nationalgridESO

EU NCER: System Defence Plan

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Contents

EU NCER: System Defence Plan

1 INTRODUCTION

The *European Network Code on Emergency & Restoration*[1] (***EU 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 EU NCER Article 11, this System Defence Plan will be designed in consultation with Stakeholders in the GB synchronous area. GB Parties who will be required to comply with the requirements of the EU NCER are detailed in Appendix A of this System Defence Plan. They will be notified in writing during the Autumn of 2019 together with the changes which are being introduced through Grid Code modification GC0127 and GC0128. In general, the NCER will apply to the following parties in GB.

- Any Party with a CUSC Contract
- Transmission Licensees
- Distribution Network Operators

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 EU NCER will be satisfied in GB. Many of the provisions contained within this System Defence Plan are already described in the GB national codes (e.g. Grid Code, CUSC, STC, 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 parties identified in Appendix A, who have code obligations referred to in this plan.

In complying with the requirements of the Grid Code, System Operator Transmission Owner Code (STC) and Distribution Code (as applicable), the NGESO, Transmission Licensees, Distribution Network Operators (including Independent Distribution Network Operators) would be considered to satisfy the requirements of EU NCER. It should also be noted that the EU NCER applies both to GB Code Users and EU Code Users.

[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 Users listed in Appendix B;
- the characteristics of the National Electricity Transmission System and Distribution Network Operator's (DNO)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 undertaken in the Summer of 2018 and Summer of 2019.

In addition, and as required under the EU NCER, the NGESO will notify (in writing, during the Autumn of 2019) those parties who would be within the scope of the NCER and any measures they need to take. These parties are defined in Table A1 of Appendix A of this document and would include Transmission Licensees, Distribution Network Operators (including Independent Distribution Network Operators) and CUSC Parties. The additional measures upon CUSC parties will be included through Grid Code modification GC0127 and GC0128 with measures upon Transmission Licensees being developed through updates to the System Operator Transmission Owner Code (STC).

2 PLAN OVERVIEW

This Great Britain System Defence Plan (**SDP**) is drafted to conform to *EU 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 EU 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 EU NCER Article 13:

2.1.1 This System Defence Plan contains procedures and automatic actions available to the NGESO to prevent the occurrence of an Emergency or manage the System when it is in an Emergency state. Under, SOGL Article 18(3), a Transmission System shall be in an Emergency State when operational security analysis requires activation of one of the following measures:

- 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 (NETS SQSS) have occurred; or

- An event which 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 the GB parties within the scope of the EU NCER as defined in Appendix A of this System Defence Plan.

2.1.3 All instructions issued by the NGESO under this System Defence Plan must be executed by each User (as defined in the Grid Code) without undue delay.

2.1.4 The NGESO will coordinate impacted Transmission Licensees and Externally Interconnected System Operators where these procedures have a significant cross border impact.

3 SYSTEM PROTECTION SCHEMES

3.1 Automatic Under Frequency Control Scheme

In Accordance with EU 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*).

3.1.5 Article 15(3) and Article 15(4) of EU 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). Under the EU NCER, the NGESO in coordination with Transmission Licensees, is required to set the time limit and active power setpoint for Energy Storage Units to switch from a mode analogous to demand to a mode analogous to generation. Under EU NCER, where the energy storage unit is not capable of switching within the time limit established by the NGESO (in co-ordination with Transmission Licensees) it shall automatically trip when acting as a load. The NGESO 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 on the Total System, unstable operation, the variable droop rates and the differences in performance between storage technologies. As a consequence, the NGESO suggest that the option of tripping Energy Storage Units is preferred and therefore under this System Defence Plan, the NGESO defines the period of time of an Energy Storage Unit to automatically switch from an importing mode of operation (i.e. demand mode) to an exporting mode of operation (i.e. generating mode) to be set to a very low value (e.g. 1µs) so the default option will be for the storage unit 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 used for Pumped Storage. It is however acknowledged that the proposals for GC0096 have yet to be approved into the Grid Code although the consultation process is well advanced. For the avoidance of doubt, this requirement would only apply to Parties owning Electricity Storage Modules which have a CUSC Contract with NGESO. To ensure all Storage Units do not trip off at the same time the trip settings would need to be graded and it is assumed that this would be best achieved through the Bilateral Agreement as provided for in OC6.6 of the Grid Code.

3.1.6 Limited Frequency Sensitive Mode – Under frequency (LFSM-U) – EU Code Users who own and operate Type C and D Power Generating Modules or HVDC System Owners who own and operate 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 EU NCER Article 15

3.2.1 The Annex of EU NCER defines the minimum requirements for Automatic Low Frequency Demand Disconnection schemes for all Synchronous Areas which is reproduced below. This requires disconnection of at least 50% of Total Load at 48Hz.

ANNEX

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

3.2.2 In GB, the Technical requirements for low frequency relays and disconnection of supplies at low frequency including the overall scheme settings are detailed in Appendix 5 of the Connection Conditions and European Connection Conditions. These settings are the same in both the Connection Conditions and European Connection Conditions and reproduced below in Table CC.A.5.5.1a.

Frequency Hz	% **Demand** disconnection for each Network Operator in Transmission Area		
	NGET	SPT	SHETL
48.8	5		
48.75	5		
48.7	10		
48.6	7.5		10
48.5	7.5	10	
48.4	7.5	10	10
48.2	7.5	10	10
48.0	5	10	10
47.8	5		
Total % **Demand**	60	40	40

Table CC.A.5.5.1a

3.2.3 As can be seen from Table CC.A.5.5.1, 55% of demand in England and Wales will be disconnected at 48Hz with 40% disconnected in Scottish Power's Transmission Area and 40% in Scottish Hydro Electricity's Transmission Area. In GB, the requirements of the NCER will be satisfied on the basis that demand in England and Wales is significantly greater than in Scotland. In England and Wales 55% of demand trips which would equate to approximately 52% of national demand which would satisfy the NCER requirements.

3.3 Automatic Over Frequency Control Scheme

In Accordance with EU 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 EU 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 *NETS 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 NETS 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 In GB, a co-ordinated Low Voltage Demand Disconnection Scheme is not implemented across the GB Synchronous Area. However, in a few specific areas, low voltage demand disconnection schemes have been installed to protect specific geographical 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 EU 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 *NETS 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 electricity 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 Generating Units/Power Generating Modules (including stationary Generating Units and/or Power Generating Modules such as open cycle gas turbines which can be started quickly), 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 at the day ahead stage (i.e. one day before the real operational timeframe) 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

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

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 EU NCER Article 22

4.2.1 If, because of a low frequency event, demand has been disconnected by Automatic Low Frequency Demand Disconnection relays, the NGESO may instruct reduction of transmission-connected demand and/or Distribution Network Operators 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 EU NCER Article 18

4.3.1 Following a demand disconnection event, Distribution Network Operators 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 EU 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 the National Electricity Transmission System Security and Quality of Supply Standard* (*NETS SQSS*) at connection points. This is achieved by maintaining dynamic reactive power reserves, held on generating 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 DNOs or IDNOs.

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 EU 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 the GB Total System Users (including disconnection), as detailed in the *Grid Code BC2.9*. These can also be issued to Distribution Network Operators 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, voltage excursions and/or system instability problems in post-fault timescales, or to protect consumer demand and/or Distribution Network Operator's systems 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 EU NCER Article 21

4.6.1 Agreements are in place with neighbouring Transmission Licensees and Externally Interconnected System Operators (EISOs) 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 or as required under BC.2.9. 6.

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 EU NCER, the NGESO shall be entitled to request assistance for active power from a CUSC Party which does not already provide a balancing service. For the avoidance of doubt this would not extend to an Embedded Power Station unless the owner of that Power Station (i.e. the Generator) had a CUSC Contract with the NGESO.

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 Distribution Network Operators 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 EU 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 DNOs, IDNOs and Non-Embedded Customers connected to the National Electricity Transmission System.

4.8.2 *Manual Demand Reduction* in respect of Distribution Network Operators 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. Distribution Network Operators 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 a 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 Distribution Network Operator 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 Distribution Network Operators accordingly.

4.9.3 Under the *Electricity Supply Emergency Code* customers vital to national infrastructure are entitled to apply to BEIS for Protected status. Distribution Network Operators 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 GB PARTIES

In Accordance with EU NCER Article 11(4)

5.1 Each GB Party which falls within the scope of the EU NCER as listed in Appendix A of this System Defence Plan 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 (EU NCER Articles 41.1 and 42.2).

5.1.1 Critical tools and facilities 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.

5.1.2 Generators who own and operate Type B Power Generating Modules have the possibility to have only a data communication system, instead

[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

of a voice communication system, if agreed upon with the NGESO (EU 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.

6 ASSURANCE & COMPLIANCE TESTING

EU NCER Article 43 states the general principles for compliance testing. Articles 44 to 49 describe the testing requirements and are summarised below.

6.1 The NGESO shall prepare a test plan by 18th December 2019. In addition, the ESO in co-ordination with Transmission Licensees 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. 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 for the equipment owned by GB Parties who are within the scope of the NCER. These changes are being introduced through Grid Code Modification GC0127 and GC0128. For the avoidance of doubt, GB parties who are within the scope of the NCER are detailed in Appendix A of this System Defence Plan.

6.2.1 Each EU Code Generator and GB Code Generator or DC Converter Station Owner or HVDC Converter Station Owner and has a Black Start Contract service shall be required to execute a Black Start capability test at least every 3 years. This requirement is being progressed through Grid Code Modification GC0125.

6.2.2 Each EU Generator which owns or operates a Power Generating Module and capable of 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. This requirement is being progressed through Grid Code Modification GC0127/GC0128.

6.2.3 GB Parties who deliver a demand response service shall execute a demand response test after 2 consecutive unsuccessful responses in real operation, or at least every year. This requirement is being progressed through Grid Code Modification GC0127/GC0128.

6.2.4 GB Parties who deliver low frequency demand disconnection shall execute a regular low frequency demand disconnection test. The frequency of these tests is being progressed through Grid Code Modification GC0127/GC0128.

6.2.5 Distribution Network Operators including Independent Distribution Network Operators in coordination with NGESO and Transmission Licensees shall execute regular testing on the Low Frequency Demand Disconnection relays implemented on their installations. The frequency of these tests are being progressed through Grid Code Modification GC0127/GC0128.

6.2.6 NGESO, Transmission Licensees, Distribution Network Operators and CUSC Parties shall test their communication systems at least every year. These requirements are being progressed through Grid Code Modification GC0127/GC0128.

6.2.7 NGESO, Transmission Licensees, Distribution Network Operators and CUSC Parties shall test the backup power supplies of their communication systems at least every 5 years. These requirements are being progressed through Grid Code Modification GC0127/GC0128.

6.2.8 NGESO and Transmission Licensees shall test the capability of main and backup power sources to supply its main and backup control rooms at least every year.

6.2.9 NGESO and Transmission Licensees shall test the functionality of critical tools and facilities at least every 3 years. Where these tools involve CUSC Parties and Distribution Network Operators, these parties shall participate in the tests.

6.2.10 NGESO and Transmission Licensees 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.

6.2.11 NGESO and Transmission Licensees shall test the transfer procedure for moving from the main control room to the backup control room at least every year.

6.3 Starting from 1st April 2020, the NGESO, Transmission Licensees, Distribution Network Operators and CUSC Parties 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.

6.4 All Distribution Network Operators 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.

7 PLAN IMPLEMENTATION

Article 12 of the *EU NCER*, provides for the implementation of the **System Defence Plan,** and requires that by 18 December 2018 the NGESO will notify all those parties defined in Appendix A of this System Defence Plan 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 which will be implemented via Grid Code Modifications GC0127 and GC0128. The second phase will include all Articles that shall apply from 18 December 2022 as per Article 55 of EU NCER (i.e. Article 15(5) to (8), Article 41 and Article 42(1)(2) and (5). The first phase (Grid Code Modifications GC0127 and GC0128) must be implemented in the Grid Code by 18 December 2019 while the code modifications required for the second phase will commence in Autumn 2019.

8 PLAN REVIEW

EU 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 GB parties 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: GB Parties within the scope of the System Defence Plan

In accordance with EU NCER, Art 2 defines the SGU's who fall within the scope of the European Emergency and Restoration Code. Table A1 defines the EU Criteria and how this translates to GB Parties including which of those parties are included within the scope of the EU Emergency and Restoration Code and those which are not.

Table A1 details which GB Parties would be within the scope of EU 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
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: ECC6.1.2, ECC.6.1.4, ECC.6.2.2.2, ECC.6.3, ECC.6.5, ECC.8, ECC.A.3, ECC.A.4, ECC.A.6, ECC.A.7, ECC.A.8 ECP.A.3, ECP.A.5, ECP.A.6 OC5.4, OC5.5 OC6.1.6, OC6.6.6* (*Note OC6.6.6 applies only to Pumped Storage Generators), OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, 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.
		Any Generator who does not have a CUSC Contract (i.e. Embedded) and owns or operates a Power Station comprising one or more Type C or Type D Power Generating Modules.	Not applicable. Under the current GB Framework, there is currently no requirement for Non-CUSC Parties who own or operate a Type C or Type D Power Generating Module to contribute to the System Defence Plan. This however is subject to review and the ESO expect to work with all Stakeholders in the future to consider the approach to including Non-CUSC Parties within the System Defence Plan.

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
	Existing	Any Generator who is a GB Code User who has a CUSC Contract with the ESO and owns or operates a Power Station comprising one or more Generating Units or Power Park Modules which i) have a maximum output of greater than 10MW but less than 50MW and connected below 110kV (equivalent to a Type C Power Generating Module) or ii) connected at 110kV or above or has a rated power output of 50MW or above (equivalent to a Type D Power Generating Module)	CC6.1.2, CC.6.1.3, CC.6.1.4, CC.6.2.2.2, CC.6.3, CC.6.5, CC.8, CC.A.3, CC.A.4, CC.A.6, CC.A.7 CP.A.3 OC5.4, OC5.5, OC5.A.1, OC.5.A.2, OC5.A.3 OC6.1.6, OC6.6.6* (*Note OC6.6.6 applies only to Pumped Storage Generators), OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, 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.
		Any Generator who does not have a CUSC Contract (ie Embedded) and owns or operates a Power Station comprising one or more Generating Units or Power Park Modules which i) have a maximum output of greater than 10MW but less than 50MW and connected below 110kV (equivalent to a Type C Power Generating Module) or ii) connected at 110kV or above or has a rated power output of 50MW or above (equivalent to a Type D Power Generating Module)	Not applicable. Under the current GB Framework, there is currently no requirement for Non-CUSC Parties who own and operate a Type C or Type D Power Generating Module to contribute to the System Defence Plan. This however is subject to review and the ESO expect to work with all Stakeholders in the future to consider the approach to including Non-CUSC Parties within the System Defence Plan.

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
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: ECC.6.1.2, ECC.6.1.4, ECC.6.2.2.2, ECC.6.3, ECC.6.4.3, ECC.6.5, ECC.8, ECC.A.3, ECC.A.4, ECC.A.6, ECC.A.7, ECC.A.8 ECP.A.3, ECP.A.5, ECP.A.6 OC5.4, OC5.5, OC6.1.6, OC6.6.6* (*Note OC6.6.6 applies only to Pumped Storage Generators), OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, In satisfying the above Grid Code requirements, Generators with a CUSC Contract who own or operate a Type B Power Generating Module would meet one or more of the requirements of the System Defence Plan.
		Any Generator who does not have a CUSC Contract (i.e. Embedded) and owns or operates a Power Station comprising one or more Type B Power Generating Modules	Not applicable. Under the current GB Framework, there is currently no requirement for Non-CUSC Parties who own and operate a Type C or Type D Power Generating Module to contribute to the System Defence Plan. This however is subject to review and the ESO expect to work with all Stakeholders in the future to consider the approach to including Non-CUSC Parties within the System Defence Plan.

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
	Existing	Any Generator who is a GB Code User who has a CUSC Contract with the ESO and owns or operates a Power Station comprising one or more Generating Units or Power Park Modules which has a maximum output of greater than 1MW but less than 10MW and connected below 110kV (equivalent to a Type B Power Generating Module)	Applicable Grid Code requirements: CC6.1.2, CC.6.1.3, CC.6.1.4, CC.6.2.2.2, CC.6.3, CC.6.5, CC.8, CC.A.3, CC.A.4, CC.A.6, CC.A.7 CP.A.3 OC5.4, OC5.5, OC.5.A.1, OC.5.A.2, OC5.A.3 OC6.1.6, OC6.6.6* (*Note OC6.6.6 applies only to Pumped Storage Generators), OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, 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.
		Any Generator who does not have a CUSC Contract (i.e. Embedded) and owns or operates a Power Station comprising one or more Generating Units or Power Park Modules which have a maximum output of greater than 1MW but less than 10MW and connected below 110kV (equivalent to a Type B Power Generating Module).	Not applicable. Under the current GB Framework, there is currently no requirement for Non-CUSC Parties who own and operate a Type B Power Generating Module to contribute to the System Defence Plan. This however is subject to review and the ESO expect to work with all Stakeholders in the future to consider the approach to including Non-CUSC Parties within the System Defence Plan.
Existing and new Transmission-connected demand facilities	New	Any Non-Embedded Customer who is an EU Code User and who has a CUSC Contract with the ESO. The requirement of the DRSC would also apply but only when the Demand Response Provider is also a CUSC Party.	Applicable Grid Code requirements: ECC6.1.2, ECC.6.1.4, ECC.6.2.3, ECC.6.4.3, ECC.6.5, ECC.A.5. DRSC

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
			ECP.A.8 OC1 OC5.4, OC5.5.4 (only in respect of CUSC Parties who are also Demand Response Providers). OC6.3, OC.6.5, OC6.6.6, OC6.8 OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) In satisfying the above Grid Code requirements, Non-Embedded Customers would meet one or more of the requirements of the System Defence Plan. All Transmission Connected Demand Facilities would have to be BM and CUSC Parties and hence satisfy the requirements of the Emergency and Restoration Code. There is no concept of an Embedded Non-Embedded Customer.
	Existing	Any Non-Embedded Customer who is a GB Code User and has a CUSC Contract with the ESO	Applicable Grid Code requirements: CC6.1.2, CC.6.1.3, CC.6.1.4, CC.6.2.3, CC.6.4.3, CC.6.5, CC.A.5. OC1 OC5.4, OC5.5.4 (only in respect of CUSC Parties who are also Demand Response Providers). OC6.3, OC.6.5, OC6.6.6, OC6.8 OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9)

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
			In satisfying the above Grid Code requirements, Non-Embedded Customers would meet one or more of the requirements of the System Defence Plan. All Transmission Connected Demand Facilities would have to be BM and CUSC Parties and hence satisfy the requirements of the Emergency and Restoration Code. There is no concept of an Embedded Non-Embedded Customer.
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: ECC6.1.2, ECC.6.1.4, ECC.6.2.3, ECC.6.4.3, ECC.6.5, ECC.A.5. DRSC ECP.A.8 OC1 OC5.4, OC5.5.4 (only in respect of CUSC Parties who are also Demand Response Providers). OC6.3, OC.6.5, OC6.6.6, OC6.8 OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3 In satisfying the above Grid Code requirements, Non-Embedded Customers (which would include a Closed Distribution System), would meet one or more of the requirements of the System Defence Plan. All Transmission Connected Closed Distribution Systems would have to be BM and CUSC Parties and hence satisfy the requirements of the Emergency and Restoration Code.

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
			There is no concept of a Transmission Connected Non CUSC Party
	Existing	Any Non-Embedded Customer who is a GB Code User and which has a CUSC Contract with the ESO	Applicable Grid Code requirements: CC6.1.2, CC.6.1.3, CC.6.1.4, CC.6.2.3, CC.6.4.3, CC.6.5, CC.A.5. OC1 OC5.4, OC5.5.4 (only in respect of CUSC Parties who are also Demand Response Providers). OC6.3, OC.6.5, OC6.6.6, OC6.8 OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) In satisfying the above Grid Code requirements, Non-Embedded Customers would meet one or more of the requirements of the System Defence Plan. All Transmission Connected Demand Facilities would have to be BM and CUSC Parties(which would include Closed Distribution Systems) and hence satisfy the requirements of the Emergency and Restoration Code. There is no concept of an Embedded Non-Embedded Customer.

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
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 including Virtual Lead Parties.	(ECC/CC 6.5 only) DRSC if they are also providing Demand Response Services and their equipment was purchased on or after 7 September 2019 and connected to the System on or after 18 August 2019. BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7 (As applicable but biased towards Generator who are registered as Gensets).
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: ECC6.1.2, ECC.6.1.4, ECC.6.2.2.2, ECC.6.3, ECC.6.5, ECC.8, ECC.A.3, ECC.A.4, ECC.A.6, ECC.A.7, ECC.A.8 ECP.A.3, ECP.A.7 OC5.4, OC5.5 OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, In satisfying the above Grid Code requirements, HVDC System Owners with a CUSC Contract who own or operate an HVDC System. DC Power Park Modules would need to satisfy the same Grid Code requirements as those applicable

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
			to new Type C and Type D Power Generating Modules listed in the first row of this table.
		Any HVDC System Owner who does not have a CUSC Contract would not be required to satisfy the requirements of the EU Emergency and Restoration Code.	Not applicable. Under the current GB Framework, there is currently no requirement for Non-CUSC Parties who own or operate a DC Converter Station to contribute to the System Defence Plan. An HVDC System does have a specific meaning within the scope of the Grid Code and would therefore be within the scope of EU NCER. This however is subject to review and the ESO expect to work with all Stakeholders in the future to consider the approach to including Non-CUSC Parties within the System Defence Plan.
	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: CC6.1.2, CC.6.1.3, CC.6.1.4, CC.6.2.2.2, CC.6.3, CC.6.5, CC.8, CC.A.3, ECC.A.4, CC.A.6, CC.A.7, CC.A.8 CP.A.3 OC5.4, OC5.5, OC5.A.4 OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, In satisfying the above Grid Code requirements, DC Converter Station Owners with a CUSC Contract who own or operate a DC Converter Station would be required to satisfy the requirements of EU NCER.. DC Power Park Modules

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
			would need to satisfy the same Grid Code requirements as those applicable to Existing Generators listed in the second row of this table.

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
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: ECC6.1.2, ECC.6.1.4, ECC.6.2.2.2, ECC.6.3, ECC.6.5, ECC.8, ECC.A.3, ECC.A.4, ECC.A.6, ECC.A.7, ECC.A.8 DRSC if they are also providing Demand Response Services and their equipment was purchased on or after 7 September 2019 and connected to the System on or after 18 August 2019. ECP.A.3, ECP.A.5, ECP.A.6 OC5.4, OC5.5 OC6.1.6, OC6.6.6* (*Note OC6.6.6 applies only to Pumped Storage Generators), OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, 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. Note that a Generator in respect of a Type A Power Generating Module will have to meet those requirements of the Grid Code as applicable to Type A Power Generating Modules. However, where a Generator in respect of a Small Power Station comprises Type A Power Generating Modules, then the requirements on Small Power Stations are less onerous than those of Large Power Stations but this does not exclude those specific requirements applicable to Type A Power Generating

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
			Modules. The requirements will also vary if the Type A Power Generating Module is Embedded or Directly Connected.

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
		Any Generator who does not have a CUSC Contract (i.e. Embedded) and owns or operates a Power Station comprising one or more Type A Power Generating Modules.	Not applicable. Under the current GB Framework, there is currently no requirement for Non-CUSC Parties who own or operate a Type A Power Generating Module to contribute to the System Defence Plan. This however is subject to review and the ESO expect to work with all Stakeholders in the future to consider the approach to including Non-CUSC Parties within the System Defence Plan.
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	Existing	Any Generator who is a GB Code User who has a CUSC Contract with the ESO and owns or operates a Power Station comprising one or more Generating Units or Power Park Modules which has a maximum output of greater than 400W but less than 1MW and connected below 110kV (equivalent to a Type A Power Generating Module). Non-Embedded Customers and BM Participants in respect of Closed Distribution Systems and Aggregators.	Applicable Grid Code requirements: CC6.1.2, CC.6.1.3, CC.6.1.4, CC.6.2.2.2, CC.6.3, CC.6.5, CC.8, CC.A.3, CC.A.4, CC.A.6, CC.A.7 DRSC if they are also providing Demand Response Services and their equipment was purchased on or after 7 September 2019 and connected to the System on or after 18 August 2019. CP.A.3 OC5.4, OC5.5, OC5.A.1, OC.5.A.2, OC5.A.3. OC6.1.6, OC6.6.6* (*Note OC6.6.6 applies only to Pumped Storage Generators), OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, 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

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
parties providing demand response where they qualify as defence service providers pursuant to Article 4(4)			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. Note that a Generator in respect of a Type A Power Generating Module will have to meet those requirements of the Grid Code as applicable to Type A Power Generating Modules. However, where a Generator in respect of a Small Power Station comprises Type A Power Generating Modules, then the requirements on Small Power Stations are less onerous than those of Large Power Stations but this does not exclude those specific requirements applicable to Type A Power Generating Modules. The requirements will also vary if the Type A Power Generating Module is Embedded or Directly Connected.
		Any Generator who does not have a CUSC Contract (i.e. Embedded) and owns or operates a Power Station comprising one or more Generating Units or Power Park Modules which have a maximum output of greater than 400W but less than 1MW and connected below 110kV (equivalent to a Type A Power Generating Module).	Not applicable. Under the current GB Framework, there is currently no requirement for Non-CUSC Parties who own or operate a Type A Power Generating Module to contribute to the System Defence Plan. This however is subject to review and the ESO expect to work with all Stakeholders in the future to consider the approach to including Non-CUSC Parties within the System Defence Plan.

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
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 including Virtual Lead Parties	ECC.ECC.6.5 BC1, BC2, (ECC/CC.6.5 applies only)
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,	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: ECC6.1.2, ECC.6.1.4, ECC.6.2.2.2, ECC.6.3, ECC.6.5, ECC.8, ECC.A.3, ECC.A.4, ECC.A.6, ECC.A.7 ECP.A.3, ECP.A.5, ECP.A.6 OC5.4, OC5.5 OC6.1.6, OC6.6.6* (*Note OC6.6.6 applies only to Pumped Storage Generators), OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12

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
provided that they are identified as such in the system defence plans restoration plans or service contract.			BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, 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.
	Existing	Any CUSC Party who owns or operates Storage plant	Applicable Grid Code requirements: CC6.1.2, CC.6.1.3, CC.6.1.4, CC.6.2.2.2, CC.6.3, CC.6.5, CC.8, CC.A.3, CC.A.4, CC.A.6, CC.A.7 CP.A.3 OC5.4, OC5.5, OC5.A.1, OC.5.A.2, OC5.A.3. OC6.1.6, OC6.6.6* (*Note OC6.6.6 applies only to Pumped Storage Generators), OC.7.4, OC7.6 (OC7.6 - Scotland and Offshore only) OC10 OC12 BC1.4, BC1.5, BC.1.7, BC1.A.1, BC1.A.2.1 BC2 (in particular BC.2.9) BC3.3, BC3.4, BC3.5, BC.3.6, BC.3.7, In general, the requirements on Storage are the same as those on Generators. However, as Storage is comparatively new, and the requirements on storage are only being introduced through GC0096, Existing Generators caught by the requirements of the Bilateral Connection Agreement would have to satisfy the requirements of the Grid Code as listed above.

CUSC Parties, Application of the Grid Code and the relationship with the Emergency and Restoration Code

The Connection and Use of System Code (CUSC) defines the arrangements for parties connecting to or using the Transmission System including but not limited to, issues such as connection, charging, Mandatory Ancillary Services and Balancing Services.

It is a Mandatory requirement for any party (such as a Generator, HVDC System Owner, Network Operator, Non-Embedded Customer, Aggregator) which: -

Is directly connected to the Transmission System

Owns or operates a Large Power Station (a Large Power Station is defined in the Grid Code)

Owns or operates an HVDC System and whose Connection Point is at 110kV or above

Owns or operates a DC Converter Station and the Installation has a rating of 50MW or more.

Applies for Transmission Entry Capacity

Is a Licensed Supplier

Wishes to participate in the Balancing Mechanism

Owns or operates a Large Power Station and that Large Power Station comprises one or more Electricity Storage Modules

To sign the CUSC and have an Agreement with National Grid ESO. A condition of signing the CUSC will necessitate the need for that Party to also meet the applicable requirements of the Grid Code. In satisfying the requirements of the Grid Code, and through the amendments being introduced through Grid Code modification GC0127 and GC0128, any one of these parties (in satisfying the requirements of the Grid Code) will satisfy the requirements of EU NCER.

For the avoidance of doubt, a non CUSC Party would include one of the following categories, unless that Party has opted to sign the CUSC:

A Generator which owns or operates a Licence Exempt Embedded Medium Power Station (LEEMPS)

A Generator which owns or operates an Embedded Small Power Station

A Demand Response Provider who may have a commercial contract with National Grid ESO to provide Commercial Ancillary Services but has not signed the CUSC.

A HVDC System Owner who owns and operates an HVDC System and that HVDC System in Embedded and has a Connection Point below 110kV and has not signed the CUSC.

An DC Converter Station Owner who owns and operates a DC Converter Station and that DC Converter Station is not connected to the Transmission System and has a rating of less than 50MW and has not signed the CUSC.

A Generator which owns or operates an Electricity Storage Module and that Electricity Storage Module is part of an Embedded Medium Power

Station or Embedded Small Power Station and that Generator has not signed the CUSC.

ESO Interpretation

The ESO considers for the implementation of the EU NCER, only CUSC Parties need to be within the scope of the EU NCER. We believe that this is an appropriate position based on the Legal Advice received (one option would be to include the legal letter as an additional appendix in the System Defence Plan).

Appendix B: High Priority Users

Within GB, a High Priority Significant Grid User would be classified as:

A Large Power Station connected directly to the National Electricity Transmission System: or

An Embedded Large Power Station

For the purposes of this Appendix, Embedded and Large Power Station have the same definition as that defined in the Grid Code

Appendix C: List of Distribution Network Operators and Independent Distribution Network Operators

A list of Distribution Network Operators and Independent Distribution Network Operators (IDNOs) are available from Ofgem's website which is available from the following link.

https://www.ofgem.gov.uk/system/files/docs/2019/08/electricity_registered_or_service_addresses_new.pdf

Appendix D: 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.
BEIS	Her Majesty's Government Department for Business, Energy and Industrial Strategy.
Black Start Service Provider	A User with a legal or contractual obligation to provide a service contributing to one or several measures of the System Restoration Plan.
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.
CUSC Contract	As defined in the Grid Code is "One or more of the following agreements as envisaged in Standard Condition C1 of The Company's Transmission Licence: (a) the CUSC Framework Agreement; (b) a Bilateral Agreement; (c) a Construction Agreement or a variation to an existing Bilateral Agreement and/or Construction Agreement;
Distribution Network Operator	A person with a User System directly connected to the National Electricity Transmission System to which Customers and/or Power Stations (not forming part of the User System) are connected, acting in its capacity as an operator of the User System, but shall not include a person acting in the capacity of an Externally Interconnected System Operator or a Generator in respect of OTSUA. For the avoidance of doubt an Independent Network Operator (IDNO) is considered to have the same meaning and obligations as a Distribution Network Operator.
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 are a consequence of GC096 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 2019.2018; 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 Generator	As defined in the Grid Code is “A Generator, or OTSDUA, who is also a GB Code User”
GB Synchronous Area	As defined in the Grid Code is “The AC power System in Great Britain which connects User’s, Relevant Transmission Licensee’s whose AC Plant and Apparatus is considered to operate in synchronism with each other at each Connection Point or User System Entry Point and at the same System Frequency”.
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.
National Electricity Transmission System Security and Quality of Supply	The National Electricity Transmission System Security and Quality of Supply Standard as published on The National Grid ESO Website: https://www.nationalgrideso.com/codes/security-and-quality-supply-standards?code-documents

Standards or NETS SQSS	
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.
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 (b) the European Connection Conditions (ECCs) shall apply to Storage Users on the basis set out in Paragraph ECC1.1(d).
System Operator Transmission Owner Code or STC	The System Operator Transmission Owner Code as published on The National Grid ESO Website: https://www.nationalgrideso.com/codes/system-operator-transmission-owner-code?code-documents
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	These are conditions defined in the NETS SQSS where: i) the steady state frequency falls outside the statutory limits of 49.5Hz to 50.5Hz; or ii) ii) a transient frequency deviation on the MITS persists outside the above statutory limits and does not recover to within 49.5Hz to 50.5Hz within 60 seconds. Transient frequency deviations outside the limits of 49.5Hz and 50.5Hz shall only occur at intervals which ought to reasonably be considered as infrequent. In order to avoid the occurrence of Unacceptable Frequency Conditions: a) The minimum level of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid frequency deviations below 49.5Hz or above 50.5Hz will be the actual loss of power infeed risk present at connections planned in accordance with the normal infeed loss risk criteria; b) The minimum level of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid frequency deviations below 49.5Hz or above 50.5Hz for more than 60 seconds will be the actual loss of power infeed risk present at connections planned in accordance with the infrequent infeed loss risk criteria. It is not possible to be prescriptive with regard to the type of secured event which could lead to transient deviations since this will depend on the extant frequency response characteristics of the system which NGESO adjust from time to time to meet the security and quality requirements of this Standard.

Appendix E: System Protection Scheme Standards

ANNEX to the *EU 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 F: 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 DNOs or IDNOs), 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 G: Energy Storage Units

Energy Storage Units within the scope of the requirements of EU NCER are defined in Table A1 of Appendix A.

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

nationalgridNGESO.com