IMP/001/915 Code of Practice for Managing Voltages on the Distribution System

1. Purpose

The purpose of this document is to state Northern Powergrid's policy for managing voltages on the distribution system. The document states the requirements to achieve a robust, economical and efficient distribution system, taking into account the initial capital investment, system losses and the maintenance and operation costs over the life of the assets forming the system. The document applies to the distribution systems of both Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc, the licenced distributors of Northern Powergrid.

This Code of Practice also helps to ensure the company achieves its requirements with respect to the Electricity Act 1989 (as amended by the Utilities Act 2000 and the Energy Act 2004), The Electricity Safety, Quality and Continuity (ESQC) Regulations 2002 (as amended[1]), the Health and Safety at Work Act 1974, the Electricity Distribution Licences, The Distribution Code and The Grid Code.

This is a new document which captures existing practices that have been implemented by the application of other Northern Powergrid Codes of Practice and Energy Network Association documents and paves the way for the implementation of advanced voltage management techniques developed via recent innovation initiatives.

2. Scope

This document applies to:

- The 132kV, EHV, HV and LV distribution systems of Northern Powergrid Northeast and Northern Powergrid Yorkshire; and
- All distribution system developments including new connections, system reinforcement and asset replacement.

The document describes conventional voltage control procedures as well as advanced voltage control approaches that can be implemented on the Northern Powergrid system. It sets out the generic requirements and provides guidance on establishing the site specific settings and configurations for advanced voltage control, rather than defining the detailed site specific requirements.

It is not intended to apply this Code of Practice retrospectively, but when work is being done on the system, the opportunity shall be taken to comply with the Code of Practice when it is practicable and economic to do so.

This document supplements the Economic Development Codes of Practices[2] that relate to specific voltage levels in the distribution system and the Code of Practice for the Economic Development of Distribution Systems with Distributed Generation, IMP/001/007.

[1] This includes The ESQC (Amendment) Regulations 2006 (No. 1521, 1st October 2006) and The ESQC (Amendment) Regulations 2009 (No. 639, 6th April 2009).

[2] IMP/001/914 Code of Practice for the Economic Development of the 132kV System;

IMP/001/913 Code of Practice for the Economic Development of the EHV System;

IMP/001/912 Code of Practice for the Economic Development of the HV System; and

IMP/001/911 Code of Practice for the Economic Development of the LV System.

2.1 Table of Contents

3. Code of practice

3.1 Assessment of relevant drivers

The key internal business drivers relating to the economic development of the distribution system are:

- Employee commitment - achieved by developing a safe distribution system to ensure that employees are not exposed to risks to their health as far as reasonably practicable;
- Financial strength - achieved by developing an integrated distribution system having minimum overall cost;
- Customer service - achieved by reducing the potential number of customer interruptions and customer minutes lost;
- Regulatory integrity - achieved by designing a robust system that meets mandatory and recommended standards;
- Environmental respect - achieved through due consideration being given to the environmental impact of new developments including the impact on system losses and carbon footprint; and
- Operational excellence - achieved through improving the quality, availability and reliability of supply.

The external business drivers relating to the development of the distribution system are detailed in the following sections.

3.1.1 Requirements of the Electricity Act 1989 (as amended)

Section 9 (1) of the Electricity Act 1989 (as amended) places an obligation on Distribution Network Operators (DNOs) to develop and maintain an efficient, co-ordinated and economical system of electricity distribution and to facilitate competition in the supply and generation of electricity.

Discharge of this obligation is supported by this document by providing guidance on the efficient management of voltages within the distribution system.

3.1.2 The Health and Safety at Work Act 1974

Section 2(1) of The Health and Safety at work Act 1974, states that ‘It shall be the duty of every employer to ensure, so far as is reasonably practicable, the health, safety and welfare at work of all his employees’. Section 3(1) also states that ‘It shall be the duty of every employer to conduct his undertaking in such a way as to ensure, so far as is reasonably practicable, that persons not in his employment who may be affected thereby are not thereby exposed to risks to their health or safety’.

This is addressed in this Code of Practice by requiring that voltages on the distribution system are maintained within the capability of equipment forming the distribution system.

3.1.3 Requirements of the Electricity Safety, Quality and Continuity (ESQC) Regulations

The ESQC Regulations 2002 (No. 2665, 31st January 2003) and its amendments[3] impose a number of obligations on the business, mainly relating to safety and quality of supply. All the requirements of the ESQC Regulations that are applicable to the management of voltages on the distribution system shall be complied with.

[3] This includes The ESQC (Amendment) Regulations 2006 (No. 1521, 1st October 2006) and The ESQC (Amendment) Regulations 2009 (No. 639, 6th April 2009).

Reg. No	Text	Application to this Code of Practice
3(1)(a)	…distributors…shall ensure that their equipment is sufficient for the purposes for and the circumstances in which it is used.	This Code of Practice will contribute to compliance with the ESQC Regulations by requiring that voltage imposed on distribution system equipment is within its capability.
27(1)	Before commencing a supply to a consumer's installation, or when the existing supply characteristics have been modified, the supplier shall ascertain from the distributor and then declare to the consumer - (a) the number of phases; (b) the frequency; and (c) the voltage, at which it is proposed to supply electricity and the extent of the permitted variations thereto.	This Code of Practice enables the voltage at the point supply to a customer to be declared.
27(2)	… the voltage declared in respect of a low voltage supply shall be 230 volts between the phase and neutral conductors at the supply terminals.	This Code of Practice enables the voltage at a low voltage point of supply to a customer to be declared to be 230V.
27(3)	For the purposes of this regulation, unless otherwise agreed in writing… the permitted variations are - (a) a variation not exceeding 1 per cent above or below the declared frequency; (b) in the case of a low voltage supply, a variation not exceeding 10 per cent above or 6 per cent below the declared voltage at the declared frequency; (c) in the case of a high voltage supply operating at a voltage below 132,000 volts, a variation not exceeding 6 per cent above or below the declared voltage at the declared frequency; and (d) in the case of a high voltage supply operating at a voltage of 132,000 volts or above, a variation not exceeding 10 per cent above or below the declared voltage at the declared frequency.	This Code of Practice states the acceptable limits of voltage variation experienced by customers connected to the distribution system and descries the systems in place to achieve this.
27(6)	Every distributor shall ensure that, save in exceptional circumstances, the characteristics of the supplies to consumer's installations connected to his network comply with the declarations made under paragraph (1).	This Code of Practice provides examples of the exceptional circumstances when voltages might be outside the statutory limits.

3.1.4 Requirements of Northern Powergrid's distribution licences

Additional external business drivers relating to the development of the distribution system are the Distribution Licences applicable to Northern Powergrid Northeast and Northern Powergrid Yorkshire. Standard Licence Condition 20 (Compliance with core industry documents) requires the licensee to comply with some of the core industry documents relevant to the design of distribution systems:

- Standard Licence Condition 20.1 requires the licensee to comply with the Grid Code;
- Standard Licence Condition 20.2 requires the licensee to at all times have in force, implement, and comply with the Distribution Code;
- Standard Licence Condition 20.3 requires the licensee to be a party to and comply with the Connection and Use of System Code (CUSC). The Connection and Use of System Code (CUSC) defines the contractual framework for connection to and use of the Great Britain's high voltage transmission system; and
- Standard Licence Condition 20.3 requires the licensee to be a party to and comply with the Distribution Connection and Use of System Agreement (DCUSA). The DCUSA is a multi-party contract between the DNOs, Suppliers and Generators that deals with the use of distribution system to transport electricity.

Standard Licence Condition 24 (Distribution System planning standard and quality of performance reporting) includes requirements relating to system planning:

- Standard Licence Condition 24.1 requires that the distribution system is planned and developed to a standard of security not less than that laid down in Engineering Recommendation P2/6 Security of Supply. This Code of Practice requires that voltage at a customer's Point of Supply is maintained within statutory limits in the secured events as defined in Engineering Recommendation P2/6.

Standard Licence Condition 49[4] (Electricity Distribution Losses Management Obligation and Distribution Losses Strategy) requires the licensee to ensure that distribution losses from its distribution system are as low as reasonably practicable and to maintain and act in accordance with its Distribution Losses Strategy.[5] In particular:

- Standard Licence Condition 49.2 requires the licensee to design, build, and operate its distribution system in a manner that can reasonably be expected to ensure that distribution losses are as low as reasonably practicable; and
- Standard Licence Condition 49.3 requires that in designing, building and operating its distribution system the licensee must act in accordance with its Distribution Losses Strategy, having regard to the following:
    - The distribution losses characteristics of new assets to be introduced to its distribution system;
    - Whether and when assets that form part of its distribution system should be replaced or repaired;
    - The way that its distribution system is operated under normal operating conditions; and
    - Any relevant legislation that may impact on its investment decisions.

For a given customer demand the selection of system voltage and the permitted voltage variation will affect the current carried through the distribution system and therefore affect system losses.

3.1.5 The Grid Code

As a distribution licence holder, Northern Powergrid is required to comply with the Grid Code. The Grid Code places specific requirements on National Grid Electricity Transmission, Generators and on Northern Powergrid in relation to voltage management including:

- the requirement for NGET to maintain voltages within defined limits except in abnormal situations;[6] and
- the requirement for NGET to maintain voltage fluctuations within defined limits.[7]

Grid Code OC6.5.3 requires DNOs to make arrangements to reduce demand on their network by implementing Demand Control by either:

- Two voltage reduction stages each of between 2 and 4 per cent (nominal 3 per cent each), each of which can be expected to deliver around 1.5 per cent demand reduction, and up to three Demand Disconnection stages, each of which can reasonably be expected to deliver between four and six per cent demand reduction; or
- Four Demand Disconnection stages each of which can reasonably be expected to deliver between four and six per cent demand reduction.

[4] Came into force in April 2015.

[5] Initially stated in Northern Powergrid's ED1 Submission Annex 1.4, Strategy for Technical Losses, March 2014 and subsequently revised in controlled updates.

[6] Grid Code CC6.1.4.

[7] Grid Code CC6.1.7.

3.1.6 The Distribution Code

As a distribution licence holder, Northern Powergrid is required to hold, maintain and comply with the Distribution Code of Licensed Distribution Network Operators of Great Britain. The Distribution Code covers all material technical aspects relating to connections to and the operation and use of the distribution systems of the Distribution Network Operators. The Distribution Code is prepared by the Distribution Code Review Panel and is specifically designed to:

- permit the development, maintenance and operation of an efficient co-ordinated and economic system for the distribution of electricity;
- facilitate competition in the generation and supply of electricity; and
- efficiently discharge the obligations imposed upon DNOs by the distribution licence and comply with the Regulation (where Regulation has the meaning defined in the distribution licence) and any relevant legally binding decision of the European Commission and/or Agency for the Co-operation of Energy Regulators. This objective is particularly relevant given the introduction of a suite of European Network Codes which will place additional obligations on Generators and DNOs.

The Distribution Planning and Connection Code, a section of the Distribution Code, specifies the technical and design criteria and the procedures which shall be complied with in the planning and development of distribution systems. It also applies to Users of distribution systems in the planning and development of their own systems in so far as they affect the Northern Powergrid systems. Annex 1 of The Distribution Code lists the key engineering documents that are relevant for voltage management. These are:

- Engineering Recommendation G5 – Planning levels for harmonic voltage distortion and the connection of non-linear equipment to the transmission systems and distribution network in the United Kingdom;
- Engineering Recommendation P2/6 – Security of supply;
- Engineering Recommendation P28 – Planning limits for voltage fluctuations caused by industrial, commercial and domestic equipment in the United Kingdom; and
- Engineering Recommendation P29 – Planning limits for voltage unbalance for voltage unbalance in the United Kingdom.

The Distribution Planning and Connection Code also requires:

- that any development of the distribution system is carried out such that there are no adverse effects on the voltage control systems deployed by the DNO and that information on the control systems should be made available to customers on request;[8] and
- that voltage step changes caused by the connection and disconnection of customer's equipment are no greater than the 3% limit set out in Engineering Recommendation P28, although this may be relaxed to 10% in special situations defined in DPC4.2.3.3.

Distribution Operating Code 6[9] requires DNOs to make provisions to reduce the demand on its distribution system under a defined set of circumstances. One means of achieving this is to reduce the voltage on the distribution system for relatively short periods of time.

3.2 Key policy requirements

The distribution system should be developed in an efficient and cost effective manner to deliver electricity to the supply terminals of customers within the statutory voltage range whilst meeting the requirements of the Electricity Act and the Distribution Licence.

The general objective in controlling voltage on distribution networks is to ensure that the voltage at customers supply terminals remains within statutory limits in all credible scenarios. Voltages shall be held within statutory limits[10] for First Circuit Outage conditions and Second Circuit Outage conditions[11] where customer supplies are

[8] DPC4.2.2.4 & DPC4.4.3.

[9] DOC6.4.3.

[10] After the operation of automatic tap changers where necessary.

required to be maintained. Other network events, provided that they are considered to be 'exceptional', might result in voltage falling outside statutory limits. The implementation of any changes to existing means of achieving this requirement shall take into account the changes imposed by the increasing amounts of distributed generation and low carbon technologies connected to the distribution system.

This Code of Practice is written to ensure that the control of voltages on the distribution system is performed in such a way as to:

- prevent danger to members of the public and Northern Powergrid staff;
- prevent a major breach of legal compliance though incorrect control of network voltages;
- comply with Distribution Code and Grid Code requirements;
- optimise power quality experienced by customers;
- minimise network losses where practicable; and
- Satisfy all other relevant obligations.

3.3 Voltage control requirements

3.3.1 Statutory voltage levels

The voltage at a customer's Point of Supply shall be within the statutory range permitted appropriate to the nominal voltage except in exceptional circumstances. This requirement is set out in the ESQC Regulations; the associated guidance note published by BEIS does not provide any guidance on what constitutes an exceptional circumstance. It is worth noting that the Distribution Code requires that equipment used to form the distribution system and customers' equipment connected to it, should be selected taking into account BS EN 50160:2010,[12] Voltage Characteristics of Electricity Supplied by Public Distribution Systems. Reference to this document is helpful in two areas:

- It contains details of the variations and disturbances to the voltage which can occur on the distribution system and sets out the exceptional situations when the standard doesn't apply, including:
  - exceptional weather conditions and other natural disasters;
  - third party interference;
  - acts by public authorities;
  - industrial actions (subject to legal requirements);
  - force majeure; and
  - power shortages resulting from external events.
- It sets out the test method under normal operating conditions:
  - during each period of one week 95% of the 10min mean r.m.s. values of the supply voltage shall be within the range of Un13 ± 10%;[14] and
  - all 10min mean r.m.s. values of the supply voltage shall be within the range of Un + 10% / - 15%.[15]

It is this test methodology that is implicitly applied to assess consumers' voltage quality when voltage is measured using a power quality meter that complies with BS EN 50160.

[11] As defined in Engineering Recommendation P2/6.

[12] As amended 2015.

[13] As defined in BS EN 50160, Un is the nominal voltage i.e. the voltage by which a supply network is designated or identified and to which certain operating characteristics are referred.

[14] The BSI Standard is not clear whether in GB the lower limit should be the lower limit 10% as per the Standard, or 6% as per ESQCR. Northern Powergrid practice is to apply the 6% limit which aligns with the approach taken in the draft Engineering Technical Report from the ENA Voltage reduction Workgroup.

[15] It is important to note that there is a relaxation on permitted lower voltage limit, but not on the upper voltage limit.

In order to comply with the licence requirement to develop and maintain an efficient, co-ordinated and economical system of electricity distribution there is a need to strike a reasonable balance between maintaining the voltage at a customer's Point of Supply in every possible system scenario and maintaining voltage at a level that should not present danger or damage to customers equipment. It is reasonable to assume that customers' installations and equipment should be capable of withstanding voltages outside statutory limits but only for a limited period of time. This, together with the scenarios where the requirements of BS EN 50160 do not apply, gives some flexibility for defining what can be reasonably be considered to be an 'exceptional circumstance'. The following are examples of scenarios that are considered by Northern Powergrid as being exceptional circumstances:

- when abnormal conditions prevail on the NGET transmission system;[16]
- when voltage control equipment[17] on the distribution system fails or fails to operate correctly;
- where only first circuit outage security is required by Engineering Recommendation P2/6, a planned or an unplanned outage on the distribution system when the demand on the system is unexpectedly high;[18]
- where second circuit outage security is required by Engineering Recommendation P2/6, an unplanned outage on the distribution system following a planned outage on an associated part of the system when the demand on the system is unexpectedly high;[19] [20] and
- where there is an adverse alignment of planning assumptions.[21]

The statutory voltage limits, as stated in the ESQCR Regulations,[22] are set out below:

Nominal Declared Voltage	Statutory Limits
230V	230V +10% to -6%[23]
400V	400V +10% to -6%
11kV[24]	11kV +6% to -6%
20kV	20kV +6% to -6%
33kV	33kV +6% to -6%
66kV	66kV +6% to -6%
132kV	132kV +10% to -10%

[16] Grid Code CC6.1.4.

[17] E.g. AVC relay, transformer tapchanger or regulator.

[18] I.e. if the demand on the distribution system at the time of the outage is greater than the demand that could reasonably have been expected.

[19] I.e. if the demand on the distribution system at the time of the outage is greater than the demand that could reasonably have been expected.

[20] The first and second circuit outage requirements are generally achieved using transformers compliant with ER P1 & ER P10.

[21] There are many assumptions made as part of a system study. Some assumptions will be conservative and other will be pessimistic and they may well interact with each other. Assumptions include i) AVC relays do not rest at the extreme end of the dead-band operating range for extended periods, ii) large voltage drops / rises on related parts of the HV and LV system (mains and services) are not coincident for extended periods of time, iii) there is a normal diversity of customer demand on the HV and LV systems, iv) the design demand (whether this is based on an ADMD or P-Q approach) is representative of the LV system demand. Further details on the design demand are in the Code of Practice for the Economic Development of the LV System, IMP/001/911.

[22] Regulation 27.

[23] There is a currently a national debate on the implications and benefits of changing the permitted LV voltage range to 230V +10% to -10%.

[24] These tolerances are applicable for other HV voltages e.g. 6kV.

Note that there is no restriction in the ESQCR on the operating voltage of the distribution system itself, however, all equipment that forms part of the distribution system must be operated within its capability as set out below.

3.3.2 Maximum voltage levels

The voltage at any part of the distribution system shall not exceed the voltage rating of the plant forming part of the distribution system. Plant ratings are stated in the Code of Practice for Distribution System Parameters, IMP/001/909, and are reproduced in the table below:

Nominal Voltage	Plant Rating
230V	1000V
400V	1000V
11kV	12kV
20kV	24kV
33kV	36kV
66kV	72kV
132kV	145kV

3.3.3 Customer connection voltage

The connection voltage made available to a customer will depend upon the type and size of the customer's demand, and shall be determined by Northern Powergrid as set out in the Code of Practice for Standard Arrangements for Customer Connections, IMP/001/010 and agreed with the customer as part of the connection application process.

3.4 Voltage control principles

3.4.1 General principles

The voltage at the source substation 132kV, 66kV, 33kV, 20kV and 11kV busbars shall be held reasonably constant by means of automatic voltage control (AVC) relays (or an automatic voltage regulator system provided by NGET) controlling the tap changers of the transformers feeding that busbar.

Voltage control shall be provided via tap changers and associated automatic voltage control relay in accordance with the general principles of Engineering Recommendation P1, 275/33kV, 132/33kV and 132/11kV Supply Point Transformers, and Engineering Recommendation P10, Voltage Control at Bulk Supply Points.

The basic requirement set out in Engineering Recommendations P1 and P10 is to ensure that the transformer rating, impedance and tap change range are selected so that a substation equipped with two transformers can cater for a range of credible operational scenarios for example maintaining the lower voltage terminals at the nominal voltage with only one transformer in service at time of maximum demand on the substation, whilst maintaining fault levels at standard values that co-ordinate with standard switchgear ratings. The selection of transformers and tap changers with these characteristic also means that under normal operational scenarios there should be sufficient taps available to allow a 6% voltage reduction to be implemented in accordance with Grid Code OC6.

The selection of transformers in general compliance with Engineering Recommendations P1 and P10, means that the voltage at EHV and HV busbars can be considered to remain at the target voltage under normal operational conditions and in credible outage scenarios.

There is generally no voltage control equipment on the HV[25] or LV systems. The voltage on the HV and LV systems is managed by the application of a set of design practices recognising that downstream of the last automatic voltage controlled point, voltage is influenced by the current flows on the HV and LV system and the tap position of HV to LV transformers.

3.5 Voltage control practice

This section describes the general principles that are currently applied in practice. The current approach of managing system voltage based on the application of standard target voltages, AVC relays with standard settings and voltage on the HV and LV system managed by design, as set out in this section, provides a low risk solution in many situations and this approach should be applied where technically acceptable and economic. The system should be designed to operate within the voltage limits defined in this document for all expected high demand / low generation and low demand / high generation scenarios apart from those considered as being exceptional.

The use of transformers equipped with tap changers and AVC equipment with settings based on these principles and practices ensure that customer requirements are met within statutory voltage limits in an environment where the system predominantly supplies relatively predictable consumer load. Distribution systems are facing an increased requirement to supply different types of customer load, including low carbon technologies and generation, such that the nature of the net demand on the distribution system is becoming less predictable. Hence some of the assumptions underpinning the legacy approach are expected to become less valid and there is a move towards the application of advanced voltage control techniques as set out in section 3.6.

3.5.1 Transformer tapchanger range

Transformers will be equipped with an On Load Tap Changer (OLTC) apart from HV to LV transformers which are normally equipped with a De-Energised Tap Changer (DETC).

The fundamental voltage related parameters of transformers tap changers are set out in the table below:

NGET transformers

Nominal Voltage Ratio	Tap Changer Range[26]
400/132kV	2-winding transformers: Taps 1 to 15 in steps of 1.43% with a nominal tap of 11, tap changer on HV winding Autotransformer: Taps 1 to 15 in steps of 1.43% voltage with a nominal tap of 11, tap changer on 132kV winding.
400/66kV	2-winding transformers Taps 1 to 19 in steps of 1.389% with a nominal tap of 5, tap changer on HV winding.
275/132kV	Autotransformers: Taps 1 to 19 in steps of 1.67% voltage with a nominal tap of 10, tap changer on 132kV winding
275/66kV	Autotransformers: Taps 1 to 19 in steps of 1.67% voltage with a nominal tap of 10, tap changer on 66kV winding
275/33kV	2-winding transformers: Taps 1 to 19 in steps of 1.67% with a nominal tap of 7, tap changer on HV winding
275/20kV	Bespoke design

[25] HV regulators are occasionally used on long rural circuits.

[26] Transformers operating at 400kV and 257kV are specified by NGET. The parameters for these transformers have been provided by NGET as being typical.

Northern Powergrid Transformers

Nominal Voltage Ratio	Tap Changer Range[27]
132/66kV	+10%/-20% in 18 steps of 1.67%
132/33kV	+10%/-20% in 18 steps of 1.67%
132/11.5kV[28]	+10%/-20% in 18 steps of 1.67%
66/33kV	Bespoke design
66/20kV	+10%/-10% in 14 steps (+7×1.5% / -7×1.5%)
66/11.5kV	+10%/-10% in 16 steps (+8×1.25% / -8×1.25%) or +5.72%/-17.16% in 16 steps (+4x1.43% / -12x1.43%)
33/20kV	+10%/-10% in 14 steps (+7×1.5% / -7×1.5%)
33/11.5kV	+10%/-10% in 16 steps (+8×1.25% / -8×1.25%) or +5.72%/-17.16% in 16 steps (+4x1.43% / -12x1.43%)
20/0.433kV[29]	+5%/-5% in 5 steps (legacy specification) or +7.5%/-2.5% in 5 step (current specification)
11/0.433kV[30]	+5%/-5% in 5 steps (legacy specification) or +7.5%/-2.5% in 5 step (current specification)
20/0.250kV	+5%/-5% in 3 steps
11/0.250kV	+5%/-5% in 3 steps

3.5.2 Automatic Voltage Control functionality

All new AVC relays fitted to transformers with an OLTC and voltage regulators shall provide for the future requirement to facilitate the transition to a Smart Grid by providing remote control, analogues, alarms and indication facilities as set out in Appendix 2. A targeted programme is being developed to proactively replace AVC equipment that does not have this functionality.

3.5.3 Voltage control via tap changers

This section describes the application of voltage control at substations where transformers are equipped with automatic on load tap changers.

[27] Transformers operating at 400kV and 257kV are specified by NGET. The parameters for these transformers have been provided by NGET as being typical.

[28] 132/11.5kV transformers are specified in the Technical Specification for CMR Transformers, NPS/003/021. However in Northern Powergrid Yorkshire 132/11kV and 132/11.5kV transformers have been installed; care should be taken when modelling these transformers that the correct transformation ratio is used.

[29] The nominal voltage ratio results in an 8% voltage boost across the HV/LV transformer (i.e. 433/400 = 1.0825%).

[30] The nominal voltage ratio results in an 8% voltage boost across the HV/LV transformer (i.e. 433/400 = 1.0825%).

3.5.3.1 Establishing AVC settings

Target voltages, dead band and delay timer settings shall be established for each 132kV, EHV and HV busbar by discussion between Asset Management, Network Management, NGET and individual customers as appropriate and recorded in a controlled document managed by Network Management. The standard target voltages set out below shall be applied unless there is a justifiable reason to apply an alternative target voltage. The reasons for any differences from the standard values shall be documented. Initially this information is recorded in Appendix 1 of this Voltage Management Code of Practice.[31] This agreed target voltage should be the voltage used by Technical Services when setting the AVC relays and by Asset Management when undertaking network modelling.

A previously agreed target voltage may need to be permanently changed as a result of:

- A request from NGET in relation to the LV busbar voltage at a GSP;
- A Network Management operational concern;
- An Asset Management design related concern; or
- A request from a customer supplied from a dedicated customer substation.

Any proposed permanent change should be support by documented evidence, and where appropriate system analysis to demonstrate that the voltage change will address the identified issue and not create any new issues. The change should be agree in writing by Asset Management, Network Management and where appropriate NGET or the requesting customer before being implemented.

Voltage control systems at the different transformation levels shall be time-graded to minimise the number of tap changer operations across the whole system.[32] Where advanced voltage control solutions are implemented, the operating times shall be considered so that plant operates in a coordinated manner.

3.5.3.2 NGET interface substations

The target voltage and dead band at the 132kV, 66kV, 33kV and 20kV low voltage busbars at a NGET interface substations are maintained by NGET at a voltage requested by Northern Powergrid and agreed with NGET. The target voltage should be agreed between Northern Powergrid and National Grid and recorded in a controlled document. Target voltages at each substation shall be established following the process set out in section 3.5.3.1. The standard target voltages are set out in the table below. Substations where alternative target voltages have been agreed are set out in Appendix A1.1.

Nominal Busbar Voltage	Standard Target Voltage	Dead-band
132kV	134kV	+/- 2%
66kV	66kV	+/- 2%
33kV	33kV	+/- 2%
20kV	20kV	+/- 2%

3.5.3.3 132kV to EHV substations

The standard target voltages, dead band and delay timer settings at the EHV busbars at 132kV to EHV substations are set out in the tables below. Settings at each substation shall be established following the process set out in section 3.5.3.1. The standard target voltages are set out in the table below. Substations where alternative settings have been agreed are set out in Appendix A1.2.

[31] In due course this information will be retained within NMS.

[32] The tap change operating time delays for primary substations in Northern Powergrid Yorkshire are set out in TS16/17.

Line-drop compensation is typically installed on 132kV to EHV transformers, but it is generally not currently operational.[33] It shall be installed on all new132kV to EHV transformers.

Northern Powergrid Northeast

Nominal busbar voltage	Standard Target Voltage	Dead Band[34]	Delay Time
66kV	66kV	+/- 1.5%	90s time delay and 10s intertap delay
33kV	33kV	+/- 1.5%	90s time delay and 10s intertap delay
25kV[35]	25kV	N/A	N/A

Northern Powergrid Yorkshire

Nominal busbar voltage	Standard Target Voltage	Dead Band	Delay Time
66kV	66kV	+/- 1.5%	90s time delay and 10s intertap delay Humber North Bank: 60s time delay and 10s intertap delay
33kV	33kV	+/- 1.5%	90s time delay and 10s intertap delay Humber North Bank: 60s time delay and 10s intertap delay
25kV[36]	25kV	N/A	N/A

3.5.3.4 132 to HV, EHV to HV and HV to LV substations

The target voltages at 132 to HV and EHV to HV substations have historically been set at slightly different values in different regions across Northern Powergrid and there is an on-going programme to harmonise and in most cases reduce the HV target voltage. The legacy and harmonised target voltages are set out in the table below:

Line-drop compensation is installed at substations with 20kV or 11kV as the lower transformer voltage, but it is generally not currently operational.[37] It shall be installed on all new 132kV to HV and EHV to HV transformers.

[33] There is programme to replace AVC relays that do not have the functionality summarised in Appendix 2.

[34] Tap changers should be set with a dead band not to exceed 2%. Normally this is 1.5%, but there are some transformers with a 1.67% tap step, and these may have a dead band set around 1.8% - 2.0%.

[35] 132 to 25kV transformers are equipped with Off Load Tap Changers.

[36] 132/25kV transformers are equipped with Off Load Tap Changers.

[37] There is programme to replace AVC relays that do not have the functionality summarised in Appendix 2.

Northern Powergrid Northeast

Area	Typical Legacy Target Voltage [38]	Harmonised Target Voltage [39]	Typical HV to LV Ground Mounted Transformer Tap [40] [41]	Dead Band and Delay Time [42]
20kV system	20.3kV (101.5%)	20.1kV (100.5%)	Tap [1-5] depending on taping zone	+/- 1.5% 120s time delay and 10s intertap delay
11kV system	11.3kV (102.7%)	11.1kV (100.9%)	Tap [1-5] depending on taping zone	+/- 1.5% 120s time delay and 10s intertap delay
Lower Voltage HV systems	Bespoke assessment	Bespoke assessment	Tap [1-5] depending on taping zone	+/- 1.5% 120s time delay and 10s intertap delay

Northern Powergrid Yorkshire

Legacy Area	Typical Legacy Target Voltage [43]	Harmonised Target Voltage [44]	Typical HV to LV Ground Mounted Transformer Tap [45] [46]	Dead Band and Delay Time
West Yorkshire	11.3kV (102.7%)	11.1kV (100.9%)	Tap 1 (+5%) – some city centre sites Tap 2 (+2.5%)	+/- 1.5% 120s time delay and 10s intertap delay
South Yorkshire	11.3kV (102.7%)	11.1kV (100.9%)	Tap 2 (+2.5%)	200V (or +/- 1.5% for Supertapp relays) 120s time delay and 10s intertap delay
Humber North Bank	11.1kV (100.9%)	11.1kV (100.9%)	Tap 2 (+2.5%) – close to source Tap 3 (0%) – Remote from source	+/- 1.5% 90s time delay and 10s intertap delay
Humber South Bank	11.4kV (103.6%)	11.1kV (100.9%)	Tap 2 (+2.5%)	+/- 1.5% 120s time delay and 10s intertap delay

[38] The percentage value is the Target Voltage relative to the nominal 11kV or 20kV voltage.

[39] The percentage value is the Target Voltage relative to the nominal 11kV or 20kV voltage.

[40] Technical Specification for 11kV & 20kV Ground-Mounted Distribution Transformers, NPS/003/011 and Technical Specification for 11kV & 20kV Pole-Mounted Distribution Transformers, NPS/003/034 specifies the tapping range for new transformers to be -2.5%, 0, +2.5%, +5% and +7.5. Most existing transformers will have a tapping range of -5%, -2.5%, 0, +2.5%, and +5%.

[41] Pole mounted transformers are typically set on +2.5%.

[42] Tap changers should be set with a dead band not to exceed 2%, nominally this is 1.5%, but there are some transformers with a 1.67% tap step, and these may have a dead band set around 1.8% - 2.0%.

[43] The percentage value is the Target Voltage relative to the nominal 11kV voltage.

[44] The percentage value is the Target Voltage relative to the nominal 11kV voltage.

[45] Technical Specification for 11kV & 20kV Ground-Mounted Distribution Transformers, NPS/003/011 and Technical Specification for 11kV & 20kV Pole-Mounted Distribution Transformers, NPS/003/034 specifies the tapping range for new transformers to be -2.5%, 0, +2.5%, +5% and +7.5. Most existing transformers will have a tapping range of -5%, -2.5%, 0, +2.5%, and +5%.

[46] Pole mounted transformers are typically set on +2.5% where there are five taps and 0% where there are three taps.

A programme started in 2012 to change the HV target voltage to lower, harmonised values of 11.1kV and 20.1kV.[47] The implementation of this programme has been focussed on those substations where:

- generation connection requests have been received and lowering system voltages facilitates the connection;
- lowering system voltages addresses high voltage issues that have been identified on the system; and
- system studies show that customers will continue to receive a voltage at the Point of Supply within (the lower) statutory limits.

In April 2015, 189 primary substations in Northern Powergrid Northeast were identified as being suitable for adopting the lower target voltage. As at July 2016 the voltage has been reduced to 11.1 / 20.1kV at 97 sites.

In May 2015, 319 primary substations in Northern Powergrid Yorkshire were identified as being suitable for adopting the lower target voltage. As at July 2016 the voltage has been reduced to 11.1kV at 49 sites.

The legacy target voltages will exist during a transitional period until the voltage reduction programme has been fully implemented, after which there will be standard harmonised target voltage at all Northern Powergrid HV busbars.

132kV to HV and EHV to HV substations where alternative target voltages have been agreed are set out in Appendix A1.3.

3.5.4 Voltage control via system design

This section describes the HV and LV design principles and key assumptions. Voltages at the HV busbar of a 132kV to HV or EHV to HV substation are controlled to the target voltage as described in the above section. There is generally no voltage control equipment on the HV or LV systems, and the voltage on the HV and LV system is managed by the application of a set of design practices. These practices recognise that downstream of the last automatic voltage controlled point system voltage is influenced by the current flows on the HV and LV system and the tap position of the HV to LV transformer. A key principle is that HV and LV systems are designed based on allocating the overall permitted voltage drop across the HV and LV system between the HV and LV system in such a way that design work on the HV and LV system can be carried out in isolation from each other. It is recognised that this approach, whilst applicable in the majority of cases, may result in unjustified reinforcement or excessive customer connection costs, and in these cases a more bespoke analysis should be carried out that jointly considers the voltage drop on the HV and associated LV systems.

The application of these design principles is set out in the Code of Practice for the Economic Development of the LV System, IMP/001/911 and Code of Practice for the Economic Development of the HV System, IMP/001/912 and is summarised below:

HV system design principles:

- The voltage at the LV terminals of the HV to LV transformer under HV first circuit outage conditions should be a minimum of 230V.[48]
- Where the HV voltage drop under first circuit outage conditions is more than 4.5%, this may be acceptable provided that the LV systems supplied from the HV system has a suitably small voltage drop.

[47] The programme was not implemented for EHV to HV substations with a nominal voltage less than 11kV.

[48] 230V is based on an 11.1kV target voltage, 4.5% voltage drop on a 11kV feeder under first circuit outage conditions, 2.5% HV to LV transformer tap, 2% regulation on the transformer and the EHV to HV transformer operating at the mid-point of its dead band.

LV system design principles:

- The design voltage at LV terminals of the HV to LV transformer is a minimum of 230V;
- The lowest permitted voltage is 216V i.e. max voltage drop of 14V (6% of 230V);
- The maximum calculated voltage drop on the LV system (i.e. on the main as well as the service) should not exceed 6%. Typically the voltage drop on a service would be no more than 0.3% (based on a typical 20m service and 4kW demand) and in many cases can be ignored.

Applying these design principles:

- Under normal operation conditions, the voltage at a customers' LV Point of Supply should be between 245V (no load)[49] and 222V (high load)[50] based on a 2% typical HV voltage drop under HV system intact conditions, 6% voltage drop on the LV circuit, 2% regulation on the HV to LV transformer and assuming that the EHV to HV transformer AVC is sitting at the midpoint of its dead band.
- Under normal operation conditions and where an LV system predominantly supplies load, between 11V and 4V is headroom is available for generation i.e. where the EHV to HV transformer AVC operates at:
  - the upper end of it dead band (equivalent to 249V) there is 4V headroom;
  - the mid-point of it dead band (equivalent to 245V) there is 8V headroom; and
  - the lower end of it dead band (equivalent to 242V) there is 11V headroom.

3.5.5 Compliance with the Grid Code

Northern Powergrid currently complies with the Demand Control requirements set out in OC6.5 of the Grid Code by implementing Voltage Reduction in preference to Demand Disconnection. The facility to reduce the operational voltage initially by 3% and then a further 3% shall be provided at all 132kV to HV and EHV to HV transformers.[51] Communications and SCADA controls shall be provided such that commands to enact these voltage reductions can be implemented within the 10 minute period defined in the Grid Code. The distribution system should be configured and operated such that under normal operational conditions both voltage reduction stages can be delivered in practice at any time; under normal operational conditions there needs to be sufficient transformer taps available to deliver this voltage reduction. When modelling changes to the EHV and HV system, consideration should be given to whether there are sufficient transformer taps available on the transformer to implement the required voltage reduction. If the design and operation of the voltage control system is such that two voltage reduction stages are not available across a material number of EHV to HV substations, then consideration should be given to implementing Demand Control via Demand Disconnection only.[52] The advantage of delivering Demand Control via Voltage Reduction is that limited demand reduction can be delivered without interrupting customer supplies; this makes it the preferred Demand Control approach.

[49] Increasing to 250V with the HV busbar at the upper end of the 2% dead band.

[50] Reducing to 218V with the HV busbar at the lower end of the 2% dead band.

[51] Equivalent facilities should be provided at 132kV to EHV transformers, as in the future implementing voltage reduction on these transformers (and locking taps on downstream transformers) may prove to be a more effective solution to deliver OC6 functionality.

[52] In this scenario guidance should be sought from the System Planning Manager. The advanced functionality provided by new AVC relays as defined in Appendix 2 will provide additional tap position information and will inform any decision regarding the viability of Voltage Reduction as a means of implementing Demand Control.

3.6 Advanced voltage management

3.6.1 Application

Where the design study carried out as part of a new demand connection, a new generation plant connection or an internally driven reinforcement (e.g. initiated as part of an Asset Serviceability Review) indicates that system voltage and / or the supply to customers cannot be maintained within the defined limits when applying the current design rules, alternative means of maintaining voltages within prescribed limits as set out in this section shall be considered as an alternative to traditional system reinforcement.

Traditional system reinforcement particularly where it would release other benefits that have value, are preferred. For instance, where there is ample voltage and thermal capacity on neighbouring feeders, re-configuring the system, especially where this provides additional security of supply, should be investigated and implemented where economic.

Where traditional reinforcement is deemed to be uneconomic[53] the following techniques should be considered. Each of these techniques are in different stages of maturity e.g. there are several installation of HV in-line regulators in service in Northern Powergrid, whilst HV to LV transformers with OLTC have only been deployed as part of the CLNR trial. Hence whilst some techniques can be readily applied, others will need more detailed consideration, potentially as part of a trial. The following table sets out the advanced techniques and their level of maturity in Northern Powergrid.

Technique	Level of Maturity
Bespoke AVC settings	High
Line Drop Compensation	Medium
HV In-line Regulators	High
LV In-line Regulators	Low
HV Shunt Capacitors	High
LV Shunt Capacitors	Low
HV to LV Distribution Transformers OLTC	Low
Generator Based Control	Low
Co-ordinated Control	Low

This Code of Practice will be developed to provide further application guidance as experience with these techniques grows.

3.6.2 Bespoke AVC settings

3.6.2.1 Application

Where modelling suggests that the standard target voltages cannot provide the required voltage capacity it may be possible to establish a non-standard target voltage in accordance with the principles set out in section 3.5.3.1. The target voltage should be set to equally balance the risk of over and under voltage considering a ten years forecast of load growth and LV and HV generation connections where available. It is more likely that this will be an acceptable solution where the supply is to a single new customer e.g. a generator connection, is being designed where it is more acceptable to implement a target voltage lower than standard.

[53] For example as determined by a cost benefit assessment of the credible options.

3.6.2.2 Capability of existing equipment

The existing AVC relay may have the required capability. If not, it may be possible to advance the replacement of the relay as part of the AVC relay replacement programme. All new AVC relays shall have the functionality summarised in Appendix 2.

3.6.3 Line Drop Compensation

3.6.3.1 Application

Where modelling suggests that neither a fixed standard or bespoke AVC voltage set point can provide the required voltage capacity, the option of applying Line Drop Compensation (LDC) to the AVC relays, if available, should be considered. This technique is likely to involve applying lower than normal standard target voltage and configuring the LDC to boost the target voltage at times of high load. Where there is a material generator connected close to or directly onto the HV busbars, there may be a need to include a generator exclusion module as part of the LDC. This functionality may not be available on older AVC relays.

LDC has potential application where:

- the voltage drop on a heavily loaded system is such that there is a material risk that the voltage at a customer's Point of Supply at the extremities of the LV system will be outside statutory limits;[54]
- there are voltage rise issues associated with generation at the HV busbar that may be addressed by reducing the standard HV target voltage; here LDC would be used to increase the target voltage under a high load / low generation scenario to offset the reduce HV target voltage; and
- there are voltage rise issues associated with generation at the HV busbar that may be addressed by reducing both the standard HV and EHV target voltages; here EHV target voltage is reduced to help the EHV to HV transformer tap changer operate more towards the mid tap position to ensure that the EHV to HV transformer has sufficient taps to implement Grid Code OC6 Demand Control. LDC applied to the 132kV to EHV transformers may help ensure satisfactory voltages are achieved under all credible scenarios.

When assessing the scope to apply LDC, consideration should be given to ensure that the voltage to all customers remains within statutory limits:

- at times of high load / low generation output and low load / high generation output;
- taking into account the specific load / generation profiles on the individual HV circuits and HV to LV substations;[55]
- when the substation load is higher than normal during credible abnormal feeding arrangements. This scenario can be managed on some AVC relays[56] by capping the extent of the voltage boost / buck; and
- when the open points on individual HV circuits are moved (permanently or temporarily), particularly where HV to LV transformers have a tap position depending upon their location within a Tapping Zone.[57]

[54] This condition may arise under a credible outage condition.

[55] A close-in HV to LV substation that is lightly loaded at the time of normal peak load will tend to limit the amount of LDC that can be applied due to the HV busbar voltage being driven higher by the LDC.

[56] This function may be available in electronic AVC relays, but is unlikely to be available in electromechanical relays.

[57] Tapping zones are extensively used in Northern Powergrid Northeast.

3.6.3.2 Capability of existing equipment

It is likely that the existing AVC relay will have the required capability unless generation exclusion functionality or voltage capping is required. If the existing relay is unsuitable it may be possible to advance the replacement of the relay which is likely to be included as part of the AVC relay replacement programme. All new AVC relays shall have the functionality summarised in Appendix 2.

3.6.3.3 AVC settings

The default arrangement for the management of voltages at the HV busbar of an EHV to HV substation is to set the AVC with a fixed target voltage, as described in section 3.5.3. Where LDC is applied, the preferred arrangement is for a standard combination of target voltage and LDC settings to be applied. The CLNR project concluded that typically it may be possible to reduce the target voltage at a HV busbar by 3% and apply a LDC setting to boost the voltage by 3% at the time of maximum demand on the HV busbar. An initial implementation of this technique has been applied at Seghill 66/11kV substation; monitoring carried out on the Seghill system will be used to establish one or more standard setting combinations[58] and further guidance should be sought from the System Planning Manager if the application of LDC is being considered.

Where application of one of the standard combinations of settings proves to be inadequate, bespoke settings can be considered.

3.6.4 HV in-line regulators

3.6.4.1 Application

The CLNR project team found that, in general, the optimal choice of device to address HV voltage issues is an in-line HV regulator in rural areas and an on-load tap-changer (OLTC) installed on a HV to LV transformer in urban areas. Voltage regulators should not need to be used on urban systems with low impedance circuits, where voltage regulation is less of an issue.

In-line HV voltage regulators can be used to maintain voltages on HV systems under system intact and under first circuit outage conditions. In this case system studies will be required to ensure that the required settings can be applied for the normal operating condition and credible outage scenarios. It is likely that the regulator will need to have bi-directional capability to achieve this. When considering the installation of an in-line HV regulator into HV circuit that already contains one or more in-line HV regulators, the interaction between the individual regulators should be assessed to confirm that appropriate settings can be applied to all the regulators to ensure that the system voltage is properly managed in all credible scenarios.

In-line HV regulators can be cost effective where localised control of voltage is needed for multiple LV systems supplied from the same HV source and can be installed in the main HV line or on HV spurs.

Where the use of an in-line HV regulator would have an adverse effect on circuit loading, shunt capacitor banks may be a more suitable alternative and should be considered.

In-line HV regulators can be ground mounted (three phase units) or pole mounted (single phase units); pole mounted units tend to be more suited to application on rural overhead lines where securing a site for a ground mounted unit may prove difficult. It is possible for single-pole mounted in-line regulators to be installed as either two unit installed in an open delta configuration or three units installed in a closed delta configuration, however in Northern Powergrid only the closed delta configuration shall be used to minimise problems associated with SEF protection and network paralleling apart from where they are installed in tail end spurs with little chance of being interconnected in the future, when an open delta configuration is acceptable.

[58] Standard LDC settings will be recorded in a future issue of this Code of Practice which will as a minimum include the target voltage, percentage boost and whether the boost is capped. Ideally this information would be retained within NMS.

When connected in a closed delta configuration, three single regulators each providing a 10% voltage buck / boost can provide a 15% buck / boost to the system voltage.

All new in-line HV regulators shall have both buck and boost capability and include a controller that has LDC functionality. LDC can be used to compensate for generation voltage rise, and reverse reactive power sensing to cater for both abnormal operational conditions and also generation causing reverse power flow under normal operational conditions.

Further guidance on the application of in-line HV regulators can be found in the Code of Practice for the Economic Development of the HV System, IMP/001/912.

3.6.4.2 Functional specification

In-line HV regulators should provide the following functionality:

- The regulator shall be designed to provide approximately +/- 10% automatic adjustment of the unregulated supply voltage on the source side of the voltage regulator. This shall be achieved in approximately 0.625% steps, with sixteen steps above and below the rated voltage; and
- The regulator shall have a Reverse Power Flow Detector that automatically senses power flow reversal and can provide indication of power flow reversal. The regulator control shall incorporate separate forward and reverse control settings for voltage level, bandwidth, time delay, and line-drop compensation.

The Northern Powergrid specification for voltage regulators is set out in the Technical Specification for 11kV and 20kV Voltage Regulators, NPS/003/020.

All new in-line HV regulators should include a means of communication to allow remote control and monitoring of key functionality in accordance with the general principles for AVC transformers set out in Appendix 2.

3.6.5 LV in-line regulators

3.6.5.1 Application

Where several LV feeders are connected to a single HV to LV substation and one or two of the feeders have materially high voltage drop at times of high load or materially high voltage rise at times of high generation export, then an in-line LV regulator may be considered as an alternative to traditional reinforcement or the application of an HV to LV transformer equipped with an OLTC.

Northern Powergrid have limited experience[59] of applying in-line LV regulators however the CLNR project suggested that:

- the number of scenarios when an in-line LV regulator proves to be an economical solution is likely to be low;
- where they do have an application, they should be either located at the substation or midway along the LV feeder; and
- in-line LV regulators are likely to be a more cost effective than a HV to LV transformer with an OLTC where voltage issues are related to only one or two feeders of a multiple feeder LV system.

Depending on the LV system and the amount and variability of the connected load and generation, it may be acceptable to install an in-line LV regulator with fixed boost or buck with no active control. Where fixed settings are not suitable, regulators with variable tapping should be installed with an appropriate AVC relay to maintain the voltage to a fixed value.

Where an in-line regulator is installed in a system where future generation is reasonably likely i.e. most systems supplying domestic customers, regulators with buck and boost should be used.

[59] There are instances where LV regulators have been used in the past, predominantly at the extremities of overhead LV systems, some of which may still be in service.

Where the installation of an in-line LV regulator appears to have merits, further guidance should be sought from the System Planning Manager.[60]

3.6.5.2 Functional specification

In-line LV regulators should provide the following functionality:

- The regulator shall be designed to provide approximately +/- 5% automatic adjustment of the unregulated voltage supply on the source side of the voltage regulator. This shall be achieved in approximately 2.5% steps, with two steps above and below the rated voltage; and
- The regulator shall have a Reverse Power Flow Detector that automatically senses power flow reversal and can provide indication of power flow reversal. The regulator control shall incorporate separate forward and reverse control settings for voltage level, bandwidth, time delay, and line-drop compensation.

Whilst there is currently no standalone specification for an in-line LV regulator, the Technical Specification for a Ground-mounted, In-Line, LV Regulator with Enhanced Automatic Voltage Control (EAVC), NPS/007/009, was developed for the CLNR project and should be used as the basis for a standalone Technical Specification for either a pole mounted or cabinet based regulator for application in overhead and underground systems respectively.

If a LV regulator installation is being considered, guidance should be sought from the System Planning Manager regarding the functional specification.

3.6.6 HV shunt capacitors

3.6.6.1 Application

Whilst the CLNR project team found that, in general, the optimal choice of device to address HV voltage issues in a rural area is an in-line HV regulator, shunt capacitors may be a solution particularly to control voltages at the end of a long HV feeder where there is little prospect for voltage rise issues associated with generation.[61]

Shunt connected capacitors have advantages and disadvantages compared to regulators:

- Capacitors can only boost system voltage rather than reduce it. Voltage boost is typically required for load-rich or high impedance systems, but their inability to buck the system voltage reduces their application in areas which are or are expected to become generation rich. This feature may limit the application of capacitors in the future;
- Capacitors increase the system voltage at the point of connection hence increasing the system voltage both upstream and downstream of the connection point. Voltage regulators can only manage (increase and decrease) the voltage downstream of their connection point to the system;
- Capacitors can provide the reactive power drawn by customers demand or the distribution system closer to the point where it is required, thus reducing system losses;
- If excess capacitance is installed to meet the local requirement reactive power can be forced back up the system potentially increasing system losses and creating voltage rise issues on adjacent parts of the system; and
- Capacitors tend to require a building and switchgear which can give rise to practical issues on site; modern voltage regulators can be pole mounted. Hence in-line HV regulators solutions tend to be less expensive than switched capacitor installations.

[60] The application of in-line LV regulators and shunt LV capacitors were explored in the ENW Low Carbon Networks Fund Project 'Voltage Management on Low Voltage Busbars' and is being developed further in their Smart Street project.

[61] On the system served from Denwick 66/20kV substation, a mechanically-switched capacitor is installed at the firm busbar at Hedgeley Moor Switch House.

Shunt capacitors banks may be arranged so that they can be switched in or out of circuit to provide variable stages of reactive power injection / voltage boost depending on system requirements. When considering the use of shunt capacitors the merits of switched capacitors should be balanced against the additional costs over static capacitor banks.[62]

The use of shunt capacitors may be a cost effective solution, compared to in-line HV regulators where there is a significant reactive element to the system or customer load, resulting in high system losses.

3.6.6.2 Functional specification

Whilst switched capacitor banks have been used in the past there is no current technical standard for a HV capacitor installation. If a HV capacitor installation is being considered, guidance should be sought from the System Planning Manager regarding the functional specification and the Policy and Standards Manager regarding the detailed technical specification.

All new shunt HV capacitors should include a means of communication to allow remote control[63] and monitoring of key functionality in accordance with the general principles for AVC transformers set out in Appendix 2.

3.6.7 LV shunt capacitors

3.6.7.1 Application

Whilst Northern Powergrid has limited practical experience of LV capacitors, Electricity North West trialled their use as part of their Low Carbon Networks Fund Project 'Voltage Management on Low Voltage Busbars'. The following information is based on the findings of this ENW project.

- LV capacitors can be used to improve the voltage profile on a LV system offsetting the reactive power requirement of the load reducing the reactive power than needs to be supplied from the HV to LV substation hence resulting in a lower volt drop;
- The optimum location for the capacitors was found to be typically around the midpoint of the feeder;
- LV capacitors tend to be less effective than HV shunt capacitors on the HV system, as the LV circuits are more resistive. For more resistive feeders, the study showed that the potential voltage boost is reduced;
- The project showed that more than one technology may be required to manage the voltages on LV feeders associated with a distribution substation. Feeders which contain more generation than demand may require a different voltage control approach than those without generation. The issue becomes more complicated when one substation contains some feeders with significant generation and others with significant new non-diverse low carbon loads such as electric vehicles and heat pumps. For example a LV capacitor may be installed to control the voltage on individual demand biased feeders whilst a HV to LV transformer equipped with an on-load tap changer may be used to manage the voltage at the substation busbars.

Where the installation of a shunt LV capacitor appears to have merits, further guidance should be sought from the System Planning Manager.[64]

3.6.7.2 Functional specification

If a LV capacitor installation is being considered, guidance should be sought from the System Planning Manager regarding the functional specification and the Policy and Standards Manager regarding the detailed technical specification.

[62] The cost difference may be material if pole mounted capacitors are being considered.

[63] Pole mounted shunt capacitors are likely to have limited remote control facilities.

[64] The application of in-line LV regulators and shunt LV capacitors were explored in the ENW Low Carbon Networks Fund Project 'Voltage Management on Low Voltage Busbars' and is being developed further in their Smart Street project.

3.6.8 HV to LV distribution transformer OLTC

3.6.8.1 Application

LV systems in densely populated areas and HV spurs in sparsely populated areas share many characteristics. Each serves up to 1MW of demand, connected to the HV circuit at a single point. The CLNR project showed that where the application of standard voltage control techniques, or bespoke AVC settings, or LDC are insufficient to manage the LV system voltage, HV in-line regulators are typically the optimum solution for LV systems supplied from rural HV spurs, and HV to LV transformers equipped with OLTC are typically the optimum solution for urban LV systems.

Installing an HV to LV transformer equipped with an OLTC effectively moves the point of voltage control closer to the customers' Point of Supply and can be used to tune out upstream HV voltage fluctuation and maintain the voltage at transformer LV terminals at the desired level.

Where the demand of and export from customers connected to HV to LV substations supplied from the same HV circuit is such that voltage control provided by the EHV to HV substation is unlikely to be sufficient to ensure the voltage at the customer Point of Supply remain within statutory limits in all credible scenarios, distribution transformers equipped with OLTCs rather than DETC should be considered, particularly where a new HV to LV substation is to be installed for thermal reasons or network development.

For existing HV to LV transformers serving voltage constrained systems, when assessing the option to install a transformer with an OLTC, consideration shall be given to the condition, age and potential for thermal overload within the ten year planning period. The designer shall assess if the overall least cost solution is to replace the existing transformer with a higher rated unit with OLTC capability to address both voltage and power flow issues.

Where possible a ten year forecasts of customer demand and generation should be used to assess the range of voltages at customers' Point of Supply and hence whether a HV to LV transformer to be equipped with an OLTC can be justified.

The OLTC AVC relay settings (target voltage, dead band and delay time) shall be set so as to maintain supplies to customers within statutory limits in all credible scenarios, balance the risk of under voltage and overvoltage in other scenarios and minimise the number of tap changer operations, taking into account the:

- HV circuit voltage profile;
- number of tap positions on the OLTC;
- tap steps on the OLTC; and
- forecast customer demand and generation over the 10 year planning period.

Based on the findings of the CLNR project, the following standard AVC settings should be applied although bespoke settings may be applied where the standard settings are unsuitable:

- Target voltage: 240V[65]
- Dead band: +/- 2.5%
- Time delay: 150s

These standard AVC settings will be reviews as our experience installing such equipment increases. Further guidance should be sought from the System Planning Manager.[66]

[65] 240V is partway between the 246V no load and 230V full load for a DETC set on tap 2, with a 4.5% HV voltage drop and 2% full load regulation on the transformer.

[66] Installing OLTC has the potential to undermine the delivery of Grid Code OC6 Voltage Reduction functionality; this should not be material with a relatively small number of OLTCs currently envisaged.

3.6.8.2 Functional specification

HV to LV transformers equipped with an OLTC should provide the following functionality:

- The transformer should be configured with their HV windings connected through the tap changer with 9 tap positions, giving a range of +/- 8% in 2% increments;
- The transformer tap changer controls should be capable operated automatically locally, manually or remotely; and
- The AVC control should incorporate separate forward and reverse control settings for voltage level, bandwidth, time delay, and line-drop compensation.

All HV to LV transformers equipped with an OLTC should include a means of communication to allow remote control and monitoring of key functionality in accordance with the general principles for AVC transformers set out in Appendix 2.

If an HV to LV transformers equipped with an OLTC is being considered, guidance should be sought from the Policy and Standards Manager regarding the detailed technical specification.

3.6.9 Generator based control

3.6.9.1 Application

Where there is significant generation connected to a system it may have an effect on the voltage management on that system. Voltage control and power factor control systems used by generators are linked. Generator controllers are usually set to fix the power factor, and let the terminal voltage fluctuate, or fix the voltage and let the power factor fluctuate. These two control options are generally referred to as PQ and PV respectively. Generators should normally be set to operate in PQ mode where normal operation the generator would not lead to voltage constraints. Further details are provided in the Code of Practice for the Economic Development of Distribution Systems with Distributed Generation, IMP/001/007.

Where the application of standard voltage control techniques, or bespoke AVC settings, or LDC are insufficient to manage the system voltage in generation rich parts of the system it may be possible for the generator to operate in PV mode to limit the potential for excessive voltage rise on feeders by importing reactive power to reduce the voltage at their Point of Supply.

Where generator control is being considered guidance should be sought from the System Planning Manager.

3.6.9.2 Functional specification

The capability of generators to operate in PV and PQ mode is an integral part of generator controllers, and no Northern Powergrid equipment would be required.

3.6.10 Co-ordinated control

3.6.10.1 Application

Where the application of legacy and individual advanced voltage control techniques does not provide an acceptable voltage control solution, it may be possible to deploy a local or central co-ordinated control system that seeks to optimise the operation of one of more pieces of customer or Northern Powergrid owned equipment.

Whilst such control systems were trialled in the CLNR project, the application of local or central co-ordinated control is not yet proven and Northern Powergrid has limited experience of designing and operating such systems. The following guidance provides an overview of the issues, identified a part of the CLNR trial, that would need to be considered in developing such a scheme.

- A local generator controller may be installed to issue set-points for a generator's reactive and real power output. At times where the generator output would not lead to a voltage constraint, the local controller should be set to minimise losses by requiring the generator to export with a power factor as close as possible to the system to which it is connected. Where the generator output would lead to a voltage constraint, the local controller should be set to operate in PV mode; and
- Where there are multiple generators contributing to voltage rise on a given feeder then, in addition to a local generator controller, a central voltage control scheme may be considered to manage voltage rise caused by several generators in near real-time. Such a scheme should consider:

    - The area of the distribution system that needs to be included within the scope;
    - The emerging voltage constraints and the scenarios when they occur;
    - Whether there is a need to consider control of the OLTC at upstream transformers;
    - The generation plant that needs to be constrained, either by increasing reactive power import or reducing real power export, having regard to:

        - Sensitivity factors, i.e. how effective a control action would be in offsetting voltage rise at the pinch point; and
        - Merit orders, i.e. the commercial basis for which generators should be constrained first.

    - The mechanism for Issue commands to the relevant generators, either as a soft inter-trip (i.e. a binary signal to move to a pre-defined output level), or as a variable MW/MVAr set-point;
    - The need for a protection mechanism at the generator site to limit the potential for excessive voltages where the local controller is unable to communicate with the generator;
    - Whether there is a need for such a control scheme to include control of the tap changers installed on the distribution system.

Where co-ordinated control is being considered guidance should be sought form the System Planning Manager. The guidance and general principles provided in the Code of Practice for the Application of Active network Management, IMP/001/016, will also be relevant.

3.6.10.2 Functional specification

If a Co-ordinated Control Scheme is being considered, guidance should be sought from the System Planning Manager regarding the functional specification and the Policy and Standards Manager regarding the detailed technical specification.

4. References

4.1 External documentation

Reference	Title	Version and date
BS EN 50160:	Voltage characteristics of electricity supplied by public electricity networks	2015
Engineering Recommendation G5	Planning Levels for Harmonic Voltage Distortion & the Connection of Non-linear Equipment to Transmission Systems and Distribution Networks in the UK	4.1 2005
Engineering Recommendation P1	275/33kV, 132/33kV and 132/11kV Supply Point Transformers	3.0 1969
Engineering Recommendation P10	Voltage Control at Bulk Supply Points	1.0 1965
Engineering Recommendation P2	Security of Supply	6.0 2006
Engineering Recommendation P28	Planning Limits for Voltage Fluctuations Caused by Industrial, Commercial and Domestic Equipment in the UK	1.0 1989
Engineering Recommendation P29	Planning Limits for Voltage Unbalance in the UK for 132kV and Below	1.0 1990
HSAWA	The Health and Safety at Work Act	1974
SI 2002 No. 2665	The Electricity Safety, Quality and Continuity Regulations	31 January 2003 (as amended)
The Act	The Electricity Act 1989 (as amended by The Utilities Act 2000 and The Energy Act 2004 and The Energy Act 2004 (Amendment) Regulations 2012 (No. 2723, 2012)	1989
The Distribution Code	The Distribution Code of Licensed Distribution Network Operators of Great Britain	Issue 27 January 2016
The Electricity Distribution License	Standard conditions of the Electricity Distribution Licence	April 2015
The Grid Code	The Grid Code	Issue 5 Revision 19 September 2016

4.2 Internal documentation

Reference	Title	Version and date
IMP/001/007	Code of Practice for the Economic Development of Distribution Systems with Distributed Generation.	4.0 2015
IMP/001/010	Code of Practice for Standard Arrangements for Customer Connections	6.0 2015
IMP/001/016	Code of Practice for the Application of Active network Management	1.0 2016
IMP/001/909	Distribution System Parameters	3.0 2014
IMP/001/911	Code of Practice for the Economic Development of the LV System	4.0 2016
IMP/001/912	Code of Practice for the Economic Development of the HV System	3.0 2016
IMP/001/913	Code of Practice for the Economic Development of the EHV System	3.0 2015
IMP/001/914	Code of Practice for the Economic Development of the 132kV System	3.0 2015
NPS/003/011	Technical Specification for 11kV & 20kV Ground-Mounted Distribution Transformers	6.0 2016
NPS/003/020	Technical Specification for 11kV and 20kV Voltage Regulators	2.0 2014
NPS/003/021	Technical Specification for CMR transformers	3.1 2012
NPS/003/034	Technical Specification for 11kV & 20kV Pole-Mounted Distribution Transformers	3.0 2016
NPS/007/009	Technical Specification for a Ground-mounted, In-Line, LV Regulator with Enhanced Automatic Voltage Control (EAVC)	1.0 2012

4.3 Amendments from previous version

Section	Amendments
Not applicable	Not applicable as this is a new document.

5. Definitions

Term	Definition
BEIS	The government department for Business Enterprise and Industrial Strategy (formerly DECC).
CLNR	Northern Powergrid's Customer Led Network Revolution innovation project.
Customer	Any person supplied or entitled to be supplied with electricity at any premises within Great Britain but shall not include any Authorised Electricity Operator in its capacity as such.
DECT	De Energised Tap Changer (sometimes referred to as an Off Load Tap Changer).
DNO	Distribution Network Operator. The person or legal entity named in Part 1 of the Distribution Licence and any permitted legal assigns or successors in title of the named party.
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).
ENATS	Energy Network Association Technical Specification.
GSP	Grid Supply Point. A substation at which electricity is delivered from a transmission system to the DNO's Distribution System.
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).
IEC	International Electrotechnical Commission.
LDC	Line Drop Compensation
LV	Means a voltage up to and including 1000V.
NGET	National Grid Electricity Transmission plc.
NMS	Network Management System.
Northern Powergrid	Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc.
Ofgem	The Office of Gas and Electricity Markets, or its successor.
OLTC	On Load Tap Changer.
SCADA	Supervisory Control and Data Acquisition (often referred to as Telecontrol).

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

		Sign	Date
Dan Rodrigues	CDS Administrator	Dan Rodrigues	09/01/2017

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
		Sign	**Date**
Alan Creighton	Senior Asset Management Engineer	Alan Creighton	16/01/2017

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

		Sign	Date
David Van Kesteren	Senior Asset Management Engineer	David Van Kesteren	25/01/2017

6.4 Approval

Approval is granted for publication of this document

		Sign	Date
Mark Nicholson	Head of System Strategy	Mark Nicholson	17/01/2017

6.5 Authorisation

Authorisation is granted for publication of this document.

		Sign	Date
Mark Drye	Director of Asset Management	Kate Butterworth (on behalf of Mark Drye)	02/02/2017

Appendix 1

Target operating voltages

The target operating voltage for each 132kV, EHV and HV busbar shall be set at the appropriate standard voltage set out in section 3.5.3 apart from at those substations in the tables below.

A1.1 Grid Supply Point substations

The target operating voltage for each 132kV, EHV and HV busbar at a Grid Supply Point substations shall be set at the appropriate standard voltage set out in section 3.5.3.2 apart from at those substations in the table below:

Northern Powergrid Northeast

Grid Supply Point	Target Voltage	Reason for Non-standard Target Voltage[67]
Blyth 132	132kV	
Fourstones	20.1kV	
Knaresborough	132kV	
Norton	133kV	
Saltholme	137kV	
Tynemouth	131kV	

Northern Powergrid Yorkshire

Grid Supply Point	Target Voltage	Reason for Non-standard Target Voltage[68]
Bradford West	132kV	
Creyke Beck	136kV	
Elland	132kV	
Grimsby West	135kV	
Kirkstall	132kV	
Saltend North	136kV	
Skelton Grange	136kV	

[67] Reason for variance from the standard target voltage to be recorded where known.

[68] Reason for variance from the standard target voltage to be recorded where known.

A1.2 132kV to EHV substations

The target operating voltage for each EHV busbar at a 132kV to EHV substation shall be set at the appropriate standard voltage set out in section 3.5.3.3 apart from at those substations in the table below.

Northern Powergrid Northeast

132kV to EHV substation	Target Voltage	Reason for Non-standard Target Voltage[69]
Annfield	64kV	Reduced to cater for high volts on local 66 to 22kV transformers
Bowesfield	32.4kV	Reduced to cater for high volts issues at Newton Aycliffe South
Coalburns	65kV	Reduced to cater for high volts at West Wylam 66 to 22kV transformers
Darlington Central	32.5kV	
Leeming Bar	32kV	
Linton	65.47kV	Reduced to cater for operation on Middlemoor WF
Malton Grid	65kV	
Ravensworth	65.3kV	Reduced to cater for high volts on Birtley Grove 66 to 22kV transformer
Spennymoor	65.3kV	
Sherriff Hutton	63.5kV	132kV to 66kV transformer live but off load. Operated on fixed Tap.
Wormald Green	33.2kV	

Northern Powergrid Yorkshire

132kV to EHV substation	Target Voltage	Reason for Non-standard Target Voltage[70]
Broughton	34kV	Dedicated customer substation – voltage set at their request

[69] Reason for variance from the standard target voltage to be recorded where known.

[70] Reason for variance from the standard target voltage to be recorded where known.

A1.3 132kV to HV & EHV to HV substations

The target operating voltage for each HV busbar at a 132kV to HV and EHV to HV substation shall be set at the appropriate standard harmonised voltage set out in section 3.5.3.4 apart from at those substations in the table below.

Northern Powergrid Northeast

132kV to HV or EHV to HV substation	Target Voltage	Reason for Non-standard Target Voltage[71]
Aycliffe Industrial	11.33kV	
Brancepeth	20kV	
Cleveland Potash	11kV	Customer site
Darlington	6.3kV	Nonstandard legacy system voltage
Greenrigg Wind SW Customer's Switchgear 1	21.7kV	Remote dedicated customer substation
Greenrigg Wind SW Customer's Switchgear 3	21.7kV	Remote dedicated customer substation
Guisborough T3 S/S Guisborough ESCO 11KV Feeder	11.6kV	Dedicated customer transformer (customer no longer present)
Harraton	11.45kV	
Haxby Road	11.35kV	
Haxby Rowntrees	10.7kV	Dedicated customer substation – voltage set at their request
Hebburn	5.65kV	Nonstandard legacy system voltage
Hedgeley Moor Capacitor	19.8kV	Remote capacitor site, set low for normal system operational configuration
Lackenby Oxygen S/S (BOC)	10.5kV	Dedicated customer substation – voltage set to their request
Leam Central	20.4kV	No local 20kV load

[71] Reason for variance from the standard target voltage to be recorded where known.

132kV to HV or EHV to HV substation	Target Voltage	Reason for Non-standard Target Voltage[71]
Nissan	11.4kV	Dedicated customer substation – voltage set at their request
North Street	11.35kV	
Peterlee West	11.36kV	
Prudhoe West	10.9kV	Dedicated customer substation – voltage set at their request
Rise Carr	6.2kV	Nonstandard legacy system voltage
Wardley	5.65kV	Nonstandard legacy system voltage
Wenslydale	11.55kV	
Windylaw Capacitor SW	20kV	Remote capacitor site, set low for normal system operational configuration
Wingates Wind SW Customers Switchgear	20.8kV	Remote dedicated customer substation
Wormald Green	11.4/11.35kV	

Northern Powergrid Yorkshire

132kV to HV or EHV to HV substation	Target Voltage	Reason for Non-standard Target Voltage[72]
Grimsby Docks	6.6kV	Nonstandard legacy system voltage

[72] Reason for variance from the standard target voltage to be recorded where known.

Appendix 2

A2 Enhanced tap change functionality

New AVC relays installed at 132kV to EHV, 132kV to HV, and EHV to HV substations should provide the functionality set out in the table below. The facilities should be made available via RTUs / SCADA to NMS, so that it can be made available to Control Engineers and Design Engineers. New relays are to be installed at those substations that meet the replacement criteria.

	Remote Facility	Future Requirement	Comment
Control	Tap Lock On	✓	
Control	Tap Lock Off	✓	
Control	Voltage Reduction Stage 1 (2% or 3%)	✓	To provide Grid Code OC6 Voltage Reduction/basic ANM
Control	Voltage Reduction Stage 2 (4% or 6%)	✓	To provide Grid Code OC6 Voltage Reduction/basic ANM
Control	Voltage Reduction Stage 3 (6% or 9%)	✓	To provide Grid Code OC6 Voltage Reduction/basic ANM
Control	Voltage Reduction Normal	✓	To provide Grid Code OC6 Voltage Reduction
Control	Tap to unity pf	Optional	Can be provided as an alternative to remote Tap Up / Tap Down
Control	Tap Up	✓	
Control	Tap Down	✓	
Control	Set Target Voltage	✓	Required to 'manually' change set point 'regularly / seasonally'. This could also be used to deliver an OC6 Voltage Reduction of values other than 3% or 6%. Required for advanced ANM. This functionality could be provided by remotely selecting preconfigured group settings.
Control	Tap Stagger	✓	Can be used to manage reactive power flows. May require an enhanced / more expensive version of Supertapp. Required to provide the capability for future reactive power ancillary service.
Control	LDC Boost in forward direction *	✓	Boost should be capable
Control	LDC Buck in reverse direction *	✓	Buck should be capable
Control	LDC – Gen exclusion *	✓	Would be acceptable as an upgradable option. Might be possible to simulate this functionality if not available in the relay by using hardwired CTs for LDC schemes (although this will corrupt analogues taken from the same secondary wiring)
Indication	Tap Lock On	✓	
Indication	Voltage Control Telecontrol On	✓	

	Remote Facility	Future Requirement	Comment
Indication	Voltage Reduction Stage 1	✓	GCode OC6 Voltage Reduction
Indication	Voltage Reduction Stage 2	✓	GCode OC6 Voltage Reduction
Indication	Voltage Reduction Stage 3	✓	GCode OC6 Voltage Reduction
Indication	Voltage Reduction Normal	✓	GCode OC6 Voltage Reduction
Indication	Tap Position indicator	✓	Required for advanced ANM, to assist network analysis and additional clarity of tap changer performance for Net Man.
Alarm	Volt Control Faulty	✓	
Alarm	Out of step lockout	✓	
Analogue	Phase Angle (4Q)	✓	Required for advanced ANM, and for network analysis. Could be provided from discrete transducers / protection relays.
Analogue	Red-Blue Voltage	✓	Required for advanced ANM, and for network analysis. Could be provided from discrete transducers / protection relays.
Analogue	Yellow Current	✓	Required for basic ANM, and for network analysis. Could be provided from discrete transducers / protection relays.

* Local facility only