nationalgridESO

NCER: System Defence Plan

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Contents

NCER: System Defence Plan

1 INTRODUCTION

The *Network Code on Emergency & Restoration*[1] (***NCER***) came into force on 18 December 2017. Pursuant to the provisions in Chapter 2, below is the proposed GB System Defence Plan on behalf of the GB National Electricity Transmission System Operator.

As provided for in the NCER Article 11, this System Defence Plan will be designed in consultation with relevant Distribution System Operators (DSOs), Significant Grid Users (SGUs), National Regulatory Authority, neighbouring Transmission System Operators (TSOs) and other TSOs in the GB synchronous area.

This Plan is not intended to replace any provisions currently in place in the GB Codes nor to amend the Operational Security Limits[2], it is a summary of how the requirements for System Defence specified in NCER will be satisfied. Many of the provisions contained within this System Defence Plan are already described in the GB national codes (Grid Code, CUSC, BSC, etc.). Where there are new mandatory requirements for GB Parties then these will be included in relevant GB Codes as appropriate.

This System Defence Plan will impact all DSOs and TSOs in Great Britain and Significant Grid Users identified in Appendices A to C, who have code obligations referred to in this plan.

This System Defence Plan has been developed taking the following into account;

- the operational security limits set out in accordance with Article 25 of Regulation (EU) 2017/1485 {SOGL};
- the behaviour and capabilities of load and generation within the synchronous area;
- the specific needs of the high priority Significant Grid Users listed in Appendix C;
- the characteristics of the National Electricity Transmission System and of the underlying DSO systems.

This has been achieved by developing this GB System Defence Plan collaboratively with affected parties through the Energy Emergencies Executive Committee, Electricity Task Group (ETG), and by collecting feedback during a public consultation period undertaken in summer 2018.

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[1] *Network Code on Emergency and Restoration*
http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2017.312.01.0054.01.ENG&toc=OJ:L:2017:312:TOC

[2] *Article 25 System Operations Guideline*
http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2017.220.01.0001.01.ENG

2 PLAN OVERVIEW

This Great Britain System Defence Plan (**SDP**) is drafted to conform to *NCER* Articles 11 to 22. It is intended to serve as an umbrella document referencing the more detailed plans for specific parties – therefore, should the NCER articles that are referenced be amended then these articles shall prevail and this document and any subordinate GB Code must also be amended.

2.1 Activation of System Defence Plan Procedures

In Accordance with NCER Article 13:

2.1.1 Procedures in this System Defence Plan will be activated when the System is in Emergency state, as defined in SOGL Article 18(3), or operational security analysis requires the activation of a measure.

2.1.2 Procedures in this System Defence Plan will be activated by the NETSO in coordination with DSOs, SGUs and Defence Service Providers.

2.1.3 All instructions issued by the NETSO under this System Defence Plan must be executed by each DSO, SGU and Defence Service Provider without undue delay.

2.1.4 The NETSO will coordinate impacted TSOs where these procedures have a significant cross border impact.

3 SYSTEM PROTECTION SCHEMES

3.1 Automatic Under Frequency Control Scheme

In Accordance with NCER Article 15:

3.1.1 Pumped Storage plant synchronised at zero generated output with capability to rapidly increase generated output at a specified Low Frequency (LF) when armed under a commercial service.

3.1.2 HVDC Interconnectors – automatic ramping of HVDC Interconnectors at specified Low Frequencies (LF) when armed under a commercial service.

3.1.3 Demand disconnection by LF relay initiation (contracted). A commercial service that disconnects industrial load when armed.

3.1.4 Fast Start from standstill - Fast Start via Low Frequency (LF) relay initiation that can be contracted at any frequency between 49 and 50 Hz (*Grid Code CC6.3.14 & ECC6.3.14*).

3.1.5 Energy Storage systems taking energy are required to automatically switch to generating mode or where it is not capable of doing this must automatically disconnect before the activation of Low Frequency Demand Disconnection Scheme.

3.1.6 Limited Frequency Sensitive Mode – Under frequency (LFSM-U) – Type C and D Power Generating Modules connected to the Total System after 27 April 2019 and HVDC Systems connected after 8th September 2019 are required to provide an automatic increase in active power at a minimum rate of 2% of output per 0.1 Hz deviation of system frequency below 49.5 Hz.

3.2 Automatic Low Frequency Demand Disconnection Scheme

In Accordance with NCER Article 15:

3.2.1 NCER requires that the Automatic Low Frequency Demand Disconnection disconnects at least 50% of Total Load. The *Grid Code OC6* obliges DSOs to provide progressive Automatic Low Frequency Demand Disconnection of up to 60% of their total demand.

3.2.2 The general technical requirements for Automatic Low Frequency Demand Disconnection schemes that are applicable in GB can be found in the *Annex to the NCER* (see Appendix F). Detailed technical requirements for GB found in *Appendix 5* of both the *Grid Code Connection Conditions and the Grid Code European Connection Conditions and will be reviewed and modified a*s necessary to ensure compliance with NCER.

3.3 Automatic Over Frequency Control Scheme

In Accordance with NCER Article 16:

3.3.1 Commercial arrangements are in place to provide static High Frequency Response by ramping HVDC Interconnectors when pre-set frequency levels are reached.

3.3.2 High Frequency Response - contracted providers of high frequency response are required to reduce active power in response to an increase in system frequency up to 50.5 Hz as agreed in an Ancillary Services Contract. Above 50.5 Hz this is to be at a minimum rate of 2% of output per 0.1 Hz deviation of frequency above 50.5 Hz *(Grid Code BC3.7.1)*.

3.3.3 Limited Frequency Sensitive Mode (LFSM) – existing connections (until 27 April 2019:

Limited Frequency Sensitive Mode – Over frequency (LFSM-O) – new connections (after 27 April 2019:

In both cases the Generating Unit or Power Generating Module is required to provide an automatic reduction in active power export at a minimum rate of 2% of output per 0.1 Hz deviation of system frequency above 50.4 Hz.

3.4 Automatic Schemes Against Voltage Collapse

In Accordance with NCER Article 17:

3.4.1 The fundamental basis of the NETSO's voltage control policy is to operate within the voltage limits defined in the *National Electricity Transmission System Security and Quality of Supply Standard* (NETS *SQSS*) in planning and operational timescales across all transmission and customer interface voltage levels. This is achieved by maintaining dynamic reactive power reserves, both leading and lagging, to further ensure operation within limits for defined contingencies.

3.4.2 System studies are performed in all planning and operational timescales to ensure that voltage levels are maintained within levels stated in *SQSS* and that voltage collapse is avoided both for transient and permanent transmission system faults.

3.4.3 The National Electricity Transmission System is designed to use Delayed Auto Reclose systems (**DAR)** to re-energise overhead line circuits following transient and semi-permanent faults, thus minimising the threat of voltage collapse.

3.4.4 The National Electricity Transmission System is designed to use Reactive Control Equipment to control transmission system and customer interface voltage levels both pre and post fault. Mechanically Switched Capacitors (MSCs) and Shunt Reactors have been installed at strategic locations to achieve this. Automatic Reactive Control Schemes (ARS) have also been installed to react to changes in transmission system or customer interface voltage levels and automatically switch in/out Mechanically Switched Capacitors/Shunt Reactors accordingly.

3.4.5 Static VAr Compensators (SVCs) are used to provide fast acting reactive power response to transmission system voltage changes. SVCs are connected to either the 400 or 275 kV system and can be set to operate in target voltage or constant reactive modes.

3.4.6 There are other geographically specific defence measures which use individual automatic schemes to cater for specific faults. For example, the Anglo-Scottish Auto-Close Scheme (ASACS).

Anglo-Scottish Auto Close Scheme (ASACS)

The specific requirement for the ASACS arises from the installation of series and shunt compensation at various locations on the Anglo-Scottish interconnector circuits, which facilitate higher transfers across the boundary. This is managed through high-speed post-fault switching of Mechanically Switched Capacitors (**MSC**) to keep post-fault voltages within the limits set by the SQSS.

The ASACS increases the transient stability limit of the Anglo-Scottish transmission circuits by closing selected MSC circuit breakers, in stability timescales, in response to the loss of selected East Coast or West Coast circuits. For such faults, ASACS may switch in to operations the MSCs at Harker, Blyth, and Stella West in less than a second to maintain generator stability.

3.4.7 Low Voltage Demand Disconnection schemes are installed to protect specific geographic areas.

3.4.8 The measures described above, including the regular security assessment, ensure that there is no need to install tap changer blocking schemes.

4 SYSTEM DEFENCE PLAN PROCEDURES

4.1 Frequency Deviation Management Procedure

In Accordance with NCER Article 18

4.1.1 The frequency limits of the National Electricity Transmission System are set by System Operations Guideline Article 127, the *Electricity Safety, Quality and Continuity Regulations (ESQCR)* [3] and the *SQSS*. As such, and under Normal State, the frequency across the National Electricity Transmission System is maintained within the Standard Frequency range of 50 +/-0.2 Hz to ensure operation within the Maximum Steady State Frequency Deviation of +/-0.5 Hz.

4.1.2 System Frequency across the GB Synchronous Area is controlled by response from contracted generation, demand side and energy storage providers.

4.1.3 Sufficient Frequency Containment Reserves (FCR) are held to ensure that frequency:

- remains within the Standard Frequency range (50 +/- 0.2 Hz) for infeed losses of < 300 MW;
- remains within the Maximum Steady State Frequency Deviation (+/- 0.5 Hz) for infeed losses of < 1000 MW;
- deviation does not exceed the Maximum Instantaneous Frequency Deviation of 0.8 Hz for the maximum credible infeed loss on the system at any time.

4.1.4 Frequency Restoration Reserves (FRR) are provided by stationary Generating Units, Power Generating Modules, storage and demand side providers. Sufficient reserves are held to enable system frequency to be returned within the Maximum Steady State Frequency Deviation within 1 minute and to within the Standard Frequency Limit within 15 minutes.

4.1.5 The system frequency is monitored on a second by second basis by the NETSO. Frequency response services required for any period are calculated from day-1 based on demand characteristics, economics, largest infeed/offtake criteria, volume of variable renewable energy sources and system inertia.

4.1.6 Frequency Restoration Reserves (FRR) availability is continually assessed by the NETSO on a long-term basis. Required FRR holding for any period is calculated from week-1 and based on demand characteristics (including seasonal variations), economics, historic plant loss statistics and volume of variable renewable energy sources.

[3] http://www.legislation.gov.uk/uksi/2002/2665/contents/made

4.1.7 Where insufficient frequency Restoration Reserve provision by the market is forecast, then BM Start-Up contracts with long notice BM Units are enacted to ensure that sufficient reserves will be available.

4.1.8 Should the frequency fall unexpectedly outside the Maximum Steady State Frequency Deviation limits then automatic under/over frequency control schemes and/or Low Frequency Demand Disconnection schemes operate.

4.1.9 *Grid Code BC2.5.4* states that in the event of the system frequency being below 49.7 Hz or above 50.3Hz, Balancing Mechanism participants must not commence any reasonably avoidable action to regulate the input or output of any BM Unit in a manner that could cause the system frequency to deviate further from 50 Hz without first using reasonable endeavours to discuss the proposed actions with the NETSO.

4.2 Additional Demand Disconnection Following Low Frequency Demand Disconnection

In Accordance with NCER Article 22

4.2.1 If, because of a low frequency event, demand has been disconnected by Automatic Low Frequency Demand Disconnection, the NETSO may instruct reduction of transmission-connected demand and/or DSOs to disconnect additional demand in accordance with *Grid Code OC6* to recover system frequency to within the frequency restoration range and restore frequency containment reserves.

4.3 Demand Restoration

In Accordance with NCER Article 18

4.3.1 Following a demand disconnection event, DSOs and/or transmission-connected demand customers can reconnect demand only on instruction from the NETSO in accordance with *Grid Code OC6*.

4.4 Voltage Deviation Management Procedure

In Accordance with NCER Article 19

4.4.1 The NETSO is obliged to plan and operate the National Electricity Transmission System within the voltage limits defined in the System Operations Guideline Article 27 and Annex II *and Security and Quality of Supply Standard* (*SQSS*) at connection points. This is achieved by maintaining dynamic reactive power reserves, held on generation plant and reactive compensation equipment, to control pre and post fault voltage levels.

4.4.2 Voltage limits used for system design are more stringent than those used for operational planning, which in turn are more stringent than those allowed in operational timescales. This reduces the risk of breaching voltage standards in operational timescales.

4.4.3 Studies are undertaken by the NETSO using offline modelling of voltages pre-fault and following a list of credible contingencies from long-term planning down to 4 hours ahead. These studies identify any potential breach of voltage standards so that remedial action can be taken pre-fault or planned for post fault implementation. These studies are repeated following any significant change in system conditions.

4.4.4 Emphasis is placed by the NETSO control engineers on the timely management of all aspects of voltage control with varying generation and demand patterns, including switching of Reactive Compensation Equipment, setting target voltages on Static VAr Compensators, switching out designated circuits and instructing generator plant to import/export reactive power, to achieve the required target voltage levels.

4.4.5 A real-time assessment tool monitors power system conditions and continually re-evaluates voltages following a list of credible contingencies so that action can be taken pre-fault to avoid post fault breach of voltage standards.

4.4.6 In operational timescales, the following measures can be taken by the NETSO to maintain reactive power reserves:

- Switching of Reactive Compensation Equipment;
- Excitation of synchronous machines by issuing reactive power instructions to generators;
- Changing reactive power flow at customer interface points, including super grid transformer tap changing;
- Repositioning generating plant, including at part load;
- Operation of gas turbines in synchronous compensation mode;
- Synchronising additional generation, including gas turbines;
- Switching out high reactive gain circuits;
- Simultaneous generator transformer tap changing;
- Demand transfer out of a group to mitigate local issues;
- Restoration of circuit outages;
- Pre-fault demand reduction actions;
- Post fault demand reduction actions;
- Manually disconnecting load.

4.4.7 Automatic Tap Change Control (ATCC) schemes are installed on super grid transformers to assist in maintaining a desired voltage profile at the interface points to customers connected to the National Electricity Transmission System. The voltage profile must be maintained with varying generation and demand patterns and the target voltage for individual schemes can be set by the NETSO to meet the requirements of DSOs.

4.4.8 Should voltages unexpectedly exceed standards following a system event then 1 or more of the above measures can be used to restore voltages to within standards.

4.5 Power Flow Management Procedure

In Accordance with NCER Article 20

4.5.1 Power flows across the National Electricity Transmission System are managed by the NETSO operating within derived transmission constraint boundaries. These constraints are dependent on transmission asset outage conditions and are optimised by the NETSO. Operating within transmission constraint limits may require the NETSO to instruct balancing actions of Balancing Service Providers; e.g. Bid Offer Acceptances (BOAs). In addition, the NETSO has several bespoke actions available to assist with the power flow management on the National Electricity Transmission System.

4.5.2 *Emergency Instructions* can be used to decrease/increase power exported/imported from GB Total System Users (including disconnection), as detailed in the *Grid Code BC2.9*. These can also be issued to DSOs to take appropriate action on their networks. In the case of HVDC Interconnectors, an Emergency Instruction can also be a reversal of flow – leading to an effective increase in generation or demand on part of the National Electricity Transmission System.

4.5.3 *Special Actions* as defined in the Grid Code BC1.7, are bespoke and bilaterally agreed between the NETSO and specific National Electricity Transmission System Users. These are agreed in advance so that they can be implemented swiftly on instruction by the NETSO following a specified credible event.

4.5.4 Generator Operational Tripping Schemes are installed to prevent circuit thermal overloads and/or system instability problems in post-fault timescales, or to protect consumer demand and/or DSO networks against the loss of the generator/super grid system connections or islanding of generation.

4.5.5 Demand Tripping Schemes are installed to protect circuits from thermal overloads and/or maintain voltage stability under fault conditions.

4.5.6 Whenever downward regulation shortfall for a transmission constraint is identified (hours ahead to real time) an Insufficient Localised Negative Reserve Active Power Margin (NRAPM) warning will be issued by the NETSO under *Grid Code BC1.5.5* to see if any increase in generator flexibility is possible.

4.6 Assistance For Active Power Procedure

In Accordance with NCER Article 21

4.6.1 Agreements are in place with neighbouring TSOs to provide Emergency Assistance. The contracted service is for blocks of energy to be provided across HVDC Interconnectors for specific periods of time, and detailed in the relevant *Balancing and Ancillary Services Agreement* for each interconnector.

4.6.2 Where a *Maximum Generation* Service Agreement is in place between the NETSO and a Generator (*CUSC Section 4.2*), the Generator will use reasonable endeavours to make available and provide Maximum Generation from each of its Maximum Generation BM Unit(s). The NETSO will request the Maximum Generation Service prior to the instruction of any measures related to Demand Control. This will be via Emergency Instructions.

4.6.3 The NETSO shall be entitled to request assistance for active power from SGUs which do not already provide a balancing service. Upon request from the NETSO any SGU shall make available all its active power, conforming to its technical constraints. The NETSO may only do this after it has activated all balancing energy bids available.

4.6.4 Whenever national downward regulation shortfall is identified (day ahead to real time) an Insufficient System Negative Reserve Active Power Margin (NRAPM) warning will be issued by the NETSO under *Grid Code BC1.5.5* to see if any increase in generator flexibility is possible.

4.7 National Electricity Transmission System Warnings Procedure

4.7.1 The *Grid Code OC6, OC7*, and *BC1* provide for circumstances in which the NETSO may issue a National Electricity Transmission System Warning to all industry participants in circumstances where Demand Reduction may be required. National Electricity Transmission System Warnings consist of the following types: -

- (a) *Electricity Margin Notice*.
- (b) *High Risk of Demand Reduction*.
- (c) *Demand Control Imminent*.
- (d) *Risk of System Disturbance*.

4.7.2 *Electricity Margin Notice* and/or *High Risk of Demand Reduction* warnings may be issued by the NETSO when insufficient system margins are anticipated for any period.

4.7.3 Should the system conditions not return within the acceptable limits or there is still further concern, a *Demand Control Imminent* warning may be issued giving warning that the NETSO expects to issue a Demand Control instruction to DSOs and/or Non-Embedded Customers in the next 30-minute window.

4.7.4 The NETSO will issue the above instructions when the need for Demand Control is identified in advance but this may not be possible in all circumstances. However, an increase level of Demand Control must be made available if a *High Risk of Demand Reduction* warning has been issued by 16:00 hours day1.

4.8 Manual Demand Disconnection Procedure

In Accordance with NCER Article 22

4.8.1 *Grid Code OC6, OC7, BC1*, and *BC2 allow Demand Control* instructions to be issued by the NETSO to all DSOs and Non-Embedded Customers connected to the National Electricity Transmission System.

4.8.2 *Manual Demand Reduction* in respect of DSOs and Non-Embedded Customers may be instructed by the NETSO to avoid unacceptable operating conditions on the National Electricity Transmission System during periods of generation shortage, or in the event of unacceptable thermal overloading and/or unacceptable voltage conditions. There are 2 types: -

(a) *Demand Reduction*. This shall be achieved by the NETSO instructing voltage reduction and/or demand disconnection equally across Non-Embedded Customers and Grid Supply Points.

(b) *Emergency Manual Demand Disconnection*. This applies to a localised section of the National Electricity Transmission System under an emergency and shall be achieved by the NETSO instructing demand disconnection at specific Grid Supply Point(s).

4.8.3 *Grid Code OC6.5* describes the stages of netted Demand Reduction. DSOs shall be able to achieve the first 20% of netted demand reduction always with or without warning. Further stages of netted demand reduction (5% steps) up to total of 40% shall be achievable following the issue of a “*National Electricity Transmission System Warning - High Risk of Demand Reduction*” by the NETSO before 16:00 hours day-1.

4.8.4 Once netted Demand Reduction has been applied each DSO must ensure that their netted Demand Reduction remains at the instructed level until the NETSO instructs otherwise.

4.8.5 Whilst netted Demand Reduction is in place, the Balancing Mechanism will still be in operation and the markets will not be suspended. Demand Reduction instructions shall be issued by the NETSO as *Emergency Instructions*.

4.9 Rota Load Disconnection Procedure

4.9.1 *Rota Load Disconnections* are described in the *Electricity Supply Emergency Code*[4]. In an electricity supply emergency, it may be necessary to restrict customers' consumption of electricity by the issue of directions under the *Energy Act 1976* or the *Electricity Act 1989* requiring rota disconnections and associated restrictions.

4.9.2 If the BEIS Emergency Response Team decides that rota disconnections must be introduced, the Secretary of State for Business, Energy and Industrial Strategy will implement the emergency powers in the *Energy Act 1976*. BEIS can then issue a direction to all Network Operators affected to implement a schedule of rota disconnections across their licence area(s) throughout the period of the emergency. Under this direction and within the provisions of the *Grid Code*, the NETSO will determine the level of disconnections required and instruct DSOs accordingly.

4.9.3 Under the *Electricity Supply Emergency Code* customers vital to national infrastructure are entitled to apply to BEIS for Protected status. DSOs are obliged to review the Protected Site List every 2 years and provide an update to BEIS on 1st October.

5 RESILIENCE MEASURES TO BE IMPLEMENTED BY TSOS AND DSOS

In Accordance with NCER Article 11(4)

5.1 Substations identified in the System Restoration Plan Appendix D as essential for restoration will be operational in case of loss of primary power supply for at least 24 hours (NCER Article 42).

5.2 The NETSO, onshore TSOs and DSOs must ensure all critical tools and facilities listed in SOGL Article 24 are designed to remain available for use for at least 24 hours in the case of a loss of external power (NCER Article 42). This includes any remote data centres required to sustain the critical tools and facilities.

5.2.1 Critical tools and facilities for the NETSO, onshore TSOs and DSOs include but are not limited to Supervisory, Control and Data Acquisition systems (SCADA), protection systems and control telephony.

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[4] *Electricity Supply Emergency Code* *https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/698739/2018_03_29_Electricity_Supply_Emergency_Code__ESEC__2018_Revision_V1.0-.pdf*

5.2.2 In addition to those listed in 5.2.1, critical tools and facilities for the NETSO will include state estimation applications, facilities for load-frequency control, security analysis and the means to facilitate cross-border market operations.

5.3 The NETSO and onshore TSOs must also ensure they have at least one geographically separate control room with backup power supply for at least 24 hours, in case of loss of primary power supply. They must also have a procedure to transfer functions to the Standby Control Room as quickly as possible but in no longer than 3 hours

6 RESILIENCE MEASURES TO BE IMPLEMENTED BY SGUS AND RESTORATION SERVICE PROVIDERS

In Accordance with NCER Article 11(4)

6.1 Each SGU listed in Appendices A, B and C and Restoration Service Providers must ensure their critical tools and facilities are designed to remain available for at least 24 hours in the case of a local loss of external power (NCER Articles 41.1 and 42.2).

6.1.1 Critical tools and facilities for SGUs and Restoration Service Providers are defined in SOGL Article 24, and include, but are not limited to, Supervisory, Control and Data Acquisition systems (SCADA), automatic logging devices and control telephony.

6.1.2 Those Restoration Service Providers that are Type B Power Generating Modules have the possibility to have only a data communication system, instead of a voice communication system, if agreed upon with the NETSO (NCER Article 41.4). In this case the data communication facilities must have the same level of resilience as required for the voice communication system.

7 ASSURANCE & COMPLIANCE TESTING

NCER Article 43 states the general principles for compliance testing of capabilities for TSOs, DSOs and SGUs. Articles 44 to 49 describe the testing requirements and are summarised below.

7.1 All TSOs shall periodically assess the proper functioning of all procedures, equipment and tools required for the System Defence Plan and System Restoration Plan. A test plan shall be produced by each TSO after consulting DSOs and SGUs by 18th December 2019. The test plan shall identify the equipment and capabilities relevant for the System Defence Plan and System Restoration Plan that must be tested, and include target periodicity and conditions of each of the tests for Power Generating Module capabilities that are Restoration Service Providers, demand side response that are Defence Service Providers, HVDC capabilities for Restoration Service Providers and Low Frequency Demand Disconnection relays.

7.2.1 Each Restoration Service Provider which is a Power Generating Module or a HVDC system delivering a Black Start service shall execute a Black Start capability test at least every 3 years.

7.2.2 Each Restoration Service Provider which is a Power Generating Module delivering a quick re-synchronisation service shall execute a trip to house load test after any changes of equipment having an impact on its house load operation capability, or after 2 unsuccessful trips in real operation.

7.2.3 Each Defence Service Provider delivering demand response shall execute a demand response test after 2 consecutive unsuccessful responses in real operation, or at least every year.

7.2.4 Each Defence Service Provider delivering low frequency demand disconnection shall execute a regular low frequency demand disconnection. The frequency of these tests will be defined in the Grid Code.

7.2.5 All DSOs and TSOs shall execute regular testing on the Low Frequency Demand Disconnection relays implemented on their installations. The frequency of these tests will be defined in the Grid Code.

7.2.6 Each TSO, DSO, SGU and Restoration Service Provider shall test their communication systems at least every year.

7.2.7 Each TSO, DSO, SGU and Restoration Service Provider shall test the backup power supplies of their communication systems at least every 5 years.

7.2.8 Each TSO shall test the capability of main and backup power sources to supply its main and backup control rooms at least every year.

7.2.9 Each TSO shall test the functionality of critical tools and facilities at least every 3 years. Where these tools involve DSOs or SGUs, these parties shall participate in the tests.

7.2.10 Each TSO shall test the capability of backup power sources to supply essential services of the substations listed in the System Restoration Plan Appendix D at least every 5 years.

7.2.11 Each TSO shall test the transfer procedure for moving from the main control room to the backup control room at least every year.

7.3 All TSOs, DSOs and SGUs shall produce a report each calendar year on their completed compliance tests, along with a measure of each test success. The report shall be made available to NETSO by 1st April of the following calendar year. The report shall also indicate procedures, when the next occurrence of each test is expected to be completed, together with a risk assessment rating and justification.

7.4 All DSOs with Low Frequency Demand Disconnection relays installed shall update the NETSO once per year of the frequency settings at which netted demand disconnection is initiated and the percentage of netted demand disconnection at every such setting. The NETSO shall monitor the Low Frequency Demand Disconnection capability based on these annual submissions.

8 PLAN IMPLEMENTATION

Article 12 of the *NCER*, provides for the implementation of the **System Defence Plan,** and requires that by 18 December 2018 the NETSO will notify all DSOs, SGUs and Defence Service Providers of their obligations.

This System Defence Plan will be fully implemented by 18 December 2019.

9 PLAN REVIEW

NCER Article 50 requires the NETSO to review the System Defence Plan to assess its effectiveness at least every five years. However, it is intended to carry out a review annually by 1st September.

The review will consider at least:

(a) The development of the National Electricity Transmission System.
(b) The capabilities of new equipment installed on the Transmission and Distribution Systems.
(c) The SGUs commissioned since the last review, their capabilities and services offered.
(d) The results of the tests carried out as defined in Section 7.
(e) The analysis of system incidents.
(f) The operational data collected during normal operation and after disturbance.

The NETSO will also review the relevant measures of the System Defence Plan in advance of a substantial change to the configuration of the National Electricity Transmission System.

Appendix A: Criteria for the List of SGUs Responsible for Implementing Measures that Result from EU Code Mandatory Requirements or from National Legislation

NCER Article 11.4(c) requires the System Defence Plan to include a list of SGUs responsible for implementing on their installations the measures that result from mandatory requirements set out in Regulations (EU) 2016/631 [NC RfG], (EU) 2016/1388 [NC DCC] and (EU) 2016/1447 [NC HVDC] or from national legislation and a list of the measures to be implemented by those SGUs.

The list shall apply to the following Significant Grid Users (SGUs):

(a) (all) existing power generating modules classified as type B, C or D in accordance with the criteria set out in Article 5 of Commission Regulation (EU) 2016/631 [NC RfG]; where they are identified as SGUs under Article 11(4) and Article 23(4) (ie, in both cases, where they have mandatory requirements under existing national legislation)

(b) (all) new power generating modules classified as type B, C or D in accordance with the criteria set out in Article 5 of Commission Regulation (EU) 2016/631 [NC RfG]; where they are identified as SGUs under Article 11(4) and Article 23(4) (ie, in both cases, where they have mandatory requirements under RfG)

(c) existing and new transmission-connected demand facilities;

(d) existing and new transmission-connected closed distribution systems;

(e) providers of redispatching of power generating modules or demand facilities by means of aggregation and providers of active power reserve in accordance with Title 8 of Part IV of Commission Regulation (EU) 2017/1485 {SOGL}; and

(f) existing and new high voltage direct current (‘HVDC’) systems and direct current-connected power park modules in accordance with the criteria in Article 4(1) of Commission Regulation (EU) 2016/1447 [NC HVDC]. (for the avoidance of doubt Article 4(1) only requires existing HVDC systems to comply with articles 26, 31, 33 and 50 of NC HVDC unless they undergo substantial modification.)

The NETSO will be responsible for producing the list in consultation with relevant DSOs and SGUs. DSOs will be responsible for notifying the NETSO of distribution-connected power generating modules. The NETSO will update the list annually as part of its review of the System Defence Plan.

Appendix B: List of SGUs Responsible for Implementing Measures that Result from EU Code Mandatory Requirements or from National Legislation

The sections of this plan that require implementation of measures resulting from mandatory requirements set out in National Legislation, and the SGUs required to implement those measures are listed below:

3.3.2 Reduction in Active Power at frequencies above 50.5 Hz

- All Power Stations with a Frequency Response contract.

3.3.3 Limited Frequency Sensitive Mode

- Defined under Grid Code BC3.5.2 – All synchronised Gensets and HVDC converters.

4.1.9 Requirement not to take action to exacerbate frequency excursion when system frequency is below 49.7 Hz or above 50.3 Hz

- Defined under Grid Code BC2.5.4 - All BM Participants.

4.4.6 Reactive Power Instructions to generating units

- All Power Stations with a Mandatory Services Agreement.

4.5.2 Emergency Instructions

- Defined under Grid Code BC2.9 - All BM Participants.

The sections of this plan that require implementation of measures resulting from mandatory requirements set out in Regulations (EU) 2016/631 [NC RfG], (EU) 2016/1388 [NC DCC] and (EU) 2016/1447 [NC HVDC] and the SGUs required to implement those measures are listed below:

3.1.5 Energy Storage Systems automatically switching to generating mode or disconnecting

- New Grid Code and Distribution Code change required – Detail to be defined under the code change procedures.

3.1.6 Limited Frequency Sensitive Mode – Under frequency (LFSM-U)

3.3.3 Limited Frequency Sensitive Mode – Over frequency (LFSM-O)

- Defined under Grid Code BC3.5.2 - All synchronised Gensets and HVDC converters.

4.6.3 Assistance for Active Power

- All SGUs as defined in Appendix A – Potential Code Change required - Detail to be defined under the code change procedures.

6.1 Resilience of critical tools and facilities

- New Grid Code and Distribution Code change required – Detail to be defined under the code change procedures.

7 Assurance and Compliance testing

- New Grid Code and Distribution Code change required – Detail to be defined under the code change procedures.

Appendix C: List of High Priority Significant Grid Users

There are no High Priority Significant Grid Users that apply for the GB System Defence Plan and System Restoration Plan.

Appendix D: List of DSOs Responsible for Implementing System Defence Plan Measures

Electricity North West

Northern Powergrid (North East)

Northern Powergrid (Yorkshire)

Scottish Power Distribution

Southern Electric Power Distribution

Scottish Hydro Electric Power Distribution

SP Manweb

UK Power Networks (Eastern Power Networks)

UK Power Networks (London Power Networks)

UK Power Networks (Southern Power Networks)

Western Power Distribution (East Midlands)

Western Power Distribution (South Wales)

Western Power Distribution (South West)

Western Power Distribution (West Midlands)

Appendix E: Glossary

These definitions have been sourced from the Electricity Transmission Licence, the Grid Code Glossary and Definitions, the Network Code Emergency and Restoration and the European Union Emissions Trading Scheme website.

Balancing Mechanism	The mechanism for the making and acceptance of offers and bids pursuant to the arrangements contained in the Balancing and Settlement Code.
Balancing Service Provider	A Balancing Service Provider (BSP) is a market participant providing Balancing Services to its Connecting TSO.
BEIS	Her Majesty's Government Department for Business, Energy and Industrial Strategy.
BM Participant	A person who is responsible for and controls one or more BM Units or where a Bilateral Agreement specifies that a User is required to be treated as a BM Participant for the purposes of the Grid Code. For the avoidance of doubt, it does not imply that they must be active in the Balancing Mechanism.
Defence Service Provider	A Defence Service Provider is a legal entity with a legal or contractual obligation to provide a service contributing to one or several measures of the System Defence Plan.
DSO	A Distribution System Operator is a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in each area and, where applicable, its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity.
Generating Unit	An Onshore Generating Unit and/or an Offshore Generating Unit which could also be part of a Power Generating Module.
Genset	A Power Generating Module (including a DC Connected Power Park Module), Generating Unit, Power Park Module or CCGT Module at a Large Power Station or any Power Generating Module (including a DC Connected Power Park Module), Generating Unit, Power Park Module or CCGT Module which is directly connected to the National Electricity Transmission System.
HVDC System	An electrical power system which transfers energy in the form of high voltage direct current between two or more alternating current (AC) buses and comprises at least two HVDC Converter Stations with DC Transmission lines or cables between the HVDC Converter Stations.
NETSO	The National Electricity Transmission System Operator is responsible for operating the Onshore Transmission System and, where owned by Offshore Transmission Licensees, Offshore Transmission Systems. The NETSO for Great Britain is currently National Grid Electricity System Operator.

Non-Embedded Customer	A Customer in Great Britain, except for a Network Operator acting in its capacity as such, receiving electricity direct from the Onshore Transmission System irrespective of from whom it is supplied.
Offshore Generating Unit	Unless otherwise provided in the Grid Code, any Apparatus located Offshore which produces electricity, including, an Offshore Synchronous Generating Unit and Offshore Non-Synchronous Generating Unit which could also be part of a Power Generating Module.
Onshore Generating Unit	Unless otherwise provided in the Grid Code, any Apparatus located Onshore which produces electricity, including, an Onshore Synchronous Generating Unit and Onshore Non-Synchronous Generating Unit which could also be part of a Power Generating Module.
Power Generating Module	Either a Synchronous Power-Generating Module or a Power Park Module owned or operated by an EU or GB Generator.
Restoration Service Provider	A Restoration Service Provider is a legal entity with a legal or contractual obligation to provide a service contributing to one or several measures of the Restoration Plan.
Total System	The National Electricity Transmission System and all User Systems in the National Electricity Transmission System Operator Area.
TSO	A Transmission System Operator is a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in each area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity.
Type A Power Generating Module	A Power-Generating Module with a Grid Entry Point or User System Entry Point below 110 kV and a Maximum Capacity of 0.8 kW or greater but less than 1MW.
Type B Power Generating Module	A Power-Generating Module with a Grid Entry Point or User System Entry Point below 110 kV and a Maximum Capacity of 1MW or greater but less than 10MW.
Type C Power Generating Module	A Power-Generating Module with a Grid Entry Point or User System Entry Point below 110 kV and a Maximum Capacity of 10 MW or greater but less than 50 MW.
Type D Power Generating Module	A Power-Generating Module: with a Grid Entry Point or User System Entry Point at, or greater than, 110 kV; or with a Grid Entry Point or User System Entry Point below 110 kV and with Maximum Capacity of 50 MW or greater.

Appendix F: System Protection Scheme Standards

ANNEX to the *NCER*

Automatic low frequency demand disconnection scheme characteristics:

Parameter	Values SA Continental Europe	Values SA Nordic	Values SA Great Britain	Values SA Ireland	Measuring Unit
Demand disconnection starting mandatory level: Frequency	49	48.7 – 48.8	48.8	48.85	Hz
Demand disconnection starting mandatory level: Demand to be disconnected	5	5	5	6	% of the Total Load at national level
Demand disconnection final mandatory level: Frequency	48	48	48	48.5	Hz
Demand disconnection final mandatory level: Cumulative Demand to be disconnected	45	30	50	60	% of the Total Load at national level
Implementation range	±7	±10	±10	±7	% of the Total Load at national level, for a given Frequency
Minimum number of steps to reach the final mandatory level	6	2	4	6	Number of steps
Maximum Demand disconnection for each step	10	15	10	12	% of the Total Load at national level, for a given step

Appendix G: Total Load and Netted Demand Definitions

The ENTSOE System Operations Committee has defined **Total Load** as the sum of all generation on both transmission and distribution systems (active power measured or estimated) and any imports, deducting power used for energy storage (e.g. pumps), house load of power plants and any exports.

Total Load = Σ generation (gross) + imports - exports - energy storage - house load

(noting that energy storage could be a positive or negative value)

If part of the generation is unknown/unavailable (e.g. distributed generation) to the system operator (NETSO or DSO), the value must be estimated.

Netted Demand is defined as the netted value of active power seen from a given point of the system, computed as (load – generation – storage consumption), at a given instant or averaged over any designated interval of time.

Appendix H: Energy Storage Units

There are currently no Significant Grid Users operating Energy Storage Units.

Faraday House, Warwick Technology Park,
Gallows Hill, Warwick, CV346DA

nationalgrideso.com