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.

The NCER defines the term Significant Grid Users (SGU's) and Defence Service Providers. Appendix B and the Glossary and Definitions of this document, define what a Significant Grid User and Defence Service Provider is in GB and which GB parties would be required to satisfy the NCER.

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 B to C, who have code obligations referred to in this plan.

For the avoidance of doubt, the ESO, Transmission Licensees and Distribution Network Operators (including Independent Distribution Network Operators) are not classified as Significant Grid Users (SGU) though they are required to satisfy the requirements of the NCER.

In complying with the requirements of the Grid Code, System Operator Transmission Owner Code (STC) and Distribution Code (as applicable), the ESO, Transmission Licensees, Distribution Network Operators (including Independent Distribution Network Operators) would be considered to satisfy the requirements of NCER,

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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*

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 public consultations.

In addition, and as required under the NCER, the ESO will notify (in writing) Transmission Licensee's, Network Operators and GB Significant Grid User's (GB SGU's) if they are affected by NCER and any measures they need to take as a result of the introduction of the NCER.

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. In summary this would occur when:-

- The reserve capacity in the GB Synchronous Area is reduced by more than 20% for longer than 30 minutes and there is no mechanism to recover the deficit in reserve capacity; or
- A situation when Unacceptable Frequency Conditions as defined under the National Electricity Transmission System Security and Quality of Supply Standard have occurred; or
- At least one secured event as defined in the SQSS leads to a violation of the security limits even with remedial actions.

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

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

2.1.4 The NGESO 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 the 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*).

3.1.5Under the proposals introduced through GC0096 (Storage), Generators in respect of Electricity Storage Modules which are charging, are required to automatically disconnect in accordance with the requirements of OC6 of the Grid Code before the activation of the Low Frequency Demand Disconnection Scheme. Article 15(3) and Article 15(4) of NCER places requirements on energy storage units acting as a load to automatically switch to generation mode during periods of low System Frequencies. This action would need to take place between 49.5Hz (the threshold associated with LFSM-U) and 48.8Hz (the threshold associated with the first stage of LFDD). The ESO does not consider the action of automatic switching from load to generation appropriate until further study work has been completed, due to the risk of any unintended consequences, the variable droop rates and the differences in performance between storage technologies. Under this System Defence Plan, the ESO define the cycle time from import to export to be set to a very low value (e.g. 1µs) so the default option will be for the storage plant to trip under low frequency. The settings will be specified on a case by case basis through the Bilateral Agreement and would be within the range of 49.5Hz – 48.8Hz. This approach would be consistent with that suggested for Storage under the GC0096 proposals, the proposals of the EU Storage Expert Group and the approach adopted for Pumped Storage.

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). Technical requirements for GB are detailed in *Appendix 5* of both the *Grid Code Connection Conditions and the Grid Code European Connection Conditions*.

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 NGESO'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 the *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.

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

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 NGESO. 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 NGESO 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.

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 NGESO.

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 NGESO 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 NGESO in accordance with *Grid Code OC6*.

4.4 Voltage Deviation Management Procedure

In Accordance with NCER Article 19

4.4.1 The NGESO 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 NGESO 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 NGESO 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 NGESO 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 NGESO 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 NGESO operating within derived transmission constraint boundaries. These constraints are dependent on transmission asset outage conditions and are optimised by the NGESO. Operating within transmission constraint limits may require the NGESO to instruct balancing actions of Balancing Service Providers; e.g. Bid Offer Acceptances (BOAs). In addition, the NGESO 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 NGESO and specific National Electricity Transmission System Users. These are agreed in advance so that they can be implemented swiftly on instruction by the NGESO 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 NGESO 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 NGESO 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 NGESO 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 Under the NCER, the NGESO shall be entitled to request assistance for active power from SGUs which do not already provide a balancing service. SGU's and Defence Service Providers in GB are defined in Table B1 of Appendix B.

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 NGESO 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 NGESO 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 NGESO 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 NGESO expects to issue a Demand Control instruction to DSOs and/or Non-Embedded Customers in the next 30-minute window.

4.7.4 The NGESO 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 NGESO 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 NGESO 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 NGESO 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 NGESO 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 NGESO 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 NGESO 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 NGESO 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 NGESO 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 NGESO, 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 NGESO, onshore TSOs and DSOs include but are not limited to Supervisory, Control and Data Acquisition systems (SCADA), protection systems and control telephony.

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

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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

5.3 The NGESO 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 NGESO (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. The general principles of the test plan in accordance with Article 43 shall be included in each of the testing requirements for Articles 44 to 47 and will be produced by NGESO after consulting DSOs and SGUs by 18th December 2019. The test plans for Articles 44 to 47 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 NGESO 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 NGESO 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 NGESO 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 NGESO will notify all DSOs, SGUs and Defence Service Providers of their obligations.

Articles relating to the System Defence plan will be implemented in two phases in GB. The first phase will include all Articles that will apply from 18 December 2019 and a second phase will include all Articles that shall apply from 18 December 2022 as per Article 55 of NCER (ie Article 15(5) to (8), Article 41 and Article 42(1)(2) and (5). The first phase must be implemented in the Grid Code by December 2019 while the code modifications required for the second phase will commence in Autumn 2019.

9 PLAN REVIEW

NCER Article 50 requires the NGESO 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 NGESO 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 SGUs Responsible for Implementing Measures that Result from EU Code Mandatory Requirements

NCER Article 2.1 – Article 2.8 defines which parties are required to satisfy the requirements of the NCER and Article 11.4 defines which of these parties are required to satisfy the requirements of the System Defence Plan. The NCER introduces the definition of a Significant Grid User (SGU) which in addition to TSO's and DSO's (which themselves are not classified as SGU's), are those parties who would be required to satisfy the requirements of the System Defence Plan. The list below is an extract from Article 2 and 11.4(c) and 11.4(d) of the NCER as to which parties are considered as SGU's.

Extract from NCER Articles 2.1 – 2.8

1. "This Regulation shall apply to TSOs, DSOs, SGUs, defence service providers, restoration service providers, balance responsible parties, balancing service providers, nominated electricity market operators ('NEMO') and other entities designated to execute market functions pursuant to Commission Regulation (EU) 2015/1222 and to Commission Regulation (EU) 2016/1719.

2. In particular, this Regulation shall apply to the following SGUs:

(a) existing and new power generating modules classified as type C and D in accordance with the criteria set out in Article 5 of Commission Regulation (EU) 2016/631

(b) existing and new power generating modules classified as type B in accordance with the criteria set out in Article 5 of Regulation (EU) 2016/631, where they are identified as SGUs in accordance with Article 11(4) and Article 23(4);

(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 Regulation (EU) 2017/1485; and

(f) existing and new high voltage direct current ('HVDC') systems and direct current-connected power park modules in accordance with the criteria set out in Article 4(1) of Commission Regulation (EU) 2016/1447.

3. This Regulation shall apply to existing and new type A power generating modules, in accordance with the criteria set out in Article 5 of Regulation (EU) 2016/631, to existing and new type B power generating modules other than those referred to in paragraph 2(b), as well as to existing and new demand facilities, closed distribution systems and third parties providing demand response where they qualify as defence service providers or restoration service providers pursuant to Article 4(4).

4. Type A and type B power generating modules referred to in paragraph 3, demand facilities and closed distribution systems providing demand response may fulfil the requirements of this Regulation either directly or indirectly through a third party, under the terms and conditions set in accordance with Article 4(4).

5. This Regulation shall apply to energy storage units of a SGU, a defence service provider or a restoration service provider, which can be used to balance the system, provided that they are identified as such in the system defence plans, restoration plans or in the relevant service contract.

6. This Regulation shall apply to all transmission systems, distribution systems and interconnections in the Union except transmission systems and

distribution systems or parts of the transmission systems and distribution systems of islands of Member States of which the systems are not operated synchronously with Continental Europe, Great Britain, Nordic, Ireland and Northern Ireland or Baltic synchronous area, provided that this non-synchronous operation does not result from a disturbance.

7. In Member States where more than one transmission system operator exists, this Regulation shall apply to all transmission system operators within that Member State. Where a transmission system operator does not have a function relevant to one or more obligations under this Regulation, Member States may provide that the responsibility for complying with those obligations is assigned to one or more different, specific transmission system operators.

8. The TSOs of Lithuania, Latvia and Estonia are, as long as and to the extent that they are operating in a synchronous mode in a synchronous area where not all countries are bound by Union legislation, exempted from the application of Articles 15, 29 and 33, unless otherwise provided for in a cooperation agreement with third country TSOs constituting the basis for their cooperation concerning secure system operation in accordance with Article 10".

Extract from Articles 11.4(c) and 11,4(d)

"(c) a list of the SGUs responsible for implementing on their installations the measures that result from the mandatory requirements set out in Regulation (EU) 2016/631, (EU) 2016/1388 and (EU) 2016/1447 or from national legislation and a list of the measures to be implemented by those SGUs;

(d) a list of high priority significant grid users and the terms and conditions for their disconnection, and…."

Each of the Regulation references above (for example Commission Regulation or Regulation 2016/631 which in this example is Commission Regulation (EU) 2016/631 of the 14th April 2016 establishing a Network Code on Requirements of Generators) are referenced the Glossary (Appendix E of this document).

Significant Grid User (SGU) is a term introduced under the suite of European Network Codes and until now has not been used in the GB arena. To address this issue, Appendix B of this document translates the above SGU list so it is clear which new and existing GB parties would be considered to be within the scope of the NCER and hence the criteria under which a GB party would be within the scope of the NCER.

For the avoidance of doubt, the GB suite of Industry Codes and documents will be updated, where necessary, so that GB parties complying with the GB Industry Codes and documents will automatically comply with the requirements of the NCER.

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Appendix B: GB Parties within the scope of the System Defence Plan

The NCER defines these requirements in terms of Significant Grid User's (SGUs) and Defence Service Providers which is a new term introduced through the suite of European Network Codes rather than an approach which has previously been used in GB. The purpose of this Appendix is therefore to define which GB parties would fall within the scope of the NCER.

Article 4.2, 4.4 and 11.4(c) and (d) of NCER detail the Regulatory and design measures of the System Defence Plan. An extract from NCER Article 4.2 and 4.4 is listed below. Extracts from NCER Article 11.4(c) and (d) is listed in Appendix A.

Extract from NCER Articles 4.2 and 4.4.

Article 4.2

"2. Each TSO shall submit the following proposals to the relevant regulatory authority in accordance with Article 37 of Directive 2009/72/EC for approval:

(a) the terms and conditions to act as defence service providers on a contractual basis in accordance with paragraph 4;

(b) the terms and conditions to act as restoration service providers on a contractual basis in accordance with paragraph 4;

(c) the list of SGUs responsible for implementing on their installations the measures that result from mandatory requirements set out in Regulations (EU) 2016/631, (EU) 2016/1388 and (EU) 2016/1447 and/or from national legislation and the list of the measures to be implemented by these SGUs, identified by the TSOs under Art. 11(4)(c) and 23(4)(c);

(d) the list of high priority significant grid users referred to in Articles 11(4)(d) and 23(4)(d) or the principles applied to define those and the terms and conditions for disconnecting and re-energising the high priority grid users, unless defined by the national legislation of Member States.

(e) the rules for suspension and restoration of market activities in accordance with Article 36(1);

(f) specific rules for imbalance settlement and settlement of balancing energy in case of suspension of market activities, in accordance with Article 39(1);

(g) the test plan in accordance with Article 43(2)".

Article 4.4

"4. The terms and conditions to act as defence service provider and as restoration service provider shall be established either in the national legal framework or on a contractual basis. If established on a contractual basis, each TSO shall develop by 18 December 2018 a proposal for the relevant terms and conditions, which shall define at least:

(a) the characteristics of the service to be provided;

(b) the possibility of and conditions for aggregation; and

(c) for restoration service providers, the target geographical distribution of power sources with black start and island operation capabilities."

Based on the above criteria, there is some scope for the SGU criteria to be determined in National Legislation, through Contractual terms and conditions. The general approach adopted is fundamentally that any party who is required the satisfy the requirements of the Grid Code and has a CUSC contract with the ESO or is a BM Participant and required to satisfy the requirements of BC1 and BC2 of the Grid Code would generally be considered to be within the Scope of NCER in GB. It is also considered that for the purpose of the System Defence Plan a GB SGU would be considered to be the same as a Defence Service Provider.

Table B1 below details which GB Parties would be within the scope of NCER.

EU Criteria	New or Existing	List of GB Parties considered to be SGUs for purposes of the System Defence Plan (GB SGU's)	Measures of the System Defence Plan	Comments
Existing and new Power Generating modules classified as Type C and D in accordance with the criteria set out in Article 5 of Commission Regulation (EU) 2016/631	New	Any Generator who is an EU Code User who has a CUSC Contract with the ESO and owns or operates a Type C or Type D Power Generating Module	Applicable Grid Code requirements: PC, ECC, ECP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC In satisfying the above Grid Code requirements, Generators with a CUSC Contract who own or operate a Type C or Type D Power Generating Module would meet one or more of the requirements of the System Defence Plan.	BC 3* applies to Large Power Stations and directly connected Power Stations. The requirements for LFSM-O are covered in ECC.6.3.7.1.
	Existing	Any Generator who is a GB Code User who has a CUSC Contract with the ESO	Applicable Grid Code requirements: PC, CC, CP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC Generators with a CUSC Contract would need to comply with the applicable requirements of the Grid Code and in doing so would satisfy one or more measures of the System Defence Plan.	BC 3* applies to Large Power Stations and directly connected Power Stations. The requirements for LFSM-O are covered in ECC.6.3.7.1.

EU Criteria	New or Existing	List of GB Parties considered to be SGUs for purposes of the System Defence Plan (GB SGU's)	Measures of the System Defence Plan	Comments
Existing and new power generating modules classified as Type B in accordance with the criteria set out in Article 5 of Regulation (EU) 2016/631, where they are identified as SGU's in accordance with Article 11(4)	New	Any Generator who is a EU Code User and has a CUSC Contract with the ESO and owns or operates a Type B Power Generating Module	Applicable Grid Code requirements: PC, ECC, ECP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC In satisfying the above Grid Code requirements, Generators with a CUSC Contract who own or operate a Power Station comprising a Type B Power Generating Module would meet one or more of the requirements of the System Defence Plan.	As the Generator has a CUSC contract and obliged to satisfy the requirements of the Grid Code, then such parties would be within the scope of NCER. BC 3* applies to Large Power Stations and directly connected Power Stations.
	Existing	Any Generator who is a GB Code User and who has a CUSC Contract with the ESO	Applicable Grid Code requirements: PC, CC, CP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC In satisfying the above Grid Code requirements, Generators with a CUSC Contract would meet one or more of the requirements of the System Defence Plan.	As the Generator has a CUSC contract and obliged to satisfy the requirements of the Grid Code, then such parties would be within the scope of NCER. BC 3* applies to Large Power Stations and directly connected Power Stations.
Existing and new Transmission-connected demand facilities	New	Any Non-Embedded Customer who is an EU Code User and who has a CUSC	Applicable Grid Code requirements: PC, ECC, ECP, DRSC*, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC	BC 3* and the DRSC* would also apply if the Non-Embedded Customer provided Ancillary Services.

EU Criteria	New or Existing	List of GB Parties considered to be SGUs for purposes of the System Defence Plan (GB SGU's)	Measures of the System Defence Plan	Comments
		Contract with the ESO	In satisfying the above Grid Code requirements, Non-Embedded Customers would meet one or more of the requirements of the System Defence Plan.	
	Existing	Any Non-Embedded Customer who is a GB Code User and has a CUSC Contract with the ESO	Applicable Grid Code requirements: PC, CC, CP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC In satisfying the above Grid Code requirements, Non-Embedded Customers would meet one or more of the requirements of the System Defence Plan.	BC 3 would apply if the Non-Embedded Customer provided Ancillary Services.
Existing and new Transmission Connected Closed Distribution Systems	New	Any Non-Embedded Customer who is an EU Code User and who has a CUSC Contract with the ESO	Applicable Grid Code requirements: PC, ECC, ECP, DRSC*, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC In satisfying the above Grid Code requirements, Non-Embedded Customers would meet one or more of the requirements of the System Defence Plan.	The Closed Distribution System is considered as a Private Network and not registered as a Network Operator or IDNO. The DRSC and BC3 would apply if the Non-Embedded Customer provided Ancillary Services.
	Existing	Any Non-Embedded Customer who is a	Applicable Grid Code requirements: PC, CC, CP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC	The Closed Distribution System is considered as a Private Network and not registered as a Network Operator or IDNO

EU Criteria	New or Existing	List of GB Parties considered to be SGUs for purposes of the System Defence Plan (GB SGU's)	Measures of the System Defence Plan	Comments
		GB Code User and which has a CUSC Contract with the ESO	In satisfying the above Grid Code requirements, Non-Embedded Customers would meet one or more of the requirements of the System Defence Plan.	
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 Regulation 2017/1485	New & Existing	BM Participants	(ECC/CC 6.5 only) DRSC*, BC1, BC2, BC3*	In general, a BM Participant will also be a User and in this case they would be caught by the requirements of NCER. Users can fall into different categories and these are detailed above. A BM Participant who is not defined as a User (such as an Aggregator) will have to satisfy the requirements of BC1 and BC2 and ECC/CC.6.5, and therefore would be considered to meet one or more requirements under the System Defence Plan. A BM Participant who also satisfies the requirements of the DRSC (ie they offer Ancillary Services and caught by the requirements of DCC (ie EU Code User's) may also have to satisfy the requirements of BC3 but this would depend on the type of Ancillary Service offered. In all cases a BM Participant would be treated as having to meet the requirements of NCER.

EU Criteria	New or Existing	List of GB Parties considered to be SGUs for purposes of the System Defence Plan (GB SGU's)	Measures of the System Defence Plan	Comments
Existing and new high voltage direct current (HVDC) Systems and direct current connected Power Park Modules in accordance with the criteria set out in Article 4(1) of commission Regulation (EU) 2016/1447	New	HVDC System Owners and Generators in respect of Transmission DC Converters and/or DC Connected Power Park Modules who are EU Code Users and have a CUSC Contract with the ESO	Applicable Grid Code requirements: PC, ECC, ECP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC In satisfying the above Grid Code requirements, HVDC System Owners and Generators in respect of DC Connected Power Park Modules with a CUSC Contract would meet one or more of the requirements of the System Defence Plan.	BC 3* applies to HVDC System Owners. The requirements for LFSM-O for HVDC Systems and DC Connected Power Park Modules are covered in ECC.6.3.7.1.
	Existing	DC Converter Station Owners and Generators in respect of Transmission DC Converters who are GB Code Users and have a CUSC Contract with the ESO	Applicable Grid Code requirements: PC, CC, CP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC In satisfying the above Grid Code requirements, DC Converter Station Owners with a CUSC Contract would meet one or more of the requirements of the System Defence Plan.	BC 3* applies to DC Converter Station Owners

Existing and new Type A Power Generating Modules in accordance with the criteria set out in Article 5 of Regulation (EU) 2016/631, to existing and new Type B Power Generating Modules other than those referred to in paragraph 2(b), as well as to existing and new demand facilities, closed distribution systems and third parties providing demand response where they qualify as defence service providers pursuant to Article 4(4)	New	Any Generator who is an EU Code User and has a CUSC Contract with the ESO and owns or operates a Type A Power Generating Module. Non-Embedded Customers and BM Participants in respect of Closed Distribution Systems and Aggregators.	Applicable Grid Code requirements: PC, ECC, ECP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC In satisfying the above Grid Code requirements, Generators with a CUSC Contract who own or operate a Power Station comprising a Type A Power Generating Module would meet one or more of the requirements of the System Defence Plan in the same way as a Generator who owns or operates a Type B Power Generating Module	As the Generator has a CUSC contract and obliged to satisfy the requirements of the Grid Code, then such parties would be within the scope of NCER. BC 3* applies to Large Power Stations and directly connected Power Stations. Type A Power Generating Modules are required to satisfy the requirements of ECC.6.3.7.1 (LFSM-O).

EU Criteria	New or Existing	List of GB Parties considered to be SGUs for purposes of the System Defence Plan (GB SGU's)	Measures of the System Defence Plan	Comments
Existing and new Type A Power Generating Modules in accordance with the criteria set out in Article 5 of Regulation (EU) 2016/631, to existing and new Type B Power Generating Modules other than those referred to in paragraph 2(b), as well as to existing and new demand facilities, closed distribution systems and third parties providing demand response where they qualify as defence service providers pursuant to Article 4(4)	Existing	Any Generator Registered as a GB Code User which has a CUSC Contract with the ESO and owns or operates a Generating Unit or Power Park Module and is required to satisfy the requirements of the Grid Code Non-Embedded Customers and BM Participants in respect of Closed Distribution Systems and Aggregators.	Applicable Grid Code requirements: PC, CC, CP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC In satisfying the above Grid Code requirements, Generators with a CUSC Contract would meet one or more of the requirements of the System Defence Plan.	As the Generator has a CUSC contract and obliged to satisfy the requirements of the Grid Code, then such parties would be within the scope of NCER. BC 3* applies to Large Power Stations and directly connected Power Stations.

EU Criteria	New or Existing	List of GB Parties considered to be SGUs for purposes of the System Defence Plan (GB SGU's)	Measures of the System Defence Plan	Comments
Type A and Type B Power Generating Modules referred to in paragraph 3, demand facilities and closed distribution systems providing demand response may fulfil the requirements of this Regulation either directly or indirectly through a third party under the terms and conditions set out in accordance with Article 4(4)	New and Existing	BM Participants	BC1, BC2, (ECC/CC.6.5 applies only)	This is a non-mandatory requirement. If a BM Participant owns or operates a Type A or Type B Power Generating Module, this would fall under the requirements of RfG. They would also need to comply with the requirements of BC1 and BC2 and therefore fall under the scope of NCER. If the party is also a EU Code User, the wider requirements of the Grid Code would apply (ie ECC's, ECP's and OC's would also apply in which case they would also considered to be within the scope of NCER. If an existing BM Participant owns or operates a Small Power Station they would need to meet the requirements of BC, BC2 and CC.6.5. They would be treated as being within the scope of NCER. If an Aggregator registered as a BM Participant has generation and/or demand and required to meet the requirements of the applicable Balancing Codes, this would also fall under the requirements of NCER.

EU Criteria	New or Existing	List of GB Parties considered to be SGUs for purposes of the System Defence Plan (GB SGU's)	Measures of the System Defence Plan	Comments
This Regulation shall apply to energy storage units of a SGU, a defence service provider or restoration service provider which can be used to balance the system, provided that they are identified as such in the system defence plans restoration plans or service contract.	New	Any EU Code Generator which has a CUSC Contract with the ESO and which owns and operates Electricity Storage Modules would be classified as a Storage User as defined under the GC0096 Grid Code proposals	Applicable Grid Code requirements: PC, ECC, ECP, OC1, OC5, OC6 (in particular OC6.6), OC7, OC10, OC12, BC1, BC2, BC3*, DRC Under the GC0096 proposals, Electricity Storage Modules are treated in the same way as Power Generating Modules. Generators who have a CUSC Contract with the ESO who own and/or operate Electricity Storage Modules would therefore be within the scope of NCER.	Under the GC0096 proposals, when a Storage Plant is in an importing mode of operation, and the System Frequency falls automatic tripping is required in accordance with the requirements of OC6.6. Within GB, the capability to switch from import to export during low system frequency conditions is not required. Tripping will be initiated prior to the start of Low Frequency Demand Disconnection which occurs at 48.8Hz. All the other requirements of the Grid Code apply and therefore Storage Units caught under the proposed requirements of GC0096 would be considered to be within the scope of NCER.
	Existing	Any CUSC Party who owns or operates Storage plant	Applicable Grid Code requirements: PC, CC, CP, OC1, OC5, OC6, OC7, OC10, OC12, BC1, BC2, BC3*, DRC	A CUSC Party owning a Storage plant would be required to satisfy the requirements of the Grid Code and hence would be considered to be within the scope of NCER. The technical requirements applicable to the storage plant including the ability to trip during low system frequencies will be as specified in the Bilateral Agreement.

For the purposes of implementing NCER, in GB, a Defence Service Provider is considered to have the same meaning as a GB SGU.

For the avoidance of doubt, the following GB Parties are not considered to be GB SGU's and for the purposes of GB, considered to fall outside the scope of the NCER.

- Any Embedded Generator in respect of a Medium or Small Power Station which does not have a CUSC Contract the ESO.
- Any Generator in respect of a Licence Exempt Embedded Medium Power Station (LEEMPS).
- A Demand Response Provider who does not have a CUSC Contract with the ESO
- Any HVDC System Owner or DC Converter Station Owner or Generator who owns and operates an HVDC System or DC Converter Station or Transmission DC Converter or DC Connected Power Park Module which does not have a CUSC Contract or Interconnector Agreement with the ESO.
- BM parties that are not required to meet the requirements of BC1, BC2 and CC.6.5 or ECC.6.5.

For the avoidance of doubt, the ESO, Transmission Licensees and Distribution Network Operators (including Independent Distribution Network Operators) are not classified as Significant Grid Users (SGU) though they are required to satisfy the requirements of the NCER.

In complying with the requirements of the Grid Code, System Operator Transmission Owner Code (STC) and Distribution Code (as applicable), the ESO, Transmission Licensees, Distribution Network Operators (including Independent Distribution Network Operators) would be considered to satisfy the requirements of NCER.

Appendix C: List of High Priority Significant Grid Users

Within GB, a High Priority Significant Grid User would be classified as one of the following:

- Generating Units, Power Park Modules and Power Generating Modules at a Power Station directly connected to the National Electricity Transmission System with priority given to Synchronous Generation; or
- Generating Units, Power Park Modules and Power Generating Modules at a Power Station with a Registered Capacity of 100MW or more with priority given to Synchronous Generation.

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.
Black Start Service Provider	As defined in the Glossary and Definitions of the Grid Code.
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. In GB, a Defence Service Provider has the same meaning as a GB Significant Grid User (GB SGU)
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.
EU Code User	A User who is any of the following:- (a) A Generator in respect of a Power Generating Module (excluding a DC Connected Power Park Module) or OTSDUA (in respect of an AC Offshore Transmission System) whose Main Plant and Apparatus is connected to the System on or after 27 April 2019 and who concluded Purchase Contracts for its Main Plant and Apparatus on or after 17 May 2018 (b) A Generator in respect of any Type C or Type D Power Generating Module which is the subject of a Substantial Modification which is effective on or after 27 April 2019. (c) A Generator in respect of any DC Connected

		Power Park Module whose Main Plant and Apparatus is connected to the System on or after 8 September 2019 and who had concluded Purchase Contracts for its Main Plant and Apparatus on or after 28 September 2018.
	(d)	A Generator in respect of any DC Connected Power Park Module which is the subject of a Substantial Modification which is effective on or after 8 September 2019.
	(e)	An HVDC System Owner or OTSDUA (in respect of a DC Offshore Transmission System including a Transmission DC Converter) whose Main Plant and Apparatus is connected to the System on or after 8 September 2019 and who had concluded Purchase Contracts for its Main Plant and Apparatus on or after 28 September 2018.
	(f)	An HVDC System Owner or OTSDUA (in respect of a DC Offshore Transmission System including a Transmission DC Converter) whose HVDC System or DC Offshore Transmission System including a Transmission DC Converter) is the subject of a Substantial Modification on or after 8 September 2019.
	(g)	A User which the Authority has determined should be considered as an EU Code User.
	(h)	A Network Operator whose entire distribution System was first connected to the National Electricity Transmission System on or after 18 August 2019 and who had placed Purchase Contracts for its Main Plant and Apparatus in respect of its entire distribution System on or after 7 September 2018. For the avoidance of doubt, a Network Operator will be an EU Code User if its entire distribution System is connected to the National Electricity Transmission System at EU Grid Supply Points only.
	(i)	A Non Embedded Customer whose Main Plant and Apparatus at each EU Grid Supply Point was first connected to the National Electricity Transmission System on or after 18 August 2019 and who had placed Purchase Contracts for its Main Plant and Apparatus at each EU Grid Supply Point on or after 7 September 2018 or is the subject of a Substantial Modification on or after 18 August 2019.
	(j)	A Storage User in respect of an Electricity Storage Module whose Main Plant and Apparatus is connected to the System on or after

	XXXX 2020 and who concluded Purchase Contracts for its Main Plant and Apparatus on or after XXXX 2019. *(Dates to be updated following the Ofgem decision on GC0096 modification)*
EU Generator	A Generator or OTSDUA who is also an EU Code User.
European Regulation (EU) 2016/631	Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a Network Code on Requirements of Generators
European Regulation (EU) 2016/1388	Commission Regulation (EU) 2016/1388 of 17 August 2016 establishing a Network Code on Demand Connection
European Regulation (EU) 2016/1447	Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for Grid Connection of High Voltage Direct Current Systems and Direct Current-connected Power Park Modules
European Regulation (EU) 2017/1485	Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation
European Regulation (EU) 2017/2195	Commission Regulation (EU) 2017/2195 of 17 December 2017 establishing a guideline on electricity balancing
GB Code User	A User in respect of: (a) A Generator or OTSDUA whose Main Plant and Apparatus is connected to the System before 27 April 2019, or who had concluded Purchase Contracts for its Main Plant and Apparatus before 17 May 2018, or whose Plant and Apparatus is not the subject of a Substantial Modification which is effective on or after 27 April 2019; or (b) A DC Converter Station owner whose Main Plant and Apparatus is connected to the System before 8 September 2019, or who had concluded Purchase Contracts for its Main Plant and Apparatus before 28 September 2018, or whose Plant and Apparatus is not the subject of a Substantial Modification which is effective on or after 8 September 2019; or (c) A Non Embedded Customer whose Main Plant and Apparatus was connected to the National Electricity Transmission System at a GB Grid Supply Point before 18 August 2019 or who had placed Purchase Contracts for its Main Plant and Apparatus before 7 September 2018 or that Non Embedded Customer is not the subject of a Substantial Modification which is effective on or after 18 August 2019; or (d) A Network Operator whose entire distribution System was connected to the National Electricity

	Transmission System at one or more GB Grid Supply Points before 18 August 2019 or who had placed Purchase Contracts for its Main Plant and Apparatus in respect of its entire distribution System before 7 September 2018 or its entire distribution System is not the subject of a Substantial Modification which is effective on or after 18 August 2019. For the avoidance of doubt, a Network Operator would still be classed as a GB Code User where its entire distribution System was connected to the National Electricity Transmission System at one or more GB Grid Supply Points, even where that entire distribution System may have one or more EU Grid Supply Points but still comprises of GB Grid Supply Points.
GB Significant Grid User or GB SGU	A GB Significant Grid User is a Party defined in Table B1 of Appendix B of this System Defence Plan.
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.
NGESO	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 NGESO 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 (including a Black Start Service Provider) to provide a service contributing to one or several measures of the Restoration Plan. In GB, a Restoration Service Provider is a GB Significant Grid User (GB SGU) and/or a Black Start Service Provider
Storage User	A Generator who owns or operates one or more Electricity Storage Modules. For the avoidance of doubt: (a) European Regulation (EU) 2016/631, European Regulation 2016/1388 and European Regulation 2016/1485 shall not apply to Storage Users; and the European Connection Conditions (ECC's) shall apply to Storage Users on the basis set out in Paragraph ECC1.1(d).
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.

Unacceptable Frequency Conditions	As defined in the Terms and Definitions of the National Electricity Transmission System Security and Quality of Supply Standard

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 (NGESO 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

Energy Storage Units within the scope of the requirements of NCER are defined in Table B1 of Appendix B.

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