipment is fit for the duty it is required to perform. In order to comply with this requirement with respect to plant fault capability, the maximum prospective fault current must be controlled such that no item of equipment on the system shall be over-stressed due to its fault interruption or making duties being greater than its assigned rating. Over-stressing of equipment can result in disruptive failure and safety hazards.

As discussed in the thermal section of Our Strategy, when considering system condition and consequential requirements for reinforcement, the fundamental philosophy is that there is a clear understanding of what the system or equipment is being required to do and its inherent capability to perform that function. When considering the system fault levels, the high level assessment remains identical to the thermal assessment, i.e. Equipment Duty and Equipment Capability:

Equipment Duty - When a fault occurs on the transmission or distribution system, the current which flows into the fault will be derived from a combination of three sources:

- *Major generating stations via the transmission and distribution networks (i.e. system derived fault current)*
- *Embedded generators connected to the local network*
- *Conversion of the mechanical inertia of rotating plant equipment connected to the system into electrical energy.*

Circuit breakers which may be called on to energise onto faulted equipment or disconnect faulty equipment from the system will have precisely defined capabilities to meet the following equipment duties:

- *Make Duty - The make duty of a circuit breaker is that imposed on the equipment in the event that a fault occurs during energisation of a faulted or otherwise earthed piece of equipment.*
- *Break Duty - Circuit breakers associated with faulted circuits are required to interrupt fault current in order to remove faulted components from the system, thereby ensuring the prevention of damage to plant and maintaining security and quality of supplies.*

Substation infrastructure such as busbars, supporting structures, flexible connections, current transformers, and terminations must be capable of withstanding the mechanical forces associated with the passage of high magnitude fault current i.e. through-current withstand duty.

Equipment Capability is the capacity that the equipment (or collection of components) has to perform the required duty. In addition to the normal load current situations (i.e. thermal assessments), system components must be able to handle those short circuit currents which occur under system fault conditions. The fault level capability falls into two broad categories – inactive components (such as cables and overhead lines) which are only required to withstand the fault currents for a defined time period without failing mechanically, and active components such as circuit breakers which are required to actively disconnect the fault from the system, again without catastrophic failure of the device.

The Assessment Process

Whether carrying out a system wide or a local assessment, assessing existing system conditions or the impact of system changes / connections, the fault level assessment process is fundamentally similar:

- *Carry out the fault level calculations,*
- *Validate the results and*
- *Carry out an assessment of equipment capability and duty.*

In the majority of circumstances where the duty is within the high level assumptions for equipment capability, then steps 2 and 3 would not be necessary. Only where the calculation indicates the duty exceeds the assumed equipment capability or design limit, would further detailed assessment or refinements be necessary.

An annual system wide condition assessment is undertaken based on the analysis models for the current year and the following ten years and the relevant system year for maximum demand conditions and generation schedules based on the Gone Green Investment Planning Background. The contribution from connected and consented embedded generation is also modelled.

Fault levels are calculated down to and including 33kV and 11kV busbars at Grid Supply Points and compared to the substation equipment rating with a similar exercise carried out for the production of the annual Long Term development Statements (LTDS).

For each substation, the following fault current characteristics are calculated, typically for both three-phase and single-phase faults:

- *Peak make current (i_p)*
- *RMS break current (I_B) at break time (t_B)*
- *Peak break current (i_B) at break time (t_B)*

Over-stressing equipment from a fault level perspective is unacceptable and therefore the prospective fault current shall never be more than 100% of the plant capability. However, the generic assumptions made in a global assessment of fault levels will, by the nature of the assumptions, have a margin of error which may be more or less onerous than reality. To reflect this potential for under-estimation, an initial 'flag' value of 95% of plant rating is employed. Any sites which exceed this value will be the subject of detailed study to validate the calculated values. This detailed study will refine the analytical model for that site and assess the load category to establish a realistic assessment of fault contribution from load. Only when this process has been completed and the system model considered accurate, will the ceiling value of 100% be accepted.

The preceding analysis work will provide a robust estimate of equipment duty. This output can then be compared with the detail of equipment capability. Circuit breakers are required to perform peak-make and peak-break duties which are essentially location-specific; however switchgear is frequently referred to in generic or RMS terms. In addition, equipment specifications and the testing standards applicable at the time of manufacture differ significantly over time (e.g. BS116 or IEC62271-100) and, particularly for peak break duty; some equipment may perform acceptably for the local conditions by virtue of the basis of the original testing standards and the prevailing decay rates at that location.

The analysis of results considers these factors and defines whether specific duty at specific locations is acceptable or not. Where deemed unacceptable, the mitigation and resolution measures are initiated.

The methodology and process flow chart for the assessment and resolution of fault level issues is covered in more detail in Appendix D.

6.3. Strategy for Assessment of Voltage Issues

Under intact conditions, the network is in steady state and any load or generation changes are managed by the system with, for example, on-load tap changers adjusting their position to regulate the target voltage. Under normal system conditions the voltage variation is gradual and the tap change control scheme load-follows to ensure that the target voltage remains within acceptable limits. To optimise voltage profile and reduce unnecessary equipment deterioration, the control scheme has inbuilt time delays aimed at avoiding tap change position hunting.

When a fault occurs, or a planned outage taken, which effectively increases the impedance between the load and the source, the instantaneous change in impedance results in a step change reduction in voltage at the point of coupling of the load. Where there are on-load tap changers, the control scheme will initiate changes to restore the target voltage. However, while the tap change control will accelerate changes (compared to normal load-following mode), there is a finite time for the steps to take place back towards target. There is also the possibility that both load and remaining circuit impedance are high such that the maximum tap position may be reached (potentially restoring minimum voltage compliance) but short of achieving the target voltage.

Network analysis is therefore required to assess the voltage consequences of credible circuit outages, the ability of the tap changer to restore voltage and the potential remaining headroom in terms of transformer tap ranges.

- *The Assessment Process*

.The assessment for voltage issues is undertaken from two perspectives:

- *Steady state voltage profile – an assessment is undertaken to ensure that, for a range of load and generation scenarios on an intact system, the busbar voltages across the system are within statutory limits.*

- *Voltage step change – the voltage at the busbars across the system immediately following an outage and before any tap change operation.*

In order to make this assessment, the analytical model assumes:

System Demand	set at site Maximum Demands
Local Generation infeed	set to zero to identify worst-case when voltage is not supported by local generation output
Load Characteristics	the behaviour of load with system voltage is important when considering voltage step changes.

In general, a system wide assessment assumes the worst case for load characteristics so that, if specific sites are highlighted as problematic, refinement of the modelling is then possible for the load characteristic appropriate to the individual or highlighted site. In reality, this is likely to be a combination of load types which are representative of the customer base supplied from that network.

The system wide scan will provide confirmation of the system's ability to regulate busbar target voltage within acceptable limits under intact system conditions. The second part of the assessment provides a view of system voltage performance immediately following an outage and after tap change recovery. In order that the post-outage voltage is recorded prior to any corrective action from tap change systems, the system tap change controls are frozen at the steady state levels. The modelling analysis also reflects the real-world system connectivity in that, in instances such as banked or teed circuits, all components are removed from service at the same time.

Appendix E provides a detailed description of the process and subsequent analysis to identify voltage issues.

6.4. Application of Strategy

Application of this strategy identifies system reinforcement requirements, assesses those requirements in the context of existing or known programmes and maintains an updated prioritised portfolio of reinforcement projects. While the strategy does not dictate the solution or method of resolution of the issue, it is appropriate to consider the broad means of resolution in the context of implementation of innovative and economic solutions.

In accordance with the economic, efficient and coordinated obligations within the licence, solutions to issues identified within the policy will be assessed on a cost benefit basis and consist of one of three broad categories (or a combination of):

Lower cost, lower yield technical solutions – these allow the capacity of the existing network to be maximised and facilitate the deferral of a substantial reinforcement. Possible solutions may include:

- *Dynamic thermal rating where temporary thermal constraints are experienced.*
- *Network automation / load transfer where load can be managed between sites.*
- *Dynamic voltage / VAr control (e.g. StatCom or voltage regulation) where a voltage constraint exists.*

Commercial solutions – where contracts with customers in the affected area are established to offset the network constraint. The service provided by the customer could include:

- *Generator response – either the use of back up generation or merchant generation.*
- *Active Network Management – to manage excess generation within system constraints.*
- *Demand Side Response / Demand Side Management – where customers agree to modify their demand to resolve network issues*

Higher cost, high yield technical solutions – these are typically conventional reinforcements which are likely to involve the installation of new assets to accommodate load growth. While generally higher cost, the headroom created is generally greater and may be justified as the preferred option by cost benefit analysis and after taking due account of environmental, viability and reliability factors.

Irrespective of the solution deployed, in general terms, all solutions will, as far as reasonably and economically practical, be future proofed, such as facilitating future automation or monitoring. The selection of project solutions and alternative options is within the normal business processes and subject to normal technical and commercial approvals.

The total portfolio of projects such as asset replacement, customer connections and load related reinforcements all broadly follow the same process for technical approvals, financial approvals and coordinated into the project pipeline. While the business-as-usual identification, scoping, filtering and selection of alternative options does not form part of this strategy, it is worthy of a high level summary to place the Load Related Strategy in context. Figure 4 provides a high level process view of the process.

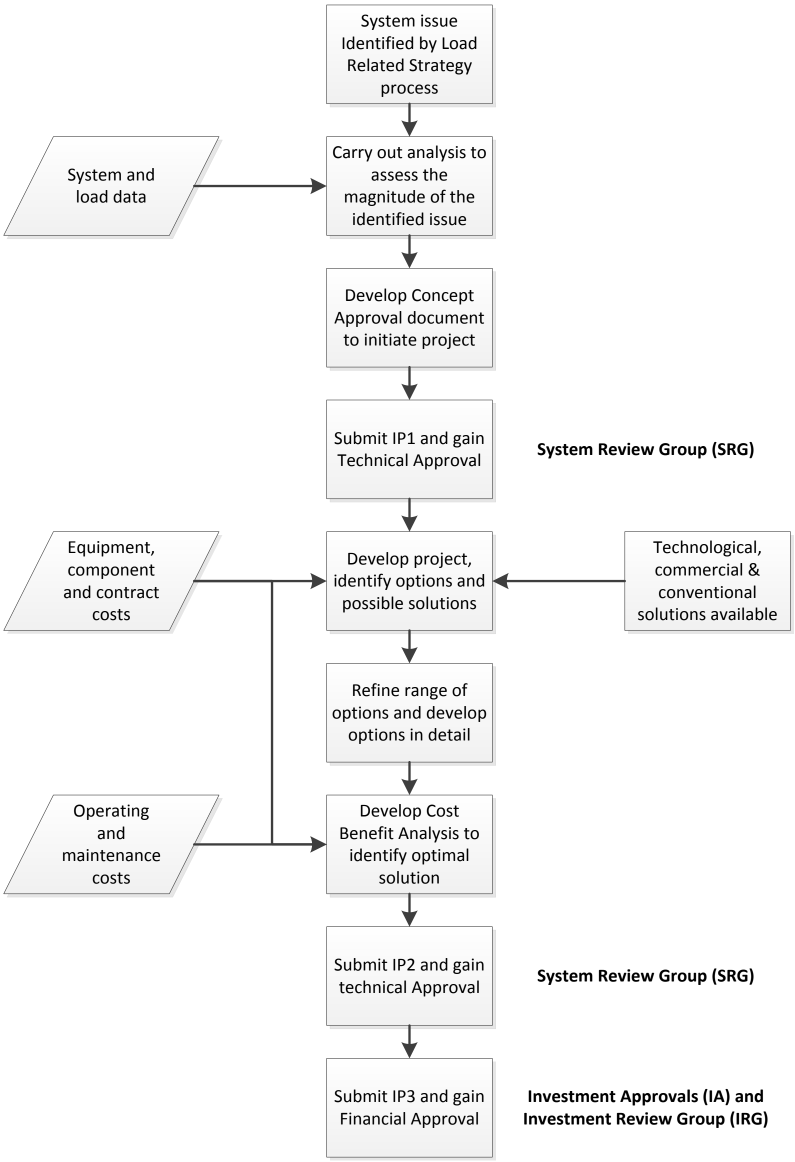


Figure 4: High Level Project Authorisation Process

Significant stages in the process are the core steps around the project development:

Develop project and identify options – at this stage of the process and with no preconceptions, all possible solutions are identified which will include technological or innovative solutions, commercial arrangements and all credible conventional solutions.

Refine range of options – during this stage in the process, the wide range of options is tested for viability, cost and benefit. This facilitates discounting those options which do not resolve the issue, are uneconomic or defer a substantive solution by only a year or two. This enables a reduction of options to a small subset with the greatest potential for success at an economical cost.

Develop optimum solution - by developing the solutions further to prove viability and refine the estimate of costs to drive out, as far as reasonably practical, cost and risk uncertainties and then incrementally compare the options by employing cost benefit analysis (CBA) methodology.

The normal governance process as briefly described in Figure 4 will ensure technical and financial company sign-off.

The technical governance process is achieved by means of review and approval by the relevant System Review Group.

Due to the differing knowledge base and geographic arrangements, the term System Review Group is generic and represents four separate review panels:

- *System Review Group (SRG) – considers all projects having an impact on the 400kV, 275kV and 132kV systems in the SPEN area of southern Scotland. The panel reviews projects down to and including the LV side (typically 33kV) of Grid Supply Points.*

- *Distribution System Review Group (D-SRG) – considers all significant developments on the 33kV and 11kV networks of SPD.*

- *SPM System Review Group – reviews all proposals for the 132kV and 33kV networks in the SPM network.*

- *SPM Distribution System Review Group (D-SRG) – considers all significant proposals on the 11kV network of SPM.*

The panels convene on a monthly basis in locations appropriate to the networks (i.e. Scotland and Merseyside). SPM meetings are typically held in the third week of every month with the Scottish meetings held in the fourth week of every month.

Application of the Strategy over the RIIO-ED1 will result in Load Index improvements in both the SDP and SPM networks. The anticipated movements inLI-3, LI-4 and LI-5 categories are indicated in the following figures. Figure 5 indicates the SPD position at the start of ED1, the position at 2023 without any interventions and at the end of ED1 taking account of the planned interventions. Figure 6 provides a similar view for the SPM network.

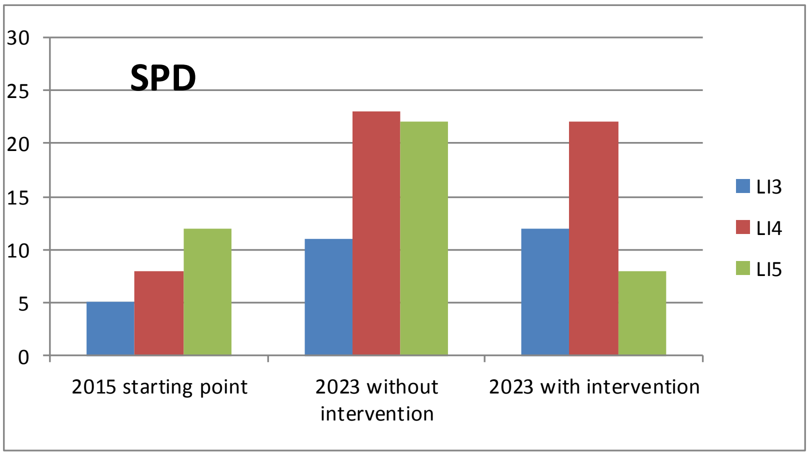


Figure 5: Load Index Movement for SPD over the ED1 Period

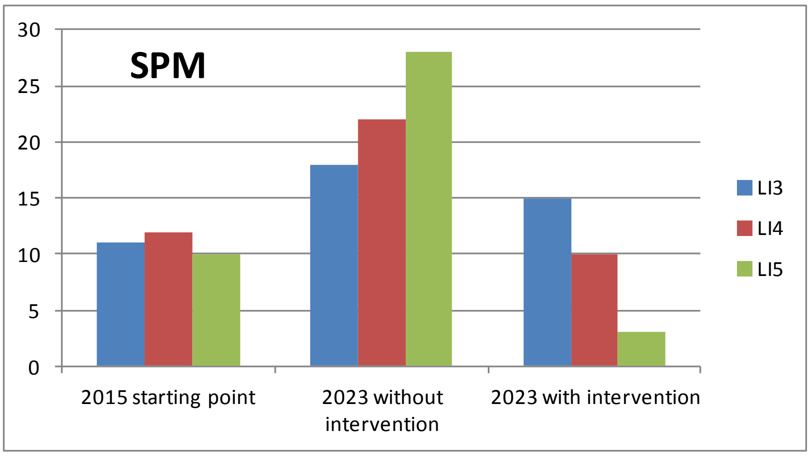


Figure 6: Load Index Movement for SPM over the ED1 Period

6.5. Programme Review

As discussed earlier, application of this policy produces an input into a portfolio of reinforcement projects. As system conditions change, the portfolio of projects will be required to flex in order to accurately reflect the current circumstances and therefore, in order that the portfolio is transparently available and reflective of current conditions, regular updating (at least annually) is essential.

As part of the overall assessment, a review of substation or group loadings will be undertaken in accordance with the guidance on Preparation of Load Estimates. Crucially, that review must identify the out-turn load variation factor which should then be compared with the predicted value from the previous year. The purpose of this is to identify whether load variation is occurring above or below the level previously predicted. This information can then be used to inform the load estimation process thereby generate a more accurate view of future loads.

Application of this revised load development factor within the Load Related Investment Strategy processes results in the routine updating of the relevant data streams and consequently informs a view on the overall programme and whether any intervention is indicated. Programme interventions that may be required include:

- *Reprioritisation of projects – where the update indicates higher activity which, if sustained, will require a project implemented earlier than planned. This may be matched by a site with slower growth which would enable a later start date for the associated project.*

- *Deferral of projects – where growth has been substantially slowed to such an extent that it is possible to defer implementation of the associated project into a subsequent price control period.*

- *Inform future investment programmes – anticipated growth or connection acquisition, together with close monitored of trends provide adequate advance warning of future reinforcement requirements that enable future investment programmes to be updated with the project requirements. This view will be validated by the annual reviews i.e. a project will be identified early but not implemented until such time as normal delivery timescales will enable an optimised commissioning.*

- *Accept higher risks until investment is possible – in the event that load development exceeds predictions and a site or group is loaded beyond normal limits before commissioning of the relief scheme (or the relief project is delayed), it is possible to accept higher technical risks provided that appropriate mitigation measures or plans have been developed, e.g. transferring demand to an adjacent group or substation under N-1 conditions.*

- *Price control re-opener – where any of the preceding options are not viable or the risks/costs are unacceptable, a Price Control Re-Opener will be considered to ensure that the solution to the network issue can be developed and implemented within the current Price Control period.*

7. Timescales and Timetable

Application of the Strategy produces an output which can potentially provide an input or modifier to the portfolio of projects. It may influence, or be influenced by asset replacement or modernisation programmes and therefore regular updates are essential.

However, application of the strategy has commonality with other business processes and regulatory / licence requirements. It is therefore logical that this process is coordinated and integrated with the common workstreams such as:

Week 24 submission	June / July
Load Estimates	July / August
RRP Submission	July
Long Term Development Statement	August / November

However, all workstreams are fundamentally dependent on source data such as system peak load data. As this data is generally not fully populated and assurance on winter peak is not absolute until spring clock-change, or at least the end of February, the data year is generally accepted as April-March. This then permits load analysis for the Week 24 submission in April which provides a baseline and data input into the other workstreams later in the year.

To best integrate and coordinate with other workstreams, the annual refresh of the strategy and resultant issues/solutions will ideally be undertaken in July.

8. Uncertainty & risk

8.1. Uncertainties and Challenges

The level of uncertainty for the requirements that are to be met by the distribution systems has never been greater than at the current time. Historically, the electrification of communities and the growth in consumerism had a single impact – increase in system demands. The challenges at that time were to keep pace with the growth and develop the network to cope with the rate of demand acquisition.

Network development was also effectively top-down to deliver the output of large power stations to communities using networks having a capability that reduced with distance from the source power stations. This has resulted in rural networks being fit for the purpose intended but inevitably weaker in nature compared with urban networks or networks close to large loads or generators. As load flows were also effectively one-way, and the components used were fairly static in nature, equipment was frequently installed recognising the one-way power flows, e.g. tapering cable sizes on the LV networks.

The use of the distribution systems has now fundamentally changed with customer equipment having different and dynamic operating regimes connecting to remote parts of the network. The emergence of low cost local generation has placed different operational requirements on legacy equipment, as will the newer emerging technologies such as heat pumps and electric vehicle charging.

The greatest uncertainties for the distribution networks are that of:

- *What technologies are going to connect?*
- *In what quantities are they going to connect?*
- *Where is it going to connect?*
- *Will reverse power flows be created?*

The DECC scenarios, industry consultation and stakeholder engagement provide some direction for the first two items but the location will generally be reactionary in nature. This may have a greater impact on the load related plans if technologies cluster and drive additional reinforcement requirements.

Technologies are developing and being deployed very rapidly and potentially there could be a consumer led technology which does not form part of the scenarios on which the plan has been based: these consumer led deployments could have widespread adoption within the ED1 period, particularly where consumer behaviours change and tipping points arise.

8.2. Mitigation Measures and Controls

In order that we can mitigate and manage these uncertainties and challenges, we have included baseline activities and platforms within our ED1 plan and business processes, which will provide a sound base for the conversion of an existing 'passive' network to a future 'smart' network.

This follows four high level approaches:

Understanding network usage

- *System Monitoring will provide greater visibility of network loading conditions (e.g. flows, voltages and power factors) which will better facilitate an assessment of system capability and spare capacity.*
- *Smart Meters will provide greater visibility of customer behaviours and final node network conditions, which will enable better extrapolation of system usage going forward.*

Technology investigation

- *We investigate, develop and innovate new and technological solutions to better facilitate the development of smart networks and better utilisation of existing assets. Examples of this are the Fault Level Monitoring device, Dynamic Line Rating, and Active Network Management installations.*
- *We engage with manufacturers to identify smarter and more economic ways of resolving issues. Solutions such as D-FACTS (Distributed Flexible AC Transmission System) devices and Power Flow Controllers are included within our ED1 plan. Other options which present opportunities include the Magnetically Controlled Shunt Reactor devices and Fault Current Limiting devices.*

Platforms for Future Innovation

- *Communications – a key part of any future smart network is the ability to remotely operate the devices, harvest and analyse data, and inter-device communication.*

- *In the dynamic network configuration that is rapidly evolving, an appropriate voltage control system is essential to ensure that it autonomously adapts to a wide range of scenarios. Control of all voltage levels down to, and including, the HV voltage level will require to be achieved in order to provide a solid baseline for future developments. Further development into the LV networks is possible although the economics will be a key consideration.*

Stakeholder Engagement

- *Understanding the needs of our customers who represent communities, cities and regions is a key input to our understanding of the necessary developments for the networks.*

- *New technologies will emerge, both consumer-led equipment and system tools, which could be utilised on the distribution system. By engaging with suppliers we will have early visibility of deployment or availability of the equipment.*

9. Glossary

B

BAU (Business As Usual) – the normal business processes on which this strategy is based or supported by.

C

Capacity – is the rated value of a component or group of components to operate satisfactorily at that level of operation.

Capability – is the ability that a component, or group of components, has to perform the duty imposed on it.

E

Equipment Duty – is the load impose on the equipment under a variety of scenarios. This can be steady state duty such as load flow or transient duty such as during the passage of fault current.

F

Fault Level – is the prospective fault current which will flow into a fault on the system from all sources of energy. Generally referred to in kA or MVA terms

Firm Capacity – is that load which can be supplied during an outage of the single largest transformer or circuit supplying the load. This is termed an N-1 scenario, i.e. an intact system minus one infeed. The resultant system must be compliant with statutory voltage requirement at the firm capacity loading. Larger sites or groups may require, in accordance with the security standards, consideration of more than one outage, e.g. N-2.

G

Group – see Substation Group

L

LCT – Low Carbon Technologies: refers to the emerging consumer led initiatives which will have an impact on the loading and utilisation of the distribution network. At this point in time, and in the context of this document, LCT refers to Photovoltaic (PV) generation, Electric Vehicle (EV) charging, Heat Pump (HP) installations and Energy Efficient home construction.

Load – is the demand placed on the system by domestic, commercial and industrial customers.

Load Index – a regulatory measure of system utilisation. The measure assesses loading as a percentage of the available capacity and groups the loading into percentage bands from low (LI-1) to highly utilised (LI-5).

Load Related Investment – relates to all investments which are triggered by system loads or additional connections. In the context of this strategy, load related investment includes those works triggered by customer connections (demand and generation), general load growth, unacceptable fault level or system voltage performance.

LTDS – Long Term Development Statement: is the annually published document by each of the Distribution Network Operator companies which provides existing and new system users and customers with information on network utilisation, investment plans and development opportunities. This is a condition of the Distribution licence.

M

Maximum Demand – generally refers to the measured peak demand on a site, substation or group of substations. Typically the measured maximum demand (MD) occurs in a winter evening although it is possible some sites may peak at other times where high process or air conditioning demand is present.

N

NMD - Normalised Maximum Demand is trend analysis used on historical maximum demand data to develop a current year NMD which is representative of the measured value and damps out excessive swings due to weather conditions at the time of the measured peak.

Non-Load – those projects or programmes which arise or are initiated due to asset condition or performance issues

P

P2/6 – See Security Standard

Primary – refers to the primary network (the 33kV system) or primary substations (generally 33/11kV substations although some exist with other lower voltage systems such as 6.6kV and 6kV).

S

Secondary – refers to the secondary network (normally the 11kV system but can also be operating at 6.6kV or 6kV) or secondary substations (generally 11kV/LV substations but 6.6/LV on some legacy 6.6kV islands).

Security Standard – this is currently P2/6 which is the sixth version of the P2 standard. The standard is an industry standard and is currently undergoing a fundamental review.

Substation Group – is, in the case of the SPM network, a number of substations which are geographically dispersed but which are connected by an integrated network at the lower voltage level. Under this arrangement, on removal of one infeed, the lower voltage network redistributes the load without customer connections or supplies being affected.

System Review Group (SRG) – the generic term applied to the four SPEN technical governance panels which technically assess and approve planned projects within their development phase prior to release for the constructional phases.

V

Voltage Step – is a measure of how the system voltage is affected by planned or unplanned outages of circuits or equipment. These events will result in an instantaneous reduction in voltage which system components as transformers with automatic tap changers will attempt recovery back towards the normal target voltage.

W

Week 24 – is an annual Grid Code obligation on Distribution Network Operators (and other significant system users), to provide data to the System Operator on system configurations, together with details of system demand and generation, fault level infeeds and predictions going forward in time.

10. Appendices

10.1. Appendix A: Assessment of Load

In order that a meaningful estimate of future system loads on a per-site (or per-group) basis can be made, the historic underlying demand and demand trend from an overall system perspective needs to be understood. The demand is that load imposed on the equipment under a variety of scenarios such as intact or a depleted system and takes account of system reactive demand. In terms of assessment for thermal issues, the high level process is indicated in the following sections:

Identify Substation / Group Measured Demand

To provide a good baseline for an assessment of future demands, derivation or capturing the current year measured demand for the site or group is required. This will generally be procured via corporate data systems such as the PI Data Historian data archive system. This provides raw values of power (expressed as MW / MVAr or MVA) which will fluctuate year-on-year due to the influence of external factors such as the weather, but provides a starting point for evaluation and assessment. At this phase of the process, the opportunity is taken to validate the raw data for unusual loading conditions such as extreme power factor ranges. Where individual sites do not have historian data streams for reactive power, the power factor will be derived from upstream data or by assessment.

As the penetration of system monitoring and Smart Meters increases with time, the increased levels of data will enable a validation and correlation with existing data streams and will facilitate a better assessment, at a much more granular level, of the underlying demand and load profiles.

Site / Group Demand Characteristics

The preceding section provides a simple measure of site or group demand. However, an understanding of the wider time-based demand profiles can be important in later analysis of equipment duty and overload assessment. Where possible, when accessing historical data systems, the data should be processed to facilitate the later development of a load duration profile for the substation or group.

Establish Substation / Group Normalised Maximum Demand (NMD)

In order to produce meaningful estimates of load against a background of historical year-on-year variations arising from external variables such as the weather, it is essential that the future load estimates are based on a normalised or corrected maximum demand value as opposed to simply the most recent measured maximum demand value. Basing an estimate of future load on an MD range high or low value will result in overly pessimistic or optimistic assessment of site or group capacity headroom. In order to derive and identify a reasonable baseline for the estimation of future demands, trend analysis is carried out for the historical maximum demands for each site (or group) and the current year (or most recent) measured demand converted to an equivalent Normalised Maximum Demand (NMD) in accordance with the trend analysis. For each substation or Group this NMD value becomes the baseline for forward extrapolation of load evolution.

Correction for the Presence of Generation

The presence of locally connected generators will have the effect of masking the standing demand connected at that site. Small generators such as G83 PV, micro-turbines and modest installations will be so deeply embedded in the network that they will perform as true negative demand and effectively net off standing demand. Given the variability, diversity and lack of transparency in much of this type of generation a broad and high level assessment of the aggregated contribution from generation at the time of site peak demand is all that may be reasonably practical. Generation that is monitored metered and with accessible data flows (either through hardware systems or through normal business settlements processes) is identified and the appropriate corrections applied to the measured demand of the site or Group. Where generation is identifiable as connected but where there is limited or no access to data flows, a high level assessment of contribution to demand is carried out.

For the purposes of this assessment and in the absence of any more specific intelligence, generic intermittency values can be assumed, such as:

Generation Technology	Assumed Intermittency (Contribution to System/Site/Group Peak Demand)
Wind	25%
CHP (including biomass and Landfill Gas)	80%
Hydro	35%
Photo-Voltaic	0%[1]

Table 3: Intermittency Values for renewable Sources

Identify Generic Future Load Movements

An estimate of future load movements can be derived which covers two aspects of load movement:

- *Background Load Movement or generic load 'growth'*
- *In order to assess the background load movements, the recent history of the area demand provides a baseline load growth factor. This provides, at this point in time, a reasonable assessment of the background changes arising from lifestyle factors such as energy efficiency lighting, modest PV uptake as well as changing consumer goods such as flat screen TVs, PCs and charging mobile devices.*
- *Impact of emerging technologies - incremental load arising from the penetration of new technologies*
- *The UK Government has set challenging targets for the reduction in the nation's greenhouse gas emissions and the achievement of these goals will require a radical shift in energy usage, resulting in major changes in the way we produce and consume electricity. We expect to see major growth in "green" electricity production (e.g. small scale embedded generation) and consumption (in the form of electrification of both heating and transport) and Scottish Power is fully committed to facilitating this change to a Low Carbon Economy on behalf of the Government and our Customers.*

Therefore, superimposed in the background load estimates we include the predicted uptake in Low Carbon Technology (LCT) equipment going forward. This equipment is anticipated to include Electric Vehicle (EV) charging, Heat Pump (HP) installations, Energy Efficient properties as well as more widespread and systematic Photo Voltaic (PV) installations. The uptake of each technology will have an impact on the load development profile (positive or negative) although the actual profile of uptake may be determined by external influencing factors such as Government incentives or increasing gas prices precipitating migration towards heat pump and electricity as source energies for domestic space heating.

1 While distributed connected PV installations will net demand, the purpose of Table 3 is to derive the contribution of the DG at the time of system/site/group demand. It is assumed that that peak demand will occur at evening peak in winter and therefore the contribution from PV will be zero. If site specific conditions differ, i.e. the peak occurs during the day, the PV contribution should be assessed on a site-specific basis.

A primary challenge in developing our Load-Related Investment Strategy is that the timing and rate of uptake / location of the new LCT network loads is uncertain, especially as we are currently at the bottom of the growth curve in terms of their general take-up. The challenge will occur at three levels:

- *National level – for the likely uptake of heat pumps and electric vehicles within the UK as a whole we rely primarily on the low carbon technology (LCT) forecasts provided by DECC.*

- *Network operator level – to gain an understanding how the uptake will differ between DNO license areas as compared with the national average we gain external intelligence from external experts in the field*

- *Local level – in future we will need to understand how LCTs will "cluster" within a network, feeder or substation.*

The TRANSFORM[2] model is an industry wide techno-economic model which can be used to assess the impact of low carbon technologies on GB's distribution networks. The basic structure of the model is shown in Figure 7.

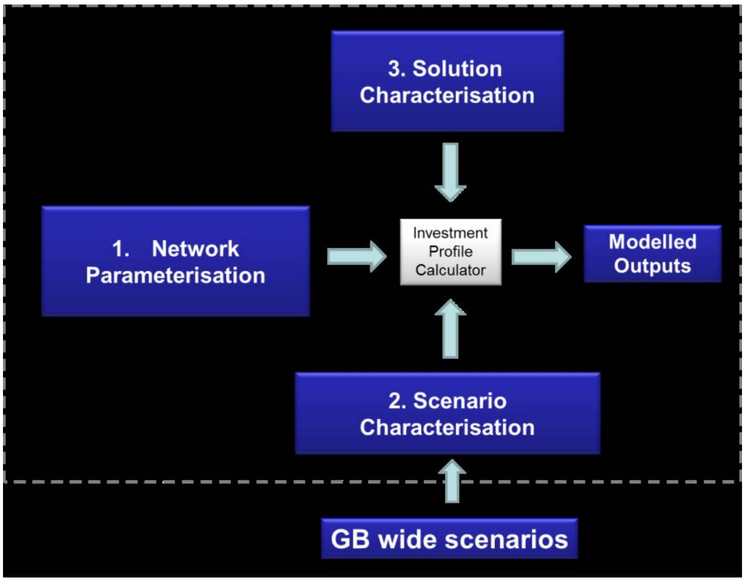


Figure 7: Basic Structure of the TRANSFORM Model

The current version of the WS3 TRANSFORM™ model uses the latest DECC/Ofgem Smart Grid Forum projections and continues to show there is a positive business case for smart technologies. The strategy showing the greatest benefit is the "selective top down" approach. The model shows that, while the bulk of network investment needed to accommodate low carbon technologies arises in RIIO ED2, there are substantial challenges for the DNOs to address in ED1. The majority of the new technologies that will be deployed in ED2 will make their first appearance on networks in ED1. The model is not overly sensitive to individual smart solutions and finds other smart solutions if any particular one is not available.

2 The Smart Grid Forum was set up by DECC and Ofgem to support the transition to a secure, safe, low carbon, affordable energy system in the UK. The forum has representation from all the UK electricity network companies, Given the broad scope of the Forum, six work streams were developed, each focussing on a different area: The TRANSFORM model is a product of WS3 (Developing Networks for Low Carbon) in accordance with the guidance from WS1 (Assumptions and Scenarios)

As discussed earlier, the load development arising from the predicted uptake in LCT is superimposed on the background load estimates from the preceding section. This will be a fairly clean split in the early period of the TRANSFORM modelling as there will be negligible uptake in the background assumptions which will be duplicated by the output of the TRANSFORM model. However, as the technologies become implemented in significant volumes, care will require to be taken to ensure that the TRANSFORM output does not double-count the technologies already appearing in the background.

The resultant load growth factors for both SPD and SPM for the ED1 period are indicated in Table 4. The overall values have been disaggregated to their background and LCT components.

Best view demand growth forecast									
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	Ave
SPD									
Background	0.10%	0.15%	0.15%	0.20%	0.20%	0.20%	0.20%	0.20%	0.18%
LCT	0.40%	0.42%	0.50%	1.37%	2.05%	1.89%	2.24%	2.31%	1.39%
Total	0.50%	0.57%	0.65%	1.57%	2.25%	2.09%	2.44%	2.51%	1.57%
SPM									
Background	0.25%	0.25%	0.25%	0.50%	0.50%	0.50%	0.50%	0.50%	0.41%
LCT	0.13%	0.16%	0.24%	0.76%	1.18%	1.15%	1.34%	1.47%	0.80%
Total	0.38%	0.41%	0.49%	1.26%	1.68%	1.65%	1.84%	1.97%	1.21%

Table 4: Load Growth Factors

Identify Local Demand Conditions

Application of the methodology in the preceding sections provides a reasonable assessment of the future demand on specific equipment or locations. However, to refine the projections, the micro-environment requires to be considered. This is intimated from either the connections or the operations environments as discussed in the following sections:

Demand Step Changes

This step in the process requires the superimposition of micro-level demand step changes which are predicted to arise from known developments. These developments can be the acquisition or disconnection of either demand blocks or generation capacity. This intelligence is likely to come from customer connection activity (load / generator connection or disconnection).

Operational Changes

Occasionally operational requirements, permanent disconnection or fault repair activities managed through the operational areas of the business will intimate changes to the network capacity or configuration changes such as the permanent disconnection of substations. These may have an impact on substation or group loadings when normal open points are moved or equipment capacities where fault repairs have been initiated.

Site / Group Capacity

One of the fundamental objectives of the process is to establish the existing / future duty on the system under consideration and then enable the validation of the duty against the equipment capability. The actual firm capacity of a site or a group shall be determined in accordance with the BAU guidance which is summarised in Appendix B. When the site or group capacity is known or has been identified, further refinement of the load duration profile is possible. Load duration curves are normally expressed in percentage terms of capacity and therefore, identification of equipment capacity in accordance with the specific guidance is essential.

Data Validation

As a final step prior to finalising and publishing the analysis, the new and future values should be assessed in context with the historical data to ensure that it is consistent, with no anomalies and where step changes occur, they are robust and are suitably documented. The data validation should also consider an assessment of out-turn versus predicted for the current year, i.e. the corrected NMD should be assessed against the predicted value from the previous period's assessment. This review and comparison is essential in order to close the loop and refine the predictive modelling.

Validation of data should also be carried out throughout the process to ensure that any significant swings are identified, the reasons understood and the data rationalised to avoid double counting. Site power factors outwith the normal range also require to be validated to ensure accuracy and competence of resultant decisions.

Smart Metering

As the penetration and deployment of Smart Metering increases with time over the ED1 period, the load data which will become available at a very granular level will be of significant benefit to inform and verify system based monitoring and data collection. This will be most useful at secondary level where the aggregated Smart Metering data could be compared and validated with LV system monitoring to provide more accurate understanding of load profiles and equipment loading. This position of greater knowledge and data will enable better informed investment decisions, i.e. Reinforce Vs No reinforcement + Risk.

Annex C7 – Smart Meter Strategy – SPEN provides greater detail on anticipated long-term benefits including those from a system planning perspective

The Scottish Power Energy Networks procedural guidance document 'Procedure for the Preparation of Load Estimates' provides more details on the process for deriving future estimates of system loads.

10.2. Appendix B: Equipment Capability

Equipment Thermal Capability

The capability of equipment varies with type and external influencing factors such as weather and temperature. When deriving equipment ratings some generic assumptions are made which enables the application of a standardised rating for that equipment type which is independent of location. Thermal capability for equipment is generally expressed in MVA (or kVA) terms which enable direct comparison with the similarly based system load values. The major component types and their assumptions are:

Overhead Lines

Overhead lines have a thermal inertia which provides these components with an element of capacity headroom under certain circumstances, and this is effectively taken account of when deriving the rating of overhead line conductors.

The rating of overhead lines is based on industry standards (e.g. ENA Engineering Recommendation P27) together with company methodology which provides a maximum rating at each applicable voltage level as well as taking account of single circuit or multiple circuit operation. Due to the impact of weather conditions on the conductor ratings, the ratings are provided for summer and winter operating regimes and assume the following credible ambient conditions of operation:

Wind speed	0.5m/s
Ambient temperature (winter)	2^0C
Ambient temperature (summer)	20^0C
Solar radiation	Nil
Maximum conductor temperature	50^0C

The resultant conductor rating values are considered absolute. While specific weather conditions in real time may provide additional cooling, for the purposes of long term system planning, any load excursions beyond the approved ratings are considered unacceptable. Operation above the approved rating may result in infringements to safety clearances as the conductors expand with the increased temperature and result in increased conductor sag and lower safety clearances.

This design timeframe philosophy is consistent with any operational time frame real-time dynamic line rating system which enables more ‘ampacity’ within the same maximum conductor temperature (and designed safety clearances) by factoring the increased cooling effects.

Underground Cables

Underground cables, due to their construction, have an inherent thermal inertia which provides a theoretical overload capability which can be exploited. In practice, this thermal capability is translated into continuous ratings, cyclic ratings and (only in the case of 11kV cables and under very tightly controlled circumstances) 3-day emergency ratings.

However, the rating of the all cable systems is fundamentally affected by the ability for the heating effects in the cable from the load currents to be dissipated to the surrounding environment (air, ground etc.). Therefore, the ratings of cables used within the distribution networks are grouped into laying methods which are reflective of the cooling effects from surrounding environment. This translates into four continuous rating capacities for a single cable type:

- *Winter rating for cable laid directly in soil or appropriate backfill,*
- *Winter rating for cables laid in ducts,*
- *Summer rating for cable laid directly in soil or appropriate backfill,*
- *Summer rating for cables laid in ducts.*

Further de-rating may be required where cables are laid in close proximity which inhibits cable cooling or provides mutual heating effects.

As the values are non-site specific and generically applied across the system, the ratings are based on assumptions with regard to installation parameters which include:

Depth of Laying	In accordance with Cable Laying Policy (CAB-15-003)
Soil Thermal Resistivity	1.2^0K m/W
Ground Temperature (winter)	10^0C (November - April)
Ground Temperature (summer)	15^0C (May - October)

Switchgear

Distribution switchgear has no real thermal inertia and the rating is dependent on the mechanical friction or touch contact between moving electrical contact systems. Operating the equipment beyond its rated capability will cause degradation of the contacts and precipitate failure. The rating of the switchgear should therefore be considered as the nameplate rating with any overload beyond that value unacceptable.

Protection Systems

By definition, protection systems are designed, installed and operated to protect the primary circuit under fault conditions and, in general terms, a course-set overload protection. The system will therefore be specified and sized to satisfactorily meet the demand at the limits of operation of the primary circuit without inhibiting the circuit or causing component failure within the protection scheme. Overload capability of a protection system is therefore unnecessary.

Transformers

Transformers and other wound components will have inherent overload capabilities. Transformers with oil insulation systems provide increased opportunity (over say resin cast equipment) especially those units which have enhanced cooling systems. The enhanced cooling systems employed are a fairly wide range:

Passive systems include:

- *External cooling fins*
- *Separate cooling banks with natural convection cooling*
  (These are generally categorised as ONAN cooled units (Oil-Natural, Air-Natural)

Active systems which apply mechanical means of forced cooling include:

- *Forced oil circulation by pumping of insulating oil around the system*
- *Cooling banks with fan-assisted cooling*
- *Forced oil circulation and forced air cooling of radiator banks (hybrid of two preceding types)*
  These are similarly categorised as OFAN (Oil-Forced, Air-Natural), ONAF (Oil-Natural, Air-Forced) and OFAF (Oil-Forced, Air-Forced) cooled units respectively.

The rating system is complex but unlike overhead lines for example, transformers can be loaded beyond their rating, but with consequences. Among many other factors, transformer life is influenced by the paper insulation medium employed in the transformer windings and that is directly influenced by the operating temperature of the unit: a lifetime of operation at or below the maximum hot spot temperature (typically 120^0C) will return a lifespan for the primary electrical components around unity (i.e. the expected life of the unit in normal operating environment and duty, with no intervention). However, if the transformer consistently operates with its hot spot temperature in excess of its rated value, the transformer lifespan degrades significantly. Figure 8 indicates a typical relationship which demonstrates the considerable impact on transformer life from increasing the operating temperature.

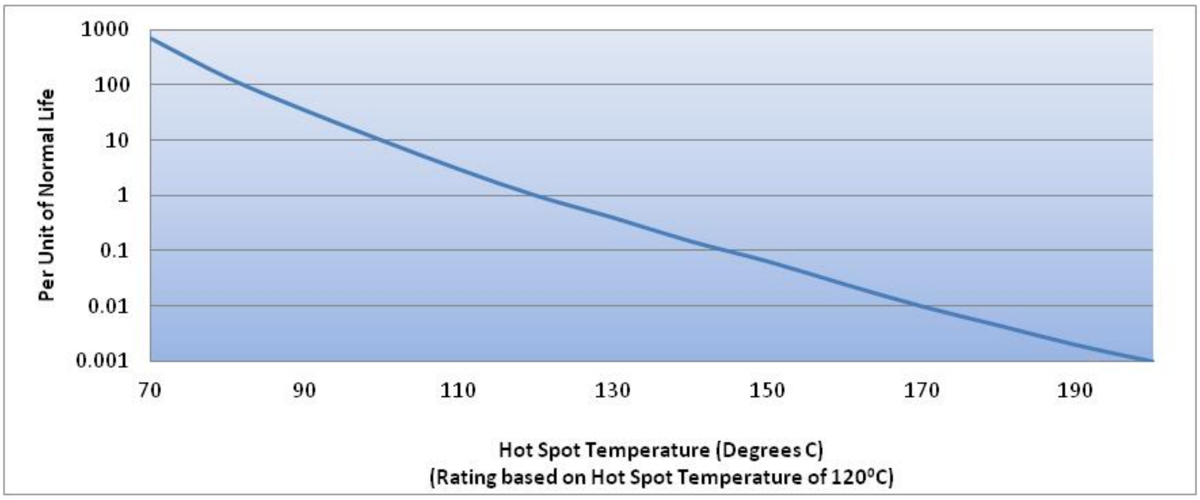


Figure 8: Relationship of Transformer Lifespan and Hot Spot Temperature

The industry standard for Primary level transformers ENATS 35-2 acknowledges this fact by defining the continuous emergency rating of the transformer as the rating at which the transformer can operate on a continuous load within the specified temperature limitations as detailed (140^0C for certain ambient and load conditions). The standard states “It is accepted that at this CER rating, loss of life will be significantly accelerated, but it is also expected that the transformer will be required to run at its CER for only a few weeks in its whole operating life. The increased loss of life should not therefore seriously reduce the life of the transformer, unless the CER is abused over long periods of time”.

Composite Circuits

The capability of individual components (overhead lines, cables etc.) in a network cannot be considered in isolation as they are components of a wider part of the network and their interaction, performance and characteristics as a whole entity require to be considered. Assessment by looking at the components on a circuit, substation or group basis is fundamental.

When developing an efficient and economic system, the capability of equipment components and circuits to be established requires to be appropriate and fit for purpose. This therefore requires that the individual components such as transformers, cable and overhead line sections shall be specified such that, as far as reasonably practicable, their relative capabilities are matched and that no single component results in a significant de-rating of the overall circuit capability. This also requires that, while an economic assessment of future requirements is made, unnecessary capacity is not established – capacity which can never be utilised and will result in asset stranding. When matching overhead line and cable section capacities, care should be taken when considering seasonal ratings as the months when summer ratings are applicable for these components are subtly different.

Careful consideration also requires to be given to the load profile of the demand and the duty on the equipment. In terms of circuit and transformer capacity, this requires that the remaining circuit(s) following a planned or unplanned outage are able to support the load without exceeding the appropriate ratings, equipment temperatures or overhead line ground clearances. Where appropriate, short-term cyclic ratings can be utilised provided that the appropriate equipment cool-back periods are available due to load transfer or demand decay.

Firm Capacity

Firm capacity is a key parameter in determining system capability. In accordance with the planning standards, for a typical primary substation or group, the firm capacity is that load which can be supplied during an outage of the single largest transformer or circuit and takes account of equipment capabilities. As in the assessment process for individual equipment or components, the firm capacity is always declared in MVA terms. The outage may be of a considerable duration to cater for (say) repair or replacement of a transformer.

For a typical two transformer primary substation with identically rated units, the firm capacity is the ‘emergency’ rating of one transformer (assuming that the associated source cables and overhead lines are similarly rated). The extent of this ‘emergency’ rating depends on the equipment type and specification and whether it has forced cooling equipment or not.

The integrated transformer group arrangement employed within the SPM networks are similarly assessed for firm capacity ratings, i.e. an out of service condition for the largest transformer is assumed and the firm capacity is the demand which can be supported by the remaining transformers within their ‘emergency’ ratings. This assumes that the remaining transformers all share the load equally but in the event that the relative geographic arrangements of the transformer infeeds and the level of interconnection between them results in unequal sharing, the firm capacity of the group may actually be constrained below the theoretical value. This can only be identified by detailed modelling of the network and is sensitive to load distribution within the group.

For single transformer sites (both SP Manweb and SP Distribution) where the alternative supply is achieved from the lower voltage network, the firm capacity is likely to be independent of transformer capacity and solely dependent on the ability of the lower voltage network to provide the alternative supply arrangements. An additional criterion is that the LV support must be within equipment thermal ratings while maintaining system voltage within acceptable limits. In very rural situations such as Wales, the limiting factor is likely to be voltage – there may be adequate thermal capacity to satisfy the demand but circuit impedance, distance or load distribution may prohibit load recovery above a percentage of the capacity in order to main statutory voltage requirements.

Equipment Fault Level Capability

As well as coping with the normal load current situations (i.e. thermal assessments), system components must be able to handle those short circuit currents which occur under system fault conditions. The fault level capability falls into two broad categories – inactive components (such as cables and overhead lines) which are only required to withstand the fault currents for a defined time period without failing mechanically, and active components such as circuit breakers which are required to actively disconnect the fault from the system, again without catastrophic failure of the device.

Overhead Lines

Current overhead line specifications will meet the present system fault level requirements, although some early equipment may have lower capability. Fault level decays with distance to source and therefore, for the purposes of assessment, it is assumed that this older equipment will be located some distance from source and therefore operating within capability.

Underground Cable

As with overhead line, underground cable specifications will meet the present system fault level requirements, although some early equipment may have lower capability. Fault level decays with distance to source and for the 33kV network; the most onerous fault condition is a three-phase fault. However, as the 33kV cable types are almost exclusively of the screened core variety, three-phase faults without an earth fault on a cable network is extremely unlikely and therefore, for the purposes of assessment, it is assumed that this equipment will be operating within capability.

Switchgear

The generic term of switchgear can be separated into two broad areas:

Switching Devices – which includes all those components which are required to make or break system or load currents. This includes devices which are automatic in nature and are required to break both load and fault current, i.e. circuit breakers which have defined make and break duties. In most cases, disconnectors will have load make and break capabilities, as well as a fault make capability. However, these devices generally have no functionality or ability to break fault current.

Connection systems - which covers all the ancillary equipment integral to an installation of circuit breakers. This generally and predominately refers to busbars and their associated clamping arrangements and supports. While these components do not have a make or break duty as such, they require to have a capability to withstand through-currents (causing mechanical stresses) which do not result in damage or failure. In a coordinated or homogeneous installation, the fault current rating of these ancillary systems generally matches those of the primary switching devices.

Modern switchgear equipment is procured and installed such that the fault level capability is appropriate for the network it is connected to and within the fault level design limits for that voltage level. However, as the system has evolved, equipment procured to meet operating conditions at that time may fall short of the current fault level environment, e.g. legacy 750MVA 33kV switchgear established in a system with a current 1,000MVA fault level limit may require mitigation or replacement.

Circuit Breaker Standards

When assessing the actual capability of switchgear and the consequential impact on the load related expenditure, due cognisance must be taken of the standard to which the switchgear was tested as this may have a material impact on whether switchgear requires mitigation measures / replacement or not.

The legacy network contains circuit breakers that are type-tested and rated to a number of differing standards. An important difference between these standards is the manner in which the DC component of the fault current is addressed. The current standard of IEC62271-100 rates circuit breakers according to a fixed DC time constant while legacy switchgear, rated to BS116, BS3659 or other superseded standards, is rated on a percentage asymmetry basis. If the standard applicable to a particular circuit breaker is not known, IEC62271-100 is assumed.

Depending on the applicable standard, the capability of the circuit breaker should be determined and each parameter compared to the corresponding parameter of the theoretical prospective fault current. If one or more circuit breaker parameters are exceeded, the circuit breaker therefore has an inadequate rating to interrupt the prospective fault current. If the breaker is in service, mitigating measures should be implemented.

No margins are allowable when assessing circuit breaker or switchgear duty and therefore, if any circuit breaker capability parameter is exceeded, even by a small margin, the equipment should be considered to be in excess of its rating.

Where analysis proves that the equipment duty is validated to be within the equipment capability, this would therefore permit further load/generation connection to this system.

The Scottish Power Energy Networks procedural guidance document 'Assessment of Equipment Capability' provides more details on the philosophy and background to assessing equipment ratings.

10.3. Appendix C: Thermal Assessment Process

Thermal Issues

Thermal issues arise when the load imposed on a piece of equipment or a system is in excess of its capacity.

In order to make that assessment and identify any consequential requirements for reinforcement, the fundamental philosophy is that there needs to be a clear understanding of what the system or equipment is being required to do and its inherent capability to perform that function. This can be summarised as Equipment Duty and Equipment Capability:

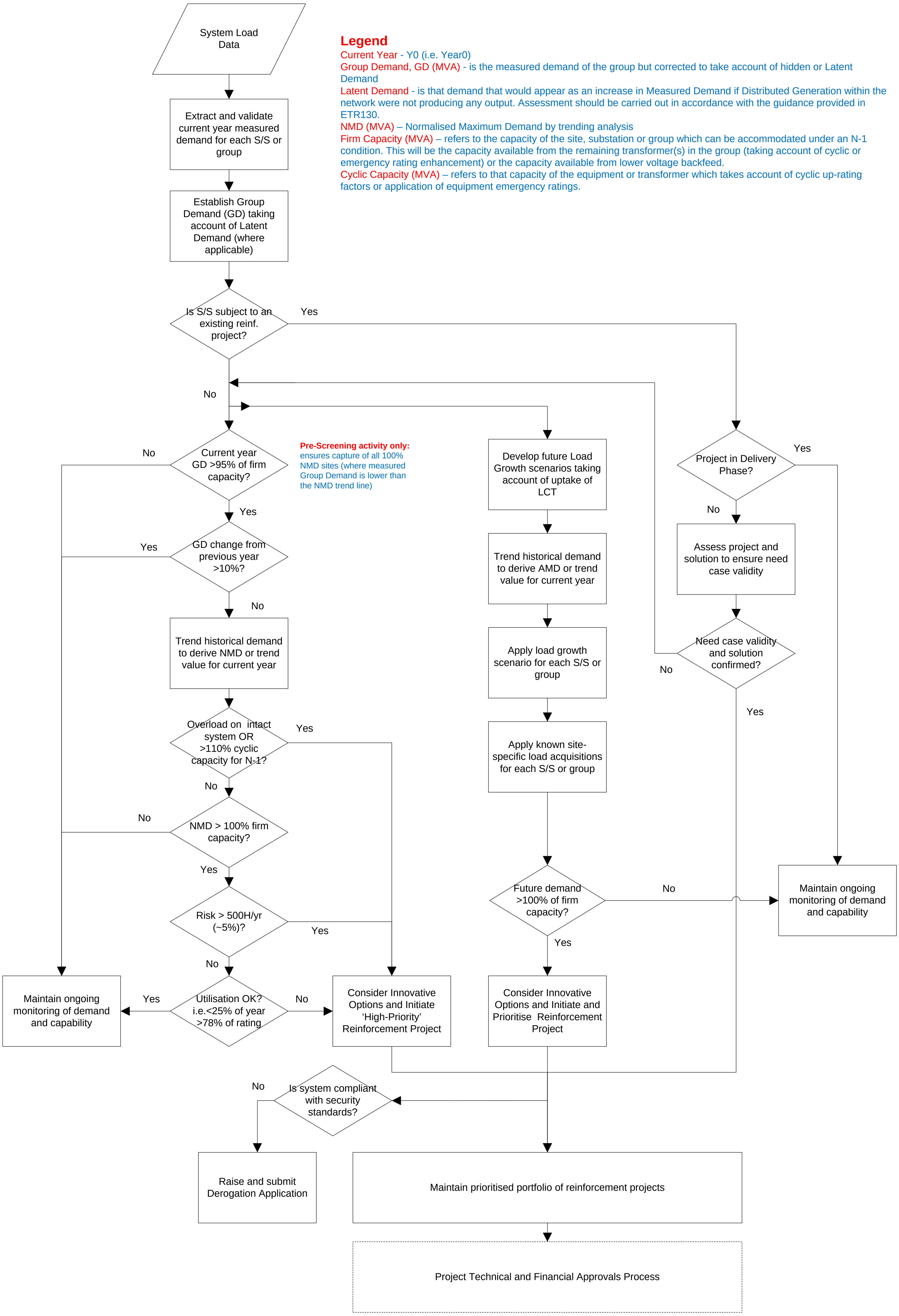
Equipment Duty is the load imposed on the equipment under a variety of scenarios such as intact or a depleted system. In the context of a thermal assessment, this generally relates to demand or current levels.

Equipment Capability is the capacity that the equipment (or collection of components) has to perform the required duty. While, under normal conditions, a site or group can be loaded beyond its firm capacity limit without overloading any equipment, there is an inherent risk that equipment will overload in the event that an outage occurs at a time when the site or group demand is close to, or at, peak. The actual duty of the site must therefore be assessed against the site capability to determine the time based level of exposure to risk. This is generally achieved by identifying the number of hours (together with their incidence) within a year where the load exceeds the firm capacity. Therefore, when the historical site/group demand exceeds capability, the duration and profile of any excursions require to be identified so that the risk and project initiation is triggered in accordance with this policy.

The Thermal Assessment Process

Figure 9 provides a high level flow chart representation of the process followed by a summary of the analysis methodology.

Process for Assessment of System Thermal Issues



Legend

Current Year - Y0 (i.e. Year0)
Group Demand, GD (MVA) - is the measured demand of the group but corrected to take account of hidden or Latent Demand
Latent Demand - is that demand that would appear as an increase in Measured Demand if Distributed Generation within the network were not producing any output. Assessment should be carried out in accordance with the guidance provided in ETR130.
NMD (MVA) – Normalised Maximum Demand by trending analysis
Firm Capacity (MVA) – refers to the capacity of the site, substation or group which can be accommodated under an N-1 condition. This will be the capacity available from the remaining transformer(s) in the group (taking account of cyclic or emergency rating enhancement) or the capacity available from lower voltage backfeed.
Cyclic Capacity (MVA) – refers to that capacity of the equipment or transformer which takes account of cyclic up-rating factors or application of equipment emergency ratings.

Figure 9: Process Overview for Thermal Issues

Summary of Analysis Methodology

This methodology for thermal issues enables an assessment of the ability of the network to meet the demands imposed on it from a load flow perspective. As indicated in Figure 9 and in accordance with the Procedure for the Preparation of Load Estimates, the raw measured demand (including the reactive component) at each point of interest on the system is identified. That initial starting point enables the derivation of a smoothed and representative Maximum Demand value (Normalised Maximum Demand or NMD). The NMD is the current year value which is representative of the maximum demand trend and therefore provides a baseline for both current-year assessment and future MD predictions.

The load estimate aspect of the assessment therefore produces:

- *A current year normalised maximum demand*
- *Predicted maximum demands for the next 10 years*

The process then compares the above loads with the equipment capacities (taking account of any known equipment changes over the period). Equipment ratings (for a typical collection of components such as overhead lines, cables and transformers forming a substation or group) can be reduced to two primary parameters:

- *Firm Capacity and*
- *Cyclic Rating.*

For a radial system, this is generally relatively straight forward, however, the SP Manweb network[1], due to the dispersed infeed arrangements, generally requires load flow analysis in order to determine these parameters.

The strategy is fundamentally based on probability, and consequences. Taking a two transformer primary substation as an example, both transformers will be in service throughout the year and any maintenance or extended constructional project will be undertaken when the load is reduced, e.g. summer months. Planned outages at times close to site maximum demand for any reason other than emergency repairs are avoided and therefore, by definition, at times of maximum demand (and apart from fault outages) each transformer will be loaded to around 50% or less. The SP Manweb[3] network, in general terms, will have higher utilisation due to the grouping of a larger number of smaller transformers, with the transformers loaded to around the 70-80% of rating. The probability of a fault event occurring at times close to substation peak is considered to be low and the consequences manageable in that, if the event does occur, the loading will be within transformer cyclic capability, albeit with a shortening of asset life.

Therefore, against the background of probability of the event occurring, the risks associated with this stretch are considered not unreasonable.

To deliver this philosophy, the process tests decision points to expand on some aspects of the equipment duty versus capability balance to identify whether an overload risk is material or not. This clarification is centred on the level of any overload and considers it from three aspects:

- *Exposure to extreme overloads, i.e. loaded beyond cyclic capability*
- *Time exposure where the cumulative time in a year, when loading exceeds firm capacity, is considered excessive*
- *High equipment utilisation where there is insufficient or inadequate cool back period*

[3] The legacy SP Manweb is planned, constructed and operated in a fundamentally different manner. More details are provided in **Annex C6 – SP Manweb Company Specific Factors – SPEN.**

Where equipment is loaded beyond cyclic capability, a reinforcement or mitigation project is indicated. The levels of time exposure beyond firm (currently set at greater than 500 hours per year) and the utilisation (currently requires to be more than 25% of the year at or below the cool-back loading of 78%[4]). This does not necessarily preclude reinforcement projects being initiated within the trigger levels if site specific conditions indicate that the risks or consequences are unacceptable – e.g. sites with little or no transfer capacity or backfeed under N-2 conditions

The Scottish Power Energy Networks policy document 'Load Related Investment Policy' provides more details on the philosophy and background to thermal assessments. The process test point values will periodically be reviewed to embed experience and factor changes to equipment specifications.

10.4. Appendix D: Fault Level Assessment Process

Fault Level

Health & Safety requirements dictate that all equipment is fit for the duty it is required to perform. In order to comply with this requirement with respect to plant fault capability, the maximum prospective fault current must be controlled such that no item of equipment on the system shall be over-stressed due to its fault interruption or making duties being greater than its assigned rating.

As discussed in the thermal section of Our Strategy, when considering system condition and consequential requirements for reinforcement, the fundamental philosophy is that there is a clear understanding of what the system or equipment is being required to do and its inherent capability to perform that function. When considering the system fault levels, the high level assessment remains identical to the thermal assessment, i.e. Equipment Duty and Equipment Capability. The derivation of these parameters in a fault level context are discussed in the following sections:

Equipment Duty

When a fault occurs on the transmission or distribution system, the current which flows into the fault will be derived from a combination of three sources:

- *Major generating stations via the transmission and distribution networks (i.e. system derived fault current)*
- *Embedded generators connected to the local network*
- *Conversion of the mechanical inertia of rotating plant equipment connected to the system into electrical energy.*

Circuit breakers which may be called on to energise onto faulted equipment or disconnect faulty equipment from the system will have precisely defined capabilities to meet the following equipment duties:

- *Make Duty - The make duty of a circuit breaker is that imposed on the equipment in the event that a fault occurs during energisation of a faulted or otherwise earthed piece of equipment.*
- *Break Duty - Circuit breakers associated with faulted circuits are required to interrupt fault current in order to remove faulted components from the system, thereby ensuring the prevention of damage to plant and maintaining security and quality of supplies.*

[4] Based on a standard cool-back requirement of 60% of cyclic rating. The cyclic rating can be assumed as 130% and therefore cool-back maximum load is 60% of 130%, i.e. 78%

Substation infrastructure such as busbars, supporting structures, flexible connections, current transformers, and terminations must be capable of withstanding the mechanical forces associated with the passage of fault current i.e. through-current withstand duty.

Equipment Capability

As discussed in the Overview section earlier, this is the capacity that the equipment (or collection of components) has to perform the required duty. In addition to the normal load current situations (i.e. thermal assessments), system components must be able to handle those short circuit currents which occur under system fault conditions. The fault level capability falls into two broad categories – inactive components (such as cables and overhead lines) which are only required to withstand the fault currents for a defined time period without failing mechanically and active components such as circuit breakers which are required to actively disconnect the fault from the system, again without catastrophic failure of the device.

The Fault Level Assessment Process

Figure 10 provides a high level flow chart representation of the process and followed by a summary of the analysis process.

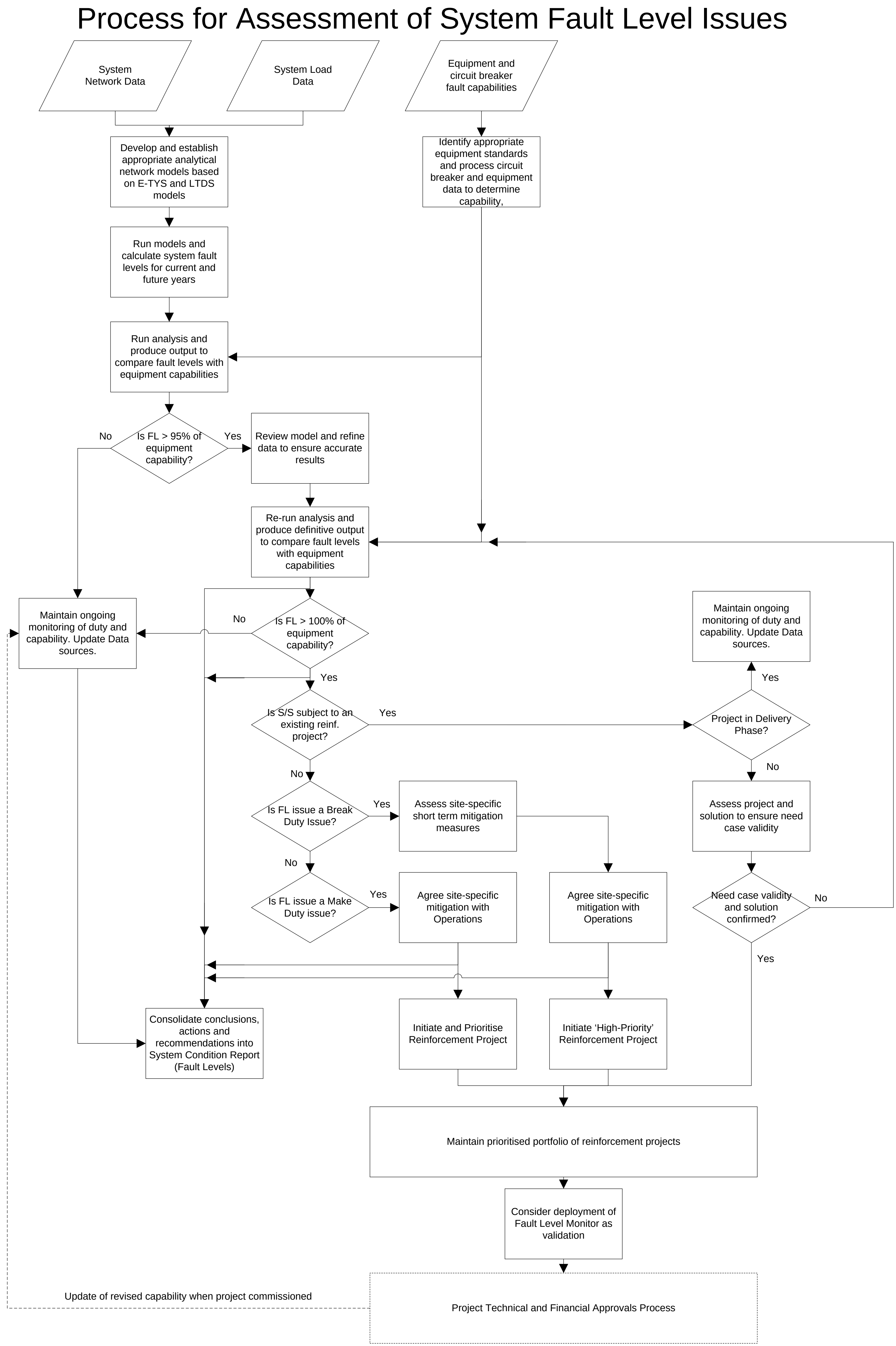


Figure 10: Process Overview for Fault Level Issues

Summary of Analysis Methodology

Whether carrying out a system wide or a local study, assessing existing system conditions or the impact of system changes / connections, the fault level assessment process is fundamentally identical:

- *Carry out the fault level calculations,*
- *Validate the results and*
- *Carry out an assessment of equipment capability and duty.*

In the majority of circumstances where the duty is within the high level assumptions for equipment capability, then steps 2 and 3 would not be necessary. Only where the calculation indicates the duty exceeds the assumed equipment capability or design limit would further detailed assessment or refinements be necessary.

An annual system wide condition assessment is undertaken based on the analysis models for the current year and the following six years and the relevant system year for maximum demand conditions and generation schedules based on the Gone Green Investment Planning Background. The contribution from connected and consented embedded generation is also modelled.

Fault levels are calculated down to and including 33kV and 11kV busbars at Grid Supply Points and compared to the substation equipment rating with a similar exercise carried out for the production of the annual Long Term development Statements (LTDS).

Model Output

For each substation, the following fault current characteristics are calculated, typically for both three-phase and single-phase faults:

- *Peak make current (i_p)*
- *RMS break current (I_B) at break time (t_B)*
- *Peak break current (i_B) at break time (t_B)*

Analytical Model Accuracy

As discussed earlier, over-stressing equipment from a fault level perspective is unacceptable and therefore the prospective fault current shall never be more than 100% of the plant capability. However, the generic assumptions made in a global assessment of fault levels will, by the nature of the assumptions, have a margin of error which may be more or less onerous than reality. To reflect this potential for under-estimation, an initial 'flag' value of 95% of plant rating is employed. Any sites which exceed this value will be the subject of detailed study to validate the calculated values. This detailed study will refine the analytical model for that site and assess the load category to establish a realistic assessment of fault contribution from load and this theoretical assessment could be supported by the deployment of a Fault Level Monitor as validation. Only when this process has been completed and the system model considered accurate, will the ceiling value of 100% be accepted.

Equipment Capability

The preceding analysis work will provide a robust estimate of equipment duty. This output can then be compared with the detail of equipment capability. Circuit breakers are required to perform peak-make and peak-break duties which are essentially location-specific; however switchgear is frequently referred to in generic or RMS terms. In addition, equipment specifications and the testing standards applicable at the time of manufacture differ significantly over time (e.g. BS116 or IEC62271-100) and, particularly for peak break duty; some equipment may perform acceptably for the local conditions by virtue of the basis of the original testing standards and the prevailing decay rates at that location.

It is worthy of note that the ‘peak break’ capability of a circuit breaker is not actually a rating, but is useful to check if a circuit breaker is capable of interrupting the predicted fault current.

The Scottish Power Energy Networks policy document ‘Load Related Investment Policy’ provides more details on the philosophy and background to fault level assessments.

Assessment of Circuit Breaker Duty With Respect to Capability

Depending on the applicable switchgear standard, the capability of the circuit breaker should be determined and each parameter compared to the corresponding parameter of the theoretical prospective fault current. If one or more circuit breaker parameters are exceeded, the circuit breaker therefore has an inadequate rating to interrupt the prospective fault current.

If, arising from the detailed analysis, any circuit breaker capability parameter is exceeded, even by a small margin, the breaker should be considered to be in excess of its rating, i.e. there is no credible rating enhancement/short term rating for circuit breaker fault level rating and therefore 100% remains the absolute operational limit for equipment capability. Where sites are indicated above the 100% level, short term mitigation measures should be established in accordance with guidance.

Special care should always be taken in situations involving reactor or capacitor switching, generator breakers or unusually high DC components (relative to the AC component) or DC time constants. In such cases, expert advice should be sought.

Process for Long Term Resolution of Fault Level Issues

The process and methodology for resolution of fault level issues is covered in detail in SPEN guidance documentation but the high level overview of the process is provided for completeness:

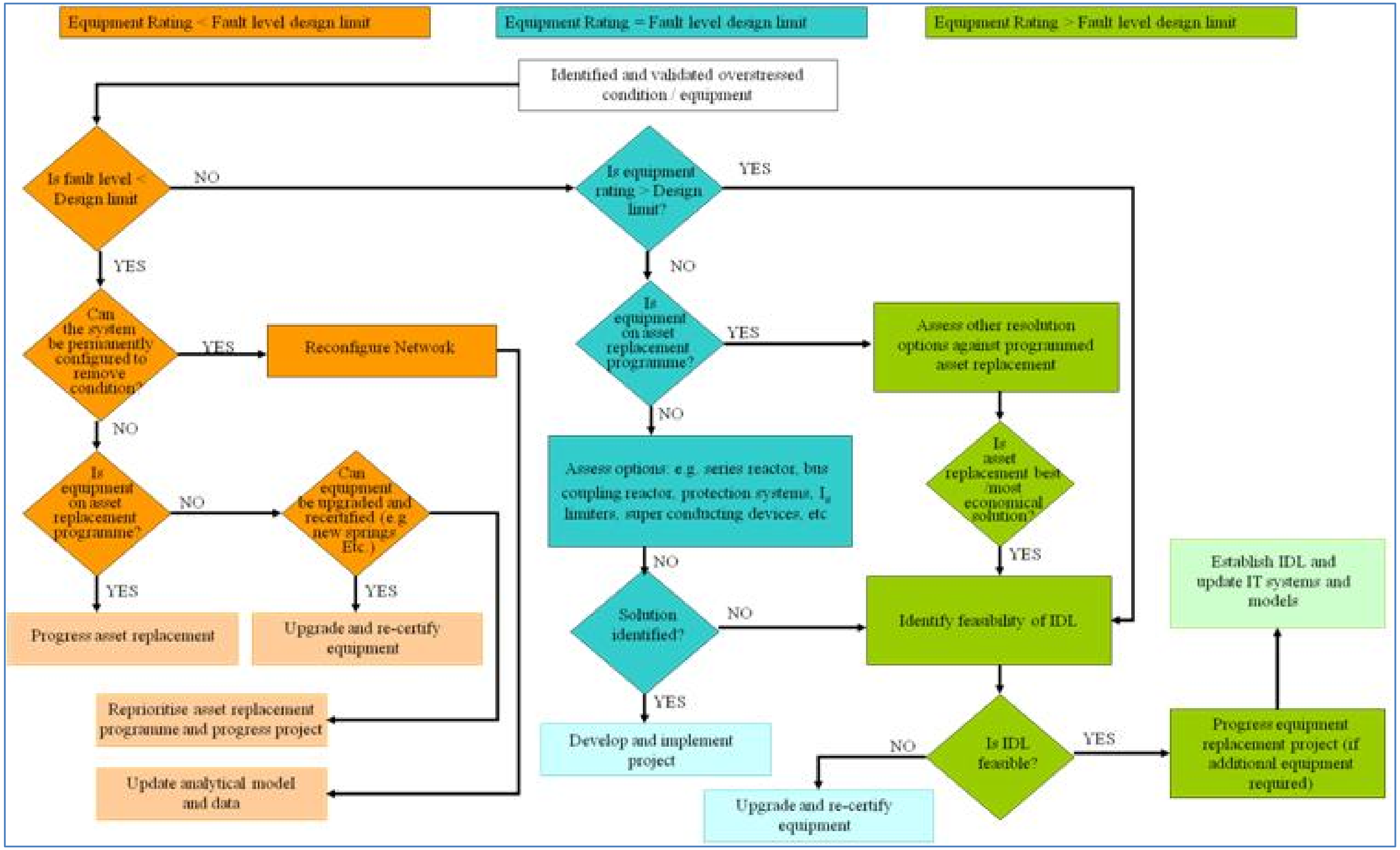


Figure 11: Decision Process for Fault Level Resolution

10.5. Appendix E: Voltage Assessment Process

Voltage Issues

Under intact conditions, the network is stable and any load or generation changes are managed by the system with, for example, on-load tap changers adjusting their position to regulate the target voltage. Under normal system conditions the voltage variation is gradual and the tap change control scheme load-follows to ensure that the target voltage is within acceptable limits. To optimise voltage profile and reduce unnecessary equipment deterioration, the control scheme has inbuilt time delays aimed at avoiding tap change position hunting.

When a fault occurs or an outage is taken which effectively increases the impedance between the load and the source, the instantaneous change in impedance results in a step change reduction in voltage at the point of coupling of the load. Where there are on-load tap changers, the control scheme will initiate changes to restore the target voltage to unity. However, while the tap change control will accelerate changes (compared to normal load-following mode), there is a finite time for the steps to take place back towards unity. There is also the possibility that, under a high load and high impedance for the remaining circuit scenario, the maximum tap position may be reached (potentially restoring voltage compliance), but short of achieving unity voltage.

Network analysis is therefore required to assess the voltage consequences of credible circuit outages, the ability of the tap changer to restore voltage and the potential remaining headroom in terms of transformer taps.

The following flow chart and the following brief explanatory text provide some guidance on the process for identification of the issues.

The Assessment Process for Voltage and Voltage Step

Figure 12 provides a high level flow chart representation of the process and followed by a summary of the analysis process.

Process for Assessment of System Voltage Issues

Legend

Contingency Analysis – refers to a modelling of the load flows which arise from switching out circuits in turn to identify system overloads or voltage excursions under N-1 conditions. The contingency outages reflects the operational configuration of the system, i.e. Where circuits are banked, both circuits are outaged at the same time during the contingency analysis.

Load Modelling –this refers to ensuring that the analytical model closely reflects the operational system in that it attempts to replicate how the load responds with voltage variation.

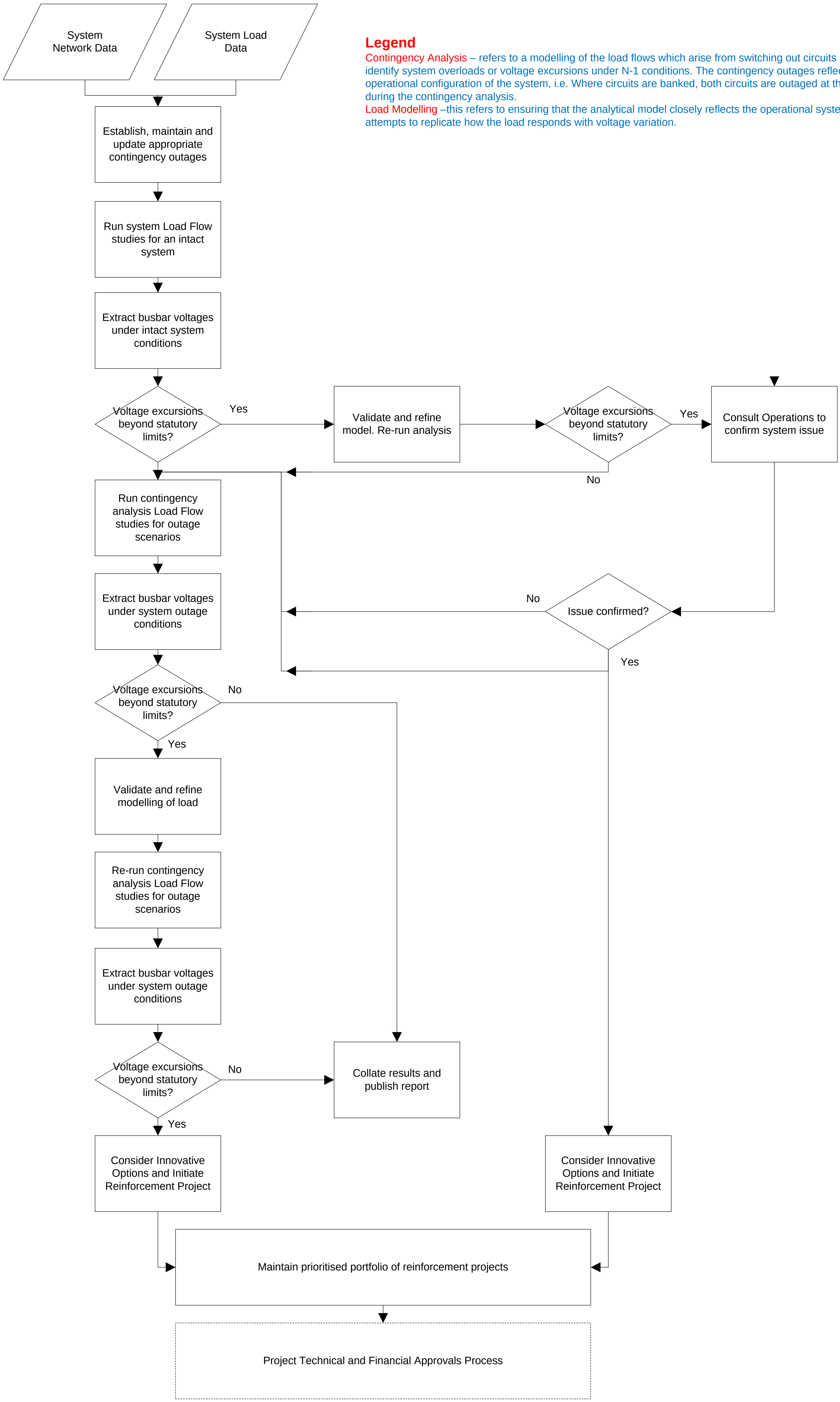


Figure 12: Process Overview for System Voltage Issue

Summary of Analysis Methodology

The assessment for voltage issues is undertaken from two perspectives:

- *Steady state voltage profile – an assessment is undertaken to ensure that, for a range of load and generation scenarios on an intact system, the busbar voltages across the system are within statutory limits.*

- *Voltage step change – the voltage at the busbars across the system immediately following an outage and before any tap change operation.*

A summary of the major factors in the assessment is provided below:

- *Load data*

As the purpose of the analysis is to identify parts of the system which may be subject to voltage and voltage step issues, the most onerous system load conditions are assumed. The load data for each node on the system is assessed to ensure representative maximum demand levels. To ensure voltage issues are not masked by local conditions, all local generators are set to zero.

- *Characteristics of Load*

Electrical equipment has an electrical load that varies as the supply voltage changes. Loads can be characterised as one of three types:

- *Constant Power – the demand is constant regardless of voltage. This will typically be resistive loads such as heating and incandescent lighting.*

- *Constant Current – demand is proportional to voltage, generally comprising of thyristor applications.*

- *Constant Impedance – demand is proportional to the square of voltage such as induction motors and controlled power supplies and tap changing transformers*

While real world loads will be a combination of the load types, from a voltage step perspective, it is useful to consider the behaviour of load with voltage:

- *Constant power - results in increasing current with reducing voltage (but MVA remains constant and independent of voltage)*

- *Constant current - draws the same current irrespective of voltage, i.e. MVA increases with voltage*

- *Constant impedance (voltage dependent) - draws reducing current and power with reducing voltage*

Therefore, when performing voltage step analysis, the worst case load characteristic of constant power is useful to perform system wide screening for step change issues as satisfactory performance with this load type will ensure satisfactory performance across the full range. Refinement of the modelling is then appropriate for the load characteristic appropriate to the individual or highlighted site. This is likely to be a combination of load types which are representative of the customer base supplied from that network. Alternatively, modelling as voltage dependent loads is useful as a base line and only those sites which are close to boundaries would benefit from closer assessment

Analysis Methodology

As discussed earlier, a system wide scan is carried out to assess the steady state voltage. The output of this study will highlight any issues regarding achievement of busbar target voltage. The major part of the assessment is to run contingency analysis load flows and capture the resultant busbar voltages. In order that the post-outage voltage is recorded prior to any corrective action from tap change systems, the system tap change controls are frozen at the steady state levels.

When setting up the contingency analysis, the real-world connectivity is replicated in the studies such that banked or teed circuits are all taken as one outage. As each circuit is outaged in turn, a load flow study is run and the voltage at all busbars are recorded. The outaged circuit is restored to service and the next circuit outaged. For system wide system condition type assessments, the process is generally automated to ensure consistency and efficiency in time and resources. Be-spoke assessments for a smaller discrete part of the network may be manually managed or automated with a smaller sub-set of contingency circuits.

The output is collated into a summary report.

The Scottish Power Energy Networks policy document 'Load Related Investment Policy' provides more details on the philosophy and background to assessment for voltage issues.

10.6. Appendix F: Stakeholder Input

Clearly new developments being undertaken by public and private bodies take time to advance from the concept stage through to project inception. Areas of significant development and customer connection activity which triggers additional infrastructure or reinforcements takes some time to progress through development, local / regional planning before it reaches a state of maturity that would support a formal application for connection. However, if there is a dependency on wider reinforcement works, then there is a danger that the reinforcement timescales may not be conducive to the development timescales.

It is essential that we engage with customers and key stakeholders in order to inform and support developer decisions to ensure that their aspirations are fulfilled. Therefore, in addition to the guidance material (such as the system 'heat maps' and Long Term Development Statements) provided through a variety of platforms to inform and assist stakeholders with site specific developments or plans, we proactively engage with stakeholders to enable mutual understanding of requirements and to better inform investment decisions.

The regions, cities and customers we serve are of vital importance to the ongoing activities of Scottish Power Energy Networks. As we plan major capital investment programmes for the network, our Local Authorities also have future plans for regeneration and development. The benefit of aligning these proposals is recognised by both SPEN and our stakeholders to be critical for the ongoing successful provision of services and to meet the wider needs of our communities. Supporting the activities of our stakeholders may also demonstrate how any future expansion is necessary for the continued operations of our network.

As a major utility provider, we engage with our customers in various ways; with informal discussions of future plans and how these can be facilitated by our network, or formally through means such as the connection application process which also provides a measure of our performance as a DNO. However, SPEN recognises the key to enhancing our stakeholder engagement lies in our commitment to participate in the decision-making process which our stakeholders undertake between the informal and formal stages.

Activities such as Integrated Energy Planning and FP7 STEP-UP partnership with Glasgow City Council (GCC) are some of the ways we add value to the policies and planning of our council partners. Through key deliverables in these projects we are able to contribute towards specific stakeholder goals. This enhances the quality of service we offer in a structured way which can be demonstrated in efficiency improvements and ultimately, measurable by local authorities. It focuses our attention (and that of our stakeholders) on how we can realise low-carbon technology deployment and continue to deliver a robust network in the future.

The FP7 STEP-UP project is an example of our ability to contribute to the strategic development plans for regions or cities and gain an understanding of how this will impact on our network in the future by:

- *Applying our energy industry knowledge to the development of policy documents such as the Strategic Energy Action Plan (SEAP) and Local Development Plans (LDPs).*

- *Using data analysis to examine the changing demographics of our urban environments through planning applications, together with existing and proposed land use categories.*

- *Delivering value to our customers by understanding the customer group and what their needs are at the point of connection to our network.*

At a local level, this informs our operational planning and identifies where we can coordinate activities to minimise disruption to communities.

By closely cooperating with local authorities and other major stakeholders on Integrated Energy Planning, not only do we ensure delivery of power to the right places at the right time, but we can also capture wider benefits such as cost efficiencies, providing support to economic development and the ability to develop smart sustainable low-carbon power solutions. We have initiated integrated planning with other cities such as Liverpool, Edinburgh and Glasgow City Councils; and we plan to make a fundamental change to our business by extending this initiative in a way that allows us to reach all 42 local authorities where we operate. We recognise that each stakeholder will require differing approaches depending on their priorities.

Creating an infrastructure investment plan aligned with City/Region Energy Plan will optimise SPEN planned investment by identifying:

- *Potential developments and investment requirements*

- *Innovation opportunities including smart grids or demand management modelling*

- *Opportunities for the application of enhanced technology that enables City/Region aspirations*

- *Improved project scheduling to minimise cost and disruption*

- *Individual forecast scenarios for local/regional areas (as a refinement of the single DECC scenario)*

Essentially for SPEN, this engagement offers insight and opportunity to align the infrastructure needs of our customers to our future business activities. The process of aligning infrastructure investment plan with energy plans for local authorities will also optimise network performance. The identification of synergies, overlaps and economies of scale together with additional infrastructure investment requirements facilitates the achievement of stakeholder aspirations and promotes cooperative working. This methodology promotes benefits to the local economy and will support economic and social investment by local authorities.