IMP/001/915/002 – An Application Guide for using Load Drop Compensation on HV Systems

1. Purpose

The purpose of this document is to provide guidance to Northern Powergrid engineers for assessing, modelling and specifying load drop compensation as a means of managing voltage regulation on Northern Powergrid's HV system in line with the requirements of Code of Practice for Managing Voltages on the Distribution System.

This document supersedes the following documents, all copies of which should be withdrawn from circulation.

Document Reference	Document Title	Version	Published Date
IMP/001/915/002	An Application Guide for using Load Drop Compensation on HV Systems	1.0	Jan 2018

2. Scope

This document applies to the primary substations in the distribution licence areas of both Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc.

This document describes the application of load drop compensation as an advanced voltage management technique that can be considered to help manage voltages on HV feeders from a primary substation. It should be read in conjunction with the following Codes of Practices:

- IMP/001/911 - Code of Practice for Economic Development of the LV System;
- IMP/001/912 - Code of Practice for Economic Development of the HV System; and
- IMP/001/915 - Code of Practice for Managing Voltages on the Distribution System.

2.1. Table of contents

3. Application Guide

3.1. Background

In UK distribution systems on-load tap changers are typically installed on primary substation transformers to control the voltage at the low voltage busbar to a level that ensures the voltage at the point of supply to customer's remains within statutory limits. In some circumstances additional voltage control devices may be necessary to fulfil this required outcome.

Automatic voltage control (AVC) schemes are employed in order to automate and optimise operation of the on-load tap changers. Traditionally AVC schemes and more conventional interventions such as reinforcement or replacement of assets have helped to maintain voltages within statutory limits under varying load conditions. However, due to the increasing uptake of different generation technologies and the uptake of new forms of demand, all with potentially differing operational profiles, the ability of traditional voltage management techniques to maintain voltages within statutory limits has become more challenging.

Therefore, more advanced forms of voltage control techniques may need to be used in particular circumstances; load drop compensation (LDC) is one of these techniques.

Equation 1 below shows the effect of the interaction of the real power and line resistance having a dominant effect on voltage regulation on circuits supplying power with typically high power factor (i.e. the line reactance only becomes significant on voltage regulation when reactive flows are significant).

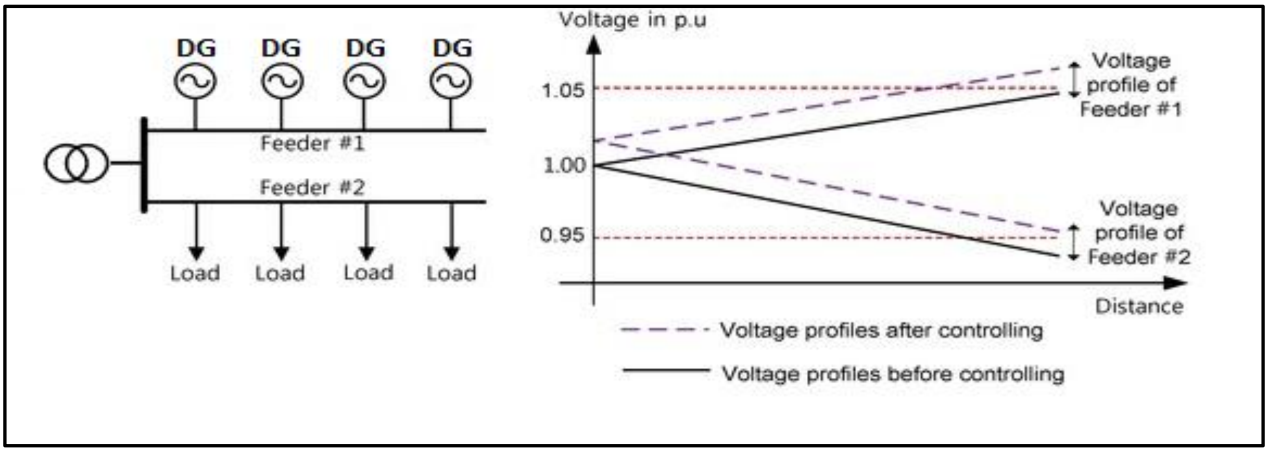
$$Vs - Vr \approx \frac{P.R - Q.X}{Vr} \qquad (1)$$

Vs = Sending end voltage	Q = Reactive Power
Vr = Receiving end voltage	R = Line Resistance
P = Real Power	X = Line Reactance

It can be seen from equation 1 that, if the real power demand from load is constant, the receiving end voltage can be increased by reducing the reactive power demand (e.g. using capacitors to supply the reactive power locally), reducing the line resistance (e.g. re-conductoring an overhead line), increasing the sending end voltage (e.g. using a voltage regulator or applying LDC) or any combination of these techniques.

The receiving end voltage can also be influenced by the operation of generation plant connected to a feeder. Graphically the effect of equation 1 above can be seen in Figure 1 where feeders with only load connected will experience a voltage drop along the feeder compared to the voltage on a feeder with distributed generation connected which will experience a voltage rise along a feeder. The amount of voltage change depends on the load supplied, generation output, system power factor and the impedance of the feeder.

Figure 1: Voltage regulation along load and generation dominated feeders[1]



3.2. Theory

3.2.1. Automatic Voltage Control (AVC) Scheme Principle

The main purpose of an AVC scheme is to maintain the target voltage at the substation busbars under varying load conditions. When a voltage outside the acceptable values (which are programmed into the AVC relay as settings) is detected by the AVC relay, a raise or lower signal is sent to the transformer on-load tap changer to change the transformation ratio in order to bring the busbar voltage back to the target voltage.

Typically, in a simple AVC scheme, a voltage measurement is used to compare the voltage on the secondary side of the transformer (V_S) to the target voltage (V_{TAR}) to establish if action is required by the AVC relay.

For the correct operation of a standard AVC scheme the target voltage, bandwidth and time delay settings are required.

3.2.1.1. Target Voltage, Bandwidth and Time Delay Settings

a) Target Voltage

The target voltage is the desired voltage on the substation busbars which the AVC relay will try to maintain. This voltage should be selected such that the voltage on the system it is supplying stays within statutory limits under all normal[2] operational scenarios. The target voltage for majority of the 11kV and 20kV system at the source substation busbar is 11.1kV and 20.1kV respectively with the aim of maintaining statutory voltage limits when supplying load and to allow for the connection of generation.

b) Bandwidth or Deadband

The function of the AVC relay is to maintain the target voltage via tap-operations. There is a need to co-ordinate the bandwidth (B_W) or deadband with the magnitude of the voltage change associated with a tap change operation i.e. the transformer tap step. The bandwidth or

[1] F T Dai, Voltage control of distribution networks with distributed generation, 2007.

[2] Normal includes the normal and abnormal operational scenarios that the system has been designed for rather than the exceptional operational scenarios (e.g. an N-2 situation) that the system isn't generally designed for and therefore when voltages could be expected to be outside of statutory limits.

deadband should be more than the transformer tap step[3] and is normally represented as a +/- % value from the target voltage.

The greater the bandwidth, fewer the number of tap changer operations however this reduces the effectiveness of the voltage control technique as the substation busbar voltage will have a greater voltage range. The other consideration is the maintenance of the tap changer itself as this is typically dictated by the number of operations as well as the current flowing at the time of each operation.

In practice, at substations with secondary voltage of 11kV and 20kV, the bandwidth is typically set at 1.5-1.8% depending on the tap step of the associated transformer.

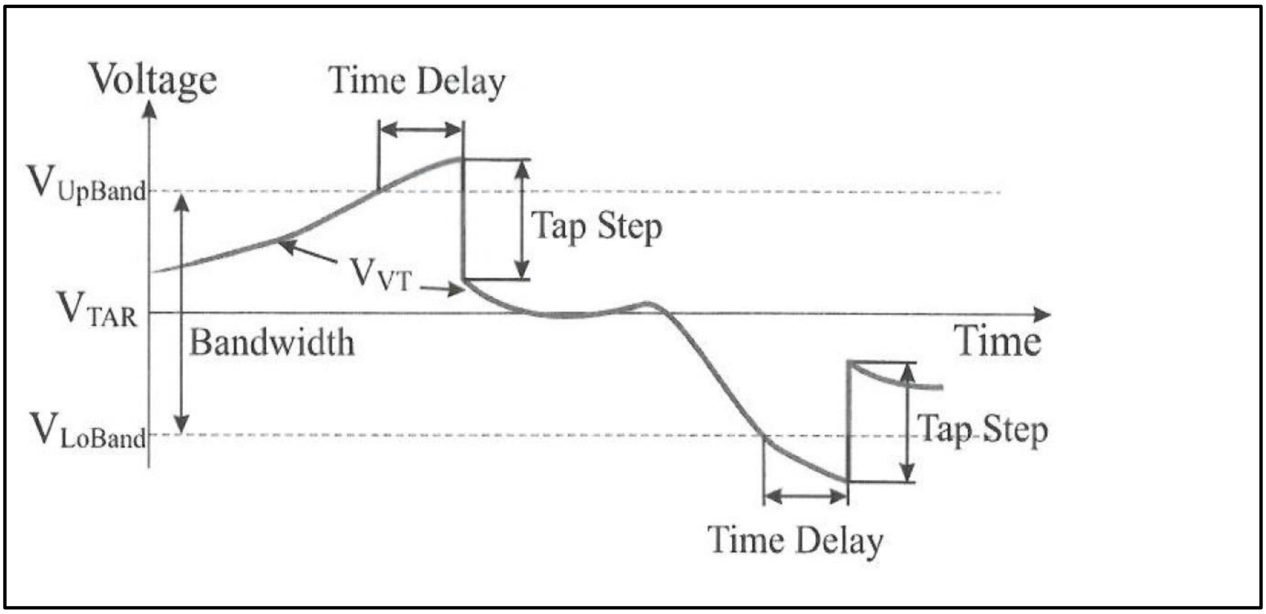
c) Time Delay

To avoid excessive and unnecessary tap change operations due to short term voltage fluctuations[4] and to co-ordinate the operation of transformer tap changes at the different voltage levels on the system, a time delay is applied to AVC schemes. This time delay is also used to provide co-ordinated AVC control between voltage control devices on the network.

For example, the time delay settings on transformers with a secondary voltage of 33kV or 66kV is typically between 90s and 60s whilst on transformers with a secondary voltage of 20kV or 11kV the time delay is typically 120s.

The interaction of the different AVC relay parameters in the time domain with target voltage (V_{TAR}), busbar voltage measured by the voltage transformer (V_{VT}), bandwidth (B_w) and time delay settings is illustrated in Figure 2.

Figure 2: AVC relay parameters and operation[5]



The AVC and tap changer operation is described as follows:

The AVC monitors the substation busbar measured voltage (V_{VT}) and compares it with the target voltage (V_{TAR}) and bandwidth settings (B_w). When the voltage fluctuates outside the acceptable voltage limits defined by B_W, the AVC relay starts its timer. If the voltage level persists outside the range for longer than the time delay settings, the AVC initiates a tap operation accordingly to reduce (buck) or

[3] E.g. a transformer with a tap step of 1.25% will typically have a bandwidth of +/- 1.5%.

[4] E.g. associated with short term changes in load.

[5] Maciej Fila, Modelling, Evaluation and Demonstration of Novel Active Voltage control schemes, October 2010.

increase (boost) the voltage at the substation busbar and bring the voltage back closer to the target voltage and within the bandwidth voltage range.

3.2.2. AVC with LDC Operating Principles

In a standard voltage management scheme, the target voltage is constant and independent of the load on the transformer and of the load on any of the feeders. This means that the applied target voltage needs to be a compromise between voltages that would be preferred in the two extreme scenarios:

i) when the transformer and all feeders are supplying their maximum demand; and

ii) when the transformer and all feeders are supporting their maximum generation export.

Traditionally the target voltage has been set to manage a scenario of maximum transformer and feeder load. This results in a 'high' target voltage which maximises the acceptable voltage drop associated with high system load. However, this approach can limit the voltage headroom available to support the export from generation at times of low load. In such a scenario it would be desirable to set the target voltage at a 'lower' value.

AVC relays are equipped with a facility to change the substation busbar voltage depending on the level of load either on a transformer or on a particular feeder. This is dependent on where the current measurement is taken.

The advantage that this function offers is that it enables a target voltage to be set which is lower than that traditionally applied. Hence, when the load on the transformer or feeder is low the substation busbar voltage is lower than that traditionally applied (which facilitates export from generation). The AVC relay can then be configured to increase the substation busbar voltage as the load on the transformer or feeder increases (which facilitates maintaining system voltages when the load on a transformer or feeder is high).

This technique is referred to as Load Drop Compensation (where the focus is on adjusting the target voltage depending on the load on the transformer) or Line Drop Compensation (where the focus is on adjusting the target voltage depending on the load on a particular feeder). Confusingly both techniques are referred to as LDC and both are implemented in the same way i.e. the target voltage is changed depending on the current flowing through the transformer; the difference being the main objective i.e. to manage the voltage depending on the load on a substation or a feeder and the way in which the AVC is configured. In Northern Powergrid, the focus is on changing the target voltage depending on the transformer current i.e. Load Drop Compensation, but for completeness both techniques are outlined below.

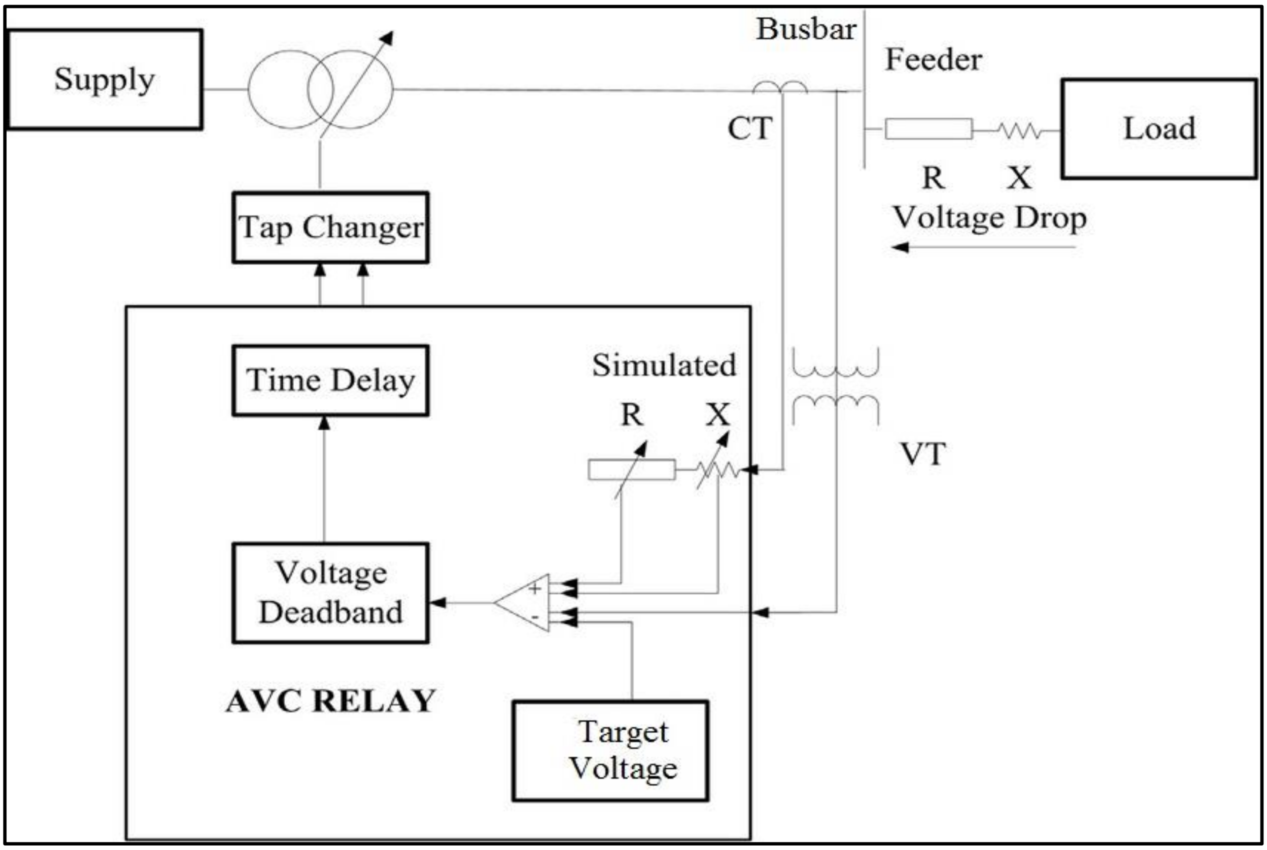
3.2.2.1. Line Drop Compensation

In a Line Drop Compensation scheme feeder current, the resistance (R) and reactance (X) of a particular feeder are used to estimate the voltage level at a remote point on that feeder. The amount by which the target voltage is increased (V_{LDC}) is a function of the estimated voltage drop along that feeder. These schemes are focussed on providing voltage support on particular feeders and can be difficult to apply where there are multiple feeders supplied from a substation with different load characteristic and different impedance parameters. The voltage bias applied at the substation busbars is in proportion to the measured current and R and X settings as shown below:

$$\boldsymbol{V_{LDC}} = \boldsymbol{I_{CT}} * (\boldsymbol{R_{FEEDER}} + \boldsymbol{jX_{FEEDER}}) \quad (2)$$

Figure 3 shows the operation of a Line Drop Compensation function in an AVC scheme where the target voltage (V_{TAR}) is modified depending on the transformer current (obtained from the CT shown in the diagram) and a simulation or estimation of the feeder resistance and reactance, with the aim of maintaining the voltage at the remote end of a particular feeder. The LDC voltage bias (V_{LDC}) is calculated via the simulated R and X and the transformer current which is then added to the target voltage and fed into the AVC (along with its parameters as described in sections above) to operate the tap changer as required to maintain the adjusted target voltage i.e. (V_{TAR} + V_{LDC}) at the substation busbar.

Figure 3: AVC scheme with line drop compensation operation[6]



3.2.2.2. Load Drop Compensation

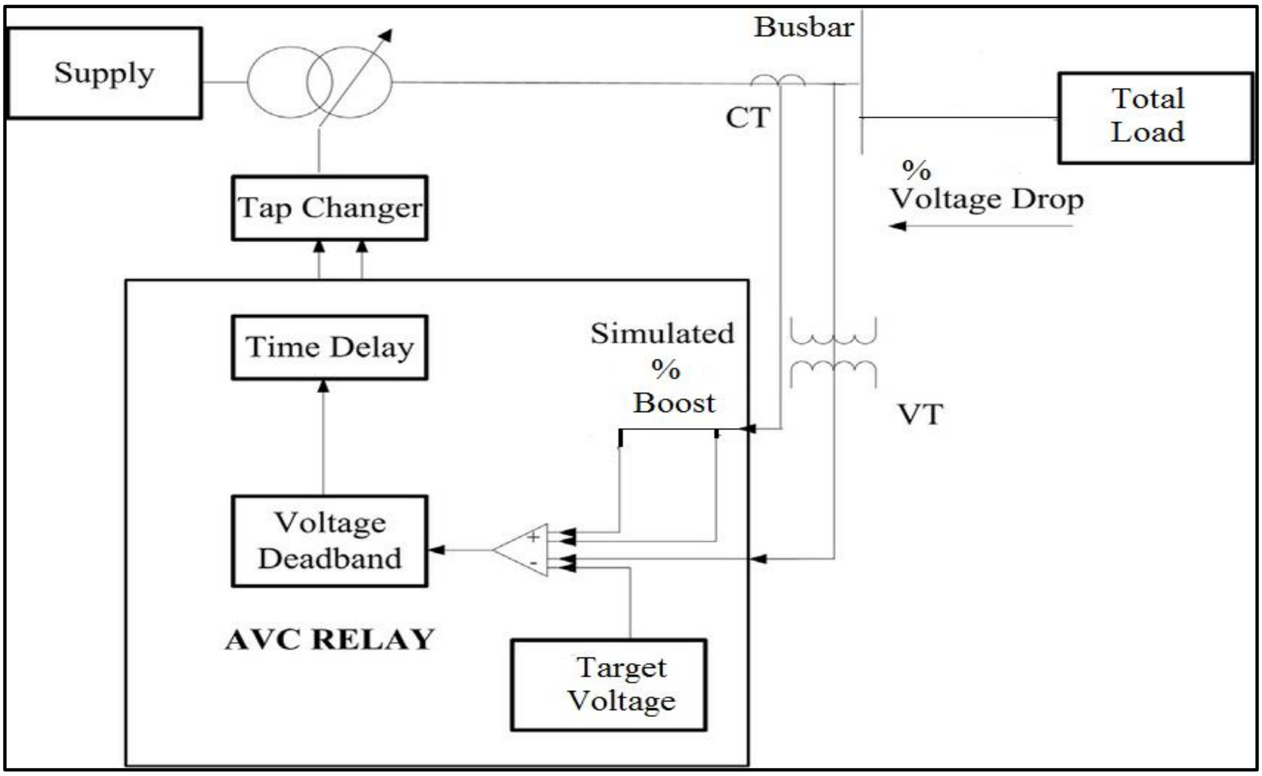
In a Load Drop Compensation scheme the amount by which the target voltage is changed is a function of the transformer load. These schemes are focussed on providing voltage support for substations with multiple feeders with differing characteristics. The voltage bias applied at the substation busbar, is in proportion to the ratio of the actual load current (I_{LOAD}) to the current at transformer full load (I_{TMAX}); calculated as shown below:

$$V_{LDC} = V_S * \frac{I_{LOAD}}{I_{TMAX}} \ (\%) \qquad (3)$$

Figure 4 shows the operation of a Load Drop Compensation function in an AVC scheme where the target voltage (V_{TAR}) is modified depending on the transformer current (obtained from the CT shown in the diagram), with the aim of increasing the voltage at the substation busbars when the transformer load is high. The LDC voltage bias (V_{LDC}) is calculated as a percentage boost depending on the ratio of the transformer load current to the maximum transformer load current which is then added to the target voltage and fed into the AVC (along with its parameters as described in sections above) to operate the tap changer as required to maintain the adjusted target voltage i.e. (V_{TAR} + V_{LDC}) at the substation bar.

[6] D Reid, G Taylor, P Lang, M R Irving M Fila, Coordinated voltage control for Active Network Management of Distributed Generation, 2009.

Figure 4: AVC scheme with load drop compensation operation



3.3. Benchmarking Against Other Voltage Control Technique

Table 1 below shows a comparison of different advanced voltage management techniques. If there are existing or forecast voltage regulation problems on a HV system then LDC is the most cost effective and it should be considered in the first instance. However, for more localised voltage problems the use of a voltage regulator or distribution OLTC transformer may be more appropriate. Traditional reinforcement should only be considered when LDC, voltage regulators and capacitors have been discounted.

Table 1: Benchmarking of Advanced Voltage Control Techniques

Advanced Voltage Control Techniques	Advantages	Disadvantages	Indicative cost (2017 prices)
Reduction in the standard target voltage and application of LDC	• Very low cost solution as existing equipment is installed at primary substations	• Affects voltages on all HV feeders supplied from a substation and may not suit needs of each individual feeder • Settings may need periodic review as load and generation on each feeder vary • Cannot be applied where the primary transformer is operating at the top end of its tapping range • May reduce the ability to implement OC6 Demand Control if reducing the target voltage would result in the transformer operating at the top end of its tapping range.	≈ circa £5,000 (to cover labour costs of design, protection and delivery)

Advanced Voltage Control Techniques	Advantages	Disadvantages	Indicative cost (2017 prices)
		• Increases future modelling complexity	
Distribution transformer On Load Tap changer (OLTC)	• Local voltage control for local problems • Lower system losses benefit compared to primary substation target voltage reduction and/or LDC solution • Can be combined with asset replacement in some instances	• Low Technology Readiness Level (TRL) of solution and equipment • Co-ordination with upstream LDC and AVC settings	≈ circa £30,000 for existing s/s locations
Voltage Regulator	• Effective at controlling individual feeder issues • Low cost compared to traditional reinforcement solutions • Quick to install where pole mounted	• Additional equipment on the distribution that needs to be operated and maintained	≈ circa £125,000
Capacitor Banks	• Low cost compared to traditional reinforcement solutions • Reduced System losses (reduction of I^2)	• Not effective on generation dominant feeders unless combined with shunt inductors (i.e. compensator) • Tend to be ground mounted and hence more expensive than voltage regulators (which tend to be pole mounted)	≈ circa £125,000
Line impedance reduction (overlay/re-conductor)	• Reduced System losses (reduction of R) • Least complexity • Low maintenance • Can be combined with asset replacement in some instances	• High capital cost • Time consuming to install	≈ circa £100,000/km for 11kV Cable

3.4. System Suitability

3.4.1. Eligibility Criteria[7]

The advanced voltage management technique considered here is to reduce the EHV/HV substation target HV voltage and arrange for LDC to increase the substation busbar voltage at times of high demand and low generation export i.e. at times of high net substation demand.

[7] Based on CLNR-L257, Proposals for a voltage control policy from CLNR learning, December 2014.

As increasing numbers of our customers are generating energy, lowering the target voltage at the source substation busbars, especially at times of minimum demand, offsets the voltage rise this generation causes. This creates headroom for generation export.

Target voltage reduction and the application of LDC can be effective at managing high voltages on HV systems supplied from primary substations with a significant amount of PV generation connected. The substation demand is likely to be low when the PV export is high; hence reducing the substation busbar target voltage is likely to be acceptable without creating low voltage issues at the remote ends of feeders. In the winter, the output from the PV generation will be low and the substation load will be high; hence it will be necessary to increase the substation busbar voltage to ensure that customers at the remote ends of feeders remain within statutory limits.

LDC may also be applied without an associated reduction in target voltage. In systems dominated by demand the substation busbar target voltage should be set at the harmonised target voltages of 11.1kV and 20.1kV for the 11 and 20kV system respectively as per IMP/001/915. The aim is to ensure that customers connected at the start of a feeder are supplied with a voltage at the upper limit of statutory voltage at times of low load and customers at the remote end to be supplied at the lower limit of statutory voltage at times of high load. Where application of the harmonised target voltages results in low voltage issues, it is permissible to apply the legacy standard target voltages of 11.3kV and 20.3kV for the 11 and 20kV system, respectively.

The increase in source voltage during high demand times can be achieved by application of LDC particularly in Northern Powergrid Northeast where there can be significant voltage drops due to the geographical layout of the rural system leading to significant feeder impedances and the associated voltage drops. The traditional system reinforcement solutions to address voltage issues would reduce the impedance by re-conductoring, reducing load on and/or length of feeders which all can be expensive and time-consuming to implement.[8]

Because the application of LDC affects the voltage on the all the feeders supplied from a substation, the design engineer needs to make a judgement on the credible combinations of load and generation at the primary substation and on each of the individual HV feeders. Where the load and generation profiles on each of the feeder are broadly the same, then LDC has the potential to be an effective advanced voltage management technique. However, where the load and generation profiles on the HV feeders are completely different,[9] whilst LDC may be applied, more detailed analysis will be required than is described in this document.[10]

This document provides guidance on the application of LDC in the following situations:

a. Where there is good alignment between the load and generation profiles on all the feeders. It is recognised that this assessment is subjective and that there is a risk that there may be some situations where the assessed target voltage and LDC settings do not cater for all the credible operational scenarios. Particular care should be taken when considering the application of LDC as part of a customer connection design study as any deficiencies in the design may need to be rectified at Northern Powergrid's cost.

b. Where there are existing voltage management issues on the HV system. In these cases the cost of implementing a voltage management solution falls to Northern Powergrid, and it would be appropriate to assess whether a low cost LDC scheme is sufficient to resolve the issues.

c. Where voltage management issues are created by multiple requests for new generation connections that are individually small but have a material cumulative effect. In these cases

[8] Reducing circuit impedance or load will also tend to reduce system losses, which may help offset the capital cost.

[9] For example, where one feeder is dominated by industrial load where the maximum demand peaks during the day whilst the other feeders supply predominantly domestic customers who have PV generation installed, where the minimum demand occurs during the day.

[10] One design issue that would need to be addressed is the establishment of the target voltage that should be applied when considering the maximum demand / minimum generation and minimum demand / maximum generation studies on any given feeder, as the target voltage would be dependent on the total substation load (rather than on the load on an individual feeder).

most of the cost of implementing a voltage management solution is likely to fall to Northern Powergrid and as above it would be appropriate to assess whether a low cost LDC scheme is sufficient to resolve the issues.

In cases b & c the application of LDC may provide an interim or enduring solution and it would normally be possible to apply LDC in a staged manner so that its effects can be monitored or observed.

3.4.2. Application

This document provides guidance on the application of LDC in conjunction with a reduction in the target voltage where the eligibility criteria are satisfied. The process for applying LDC alone, for example at a rural primary substation or simply reducing the target voltage without an associated LDC setting is similar.

Where the eligibility criteria are not satisfied, the application of LDC alone or LDC in conjunction with target voltage reduction may be considered although the assessment process will be more complex and might involve the use of substation monitoring equipment[11] or, in the future smart metering data. [12]

3.4.2.1. Application Stages

- Stage 1: Application of the harmonised target voltages
  - Confirm if the harmonised target voltages of 11.1kV and 20.1kV for the 11kV and 20kV system respectively have been applied. The application of these harmonised voltages may create sufficient headroom for generation connections.
- Stage 2: Application of target voltage reduction and LDC
  - Calculate the acceptable reduction of the target voltage based on the system modelling studies described in section 3.5.1. This is likely to be between 1% & 3%.
  - Calculate the LDC boost setting. The general requirement is to restore the substation busbar voltage back to the original target voltage; hence the LDC boost is likely to be between 1% and 3%. The value should be based on the transformer load, power system studies and the automatic voltage control relay functionality available.
- Stage 3: Application of additional advanced voltage management techniques
  - Where the application of LDC is insufficient to address the voltage issues, the application of further advanced techniques can be considered with as standalone solutions or injunction with LDC.[13] These include:
    - Application of more local voltage control solutions for local problems including on-load tap changers (OLTCs) and voltage regulators on the HV feeders and distribution substations;
    - Application of bespoke settings to AVC deadband and to LDC including or excluding load and or generation on key feeders as appropriate; and

[11] LDC could also be applied in conjunction with detailed monitoring installed at key points on the HV system to establish the existing voltage profiles and assess the scope for voltage reduction. Such an assessment was conducted, as detailed in section 3.6.2, as part of the Seghill monitoring trial. In this trial, voltage and power readings with 1 minute resolution were recorded on the majority of the feeders supplied from Seghill 66/11kV substation and also on the HV busbar. The aim of the detailed monitoring assessment was to establish the voltage profile across the system to give an indication of the voltage headroom and legroom which could be utilised to determine the acceptable target voltage reduction and level of LDC which could be deployed.

[12] Once distribution substation monitoring and good penetration of smart meters is deployed on the network this could be part of a potential future solution.

[13] See IMP/001/915.

- Move to full coordinated control with central and local solutions working together and having better control by having additional distribution monitoring and smart metering data.

This document concentrates on the application of the techniques summarised in section 3.4.2.1 Stages 1 and 2.

3.4.3. Equipment Selection

3.4.3.1. AVC Relay Types and Upgrade Program

Historically most of the AVC relays used in Northern Powergrid Northeast and Northern Powergrid Yorkshire are GEC AVE, Siemens MicroTAPP, Siemens SuperTAPP and GEC MVGC01 units. These relays have slightly different LDC functionality and settings. Hence before LDC is applied to a transformer the designer needs know the AVC manufacturer and type currently installed. This is recorded in the Northern Powergrid asset register.[14] Where the asset register indicates that a modern relay is not installed more up to date information may be available from Major Projects as part of the rollout programme for smart AVC relays as described below.

An AVC upgrade program is currently being implemented across Northern Powergrid Northeast and Northern Powergrid Yorkshire regions.[15] The AVC upgrade program will replace all the existing AVC relays (except MicroTAPP relays) with either Siemens SuperTAPP SG and Maschinenfabrik Reinhausen (MR) Tapcon relays.

Where relays are yet to be replaced, the planned replacement date may be included in the Northern Powergrid Northeast and Northern Powergrid Yorkshire AVC upgrade programme project management spreadsheets. These files list all substations and relevant AVC details along with other information. These files are owned and managed by Major Projects and they are updated regularly as part of the AVC upgrade program.

The Northern Powergrid Northern replacement programme is summarised in the following "Internal_EAVC Master Schedule NE" spreadsheet accessible via the following link:

\\ad03.local\shares\PEP\6a RIIO Project Files\01 Smart Grid Work Programmes\01 AVC Replacements\01 North East\11. Progress Information\Master Schedule

The Northern Powergrid Yorkshire replacement programme is summarised in the following "191113_INTERNAL_AVC Master Schedule" spreadsheet accessible via the following link:

\\ad03.local\shares\PEP\6a RIIO Project Files\01 Smart Grid Work Programmes\01 AVC Replacements\02 Yorkshire\09. Time Planning\Master AVC Schedule

If, when considering the application of LDC, it becomes evident that the existing AVC relay is not suitable due to its age, condition or the settings available, Major Projects/Technical Services should be asked to expedite the replacement of that particular AVC relay within the replacement programme.

In order to use all of the new AVC functionality IP communications protocol is required at the substation. Major Projects will be able to provide an update as to which substations have had the communications protocol updated.

Those substations in the Northern Powergrid Yorkshire region that are operating on an IP communications profile are recorded in the ".u INTERNAL ALL YE RTU Sites – Working Copy." spreadsheet accessible via the following link:

[14] Accessed via the iSmart application.

[15] The AVC relay replacement programme in Northern Powergrid Northeast is expected to be complete by early ED2. The AVC relay replacement programme in Northern Powergrid Yorkshire is expected to be complete by early 2023.

\\ad03.local\shares\PEP \6a RIIO Project Files\Yorkshire\3-Work Programmes\WP75 RTU C10 replacements\16.Operational Requirements

Those substations in the Northern Powergrid Northeast region that are operating on an IP communications profile are recorded in the "220622_INTERNAL_ NE SCADA IP UPgrade 2022 Progress" spreadsheet[16] accessible via the following link:

\\ad03.local\shares\PEP\6a RIIO Project Files\Northeast\3-Work Programmes\WP75 RTU IP Upgrade NE

Figures 5 and 6 show the different AVC types and volumes as of October 2017.

Figure 5: Northern Powergrid Northeast AVC types and breakdown as of October 2017

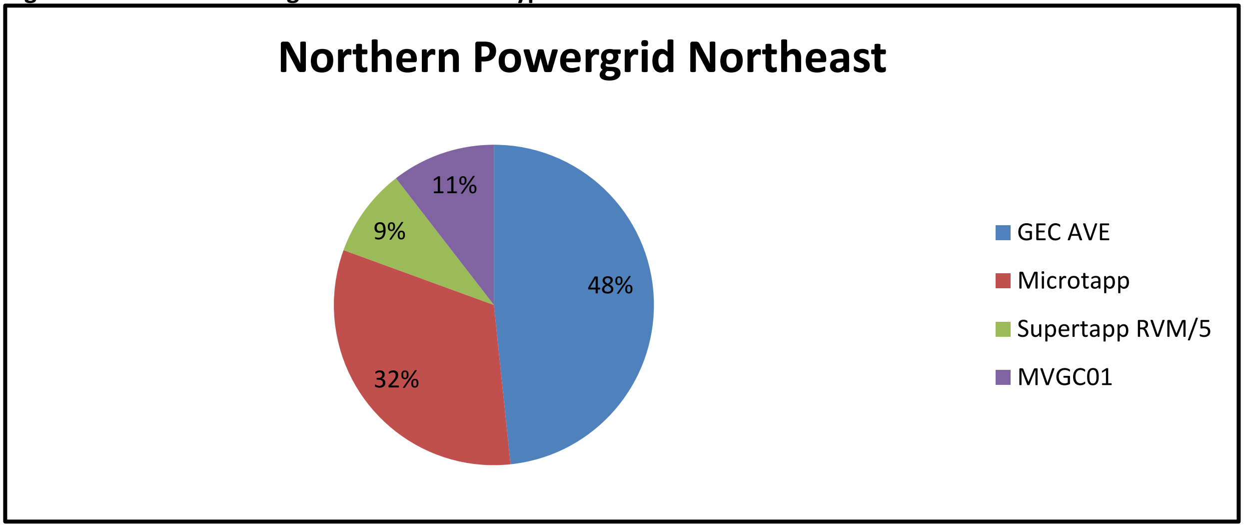
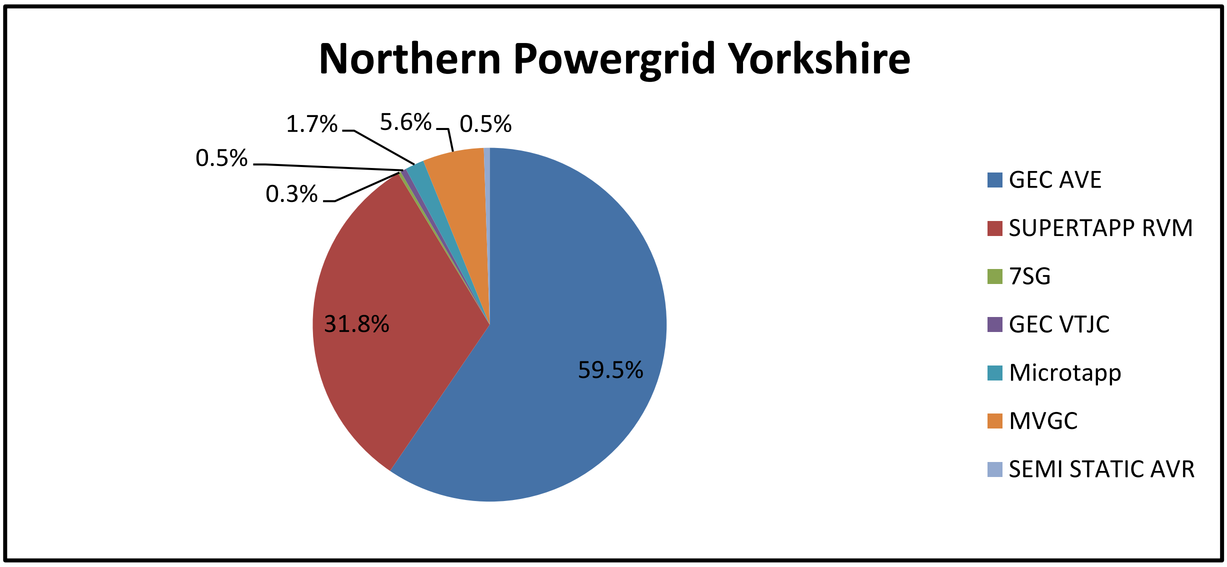


Figure 6: Northern Powergrid Yorkshire AVC types and breakdown as of October 2017



3.4.3.2. AVC Relay Types and Functionalities

The following section summarises the voltage management related functionalities and limitations of AVC relay types which will be deployed on the Northern Powergrid system once the upgrade program is complete.

[16] Column O shows the RTUs upgraded to IP.

1) MicroTAPP

- Three different setting groups can be applied. For example these could be:
  - 3 x LDC settings each with different target voltages; or
  - 2 x LDC settings each with different target voltages and 1 x no LDC with a different target voltage
  - 2 x LDC settings each with different target voltages and 1 x winter (or summer) target voltage

  Settings need to be set up on site but can be switched on / off remotely, depending on the system need, if required.

- Compensation is provided based on a linear relationship between system load up to maximum boost percentage defined at a 'group load setting' in MVA. For example, if the LDC is set to provide a 3% voltage boost with a 'group load setting' of 20MVA, at 10MVA a 1.5% boost would be applied. Each setting group has only one set point; in the previous example it is 3% at maximum demand of 20MVA so the slope of the 'voltage variation against load' curve is constant.

- LDC is only available to boost the substation busbar voltage with positive power flows only (i.e. this type of AVC relay can provide boost for positive power flows through the transformers only and cannot be used to reduce the substation busbar voltage for negative/reverse power flows) and hence can only be used to boost voltage as the substation load increases.

- Load exclusion (i.e. excluding specific loads such as significant non-linear point loads or loads which affect the power factor significantly, from the measured load current used to determine the voltage boost,) and Generation exclusion[17] not possible.

- Settings group can be turned on / off remotely but individual parameters within the setting group cannot be changed remotely e.g. the target voltage cannot be changed remotely via SCADA.

2) Tapcon

- Only a single setting group is available but multiple set points, to provide different levels of compensation, can be defined. For example, a primary substation with a maximum demand of 20MVA could have one setting group of 3% boost at 20MVA with multiple set point i.e.
  - One set point could be 0% boost for 0-10MVA to manage high voltage issues due to generation export;
  - A second set point could be 1% boost for 10-15MVA; and
  - A third set point could be 2% for 15-20MVA.

  Setting groups and set points need to be set up on site manually depending on system need.

- Compensation is provided based on a linear or non-linear relationship. Multiple sets points can be applied to implement a non-linear functionality as described in the bullet above so that the slope of the 'voltage variation against load' curve can be variable.

[17] Depending on the size/export of the generation there could be potential solutions to manually exclude generation effect to the LDC compensation settings.

- LDC is available via the Boost setting but with both positive and negative power flows (i.e. this type of relay can provide compensation for positive and/or negative/reverse power flows through the transformers) and hence can provide both a voltage boost for demand and a voltage buck for generation compensation.
- Load exclusion (i.e. excluding specific loads such as significant non-linear point loads or loads which affect the power factor significantly, from the measured load current used to determine the voltage boost,) and generation exclusion not currently possible.[15] However, it may be possible to simulate generation exclusion by utilising the capability to define different compensation values /set points for negative/reverse power flows.
- The target voltage can be varied remotely via a Distribution Network Protocol (DNP3) IP communication path, provided that the substation communications have been updated.

3) SuperTAPP SG

- Only a single setting group available to provide compensation.
- Compensation is based on a linear relationship between system load up to maximum boost percentage defined at a 'group load setting' in MVA. Substation voltage boost is available in both directions i.e. for positive and negative power flows both.
- LDC is via Boost setting, both positive and negative power flow with different settings in either direction.
- Load exclusion (i.e. excluding specific loads such as significant non-linear point loads or loads which affect the power factor significantly, from the measured load current used to determine the voltage boost,) and Generation exclusion is possible.
- The target voltage can be varied remotely via a Distribution Network Protocol (DNP3) communication path, provided that the substation communications have been updated.

3.5. LDC Scheme Design

3.5.1. LDC Scheme Design Process

This section details the LDC scheme design process which is summarised in the flowchart in Figure 7. This flowchart shows key design stages in the process to apply LDC.

The objective of the system modelling is to ensure that under the worst case conditions of maximum demand / minimum generation and maximum generation / minimum demand the voltage at the point of supply to all customers is within the statutory limits.

The modelling studies should assess the worst case assumption of maximum load / minimum generation and maximum generation / minimum load independently on each feeder. The substation busbar voltage used for the maximum load / minimum generation study should be the maximum value anticipated i.e. the revised (lower) target voltage and the LDC voltage boost. The substation busbar voltage used for the maximum generation / minimum load study should be the proposed new target voltage.

In order to limit the modelling to the HV system only, the voltage at the LV terminals of the HV/LV transformer shall be calculated; these values should be within the range 230V to 230V+10% (253V). This is in accordance with Northern Powergrid policy to maintain a minimum of 230V at the LV terminals of the HV/LV transformer to allow for a 6% voltage drop on the LV system and maintain voltages within statutory voltages.

The following text relates to the clarification notes referred to in the flowchart in Figure 7:

1) Where the primary substation transformer operates at the top tap, it is not possible to reduce the target voltage, although LDC alone could still be applied to increase the substation busbar

voltage with increasing demand. Where there is a need to reduce the target voltage, it may be possible to reduce the target voltage at the source substation e.g. at the 132/33kV substation. The implications of this on the other primary substations and customers supplied from the same source would need to be assessed. Local advanced voltage management techniques such as voltage regulators and/or on load tap changers should also be considered.

2) The guide proposes an approach based on pairs of target voltage and LDC boost as shown in Table 2. This approach minimises the number of system studies and minimises the risk of high voltages occurring at customers connected close to a primary substation that may arise if the LDC boost is greater than the reduction in target voltage.

Table 2: LDC % Boost and Target Voltage (11kV nominal voltage)

LDC boost	Target Voltage[18]
3%	Harmonised target voltage - 3% (10.8kV)
2%	Harmonised target voltage - 2% (10.9kV)
1%	Harmonised target voltage - 1% (11.0kV)

It is suggested that the system studies are carried out for the 3% scenario initially. If this scenario results in all LV voltage at the HV/LV transformer being within permitted range, then a harmonised target voltage - 3% with a 3% LDC boost could be applied.

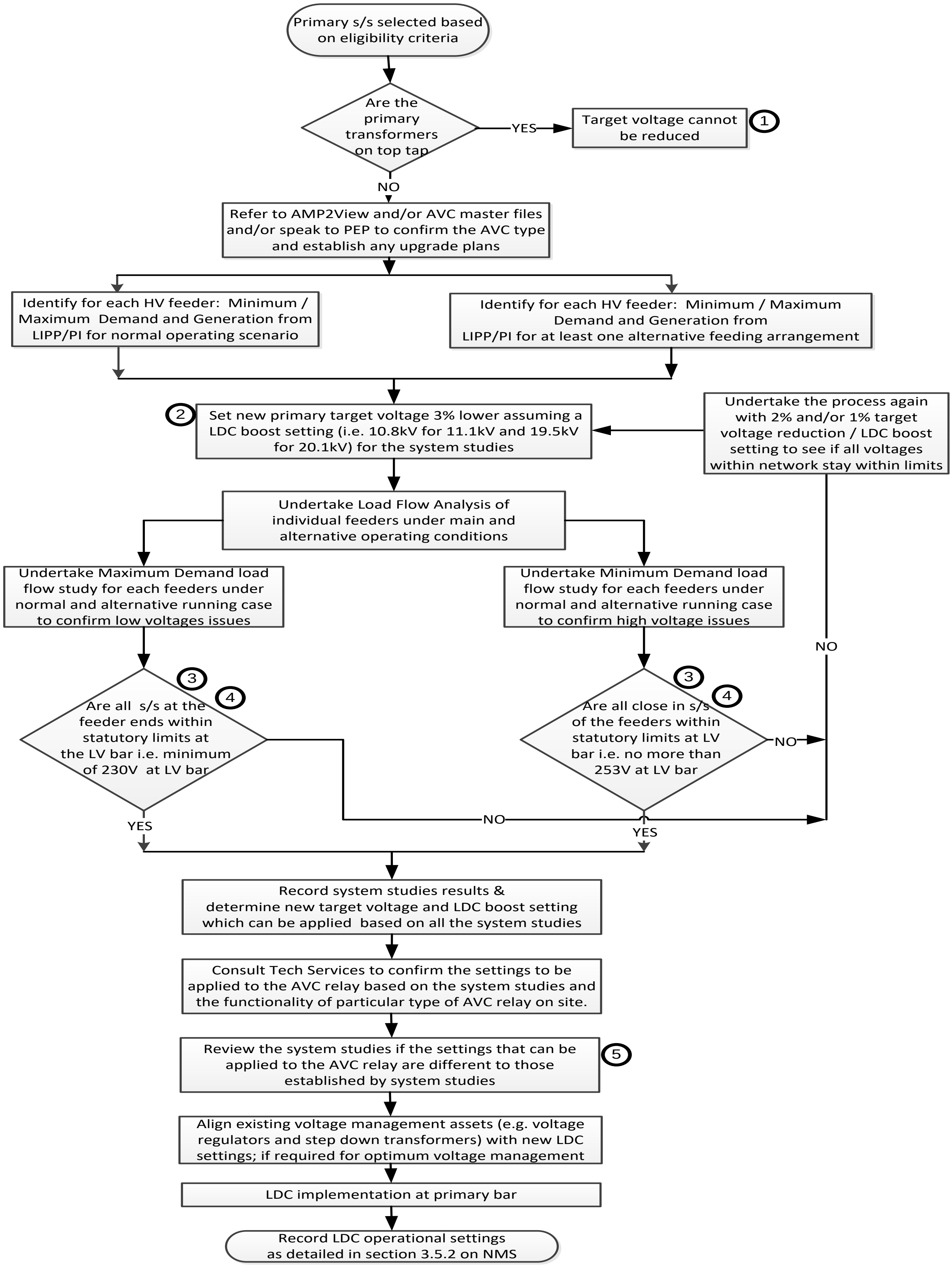
1) If there is a concern that the voltage drop on the LV feeders may be in excess of 6% (possibly due to historical reasons) than further investigation on the LV network shall be undertaken.

2) The HV/LV Voltage calculator i.e. Tapzone calculator shall be used to determine the voltage on the LV bar in Northern Powergrid Northeast together with DINIS. In the Northern Powergrid Yorkshire DINIS model, this voltage is shown in DINIS.

3) Where the AVC settings established by the system studies cannot be applied to the AVC relay due to limitations in its functionality, and compromise settings need to be applied, there may be a need to repeat some of the system studies to ensure that the voltage criteria are satisfied in all the demand and generation scenarios.

[18] The values relate to a nominal 11kV voltage; the same principles apply if the nominal voltage is 20kV.

Figure7: LDC Scheme Design Process Flowchart



3.5.2. LDC Scheme Settings

Table 3 details the AVC operational settings required for the LDC scheme to be implemented by Technical Services.

The settings detailed in Table 3 shall be stored in Network Management System (NMS) as LDC settings against the primary substation. The settings should be periodically reviewed to cater for the effect of load changes on the system loading or when any system design work is carried out on that part of the HV system.

Table 3: AVC Operational Settings

Parameter		Units
Target Voltage	To be calculated based on system studies	kV
System power factor	Available from Distribution Load Estimates	pf
Bandwidth	Based on AVC relay type; obtain from AMP2view or s/s drawings	+/- % of target voltage
Time delay	Based on IMP/001/915 & agreed with Tech Services	seconds
Configuration e.g. auto, non-auto, master follower	Based on AVC relay type; obtain from AMP2view or s/s drawings	Type of AVC scheme
Over voltage alarm	To be calculated[19]	kV and seconds
Under voltage alarm	To be calculated[20]	kV and seconds
LDC – Group capacity	To be calculated based on system studies	MVA
LDC – percentage boost	To be calculated based on system studies	%

3.6. Seghill Trial Learnings and Results

3.6.1. Trial Aims

The purpose of the trial was to measure and model voltages at Seghill 66/11kV substation and the outgoing 11kV feeders to better understand whether LDC can be applied to the Seghill substation, to inform this application guide and the debate as to whether LDC can be applied more widely.

The trail supported the longer-term objectives which were to:

- Establish a means of lowering HV system voltage at times of light load whilst ensuring voltages at customers Points of Supply remain within (statutory) limits at times of both low and high load;
- Inform the new Voltage Management Code of Practice and LDC application guide;
- Understanding where LDC can be applied i.e. – develop initial selection criteria;
- Develop a methodology to establish the settings, where LDC can be applied;

[19] Overvoltage (O/V) Alarm to detect if excessive voltage boost is applied leading to voltages outside statutory limits to customers. For example, O/V alarm to be set at 11.45kV for a target voltage of 10.9kV (10.9kV + 1.5% (Bandwidth) + 3% (Boost) + 0.5% (Margin)) with 180s Time Delay.

[20] Undervoltage Alarm (U/V) to detect if the lower voltage statutory limit is breached. For example, U/V alarm to be set at 10.03kV for a target voltage of 10.9kV (10.9kV - 1.5% (Bandwidth) - 6% - 0.5% (Margin)) with 180s Time Delay.

- Assess whether a standard LDC setting can be developed that could be applied at most primary substations; and
- Develop a set of prioritisation criteria for replacement of AVC relays with modern voltage control schemes i.e. where it may not be possible to apply the LDC settings.

3.6.2. Network and Monitoring

Seghill 66/11kV primary is an urban primary with outgoing HV feeders of typical length and with a majority of domestic load giving it a diurnal load profile with a 3MW generator connected on the primary busbar. The AVC relay on the primary substation transformers is a Siemens MicroTAPP which has the features listed in section 3.4.3.2.

As part of the trial, substation monitoring was deployed to locations as listed in the Table 4 which recorded 1min resolution readings of the listed quantities. The locations were selected to provide the best representation of the complete network based on feeder make up (i.e. one out of multiple feeders which are similar in make-up) and voltage sensitive points on the feeder (i.e. the closest, mid-point and remote s/s on the feeders and couple of HV metered customers and half hourly LV customers).

The detailed monitoring equipment was deployed on the Seghill system at significant time and cost input to achieve the trail aims; this would not be cost-effective on every LDC scheme design. Hence the guide proposes a high level solution to be implemented as a standard solution with option of future development on LDC implementation solutions.

Table 4: Network Monitoring Locations and Parameters

Location	HV feeder	Monitoring point	Categorisation	Data *
Seghill primary substation	N/A	11kV	Primary	Voltage, current and power factor (combined transformer current & power factor). T1 and T2 tap position[21].
Seghill primary substation	Seghill Generation (3MW)	11kV		Generator feeder current, average power and power factor.
Seghill Station LV bar (Dist s/s)	Seghill Signal Teed feeder	LV	Local LV	LV voltage, transformer current, transformer power. Transformer tap position.
Bates Cottage LV bar[22]	Shulton feeder		Remote point LV adjacent to NOP	LV voltage, transformer current, transformer power. Transformer tap position.
Avenue School LV bar	Shulton feeder	LV	Middle point LV	LV voltage, transformer current, transformer power. Transformer tap position.
Melrose	Shulton feeder	LV	Middle point LV (upstream of Avenue School)	Voltage and transformer load. Transformer tap position.
Northcott LV bar	Northcote feeder	LV	Local LV	LV voltage, transformer current, transformer power. Transformer tap position.
Dudley Burroughs (HV Connected	Northcote feeder	11kV	Remote HV adjacent to NOP	11kV voltage, current, power and pf.

[21] Transformer tap position is stored in the microtapp relay for 24 hours. This data could be used in the modelling as an additional check.

[22] Hollywell Village LV bar replaced by Bates Cottage as the monitoring equipment couldn't be connected to the new UDE.

Location	HV feeder	Monitoring point	Categorisation	Data *
Customer) which is adjacent to Dudley West				
Moor Farm Businesses Dist s/s	Northcote feeder	LV	Remote LV adjacent to Dudley Burroughs	LV voltage, transformer current, transformer power. Transformer tap position.
Moor Farm Businesses LV Customer[23]	Northcote feeder	LV	Remote LV adjacent to Dudley Burroughs	LV voltage, current, power 3 Phase LV customer (bulk LV supply).

3.6.3. Application and Results

3.6.3.1. Monitoring Results

The recorded data from the selected substations was collected over a 2-month period between 26 May 2016 and 27 July 2016. The voltage readings were normalised so that the results were adjusted to provide the LV measured voltage as if the EHV/HV transformer was operating at its target voltage (rather than at an operating position within its dead band) so that it could be compared against the output from the system models. The scatter diagram in Figure 9 plots voltage of the monitored locations against the aggregated real power through the 66/11kV transformers at Seghill primary. It is important to note that the voltage shown on the scatter diagram could be up to 1.5% typically lower depending on where the operating voltage is within the dead band.

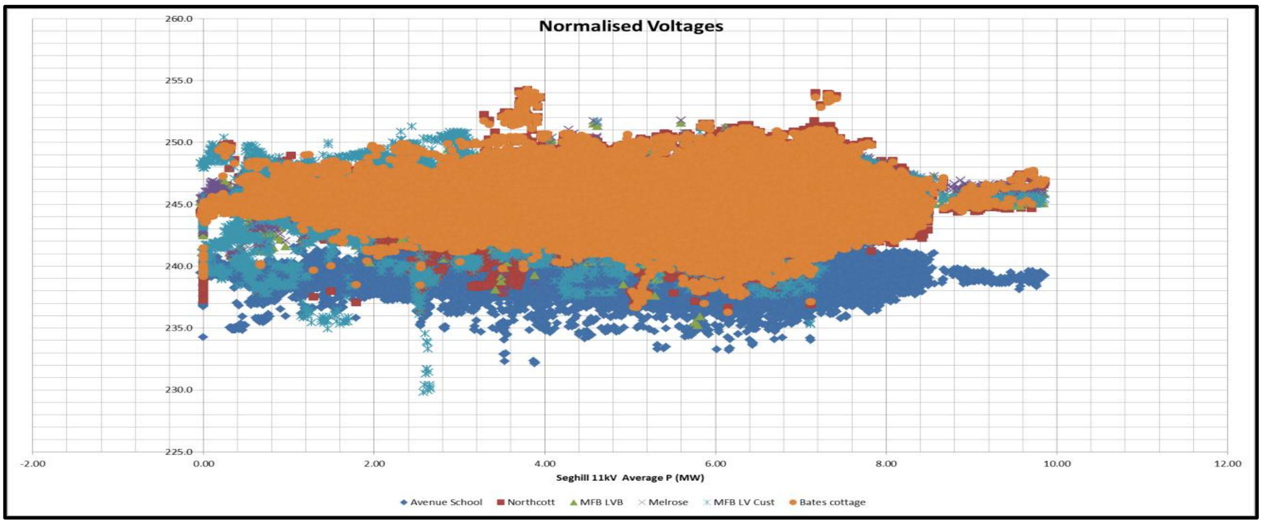
The scatter diagram which highlights the voltage head/legroom indicated that:

- The minimum observed voltage at Avenue School distribution s/s is c233V;
- The minimum observed voltage at Bates Cottages distribution s/s is c239V;
- The observed voltage range at Bates Cottage is 239-247V i.e. 4%, which is slightly higher than the AVC bandwidth which is +/- 1.5%; and
- The observed voltage range at Bates Cottage is independent of the demand on Seghill once the load is higher than 2MVA.

The implication is that the system voltage could be reduced by at least 3V (1.5%) and the observed voltage would remain above 230V which is the proposed nominal design voltage for the LV terminal voltage of the HV/LV transformer. With a LV terminal voltage of 230V should ensure that customer terminal voltages remain within 230V -6% as 6% voltage drop on the LV feeder has been the legacy design practice.

[23] The customer is "ABS-Unit 10; fed from LV feeder C of the s/s.

Figure 5: Scatter Diagram of the Seghill Normalised Voltages to show Head/Legroom on Voltages



3.6.3.2. Modelling Results

System modelling was carried out using the normal Northern Powergrid Northeast design tools i.e. DINIS and a HV/LV Voltage Regulation calculator spread sheet and as detailed in the LDC scheme design process flowchart in section 3.5.1. The results of the analysis are shown in Figure 10. The standard modelling approach assumes that the HV busbar target voltage is maintained at the nominal target voltage (i.e. the dead band is ignored), so the modelling approach is consistent with the scatter diagram approach.

The modelling shows:

- The voltage variation at Bates Cottage is 239V (high load) - 249V (low load). This compares well with the observed range, but the measurements are taken during June and July, when the load would be lower, i.e. the observed voltage could be lower than the modelled voltages during peak winter demand. Based on the summer LIPP peak load the Bates Cottage and Avenue School voltages range between 239.8V-249V and 234V-243V, respectively.
- The HV voltage drops are relatively low, with the exception of the Seton Delaval feeder which at 2.7% is more typical of a rural circuit.

3.6.3.3. Proposed Solution

As the monitored solution and modelled solution compared well, the headline solution was to reduce the target voltage by 200V (1.8%) from 11.1kV to 10.9kV. This is slightly more than 1.5% i.e. a step, so should result in the transformer generally operating one tap higher than at present. Ignoring the deadband, this should result in a lowering of the LV voltages by 1.8% i.e. approx. 4V.

In conjunction with this, it was proposed to apply an LDC setting to boost the voltage by 1.8% gradually as the Seghill transformer aggregate demand increases from no load to 50% full load (12MVA) i.e. 6MVA. The boost was to be capped at 2%. Due to the availability of only one set point on the AVC relay (i.e. MicroTAPP) as the maximum demand of 18MVA was well in excess of the observed of 12MVA, the AVC relay was set to deliver a 3% boost at 18MVA i.e. 12MVA at 2%. The individual settings are shown in section 3.6.4.

Figure 6 : Seghill LDC Modelling Results

Seghill Winter Demand as Max

HV feeder	Dinis Feeder No	Max Load [2]	Min Load [3]	Worst Case HV Vdrop [4]				Worst Case LV Voltage [5]					Tap Position	Transformer Rating / Max Demand kVA
				Max Feeder Load		Min Feeder Load		Max Feeder Load		Min Feeder Load				
		A	A	Distribution s/s	% [6]	Distribution s/s	%	Distribution s/s	LV Voltage [1][7]	Distribution s/s	LV Voltage [1]			
IDNO Cramlington Hospotal				*Dedicated HV Fdr*										
Entek Sw1	6	189	6	*Dedicated HV Fdr*										
Northcott Td	1	100	25	Dudley Burroughs	0.2	Dudley Burroughs	0	Dudley Burroughs	240.5/236.1	Dudley Burroughs	249/244	Dudley Burroughs	HV POC	1250
Seghill Signal Teed	7	60	15	Murrayfield	0.2	Murrayfield	0	Murrayfield	240.5/236.1	Murrayfield	249/244	Murrayfield	102.5	500/216
Delaval Blyth	13	61	11	Baxter	0.3	Baxter	0	Baxter	240.3/235.9	Baxter	249/244	Baxter	102.5	500/283
Shulton	12	113	13	Holywell Village	0.8	Holywell Village	0.1	Holywell Village	239.1/234.7	Holywell Village	249/244	Holywell Village	102.5	315/220
				Bates Cottage	0.6	Bates Cottage	0.1	Bates Cottage	239.5/235.2	Bates Cottage	249/244	Bates Cottage	TBC	500/300
				Avenue School	0.5	Avenue School	0.1	Avenue School	233.8/229.4	Avenue School	243/238	Avenue School	TBC	300/192
Delaval Avenue	14	115	23	Earsdon south	1.3	Earsdon south	0.3	Earsdon south	237.9/233.5	Earsdon south	248/244	Earsdon south	NA	800/397
Ambridge WAY IDNO	15	9	3	Newsham, Village	0.1	Newsham, Village	0	Newsham, Village	240.7/236.4	Newsham, Village	249/244	Newsham, Village	102.5	315/203
Wheatbridge	2	71	16	Newsham Central	1.2	Newsham Central	0.1	Newsham Central	238.1/233.7	Newsham Central	249/244	Newsham Central	102.5	500/207
Seaton Delaval	3	105	20	Anton	2.7	Anton	0.5	Anton	234.5/230.1	Anton	248/243	Anton	102.5	500/146
Seghill Generation	11			*3MW Generation*										

Notes

1 Terminal voltage of the HV:LV transformer Voltage at 11.1kV/10.9kV
2 Max Load as determined from LIPP
3 Min Load as determined from LIPP
4 Distribution ss with the largest volatge drop under max / min load conditions
5 LV terminal voltage with max / min demand on feeder
6 % HV voltage on 11kV base
7 LV voltage based on a typical regulation of 2%
8 Voltages under normal operating conditions

Seghill Summer Demand as Max

HV feeder	Dinis Feeder No	Max Load [2]	Min Load [3]	Worst Case HV Vdrop [4]				Worst Case LV Voltage [5]					Tap Position	Transformer Rating / Max Demand kVA
				Max Feeder Load		Min Feeder Load		Max Feeder Load		Min Feeder Load				
		A	A	Distribution s/s	% [6]	Distribution s/s	%	Distribution s/s	LV Voltage [1][7]	Distribution s/s	LV Voltage [1]			
IDNO Cramlington Hospotal				*Dedicated HV Fdr*										
Entek Sw1	6			*Dedicated HV Fdr*										
Northcott Td	1	70	25	Dudley Burroughs	0.1	Dudley Burroughs	0	Dudley Burroughs	240.7/236.4	Dudley Burroughs	249/244	Dudley Burroughs	HV POC	1250
Seghill Signal Teed	7	39	15	Murrayfield	0.1	Murrayfield	0	Murrayfield	240.7/236.4	Murrayfield	249/244	Murrayfield	102.5	500/216
Delaval Blyth	13	39	11	Baxter	0.2	Baxter	0	Baxter	240.5/236.1	Baxter	249/244	Baxter	102.5	500/283
Shulton	12	82	13	Holywell Village	0.6	Holywell Village	0.1	Holywell Village	239.5/235.2	Holywell Village	249/244	Holywell Village	102.5	315/220
				Bates Cottage	0.5	Bates Cottage	0.1	Bates Cottage	239.8/235.4	Bates Cottage	249/244	Bates Cottage	102.5	500/300
				Avenue School	0.4	Avenue School	0.1	Avenue School	234/229.7	Avenue School	243/238	Avenue School	105	300/192
Delaval Avenue	14	87	23	Earsdon south	1	Earsdon south	0.3	Earsdon south	238.6/234.2	Earsdon south	248/244	Earsdon south	NA	800/397
Ambridge WAY IDNO	15	6	3	Newsham, Village	0.1	Newsham, Village	0	Newsham, Village	240.7/236.4	Newsham, Village	249/244	Newsham, Village	102.5	315/203
Wheatbridge	2	45	16	Newsham Central	0.7	Newsham Central	0.1	Newsham Central	239.3/234.9	Newsham Central	249/244	Newsham Central	102.5	500/207
Seaton Delaval	3	61	20	Anton	1.5	Anton	0.5	Anton	237.4/233	Anton	248/243	Anton	102.5	500/146
Seghill Generation	11			*3MW Generation*										

3.6.4. Seghill LDC Settings

The following section details the AVC operational settings for the Seghill LDC scheme.

- Target voltage 10.9kV
- Bandwidth 1.5%
- System pf 0.99Lag
- Group Capacity 18MVA
- Boost 3% (i.e. the maximum boost of 3% will be applied at 18MVA maximum demand only)
- Software alarms decided with Technical Services assistance.
  - Overvoltage Alarm to make sure excessive voltage boost is not applied leading to voltages outside statutory limits to customers: 11.45kV (10.9kV + 1.5% (Bandwidth) + 3% (Boost) + 0.5% (Margin)) with 180s Time Delay.
  - Undervoltage Alarm to make sure that the lower voltage statutory limit is not breached: 10.03kV ((10.9kV -1.5% (Bandwidth) - 6% - 0.5% (Margin)) with 180s Time Delay.

The Grid Code OC6 voltage reduction facilities were based on the target voltage, so will be -3% and -6% of 10.9kV.

4. References

4.1. External Documentation

Reference	Title
N/A	

4.2. Internal Documentation

Reference	Title
IMP/001/911	Code of Practice for Economic Development of the LV System
IMP/001/912	Code of Practice for Economic Development of the HV System
IMP/001/915	Code of Practice for Managing Voltages on the Distribution System

4.3. Amendments from Previous Version

Reference	Title
All document	Minor editorial updates

5. Definitions

Term	Definition
AVC	Automatic Voltage Control
EHV	Means voltages equal to or greater than 33kV and less than 132kV (for the purpose of this Code of Practice 25kV traction supplies are considered to be EHV)
HV	Means voltages greater than 1kV and less than 33kV (for the purpose of this Code of Practice 25kV traction supplies are considered to be EHV)
LDC	Load Drop Compensation or Line Drop Compensation
Primary Substation	A 132kV to HV or EHV to HV substation

6. Authority for Issue

6.1. CDS assurance

I sign to confirm that I have completed and checked this document and I am satisfied with its content and submit it for approval and authorisation.

		Date
Liz Beat	Governance Administrator	05/01/2023

6.2. Author

I sign to confirm that I have completed and checked this document and I am satisfied with its content and submit it for approval and authorisation.

Review Period - This document should be reviewed within the following time period.

Standard CDS review of 3 years	Non Standard Review Period & Reason	
Yes	Period: n/a	Reason: n/a
Should this document be displayed on the Northern Powergrid external website?		Yes

		Date
Alan Creighton	Senior Smart Grid Development Engineer	20/01/2023

6.3. Technical Assurance

I sign to confirm that I am satisfied with all aspects of the content and preparation of this document and submit it for approval and authorisation.

		Date
Mark Callum	Smart Grid Development Manager	08/01/2023

6.4. Authorisation

Authorisation is granted for publication of this document.

		Date
Mark Callum	Smart Grid Development Manager	08/01/2023