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Dear Sir/Madam

THE SERVICED GRID CODE – ISSUE 5 REVISION 40

Issue 5 Revision 40 of the Grid Code has been approved by the Grid Code Review Panel for implementation on **05 March 2020.**

In order to ensure your copy of the Grid Code remains up to date, you will need to replace the sections affected with the revised versions available on the National Grid Electricity System Operator website.

The revisions document provides an overview of the changes made to the Grid Code since the previous issue.

Yours faithfully

Rachel Beaufoy

Frameworks Officer

Code Administrator

Future Markets

nationalgridESO

THE GRID CODE – ISSUE 5 REVISION 40

INCLUSION OF REVISED SECTIONS

- Glossary and Definitions
- Operating Code 5
- Balancing Code 1
- Balancing Code 2
- Data Registration Code

SUMMARY OF CHANGES

The changes arise from the implementation of modifications proposed in the following Consultation Paper:

- **GC0135 - Removal of Redundant Provisions**

Summary of GC0135 and Impact:

Balancing and Settlement Code (BSC) Modification P394 (which has been approved and was implemented on 27 February 2020) removes references to Quiescent Physical Notifications (inclusive of its abbreviated form “QPNs”) and Joint BM Units from the BSC.

As a consequence, the use of these terms within the Grid Code will be rendered redundant and should be removed for clarity.

Low Impact: All Parties

THE GRID CODE

ISSUE 5

REVISION 40

05 March 2020

THE GRID CODE

CONTENTS

*does not constitute part of the Grid Code

GLOSSARY & DEFINITIONS
(GD)

GD.1 In the Grid Code the following words and expressions shall, unless the subject matter or context otherwise requires or is inconsistent therewith, bear the following meanings:

Access Group	A group of **Connection Points** within which a **User** declares under the **Planning Code** (a) An interconnection and/or (b) A need to redistribute **Demand** between those **Connection Points** either pre-fault or post-fault Where a single **Connection Point** does not form part of an **Access Group** in accordance with the above, that single **Connection Point** shall be considered to be an **Access Group** in its own right.
Access Period	A period of time in respect of which each **Transmission Interface Circuit** is to be assessed as whether or not it is capable of being maintained as derived in accordance with PC.A.4.1.4. The period shall commence and end on specified calendar weeks.
Act	The Electricity Act 1989 (as amended by the Utilities Act 2000 and the Energy Act 2004).
Active Energy	The electrical energy produced, flowing or supplied by an electric circuit during a time interval, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, ie: 1000 Wh = 1 kWh 1000 kWh = 1 MWh 1000 MWh = 1 GWh 1000 GWh = 1 TWh
Active Power	The product of voltage and the in-phase component of alternating current measured in units of watts and standard multiples thereof, ie: 1000 Watts = 1 kW 1000 kW = 1 MW 1000 MW = 1 GW 1000 GW = 1 TW

Additional BM Unit	Has the meaning as set out in the **BSC**
Affiliate	In relation to any person, any holding company or subsidiary of such person or any subsidiary of a holding company of such person, in each case within the meaning of Section 736, 736A and 736B of the Companies Act 1985 as substituted by section 144 of the Companies Act 1989 and, if that latter section is not in force at the **Transfer Date**, as if such section were in force at such date.
AF Rules	Has the meaning given to "allocation framework" in section 13(2) of the Energy Act 2013.
Agency	As defined in **The Company's Transmission Licence.**
Aggregator	A **BM Participant** who controls one or more **Additional BM Units** or **Secondary BM Units**.
Aggregator Impact Matrix	Defined for an **Additional BM Unit** or a **Secondary BM Unit**. Provides data allowing **The Company** to model the result of a Bid-Offer Acceptance on each of the **Grid Supply Points** within the **GSP Group** over which the **Additional BM Unit** or **Secondary BM Unit** is defined
Alternate Member	Shall mean an alternate member for the **Panel Members** elected or appointed in accordance with this GR.7.2(a) or (b).
Ancillary Service	A **System Ancillary Service** and/or a **Commercial Ancillary Service**, as the case may be. An **Ancillary Service** may include one or more **Demand Response Services**.
Ancillary Services Agreement	An agreement between a **User** and **The Company** for the payment by **The Company** to that **User** in respect of the provision by such **User** of **Ancillary Services**.
Annual Average Cold Spell Conditions or **ACS Conditions**	A particular combination of weather elements which gives rise to a level of peak **Demand** within a **Financial Year** which has a 50% chance of being exceeded as a result of weather variation alone.
Apparent Power	The product of voltage and of alternating current measured in units of voltamperes and standard multiples thereof, ie: 1000 VA = 1 kVA 1000 kVA = 1 MVA
Apparatus	Other than in **OC8**, means all equipment in which electrical conductors are used, supported or of which they may form a part. In **OC8** it means **High Voltage** electrical circuits forming part of a **System** on which **Safety Precautions** may be applied to allow work and/or testing to be carried out on a **System**.
Approved Fast Track Proposal	Has the meaning given in GR.26.7, provided that no objection is received pursuant to GR.26.12.
Approved Grid Code Self-Governance Proposal	Has the meaning given in GR.24.10.
Approved Modification	Has the meaning given in GR.22.7

Authorised Certifier	An entity that issues **Equipment Certificates** and **Power Generating Module Documents** and whose accreditation is given by the national affiliate of the European cooperation for Accreditation ('EA'), established in accordance with Regulation (EC) No 765/2008 of the European Parliament and of the Council (1).
Authorised Electricity Operator	Any person (other than **The Company**) who is authorised under the **Act** to generate, participate in the transmission of, distribute or supply electricity which shall include any **Interconnector Owner** or **Interconnector User**
Authority-Led Modification	A **Grid Code Modification Proposal** in respect of a **Significant Code Review**, raised by the Authority pursuant to GR.17
Authority-Led Modification Report	Has the meaning given in GR.17.4.
Automatic Voltage Regulator or **AVR**	The continuously acting automatic equipment controlling the terminal voltage of a **Synchronous Generating Unit** or **Synchronous Power Generating Module** by comparing the actual terminal voltage with a reference value and controlling by appropriate means the output of an **Exciter**, depending on the deviations.
Authority for Access	An authority which grants the holder the right to unaccompanied access to sites containing exposed **HV** conductors.
Authority, The	The **Authority** established by section 1 (1) of the Utilities Act 2000.
Auxiliaries	Any item of **Plant** and/or **Apparatus** not directly a part of the boiler plant or **Power Generating Module** or **Generating Unit** or **DC Converter** or **HVDC Equipment** or **Power Park Module**, but required for the boiler plant's or **Power Generating Module's** or **Generating Unit's** or **DC Converter's** or **HVDC Equipment's** or **Power Park Module's** functional operation.
Auxiliary Diesel Engine	A diesel engine driving a **Power Generating Module** or **Generating Unit** which can supply a **Unit Board** or **Station Board**, which can start without an electrical power supply from outside the **Power Station** within which it is situated.
Auxiliary Gas Turbine	A **Gas Turbine Unit**, which can supply a **Unit Board** or **Station Board**, which can start without an electrical power supply from outside the **Power Station** within which it is situated.
Average Conditions	That combination of weather elements within a period of time which is the average of the observed values of those weather elements during equivalent periods over many years (sometimes referred to as normal weather).
Back-Up Protection	A **Protection** system which will operate when a system fault is not cleared by other **Protection**.
Balancing and Settlement Code or **BSC**	The code of that title as from time to time amended.

Balancing Code or **BC**	That portion of the Grid Code which specifies the **Balancing Mechanism** process.
Balancing Mechanism	Has the meaning set out in **The Company's Transmission Licence**
Balancing Mechanism Reporting Agent or **BMRA**	Has the meaning set out in the **BSC**.
Balancing Mechanism Reporting Service or **BMRS**	Has the meaning set out in the **BSC**.
Balancing Principles Statement	A statement prepared by **The Company** in accordance with Condition C16 of **The Company's Transmission Licence**.
Baseline Forecast	Has the meaning given to the term 'baseline forecase' in Section G of the **BSC**.
Bid-Offer Acceptance	(a) A communication issued by **The Company** in accordance with BC2.7; or (b) an **Emergency Instruction** to the extent provided for in BC2.9.2.3.
Bid-Offer Data	Has the meaning set out in the **BSC**.
Bilateral Agreement	Has the meaning set out in the **CUSC**
Black Start	The procedure necessary for a recovery from a **Total Shutdown** or **Partial Shutdown**.
Black Start Capability	In case of a **Black Start Station**, is the ability for at least one of its **Gensets** to **Start-Up** from **Shutdown** and to energise a part of the **System** and be **Synchronised** to the **System** upon instruction from **The Company**, within two hours, without an external electrical power supply. In the case of a **Black Start HVDC System** is the ability of an **HVDC System** to **Start-Up** from **Shutdown** and to energise a part of the **System** and be **Synchronised** to the **System** upon instruction from **The Company** within two hours, without an external electrical power supply from the **GB Synchronous Area.**
Black Start Contract	An agreement between a **Black Start Service Provider** and **The Company** under which the **Black Start Service Provider** provides **Black Start Capability** and other associated services.
Black Start HVDC System	An **HVDC System** or **DC Converter Station** which are registered, pursuant to the **Bilateral Agreement** with a **User**, as having a **Black Start Capability**.
Black Start HVDC Test	A **Black Start Test** carried out by an **HVDC System Owner** or **DC Converter Station Owner** with a **Black Start HVDC System** while the **Black Start HVDC System** is disconnected from all external electrical power supplies from the **GB Synchronous Area**.
Black Start Service Provider	A **Generator** with a **Black Start Station** or an **HVDC System Owner** or **DC Converter Station Owner** with a **Black Start HVDC System**.

Black Start Stations	**Power Stations** which are registered, pursuant to the **Bilateral Agreement** with a **User**, as having a **Black Start Capability**.
Black Start Station Test	**A Black Start Test** carried out by a **Generator** with a **Black Start Station** while the **Black Start Station** is disconnected from all external electrical power supplies from the **GB Synchronos Area**
Black Start Test	A **Black Start Test** carried out by a **Generator** with a **Black Start Service Provider** on the instructions of **The Company**, in order to demonstrate that a **Black Start Station** or a **Black Start HVDC System** has a **Black Start Capability**. For the avoidance of doubt, a **Black Start Test** could compromise a **Black Start Station Test,** a **Black Start Unit Test** or **Black Start HVDC Test.**
Block Load Capability	The incremental **Active Power** steps, from no load to **Rated MW**, which a **Genset** or **HVDC System** or **DC Converter Station** can instantaneously supply without causing it to trip or go outside the **Frequency** range of 47.5 – 52Hz (or an otherwise agreed **Frequency** range). The time between each incremental step shall also be provided.
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**.
BM Unit	Has the meaning set out in the **BSC**, except that for the purposes of the Grid Code the reference to "Party" in the **BSC** shall be a reference to **User**.
BM Unit Data	The collection of parameters associated with each **BM Unit**, as described in Appendix 1 of **BC1**.
Boiler Time Constant	Determined at **Registered Capacity** or **Maximum Capacity** (as applicable), the boiler time constant will be construed in accordance with the principles of the IEEE Committee Report "Dynamic Models for Steam and Hydro Turbines in Power System Studies" published in 1973 which apply to such phrase.
British Standards or **BS**	Those standards and specifications approved by the British Standards Institution.
BSCCo	Has the meaning set out in the **BSC**.
BSC Panel	Has meaning set out for "Panel" in the **BSC**.
Black Start Unit Test	A **Black Start Test** carried out on a **Generating Unit** or a **CCGT Unit** or a **Power Generating Module**, as the case may be, at a **Black Start Station** while the **Black Start Station** remains connected to an external alternating current electrical supply.
Business Day	Any week day (other than a Saturday) on which banks are open for domestic business in the City of London.
Cancellation of National Electricity Transmission System Warning	The notification given to **Users** when a **National Electricity Transmission System Warning** is cancelled.

Capacity Market Documents	The **Capacity Market Rules**, The Electricity Capacity Regulations 2014 and any other Regulations made under Chapter 3 of Part 2 of the Energy Act 2013 which are in force from time to time.
Capacity Market Rules	The rules made under section 34 of the Energy Act 2013 as modified from time to time in accordance with that section and The Electricity Capacity Regulations 2014.
Cascade Hydro Scheme	Two or more hydro-electric **Generating Units**, owned or controlled by the same **Generator**, which are located in the same water catchment area and are at different ordnance datums and which depend upon a common source of water for their operation, known as: (a) Moriston (b) Killin I Garry (d) Conon (e) Clunie (f) Beauly which will comprise more than one **Power Station**.
Cascade Hydro Scheme Matrix	The matrix described in Appendix 1 to **BC1** under the heading **Cascade Hydro Scheme Matrix**.
Caution Notice	A notice conveying a warning against interference.
Category 1 Intertripping Scheme	A **System to Generator Operational Intertripping Scheme** arising from a Variation to Connection Design following a request from the relevant **User** which is consistent with the criteria specified in the **Security and Quality of Supply Standard**.
Category 2 Intertripping Scheme	A System to Generator Operational Intertripping Scheme which is:- (i) required to alleviate an overload on a circuit which connects the **Group** containing the **User's** Connection Site to the **National Electricity Transmission System**; and (ii) installed in accordance with the requirements of the planning criteria of the **Security and Quality of Supply Standard** in order that measures can be taken to permit maintenance access for each transmission circuit and for such measures to be economically justified, and the operation of which results in a reduction in **Active Power** on the overloaded circuits which connect the **User's Connection Site** to the rest of the **National Electricity Transmission System** which is equal to the reduction in **Active Power** from the **Connection Site** (once any system losses or third party system effects are discounted).
Category 3 Intertripping Scheme	A **System to Generator Operational Intertripping Scheme** which, where agreed by **The Company** and the **User**, is installed to alleviate an overload on, and as an alternative to, the reinforcement of a third party system, such as the **Distribution System** of a **Public Distribution System Operator**.

Category 4 Intertripping Scheme	A **System to Generator Operational Intertripping Scheme** installed to enable the disconnection of the **Connection Site** from the **National Electricity Transmission System** in a controlled and efficient manner in order to facilitate the timely restoration of the **National Electricity Transmission System**.
CENELEC	European Committee for Electrotechnical Standardisation.
Citizens Advice	Means the National Association of Citizens Advice Bureaux.
Citizens Advice Scotland	Means the Scottish Association of Citizens Advice Bureaux.
CfD Counterparty	A person designated as a “CfD counterparty” under section 7(1) of the Energy Act 2013.
CfD Documents	The **AF Rules**, The Contracts for Difference (Allocation) Regulations 2014, The Contracts for Difference (Definition of Eligible Generator) Regulations 2014 and The Contracts for Difference (Electricity Supplier Obligations) Regulations 2014 and any other regulations made under Chapter 2 of Part 2 of the Energy Act 2013 which are in force from time to time.
CfD Settlement Services Provider	means any person: (i) appointed for the time being and from time to time by a **CfD Counterparty**; or (ii) who is designated by virtue of Section C1.2.1B of the Balancing and Settlement Code, in either case to carry out any of the CFD settlement activities (or any successor entity performing CFD settlement activities).
CCGT Module Matrix	The matrix described in Appendix 1 to BC1 under the heading **CCGT Module Matrix**.
CCGT Module Planning Matrix	A matrix in the form set out in Appendix 3 of OC2 showing the combination of **CCGT Units** within a **CCGT Module** which would be running in relation to any given MW output.
Closed Distribution System or **CDSO**	A distribution system classified pursuant to Article 28 of Directive 2009/72/EC as a **Closed Distribution System** by the **Authority** which distributes electricity within a geographically confined industrial, commercial or shared services site and does not supply household **Customers**, without prejudice to incidental use by a small number of households located within the area served by the **System** and with employment or similar associations with the owner of the **System**.
CM Administrative Parties	The **Secretary of State**, the **CM Settlement Body**, and any **CM Settlement Services Provider**.
CM Settlement Body	the Electricity Settlements Company Ltd or such other person as may from time to time be appointed as Settlement Body under regulation 80 of the Electricity Capacity Regulations 2014.

CM Settlement Services Provider	any person with whom the **CM Settlement Body** has entered into a contract to provide services to it in relation to the performance of its functions under the **Capacity Market Documents**.
Code Administration Code of Practice	Means the code of practice approved by the **Authority** and: (a) developed and maintained by the code administrators in existence from time to time; and (b) amended subject to the **Authority's** approval from time to time; and (c) re-published from time to time;
Code Administrator	Means **The Company** carrying out the role of **Code Administrator** in accordance with the General Conditions.
Combined Cycle Gas Turbine Module or **CCGT Module**	A collection of **Generating Units** (registered as a **CCGT Module** (which could be within a **Power Generating Module**) under the PC) comprising one or more **Gas Turbine Units** (or other gas based engine units) and one or more **Steam Units** where, in normal operation, the waste heat from the **Gas Turbines** is passed to the water/steam system of the associated **Steam Unit** or **Steam Units** and where the component units within the **CCGT Module** are directly connected by steam or hot gas lines which enable those units to contribute to the efficiency of the combined cycle operation of the **CCGT Module.**
Combined Cycle Gas Turbine Unit or **CCGT Unit**	A **Generating Unit** within a **CCGT Module**.
Commercial Ancillary Services	**Ancillary Services**, other than **System Ancillary Services**, utilised by **The Company** in operating the **Total System** if a **User** (or other person such as a **Demand Response Provider**) has agreed to provide them under an **Ancillary Services Agreement** or under a **Bilateral Agreement** with payment being dealt with under an **Ancillary Services Agreement** or in the case of **Externally Interconnected System Operators** or **Interconnector Users**, under any other agreement (and in the case of **Externally Interconnected System Operators** and **Interconnector Users** includes ancillary services equivalent to or similar to **System Ancillary Services**).
Commercial Boundary	Has the meaning set out in the **CUSC**
Committed Level	The expected **Active Power** output from a **BM Unit** after accepting a **Bid-Offer Acceptance** or **RR Instruction** or a combination of **Bid-Offer Acceptances** and **RR Instructions**
Committed Project Planning Data	Data relating to a **User Development** once the offer for a **CUSC Contract** is accepted.
Common Collection Busbar	A busbar within a **Power Park Module** to which the higher voltage side of two or more **Power Park Unit** generator transformers are connected.

Completion Date	Has the meaning set out in the **Bilateral Agreement** with each **User** to that term or in the absence of that term to such other term reflecting the date when a **User** is expected to connect to or start using the **National Electricity Transmission System**. In the case of an **Embedded Medium Power Station** or **Embedded DC Converter Station** or **Embedded HVDC System** having a similar meaning in relation to the **Network Operator's System** as set out in the **Embedded Development Agreement**.
Complex	A **Connection Site** together with the associated **Power Station** and/or **Network Operator** substation and/or associated **Plant** and/or **Apparatus**, as appropriate.
Compliance Processes or **CP**	That portion of the Grid Code which is identified as the **Compliance Processes**.
Compliance Statement	A statement completed by the relevant **User** confirming compliance with each of the relevant Grid Code provisions, and the supporting evidence in respect of such compliance, of its: **Generating Unit(s)**; or, **Power Generating Modules** (including **DC Connected Power Park Modules**); or, **CCGT Module(s)**; or, **Power Park Module(s)**; or, **DC Converter(s);** or **HVDC Systems; or** **Plant** and **Apparatus** at an **EU Grid Supply Point** owned or operated by a **Network Operator**; or **Network Operator's** entire distribution **System** where such **Network Operator's** distribution **System** comprises solely of **Plant** and **Apparatus** procured on or after 7 September 2018 and was connected to the **National Electricity Transmission System** on or after 18 August 2019. In this case, all connections to the **National Electricity Transmission System** would comprise only of **EU Grid Supply Points**; or **Plant** and **Apparatus** at an **EU Grid Supply Point** owned or operated by a **Non-Embedded Customer** where such **Non-Embedded Customer** is defined as an **EU Code User**; in the form provided by **The Company** to the relevant **User** or another format as agreed between the **User** and **The Company**.
Configuration 1 AC Connected Offshore Power Park Module	One or more **Offshore Power Park Modules** that are connected to an AC **Offshore Transmission System** and that AC **Offshore Transmission System** is connected to only one **Onshore** substation and which has one or more **Interface Points**.
Configuration 2 AC Connected Offshore Power Park Module	One or more **Offshore Power Park Modules** that are connected to a meshed AC **Offshore Transmission System** and that **AC Offshore Transmission System** is connected to two or more **Onshore** substations at its **Transmission Interface Points**.

Configuration 1 DC Connected Power Park Module	One or more **DC Connected Power Park Modules** that are connected to an **HVDC System** or **Transmission DC Converter** and that **HVDC System** or **Transmission DC Converter** is connected to only one **Onshore** substation and which has one or more **Interface Points**.
Configuration 2 DC Connected Power Park Module	One or more **DC Connected Power Park Modules** that are connected to an **HVDC System** or **Transmission DC Converter** and that **HVDC System** or **Transmission DC Converter** is connected to only more than one **Onshore** substation at its **Transmission Interface Points**.
Connection Conditions or **CC**	That portion of the Grid Code which is identified as the **Connection Conditions** being applicable to **GB Code** ~~**Existing**~~ **Users**.
Connection Entry Capacity	Has the meaning set out in the **CUSC**
Connected Planning Data	Data which replaces data containing estimated values assumed for planning purposes by validated actual values and updated estimates for the future and by updated forecasts for **Forecast Data** items such as **Demand**.
Connection Point	A **Grid Supply Point** or **Grid Entry Point**, as the case may be.
Connection Site	A **Transmission Site** or **User Site**, as the case may be.
Construction Agreement	Has the meaning set out in the **CUSC**
Consumer Representative	Means the person appointed by the **Citizens Advice** or the **Citizens Advice Scotland** (or any successor body) representing all categories of customers, appointed in accordance with GR.4.2(b)
Contingency Reserve	The margin of generation over forecast **Demand** which is required in the period from 24 hours ahead down to real time to cover against uncertainties in **Large Power Station** availability and against both weather forecast and **Demand** forecast errors.
Control Calls	A telephone call whose destination and/or origin is a key on the control desk telephone keyboard at a **Transmission Control Centre** and which, for the purpose of **Control Telephony**, has the right to exercise priority over (ie. disconnect) a call of a lower status.
Control Centre	A location used for the purpose of control and operation of the **National Electricity Transmission System** or **DC Converter Station** owner's **System** or **HVDC System Owner's System** or a **User System** other than a **Generator's System** or an **External System**.
Control Engineer	A person nominated by the relevant party for the control of its **Plant** and **Apparatus**.
Control Person	The term used as an alternative to "**Safety Co-ordinator**" on the **Site Responsibility Schedule** only.

Control Phase	The **Control Phase** follows on from the **Programming Phase** and covers the period down to real time.
Control Point	The point from which:- (a) A **Non-Embedded Customer's Plant** and **Apparatus** is controlled; or (b) A **BM Unit** at a **Large Power Station** or at a **Medium Power Station** or representing a **Cascade Hydro Scheme** or with a **Demand Capacity** with a magnitude of: (i) 50MW or more in **NGET's Transmission Area**; or (ii) 30MW or more in **SPT's Transmission Area**; or (iii) 10MW or more in **SHETL's Transmission Area**, (iv) 10MW or more which is connected to an **Offshore Transmission System** is physically controlled by a **BM Participant**; or (c) In the case of any other **BM Unit** or **Generating Unit** (which could be part of a **Power Generating Module**), data submission is co-ordinated for a **BM Participant** and instructions are received from **The Company**, as the case may be. For a **Generator** this will normally be at a **Power Station** but may be at an alternative location agreed with **The Company**. In the case of a **DC Converter Station** or **HVDC System**, the **Control Point** will be at a location agreed with **The Company**. In the case of a **BM Unit** of an **Interconnector User**, the **Control Point** will be the **Control Centre** of the relevant **Externally Interconnected System Operator**.
Control Telephony	The principal method by which a **User's Responsible Engineer/Operator** and **The Company's Control Engineer(s)** speak to one another for the purposes of control of the **Total System** in both normal and emergency operating conditions.
Core Industry Document	as defined in the **Transmission Licence**
Core Industry Document Owner	In relation to a **Core Industry Document**, the body(ies) or entity(ies) responsible for the management and operation of procedures for making changes to such document

CUSC	Has the meaning set out in **The Company's Transmission Licence**
CUSC Contract	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**;
CUSC Framework Agreement	Has the meaning set out in **The Company's Transmission Licence**
CUSC Party	As defined in the **The Company's** Transmission Licence and "CUSC Parties" shall be construed accordingly.
Customer	A person to whom electrical power is provided (whether or not he is the same person as the person who provides the electrical power).
Customer Demand Management	Reducing the supply of electricity to a **Customer** or disconnecting a **Customer** in a manner agreed for commercial purposes between a **Supplier** and its **Customer**.
Customer Demand Management Notification Level	The level above which a **Supplier** has to notify **The Company** of its proposed or achieved use of **Customer Demand Management** which is 12 MW in England and Wales and 5 MW in Scotland.
Customer Generating Plant	A **Power Station** or **Generating Unit** or **Power Generating Module** of a **Customer** to the extent that it operates the same exclusively to supply all or part of its own electricity requirements, and does not export electrical power to any part of the **Total System**.
Data Registration Code or **DRC**	That portion of the Grid Code which is identified as the **Data Registration Code**.
Data Validation, Consistency and Defaulting Rules	The rules relating to validity and consistency of data, and default data to be applied, in relation to data submitted under the **Balancing Codes**, to be applied by **The Company** under the **Grid Code** as set out in the document "Data Validation, Consistency and Defaulting Rules" - Issue 8, dated 25th January 2012. The document is available on the National Grid website or upon request from **The Company**.
DC Connected Power Park Module	A **Power Park Module** that is connected to one or more **HVDC Interface Points**.
DC Converter	Any **Onshore DC Converter** or **Offshore DC Converter** as applicable to **Existing User's**.
DC Converter Station	An installation comprising one or more **Onshore DC Converters** connecting a direct current interconnector: to the **National Electricity Transmission System**; or, (if the installation has a rating of 50MW or more) to a **User System**, and it shall form part of the **External Interconnection** to which it relates.

DC Network	All items of **Plant** and **Apparatus** connected together on the direct current side of a **DC Converter** or **HVDC System**.
DCUSA	The Distribution Connection and Use of System Agreement approved by the **Authority** and required to be maintained in force by each **Electricity Distribution Licence** holder.
Defence Service Provider	A **User** with a legal contractual obligation to provide a service contributing to one or several measures of the **System Defence Plan.**
De-Load	The condition in which a **Genset** has reduced or is not delivering electrical power to the **System** to which it is **Synchronised**.
Δf	Deviation from **Target Frequency**
Demand	The demand of MW and Mvar of electricity (i.e. both **Active** and **Reactive Power**), unless otherwise stated.
Demand Aggregation	A process where one or more **Demand Facilities** or **Closed Distribution Systems** can be controlled by a **Demand Response Provider** either as a single facility or **Closed Distribution System** for the purposes of offering one or more **Demand Response Services.**
Demand Capacity	Has the meaning as set out in the **BSC**.
Demand Control	Any or all of the following methods of achieving a **Demand** reduction: (a) **Customer** voltage reduction initiated by **Network Operators** (other than following an instruction from **The Company**); (b) **Customer Demand** reduction by **Disconnection** initiated by **Network Operators** (other than following an instruction from **The Company**); (c) **Demand** reduction instructed by **The Company**; (d) automatic low **Frequency Demand Disconnection**; (e) emergency manual **Demand Disconnection**.
Demand Control Notification Level	The level above which a **Network Operator** has to notify **The Company** of its proposed or achieved use of **Demand Control** which is 12 MW in England and Wales and 5 MW in Scotland.
Demand Facility	A facility which consumes electrical energy and is connected at one or more **Grid Supply Points** to the **National Electricity Transmission System** or connection points to a **Network Operator's System**. A **Network Operator's System** and/or auxiliary supplies of a **Power Generating Module** do no constitute a **Demand Facility**.
Demand Facility Owner	A person who owns or operates one or more **Demand Units** within a **Demand Facility**. A **Demand Facility Owner** who owns or operates a **Demand Facility** which is directed connected to the **Transmission System** shall be treated as a **Non Embedded Customer**.
Demand Response Active Power Control	**Demand** within a **Demand Facility** or **Closed Distribution System** that is available for modulation by **The Company** or **Network Operator** or **Relevant Transmission Licensee**, which results in an **Active Power** modification.

Demand Response Provider	A party (other than **The Company**) who owns, operates, controls or manages **Main Plant and Apparatus** (excluding storage equipment) which was first connected to the **Total System** on or after 18 August 2019 and who had placed **Purchase Contracts** for its **Main Plant and Apparatus** on or after 7 September 2018 or is the subject of a **Substantial Modification** on or after 18 August 2019 and has an agreement with **The Company** to provide a **Demand Response Service**(s). The party may be one or more **Customers**, a **Network Operator** or **Non-Embedded Customer** or **EU Code User** contracting bilaterally with **The Company** for the provision of services, or may be a third party providing **Demand Aggregation** from many individual **Customers**.
Demand Response Reactive Power Control	A **Demand Response Service** derived from **Reactive Power** or **Reactive Power** compensation devices in a **Demand Facility** or **Closed Distribution System** that are available for modulation by **The Company** or **Network Operator** or **Relevant Transmission Licensee**.
Demand Response Transmission Constrain Management	A **Demand Response Service** derived from **Demand** within a **Demand Facility** or **Closed Distribution System** that is available for modulation by **The Company** or **Network Operator** or **Relevant Transmission Licensee** to manage transmission constraints within the **System**.
Demand Response Service	A **Demand Response Service** includes one of more of the following services: (a) **Demand Response Active Power Control**; (b) **Demand Response Reactive Power Control**; (c) **Demand Response Transmission Constraint Management**; (d) **Demand Response System Frequency Control**; (e) **Demand Response Very Fast Active Power Control**. The above **Demand Response Services** are not exclusive and do not preclude **Demand Response Providers** from negotiating other services for demand response capability with **The Company**. Where such services are negotiated they would still be treated as a **Demand Response Service**.
Demand Response Services Code (DRSC)	That portion of the Grid Code which is identified as the **Demand Response Services Code** being applicable to **Demand Response Providers**.
Demand Response System Frequency Control	A **Demand Response Service** derived from a **Demand** within one or more **Demand Facilities** or **Closed Distribution Systems** that is available for the reduction or increase in response to **Frequency** fluctuations, made by an autonomous response from those **Demand Facilities** or **Closed Distribution Systems** to diminish these fluctuations.
Demand Response Unit Document (DRUD)	A document, issued either by the **Non Embedded Customer**, **Demand Facility Owner** or the **CDSO** to **The Company** or the **Network Operator** (as the case may be) for **Demand Units** with demand response and providing a **Demand Response Service** which confirms the compliance of the **Demand Unit** with the technical requirements set out in the Grid Code and provides the necessary data and statements, including a statement of compliance.
Demand Response Very Fast Active Power Control	A **Demand Response Service** derived from **a Demand** within a **Demand Facility** or **Closed Distribution System** that can be modulated very fast in response to a **Frequency** deviation, which results in a very fast **Active Power** modification.
Demand Unit	An indivisible set of installations containing equipment which can be actively controlled at one or more sites by a **Demand Response Provider**, **Demand Facility Owner**, **CDSO** or by a **Non Embedded Customer**, either individually or commonly as part of **Demand Aggregation** through a third party who has agreed to provide **Demand Response Services**.

Designed Minimum Operating Level	The output (in whole MW) below which a **Genset** or a **DC Converter** at a **DC Converter Station** (in any of its operating configurations) has no **High Frequency Response** capability.
De-Synchronise	(a) The act of taking a **Power Generating Module** (including a **DC Connected Power Park Module**), **Generating Unit**, **Power Park Module**, **HVDC System** or **DC Converter** off a **System** to which it has been **Synchronised**, by opening any connecting circuit breaker; or (b) The act of ceasing to consume electricity at an importing **BM Unit**; and the term "**De-Synchronising**" shall be construed accordingly.
De-synchronised Island(s)	Has the meaning set out in OC9.5.1(a)
Detailed Planning Data	Detailed additional data which **The Company** requires under the **PC** in support of **Standard Planning Data**, comprising **DPD I** and **DPD II**
Detailed Planning Data Category I or **DPD I**	The **Detailed Planning Data** categorised as such in the **DRC** and **EDRC**, and submitted in accordance with PC.4.4.2 or PC.4.4.4 as applicable.
Detailed Planning Data Category II or **DPD II**	The **Detailed Planning Data** categorised as such in the **DRC** and **EDRC**, and submitted in accordance with PC.4.4.2 or PC.4.4.4 as applicable.
Discrimination	The quality where a relay or protective system is enabled to pick out and cause to be disconnected only the faulty **Apparatus**.
Disconnection	The physical separation of **Users** (or **Customers**) from the **National Electricity Transmission System** or a **User System** as the case may be.
Disputes Resolution Procedure	The procedure described in the **CUSC** relating to disputes resolution.
Distribution Code	The distribution code required to be drawn up by each **Electricity Distribution Licence** holder and approved by the **Authority**, as from time to time revised with the approval of the **Authority**.
Droop	The ratio of the per unit steady state change in speed, or in **Frequency** to the per unit steady state change in power output. Whilst not mandatory, it is often common practice to express **Droop** in percentage terms.
Dynamic Parameters	Those parameters listed in Appendix 1 to **BC1** under the heading **BM Unit Data** – **Dynamic Parameters**.
E&W Offshore Transmission System	An **Offshore Transmission System** with an **Interface Point** in England and Wales.
E&W Offshore Transmission Licensee	A person who owns or operates **an E&W Offshore Transmission System** pursuant to a **Transmission Licence**.
E&W Transmission System	Collectively **NGET's Transmission System** and any **E&W Offshore Transmission Systems**.
E&W User	A **User** in **England** and **Wales** or any **Offshore User** who owns or operates **Plant** and/or **Apparatus** connected (or which will at the **OTSUA Transfer Time** be connected) to an **E&W Offshore Transmission System**.

Earth Fault Factor	At a selected location of a three-phase **System** (generally the point of installation of equipment) and for a given **System** configuration, the ratio of the highest root mean square phase-to-earth power **Frequency** voltage on a sound phase during a fault to earth (affecting one or more phases at any point) to the root mean square phase-to-earth power **Frequency** voltage which would be obtained at the selected location without the fault.
Earthing	A way of providing a connection between conductors and earth by an **Earthing Device** which is either: (a) Immobilised and **Locked** in the earthing position. Where the **Earthing Device** is **Locked** with a **Safety Key**, the **Safety Key** must be secured in a **Key Safe** and the **Key Safe Key** must be, where reasonably practicable, given to the authorised site representative of the **Requesting Safety Co-ordinator** and is to be retained in safe custody. Where not reasonably practicable the **Key Safe Key** must be retained by the authorised site representative of the **Implementing Safety Co-ordinator** in safe custody; or (b) maintained and/or secured in position by such other method which must be in accordance with the **Local Safety Instructions** of **NGET** or the **Safety Rules** of the **Relevant Transmission Licensee** or that **User**, as the case may be.
Earthing Device	A means of providing a connection between a conductor and earth being of adequate strength and capability.
Elected Panel Members	Shall mean the following **Panel Members** elected in accordance with GR4.2(a): (a) the representative of the **Suppliers**; (b) the representative of the **Onshore Transmission Licensees**; (c) the representative of the **Offshore Transmission Licensees**; and (d) the representatives of the **Generators**
Electrical Standard	A standard listed in the Annex to the **General Conditions**.
Electricity Council	That body set up under the Electricity Act, 1957.
Electricity Distribution Licence	The licence granted pursuant to Section 6(1) (c) of the **Act**.
Electricity Regulation	As defined in the **Transmission Licence.**
Electricity Storage	The conversion of electrical energy into a form of energy which can be stored, the storing of that energy, and the subsequent reconversion of that energy back into electrical energy.
Electricity Storage Module	Is either one or more **Synchronous Electricity Storage Unit**(s) or **Non-Synchronous Electricity Storage Unit**(s) which could also be part of a **Power Generating Module**. For the avoidance of doubt, **Non-Controllable Electricity Storage Equipment** would not be considered to be classed as an **Electricity Storage Module** or as an **Electricity Storage Unit**.

Electricity Supply Industry Arbitration Association	The unincorporated members' club of that name formed inter alia to promote the efficient and economic operation of the procedure for the resolution of disputes within the electricity supply industry by means of arbitration or otherwise in accordance with its arbitration rules.
Electricity Supply Licence	The licence granted pursuant to Section 6(1) (d) of the **Act**.
Electromagnetic Compatibility Level	Has the meaning set out in **Engineering Recommendation** G5/4.
Embedded	Having a direct connection to a **User System** or the **System** of any other **User** to which **Customers** and/or **Power Stations** are connected, such connection being either a direct connection or a connection via a busbar of another **User** or of a **Relevant Transmission Licensee** (but with no other connection to the **National Electricity Transmission System**).
Embedded Development	Has the meaning set out in PC.4.4.3(a)
Embedded Development Agreement	An agreement entered into between a **Network Operator** and an **Embedded Person**, identifying the relevant site of connection to the **Network Operator's System** and setting out other site specific details in relation to that use of the **Network Operator's System**.
Embedded Person	The party responsible for a **Medium Power Station** not subject to a **Bilateral Agreement** or **DC Converter Station** not subject to a **Bilateral Agreement** or **HVDC System** not subject to a **Bilateral Agreement** connected to or proposed to be connected to a **Network Operator's System**.
Emergency Deenergisation Instruction	an **Emergency Instruction** issued by **The Company** to **De-Synchronise** a **Power Generating Module** (including a **DC Connected Power Park Module**), **Generating Unit**, **Power Park Module, HVDC System** or **DC Converter** in circumstances specified in the **CUSC**.
Emergency Instruction	An instruction issued by **The Company** in emergency circumstances, pursuant to BC2.9, to the **Control Point** of a **User**. In the case of such instructions applicable to a **BM Unit**, it may require an action or response which is outside the **Dynamic Parameters**or **Other Relevant Data**, and may include an instruction to trip a **Genset**.
EMR Administrative Parties	Has the meaning given to "administrative parties" in The Electricity Capacity Regulations 2014 and each **CfD Counterparty** and **CfD Settlement Services Provider**.
EMR Documents	The Energy Act 2013, The Electricity Capacity Regulations 2014, the **Capacity Market Rules**, The Contracts for Difference (Allocation) Regulations 2014, The Contracts for Difference (Definition of Eligible Generator) Regulations 2014, The Contracts for Difference (Electricity Supplier Obligations) Regulations 2014, The Electricity Market Reform (General) Regulations 2014, the **AF Rules** and any other regulations or instruments made under Chapter 2 (contracts for difference), Chapter 3 (capacity market) or Chapter 4 (investment contracts) of Part 2 of the Energy Act 2013 which are in force from time to time.
EMR Functions	Has the meaning given to "EMR functions" in Chapter 5 of Part 2 of the Energy Act 2013.

Engineering Recommendations	The documents referred to as such and issued by the Energy Networks Association or the former Electricity Council.
Energisation Operational Notification or **EON**	A notification (in respect of **Plant** and **Apparatus** (including **OTSUA**) which is directly connected to the **National Electricity Transmission System**) from **The Company** to a **User** confirming that the **User** can in accordance with the **Bilateral Agreement** and/or **Construction Agreement**, energise such **User's Plant** and **Apparatus** (including **OTSUA**) specified in such notification.
Equipment Certificate	A document issued by an **Authorised Certifier** for equipment used by a **Power Generating Module**, **Demand Unit**, **Network Operators System**, **Non Embedded Customers System**, **Demand Facility** or **HVDC System**. The **Equipment Certificate** defines the scope of its validity at a national or other level at which a specific value is selected from the range allowed at a European level. For the purpose of replacing specific parts of the compliance process, the **Equipment Certificate** may include models or equivalent information that have been verified against actual test results.
Estimated Registered Data	Those items of **Standard Planning Data** and **Detailed Planning Data** which either upon connection will become **Registered Data**, or which for the purposes of the **Plant** and/or **Apparatus** concerned as at the date of submission are **Registered Data**, but in each case which for the seven succeeding **Financial Years** will be an estimate of what is expected.

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.
EU Generator	A **Generator** or **OTSDUA** who is also an **EU Code User**.

EU Grid Supply Point	A **Grid Supply Point** where either:- (i) (a) the **Network Operator** or **Non Embedded Customer** had placed **Purchase Contracts** for all of its **Plant** and **Apparatus** at that **Grid Supply Point** on or after 7 September 2018, and (b) All of the **Network Operator's** or **Non Embedded Customer's** **Plant** and **Apparatus** at that **Grid Supply Point** was first connected to the **Transmission System** on or after 18 August 2019; or (ii) the **Network Operator's** or **Non Embedded Customer's Plant** and **Apparatus** at a **Grid Supply Point** is the subject of a **Substantial Modification** which is effective on or after 18 August 2019.
EU Transparency Availability Data	Such data as Customers and Generators are required to provide under Articles 7.1(a) and 7.1(b) and Articles 15.1(a), 15.1(b), 15.1(c), 15.1(d) of European Commission Regulation (EU) No. 543/2013 respectively (known as the Transparency Regulation), and which also forms part of **DRC** Schedule 6 (Users' Outage Data).
European Compliance Processes or **ECP**	That portion of the Grid Code which is identified as the **European Compliance Processes**.
European Connection Conditions or **ECC**	That portion of the Grid Code which is identified as the **European Connection Conditions** being applicable to **EU Code Users**.
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
European Regulation (EU) 2017/2196	**Commission Regulation (EU) 2017/2196** of 24 November 2017 establishing a network code on emergency and restoration.
European Specification	A common technical specification, a **British Standard** implementing a European standard or a European technical approval. The terms "common technical specification", "European standard" and "European technical approval" shall have the meanings respectively ascribed to them in the **Regulations**.

Event	An unscheduled or unplanned (although it may be anticipated) occurrence on, or relating to, a **System** (including **Embedded Power Stations**) including, without limiting that general description, faults, incidents and breakdowns and adverse weather conditions being experienced.
Exciter	The source of the electrical power providing the field current of a synchronous machine.
Excitation System	The equipment providing the field current of a machine, including all regulating and control elements, as well as field discharge or suppression equipment and protective devices.
Excitation System No-Load Negative Ceiling Voltage	The minimum value of direct voltage that the **Excitation System** is able to provide from its terminals when it is not loaded, which may be zero or a negative value.
Excitation System Nominal Response	Shall have the meaning ascribed to that term in **IEC** 34-16-1:1991 [equivalent to **British Standard BS**4999 Section 116.1 : 1992]. The time interval applicable is the first half-second of excitation system voltage response.
Excitation System On-Load Positive Ceiling Voltage	Shall have the meaning ascribed to the term 'Excitation system on load ceiling voltage' in **IEC** 34-16-1:1991[equivalent to **British Standard BS**4999 Section 116.1 : 1992].
Excitation System No-Load Positive Ceiling Voltage	Shall have the meaning ascribed to the term 'Excitation system no load ceiling voltage' in **IEC** 34-16-1:1991[equivalent to **British Standard BS**4999 Section 116.1 : 1992].
Exemptable	Has the meaning set out in the **CUSC**.
Existing AGR Plant	The following nuclear advanced gas cooled reactor plant (which was commissioned and connected to the **Total System** at the **Transfer Date**):- (a) Dungeness B (b) Hinkley Point B (c) Heysham 1 (d) Heysham 2 (e) Hartlepool (f) Hunterston B (g) Torness

Existing AGR Plant Flexibility Limit	In respect of each **Genset** within each **Existing AGR Plant** which has a safety case enabling it to so operate, 8 (or such lower number which when added to the number of instances of reduction of output as instructed by **The Company** in relation to operation in **Frequency Sensitive Mode** totals 8) instances of flexibility in any calendar year (or such lower or greater number as may be agreed by the Nuclear Installations Inspectorate and notified to **The Company**) for the purpose of assisting in the period of low **System NRAPM** and/or low **Localised NRAPM** provided that in relation to each **Generating Unit** each change in output shall not be required to be to a level where the output of the reactor is less than 80% of the reactor thermal power limit (as notified to **The Company** and which corresponds to the limit of reactor thermal power as contained in the "Operating Rules" or "Identified Operating Instructions" forming part of the safety case agreed with the Nuclear Installations Inspectorate).
Existing Gas Cooled Reactor Plant	Both **Existing Magnox Reactor Plant** and **Existing AGR Plant**.
Existing Magnox Reactor Plant	The following nuclear gas cooled reactor plant (which was commissioned and connected to the **Total System** at the **Transfer Date**):- (a) Calder Hall (b) Chapelcross (c) Dungeness A (d) Hinkley Point A (e) Oldbury-on-Severn (f) Bradwell (g) Sizewell A (h) Wylfa
Export and Import Limits	Those parameters listed in Appendix 1 to **BC1** under the heading **BM Unit Data** – **Export and Import Limits**.
External Interconnection	**Apparatus** for the transmission of electricity to or from the **National Electricity Transmission System** or a **User System** into or out of an **External System**. For the avoidance of doubt, a single **External Interconnection** may comprise several circuits operating in parallel.
External Interconnection Circuit	**Plant** or **Apparatus** which comprises a circuit and which operates in parallel with another circuit and which forms part of the **External Interconnection**.
Externally Interconnected System Operator or **EISO**	A person who operates an **External System** which is connected to the **National Electricity Transmission System** or a **User System** by an **External Interconnection**.
External System	In relation to an **Externally Interconnected System Operator** means the transmission or distribution system which it owns or operates which is located outside **the National Electricity Transmission System Operator Area** any **Apparatus** or **Plant** which connects that system to the **External Interconnection** and which is owned or operated by such **Externally Interconnected System Operator**.

Fast Fault Current	A current delivered by a **Power Park Module** or **HVDC System** during and after a voltage deviation caused by an electrical fault within the **System** with the aim of identifying a fault by network **Protection** systems at the initial stage of the fault, supporting **System** voltage retention at a later stage of the fault and **System** voltage restoration after fault clearance.
Fault Current Interruption Time	The time interval from fault inception until the end of the break time of the circuit breaker (as declared by the manufacturers).
Fault Ride Through	The capability of **Power Generating Modules** (including **DC Connected Power Park Modules**) and **HVDC Systems** to be able to be able to remain connected to the **System** and operate through periods of low voltage at the **Grid Entry Point** or **User System Entry Point** caused by secured faults
Fast Start	A start by a **Genset** with a **Fast Start Capability**.
Fast Start Capability	The ability of a **Genset** to be **Synchronised** and **Loaded** up to full **Load** within 5 minutes.
Fast Track Criteria	A proposed Grid Code Modification Proposal that, if implemented, (a) would meet the **Self-Governance Criteria**; and (b) is properly a housekeeping modification required as a result of some error or factual change, including but not limited to: (i) updating names or addresses listed in the **Grid Code**; (ii) correcting any minor typographical errors; (iii) correcting formatting and consistency errors, such as paragraph numbering; or (iv) updating out of date references to other documents or paragraphs
Final Generation Outage Programme	An outage programme as agreed by **The Company** with each **Generator** and each **Interconnector Owner** at various stages through the **Operational Planning Phase** and **Programming Phase** which does not commit the parties to abide by it, but which at various stages will be used as the basis on which **National Electricity Transmission System** outages will be planned.
Final Operational Notification or **FON**	A notification from **The Company** to a **Generator** or **DC Converter Station** owner or **HVDC System Owner** or **Network Operator** or **Non-Embedded Customer** confirming that the **User** has demonstrated compliance: (a) with the Grid Code, (or where they apply, that relevant derogations have been granted), and (b) where applicable, with Appendices F1 to F5 of the **Bilateral Agreement**, in each case in respect of the **Plant** and **Apparatus** specified in such notification.
Final Physical Notification Data	Has the meaning set out in the **BSC**.

Final Report	A report prepared by the **Test Proposer** at the conclusion of a **System Test** for submission to **The Company** (if it did not propose the **System Test**) and other members of the **Test Panel**.
Financial Year	Bears the meaning given in Condition A1 (Definitions and Interpretation) of **The Company's Transmission Licence**.
Fixed Proposed Implementation Date	The proposed date(s) for the implementation of a **Grid Code Modification Proposal** or **Workgroup Alternative Grid Code Modification** such date to be a specific date by reference to an assumed date by which a direction from the **Authority** approving the **Grid Code Modification Proposal** or **Workgroup Alternative Grid Code Modification** is required in order for the **Grid Code Modification Proposal** or any **Workgroup Alternative Grid Code Modification**, if it were approved, to be implemented by the proposed date.
Flicker Severity **(Long Term)**	A value derived from 12 successive measurements of **Flicker Severity** (**Short Term**) (over a two hour period) and a calculation of the cube root of the mean sum of the cubes of 12 individual measurements, as further set out in **Engineering Recommendation** P28 as current at the **Transfer Date**.
Flicker Severity **(Short Term)**	A measure of the visual severity of flicker derived from the time series output of a flickermeter over a 10 minute period and as such provides an indication of the risk of **Customer** complaints.
Forecast Data	Those items of **Standard Planning Data** and **Detailed Planning Data** which will always be forecast.
Frequency	The number of alternating current cycles per second (expressed in Hertz) at which a **System** is running.
Frequency Containment Reserves (FCR)	means, in the context of **Balancing Services,** the active power reserves available to contain system frequency after the occurrence of an imbalance.
Frequency Restoration Reserves (FRR)	means, in the context of **Balancing Services,** the active power reserves available to restore system frequency to the nominal frequency.
Governor Deadband	An interval used intentionally to make the frequency control unresponsive In the case of mechanical governor systems the Governor Deadband is the same as Frequency Response Insensitivity
Governor Insensitivity	The inherent feature of the control system specified as the minimum magnitude of change in the frequency or input signal that results in a change of output power or output signal
GSP Group	Has the meaning as set out in the **BSC**
Frequency Sensitive AGR Unit	Each **Generating Unit** in an **Existing AGR Plant** for which the **Generator** has notified **The Company** that it has a safety case agreed with the Nuclear Installations Inspectorate enabling it to operate in **Frequency Sensitive Mode**, to the extent that such unit is within its **Frequency Sensitive AGR Unit Limit**. Each such **Generating Unit** shall be treated as if it were operating in accordance with BC3.5.1 provided that it is complying with its **Frequency Sensitive AGR Unit Limit**.

Frequency Sensitive AGR Unit Limit	In respect of each **Frequency Sensitive AGR Unit**, 8 (or such lower number which when added to the number of instances of flexibility for the purposes of assisting in a period of low **System** or **Localised NRAPM** totals 8) instances of reduction of output in any calendar year as instructed by **The Company** in relation to operation in **Frequency Sensitive Mode** (or such greater number as may be agreed between **The Company** and the **Generator**), for the purpose of assisting with **Frequency** control, provided the level of operation of each **Frequency Sensitive AGR Unit** in **Frequency Sensitive Mode** shall not be outside that agreed by the Nuclear Installations Inspectorate in the relevant safety case.
Frequency Sensitive Mode	A **Genset**, or **Type C Power Generating Module** or **Type D Power Generating Module** or **DC Connected Power Park Module** or **HVDC System** operating mode which will result in **Active Power** output changing, in response to a change in **System Frequency**, in a direction which assists in the recovery to **Target Frequency**, by operating so as to provide **Primary Response** and/or **Secondary Response** and/or **High Frequency Response**.
Fuel Security Code	The document of that title designated as such by the **Secretary of State**, as from time to time amended.
Gas Turbine Unit	A **Generating Unit** driven by a gas turbine (for instance by an aero-engine).
Gas Zone Diagram	A single line diagram showing boundaries of, and interfaces between, gas-insulated **HV Apparatus** modules which comprise part, or the whole, of a substation at a **Connection Site** (or in the case of **OTSDUW Plant and Apparatus**, **Transmission Interface Site**), together with the associated stop valves and gas monitors required for the safe operation of the **National Electricity Transmission System** or the **User System**, as the case may be.
Gate Closure	Has the meaning set out in the **BSC**.

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	A **Generator,** or **OTSDUA**, who is also a **GB Code User**.
GB Grid Supply Point	A **Grid Supply Point** which is not an **EU Grid Supply Point**.
GB Synchronous Area	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**.
GCDF	Means the Grid Code Development Forum.
General Conditions or **GC**	That portion of the Grid Code which is identified as the **General Conditions**.
Generating Plant Demand Margin	The difference between **Output Usable** and forecast **Demand**.

Generating Unit	An **Onshore Generating Unit** and/or an **Offshore Generating Unit** which could also be part of a **Power Generating Module**.
Generating Unit Data	The **Physical Notification**, **Export and Import Limits** and **Other Relevant Data** only in respect of each **Generating Unit** (which could be part of a **Power Generating Module**): (a) which forms part of the **BM Unit** which represents that **Cascade Hydro Scheme**; (b) at an **Embedded Exemptable Large Power Station**, where the relevant **Bilateral Agreement** specifies that compliance with **BC1** and/or **BC2** is required: (i) to each **Generating Unit**, or (ii) to each **Power Park Module** where the **Power Station** comprises **Power Park Modules**
Generation Capacity	Has the meaning set out in the **BSC**.
Generation Planning Parameters	Those parameters listed in Appendix 2 of **OC2**.
Generator	A person who generates electricity under licence or exemption under the **Act** acting in its capacity as a generator in **Great Britain** or **Offshore**. The term **Generator** includes a **EU Generator** and a **GB Generator**.
Generator Performance Chart	A diagram which shows the MW and Mvar capability limits within which a **Generating Unit** will be expected to operate under steady state conditions.
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**.
Good Industry Practice	The exercise of that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced operator engaged in the same type of undertaking under the same or similar circumstances.
Governance Rules or **GR**	That portion of the **Grid Code** which is identified as the **Governance Rules**.
Great Britain or **GB**	The landmass of England and Wales and Scotland, including internal waters.
Grid Code Fast Track Proposals	A proposal to modify the **Grid Code** which is raised pursuant to GR.26 and has not yet been approved or rejected by the **Grid Code Review Panel**.
Grid Code Modification Fast Track Report	A report prepared pursuant to GR.26
Grid Code Modification Register	Has the meaning given in GR.13.1.

Grid Code Modification Report	Has the meaning given in GR.22.1.
Grid Code Modification Procedures	The procedures for the modification of the **Grid Code** (including the implementation of **Approved Modifications**) as set out in the **Governance Rules**.
Grid Code Modification Proposal	A proposal to modify the **Grid Code** which is not yet rejected pursuant to GR.15.5 or GR.15.6 and has not yet been implemented.
Grid Code Modification Self- Governance Report	Has the meaning given in GR.24.5
Grid Code Objectives	Means the objectives referred to in Paragraph 1b of Standard Condition C14 of **The Company's Transmission Licence**.
Grid Code Review Panel or **Panel**	The panel with the functions set out in GR.1.2.
Grid Code Review Panel Recommendation Vote	The vote of **Panel Members** undertaken by the **Panel Chairman** in accordance with Paragraph GR.22.4 as to whether in their view they believe each proposed **Grid Code Modification Proposal**, or **Workgroup Alternative Grid Code Modification** would better facilitate achievement of the **Grid Code Objective(s)** and so should be made.
Grid Code Review Panel Self-Governance Vote	The vote of **Panel Members** undertaken by the **Panel Chairman** in accordance with GR.24.9 as to whether they believe each proposed Grid Code Modification Proposal, as compared with the then existing provisions of the **Grid Code** and any **Workgroup Alternative Grid Code Modification** set out in the **Grid Code Modification Self- Governance Report**, would better facilitate achievement of the **Grid Code Objective(s)**.
Grid Code Self-Governance Proposals	**Grid Code Modification Proposals** which satisfy the **Self Governance Criteria**.
Grid Entry Point	An **Onshore Grid Entry Point** or an **Offshore Grid Entry Point**.
Grid Supply Point	A point of supply from the **National Electricity Transmission System** to **Network Operators** or **Non-Embedded Customers** which could be a **GB Grid Supply Point** or an **EU Grid Supply Point**.
Group	Those **National Electricity Transmission System** sub-stations bounded solely by the faulted circuit(s) and the overloaded circuit(s) excluding any third party connections between the **Group** and the rest of the **National Electricity Transmission System**, the faulted circuit(s) being a **Secured Event**.
Headroom	The **Power Available** (in MW) less the actual **Active Power** exported from the **Power Park Module** (in MW).

High Frequency Response	An automatic reduction in **Active Power** output in response to an increase in **System Frequency** above the **Target Frequency** (or such other level of **Frequency** as may have been agreed in an **Ancillary Services Agreement**). This reduction in **Active Power** output must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be released increasingly with time over the period 0 to 10 seconds from the time of the **Frequency** increase on the basis set out in the **Ancillary Services Agreement** and fully achieved within 10 seconds of the time of the start of the **Frequency** increase and it must be sustained at no lesser reduction thereafter. The interpretation of the **High Frequency Response** to a + 0.5 Hz frequency change is shown diagrammatically in Figure CC.A.3.3.
High Voltage or **HV**	For **E&W Transmission Systems**, a voltage exceeding 650 volts. For **Scottish Transmission Systems**, a voltage exceeding 1000 volts.
Houseload Operation	Operation which ensures that a **Power Station** is able to continue to supply its in-house load in the event of **System** faults resulting in **Power-Generating Modules** being disconnected from the **System** and tripped onto their auxiliary supplies
HV Connections	**Apparatus** connected at the same voltage as that of the **National Electricity Transmission System**, including **Users'** circuits, the higher voltage windings of **Users'** transformers and associated connection **Apparatus**.
HVDC Converter	Any **EU Code User Apparatus** used to convert alternating current electricity to direct current electricity, or vice versa. An **HVDC Converte**r is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, reactors, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion. In a bipolar arrangement, an **HVDC Converter** represents the bipolar configuration.
HVDC Converter Station	Part of an **HVDC System** which consists of one or more **HVDC Converters** installed in a single location together with buildings, reactors, filters reactive power devices, control, monitoring, protective, measuring and auxiliary equipment.
HVDC Equipment	Collectively means an **HVDC System** and a **DC Connected Power Park Module** and a **Remote End HVDC Converter Station**.
HVDC Interface Point	A point at which **HVDC Plant** and **Apparatus** is connected to an AC **System** at which technical specifications affecting the performance of the **Plant** and **Apparatus** can be prescribed.
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**.
HVDC System Owner	A party who owns and is responsible for an **HVDC System**. For the avoidance of doubt a **DC Connected Power Park Module** owner would be treated as a **Generator**.
HP Turbine Power Fraction	Ratio of steady state mechanical power delivered by the HP turbine to the total steady state mechanical power delivered by the total steam turbine at **Registered Capacity** or **Maximum Capacity**.
IEC	International Electrotechnical Commission.
IEC Standard	A standard approved by the International Electrotechnical Commission.

Implementation Date	Is the date and time for implementation of an **Approved Modification** as specified in accordance with Paragraph GR.25.3.
Implementing Safety Co-ordinator	The **Safety Co-ordinator** implementing **Safety Precautions**.
Import Usable	That portion of **Registered Import Capacity** which is expected to be available and which is not unavailable due to a **Planned Outage**.
Incident Centre	A centre established by **The Company** or a **User** as the focal point in **The Company** or in that **User**, as the case may be, for the communication and dissemination of information between the senior management representatives of **The Company**, or of that **User**, as the case may be, and the relevant other parties during a **Joint System Incident** in order to avoid overloading **The Company's**, or that **User's**, as the case may be, existing operational/control arrangements.
Independent Back-Up Protection	A **Back-Up Protection** system which utilises a discrete relay, different current transformers and an alternate operating principle to the **Main Protection** systems(s) such that it can operate autonomously in the event of a failure of the **Main Protection**.
Independent Main Protection	A **Main Protection** system which utilises a physically discrete relay and different current transformers to any other **Main Protection**.
Indicated Constraint Boundary Margin	The difference between a constraint boundary transfer limit and the difference between the sum of **BM Unit** Maximum Export Limits and the forecast of local **Demand** within the constraint boundary.
Indicated Imbalance	The difference between the sum of **Physical Notifications** for **BM Units** comprising **Generating Units** or **CCGT Modules** or **Power Generating Modules** and the forecast of **Demand** for the whole or any part of the **System**.
Indicated Margin	The difference between the sum of **BM Unit** Maximum Export Limits submitted and the forecast of **Demand** for the whole or any part of the **System**
Installation Document	A simple structured document containing information about a **Type A Power Generating Module** or a **Demand Unit**, with demand response connected below 1000 V, and confirming its compliance with the relevant requirements
Instructor Facilities	A device or system which gives certain **Transmission Control Centre** instructions with an audible or visible alarm, and incorporates the means to return message acknowledgements to the **Transmission Control Centre**
Integral Equipment Test or **IET**	A test on equipment, associated with **Plant** and/or **Apparatus**, which takes place when that **Plant** and/or **Apparatus** forms part of a **Synchronised System** and which, in the reasonable judgement of the person wishing to perform the test, may cause an **Operational Effect**.

Intellectual Property" or "IPRs	Patents, trade marks, service marks, rights in designs, trade names, copyrights and topography rights (whether or not any of the same are registered and including applications for registration of any of the same) and rights under licences and consents in relation to any of the same and all rights or forms of protection of a similar nature or having equivalent or similar effect to any of the same which may subsist anywhere in the world.
Interconnection Agreement	An agreement made between **The Company** and an **Externally Interconnected System Operator** and/or an **Interconnector User** and/or other relevant persons for the **External Interconnection** relating to an **External Interconnection** and/or an agreement under which an **Interconnector User** can use an **External Interconnection**.
Interconnector Export Capacity	In relation to an **External Interconnection** means the (daily or weekly) forecast value (in MW) at the time of the (daily or weekly) peak demand, of the maximum level at which the **External Interconnection** can export to the **Grid Entry Point**.
Interconnector Import Capacity	In relation to an **External Interconnection** means the (daily or weekly) forecast value (in MW) at the time of the (daily or weekly) peak demand of the maximum level at which the **External Interconnection** can import from the **Grid Entry Point**.
Interconnector Owner	Has the meaning given to the term in the **Connection and Use of System Code**.
Interconnector User	Has the meaning set out in the **BSC**.
Interface Agreement	Has the meaning set out in the **CUSC**.
Interface Point	As the context admits or requires either; (a) the electrical point of connection between an **Offshore Transmission System** and an **Onshore Transmission System**, or (b) the electrical point of connection between an **Offshore Transmission System** and a **Network Operator's User System**.
Interface Point Capacity	The maximum amount of **Active Power** transferable at the **Interface Point** as declared by a **User** under the **OTSDUW Arrangements** expressed in whole MW.
Interface Point Target Voltage/Power factor	The nominal target voltage/power factor at an **Interface Point** which a **Network Operator** requires **The Company** to achieve by operation of the relevant **Offshore Transmission System**.

Interim Operational Notification or **ION**	A notification from **The Company** to a **Generator** or **DC Converter Station** owner or **HVDC System Operator** or **Network Operator** or **Non Embedded Customer** acknowledging that the **User** has demonstrated compliance, except for the **Unresolved Issues**; (a) with the Grid Code, and (b) where applicable, with Appendices F1 to F5 of the **Bilateral Agreement**, in each case in respect of the **Plant** and **Apparatus** (including **OTSUA**) specified in such notification and provided that in the case of the **OTSDUW Arrangements** such notification shall be provided to a **Generator** in two parts dealing with the **OTSUA** and **Generator's Plant** and **Apparatus** (called respectively "**Interim Operational Notification Part A**" or "**ION A**" and "**Interim Operational Notification Part B**" or "**ION B"**) as provided for in the **CP**.
Intermittent Power Source	The primary source of power for a **Generating Unit or Power Generating Module** that can not be considered as controllable, e.g. wind, wave or solar.
Intertripping	(a) The tripping of circuit-breaker(s) by commands initiated from **Protection** at a remote location independent of the state of the local **Protection**; or (b) **Operational Intertripping**.
Intertrip Apparatus	**Apparatus** which performs **Intertripping**.
IP Turbine Power Fraction	Ratio of steady state mechanical power delivered by the IP turbine to the total steady state mechanical power delivered by the total steam turbine at **Registered Capacity** or **Maximum Capacity**.
Isolating Device	A device for achieving **Isolation**.

Isolation	The disconnection of **HV Apparatus** (as defined in OC8A.1.6.2 and OC8B.1.7.2) from the remainder of the **System** in which that **HV Apparatus** is situated by either of the following: (a) an **Isolating Device** maintained in an isolating position. The isolating position must either be: (i) maintained by immobilising and **Locking** the **Isolating Device** in the isolating position and affixing a **Caution Notice** to it. Where the **Isolating Device** is **Locked** with a **Safety Key**, the **Safety Key** must be secured in a **Key Safe** and the **Key Safe Key** must be, where reasonably practicable, given to the authorised site representative of the **Requesting Safety Co-Ordinator** and is to be retained in safe custody. Where not reasonably practicable the **Key Safe Key** must be retained by the authorised site representative of the **Implementing Safety Co-ordinator** in safe custody; or (ii) maintained and/or secured by such other method which must be in accordance with the **Local Safety Instructions** or the **Safety Rules** of the **Relevant Transmission Licensee** or that **User**, as the case may be; or (b) an adequate physical separation which must be in accordance with and maintained by the method set out in the **Local Safety Instructions** or the **Safety Rules** of the **Relevant Transmission Licensee** or that **User**, as the case may be.
Joint System Incident	An **Event** wherever occurring (other than on an **Embedded Medium Power Station** or an **Embedded Small Power Station**) which, in the opinion of **The Company** or a **User**, has or may have a serious and/or widespread effect, in the case of an **Event** on a **User(s) System(s)** (other than on an **Embedded Medium Power Station** or **Embedded Small Power Station**), on the **National Electricity Transmission System**, and in the case of an **Event** on the **National Electricity Transmission System**, on a **User(s) System(s)** (other than on an **Embedded Medium Power Station** or **Embedded Small Power Station**).
Key Safe	A device for the secure retention of keys.
Key Safe Key	A key unique at a **Location** capable of operating a lock, other than a control lock, on a **Key Safe**.

Large Power Station	A **Power Station** which is (a) directly connected to: (i) **NGET's Transmission System** where such **Power Station** has a **Registered Capacity** of 100MW or more; or (ii) **SPT's Transmission System** where such **Power Station** has a **Registered Capacity** of 30MW or more; or (iii) **SHETL's Transmission System** where such **Power Station** has a **Registered Capacity** of 10MW or more; or (iv) an **Offshore Transmission System** where such **Power Station** has a **Registered Capacity** of 10MW or more; or, (b) **Embedded** within a **User System** (or part thereof) where such **User System** (or part thereof) is connected under normal operating conditions to: (i) **NGET's Transmission System** and such **Power Station** has a **Registered Capacity** of 100MW or more; or (ii) **SPT's Transmission System** and such **Power Station** has a **Registered Capacity** of 30MW or more; or (iii) **SHETL's Transmission System** and such **Power Station** has a **Registered Capacity** of 10MW or more; or, (c) **Embedded** within a **User System** (or part thereof) where the **User System** (or part thereof) is not connected to the **National Electricity Transmission System**, although such **Power Station** is in: (i) **NGET's Transmission Area** where such **Power Station** has a **Registered Capacity** of 100MW or more; or (ii) **SPT's Transmission Area** where such **Power Station** has a **Registered Capacity** of 30MW or more; or (iii) **SHETL's Transmission Area** where such **Power Station** has a **Registered Capacity** of 10MW or more; For the avoidance of doubt a **Large Power Station** could comprise of **Type A**, **Type B**, **Type C** or **Type D Power Generating Modules**.
Legal Challenge	Where permitted by law a judicial review in respect of the **Authority's** decision to approve or not to approve a **Grid Code Modification Proposal**.
Licence	Any licence granted to **The Company** or a **Relevant Transmission Licensee** or a **User**, under Section 6 of the **Act**.
Licence Standards	Those standards set out or referred to in Condition C17 of **The Company's Transmission Licence** and/or Condition D3 and/or Condition E16 of a **Relevant Transmission Licensee's Transmission Licence**.

Limited Frequency Sensitive Mode	A mode whereby the operation of the **Genset** or **Power Generating Module** (or **DC Converter** at a **DC Converter Station** or **HVDC Systems** exporting **Active Power** to the **Total System)** is **Frequency** insensitive except when the **System Frequency** exceeds 50.4Hz, from which point **Limited High Frequency Response** must be provided. For **Power Generating Modules** (including **DC Connected Power Park Modules**) and **HVDC Systems**, operation in **Limited Frequency Sensitive Mode** would require **Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)** capability and **Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)** capability.
Limited Frequency Sensitive Mode – Overfrequency or **LFSM-O**	A **Power Generating Module** (including a **DC Connected Power Park Module**) or **HVDC System** operating mode which will result in **Active Power** output reduction in response to a change in **System Frequency** above a certain value.
Limited Frequency Sensitive Mode – Underfrequency or **LFSM-U**	A **Power Generating Module** (including a **DC Connected Power Park Module**) or **HVDC System** operating mode which will result in **Active Power** output increase in response to a change in **System Frequency** below a certain value.
Limited High Frequency Response	A response of a **Genset** (or **DC Converter** at a **DC Converter Station** exporting **Active Power** to the **Total System)** to an increase in **System Frequency** above 50.4Hz leading to a reduction in **Active Power** in accordance with the provisions of BC3.7.2.1
Limited Operational Notification or **LON**	A notification from **The Company** to a **Generator** or **DC Converter Station** owner or **HVDC System Owner** or **Network Operator** or **Non-Embedded Customer** stating that the **User's Plant** and/or **Apparatus** specified in such notification may be, or is, unable to comply: (a) with the provisions of the Grid Code specified in the notice, and (b) where applicable, with Appendices F1 to F5 of the **Bilateral Agreement** , and specifying the **Unresolved Issues**.
Load	The **Active**, **Reactive** or **Apparent Power**, as the context requires, generated, transmitted or distributed.
Loaded	Supplying electrical power to the **System**.
Load Factor	The ratio of the actual output of a **Generating Unit** or **Power Generating Module** to the possible maximum output of that **Generating Unit** or **Power Generating Module**.
Load Management Block	A block of **Demand** controlled by a **Supplier** or other party through the means of radio teleswitching or by some other means.
Local Joint Restoration Plan	A plan produced under OC9.4.7.12 detailing the agreed method and procedure by which a **Black Start Service Provider** will energise part of the **Total System** and meet complementary blocks of local **Demand** so as to form a **Power Island**. In Scotland, the plan may also: cover more than one **Black Start Service Provider**; including **Gensets** other than those at a **Black Start Station** and cover the creation of one or more **Power Islands**.

Local Safety Instructions	For safety co-ordination in England and Wales, instructions on each **User Site** and **Transmission Site**, approved by **NGET's** or **User's** relevant manager, setting down the methods of achieving the objectives of **NGET's** or the **User's Safety Rules**, as the case may be, to ensure the safety of personnel carrying out work or testing on **Plant** and/or **Apparatus** on which his **Safety Rules** apply and, in the case of a **User**, any other document(s) on a **User Site** which contains rules with regard to maintaining or securing the isolating position of an **Isolating Device**, or maintaining a physical separation or maintaining or securing the position of an **Earthing Device**.
Local Switching Procedure	A procedure produced under OC7.6 detailing the agreed arrangements in respect of carrying out of **Operational Switching** at **Connection Sites** and parts of the **National Electricity Transmission System** adjacent to those **Connection Sites**.
Localised Negative Reserve Active Power Margin or **Localised NRAPM**	That margin of **Active Power** sufficient to allow transfers to and from a **System Constraint Group** (as the case may be) to be contained within such reasonable limit as **The Company** may determine.
Location	Any place at which **Safety Precautions** are to be applied.
Locked	A condition of **HV Apparatus** that cannot be altered without the operation of a locking device.
Locking	The application of a locking device which enables **HV Apparatus** to be **Locked**.
Low Frequency Relay	Has the same meaning as **Under Frequency Relay**.
Low Voltage or **LV**	For **E&W Transmission Systems** a voltage not exceeding 250 volts. For **Scottish Transmission Systems**, a voltage exceeding 50 volts but not exceeding 1000 volts.
LV Side of the Offshore Platform	Unless otherwise specified in the **Bilateral Agreement**, the busbar on the **Offshore Platform** (typically 33kV) at which the relevant **Offshore Grid Entry Point** is located.
Main Plant and Apparatus	In respect of a **Power Station** (including **Power Stations** comprising of **DC Connected Power Park Modules**) is one or more of the principal items of **Plant** or **Apparatus** required to convert the primary source of energy into electricity. In respect of **HVDC Systems** or **DC Converters** or **Transmission DC Converters** is one of the principal items of **Plant** or **Apparatus** used to convert high voltage direct current to high voltage alternating current or vice versa. In respect of a **Network Operator's** equipment or a **Non-Embedded Customer's** equipment, is one of the principal items of **Plant** or **Apparatus** required to facilitate the import or export of **Active Power** or **Reactive Power** to or from a **Network Operator's** or **Non Embedded Customer's System**.

Main Protection	A **Protection** system which has priority above other **Protection** in initiating either a fault clearance or an action to terminate an abnormal condition in a power system.
Manufacturer's Data & Performance Report	A report submitted by a manufacturer to **The Company** relating to a specific version of a **Power Park Unit** demonstrating the performance characteristics of such **Power Park Unit** in respect of which **The Company** has evaluated its relevance for the purposes of the **Compliance Processes**.
Manufacturer's Test Certificates	A certificate prepared by a manufacturer which demonstrates that its **Power Generating Module** has undergone appropriate tests and conforms to the performance requirements expected by **The Company** in satisfying its compliance requirements and thereby satisfies the appropriate requirements of the Grid Code and **Bilateral Agreement**.
Market Operation Data Interface System (MODIS)	A computer system operated by **The Company** and made available for use by **Customers** connected to or using the **National Electricity Transmission System** for the purpose of submitting **EU Transparency Availability Data** to **The Company.**
Market Suspension Threshold	Has the meaning given to the term 'Market Suspension Threshold' in Section G of the **BSC**.
Material Effect	An effect causing **The Company** or a **Relevant Transmission Licensee** to effect any works or to alter the manner of operation of **Transmission Plant** and/or **Transmission Apparatus** at the **Connection Site** (which term shall, in this definition and in the definition of "**Modification**" only, have the meaning ascribed thereto in the **CUSC**) or the site of connection or a **User** to effect any works or to alter the manner of operation of its **Plant** and/or **Apparatus** at the **Connection Site** or the site of connection which in either case involves that party in expenditure of more than £10,000.
Materially Affected Party	Any person or class of persons designated by the **Authority** as such.
Maximum Export Capability	The maximum continuous **Active Power** that a **Network Operator** or **Non Embedded Customer** can export to the **Transmission System** at the **Grid Supply Point**, as specified in the **Bilateral Agreement**.
Maximum Export Capacity	The maximum continuous **Apparent Power** expressed in MVA and maximum continuous **Active Power** expressed in MW which can flow from an **Offshore Transmission System** connected to a **Network Operator's User System**, to that **User System**.
Maximum Capacity or P_{max}	The maximum continuous **Active Power** which a **Power Generating Module** can produce, less any demand associated solely with facilitating the operation of that **Power Generating Module** and not fed into the **System.**
Maximum Generation Service or MGS	A service utilised by **The Company** in accordance with the **CUSC** and the **Balancing Principles Statement** in operating the **Total System**.
Maximum Generation Service Agreement	An agreement between a **User** and **The Company** for the payment by **The Company** to that **User** in respect of the provision by such **User** of a **Maximum Generation Service**.

Maximum HVDC Active Power Transmission Capacity (PHmax)	The maximum continuous **Active Power** which an **HVDC System** can exchange with the network at each **Grid Entry Point** or **User System Entry Point** as specified in the **Bilateral Agreement** or as agreed between **The Company** and the **HVDC System Owner**.
Maximum Import Capability	The maximum continuous **Active Power** that a **Network Operator** or **Non Embedded Customer** can import from the **Transmission System** at the **Grid Supply Point**, as specified in the **Bilateral Agreement**.
Maximum Import Capacity	The maximum continuous **Apparent Power** expressed in MVA and maximum continuous **Active Power** expressed in MW which can flow to an **Offshore Transmission System** connected to a **Network Operator's User System**, from that **User System**.
Medium Power Station	A **Power Station** which is (a) directly connected to **NGET's Transmission System** where such **Power Station** has a **Registered Capacity** of 50MW or more but less than 100MW; or, (b) **Embedded** within a **User System** (or part thereof) where such **User System** (or part thereof) is connected under normal operating conditions to **NGET's Transmission System** and such **Power Station** has a **Registered Capacity** of 50MW or more but less than 100MW; or, (c) **Embedded** within a **User System** (or part thereof) where the **User System** (or part thereof) is not connected to the **National Electricity Transmission System**, although such **Power Station** is in **NGET's Transmission Area** and such **Power Station** has a **Registered Capacity** of 50MW or more but less than 100MW. For the avoidance of doubt a **Medium Power Station** could comprise of **Type A**, **Type B**, **Type C** or **Type D Power Generating Modules**.
Medium Voltage or **MV**	For **E&W Transmission Systems** a voltage exceeding 250 volts but not exceeding 650 volts.
Mills	Milling plant which supplies pulverised fuel to the boiler of a coal fired **Power Station**.
Minimum Generation	The minimum output (in whole MW) which a **Genset** can generate or **DC Converter** at a **DC Converter Station** can import or export to the **Total System** under stable operating conditions, as registered with **The Company** under the **PC** (and amended pursuant to the **PC**). For the avoidance of doubt, the output may go below this level as a result of operation in accordance with BC3.7.
Minimum Active Power Transmission Capacity (PHmin)	The minimum continuous **Active Power** which an **HVDC System** can exchange with the System at each **Grid Entry Point** or **User System Entry Point** as specified in the **Bilateral Agreement** or as agreed between **The Company** and the **HVDC System Owner**

Minimum Import Capacity	The minimum input (in whole MW) into a **DC Converter** at a **DC Converter Station** or **HVDC System at an HVDC Converter** (in any of its operating configurations) at the **Onshore Grid Entry Point** (or in the case of an **Embedded DC Converter** or an **Embedded HVDC Converter** at the **User System Entry Point**) at which a **DC Converter** or **HVDC Converter** can operate in a stable manner, as registered with **The Company** under the **PC** (and amended pursuant to the **PC**).
Minimum Regulating Level	The minimum **Active Power**, as specified in the **Bilateral Agreement** or as agreed between **The Company** and the **Generator**, down to which the **Power Generating Module** can control **Active Power**;
Minimum Stable Operating Level	The minimum **Active Power**, as specified in the **Bilateral Agreement** or as agreed between **The Company** and the **Generator**, at which the **Power Generating Module** can be operated stably for an unlimited time.
Modification	Any actual or proposed replacement, renovation, modification, alteration or construction by or on behalf of a **User** or **The Company** to either that **User's Plant** or **Apparatus** or **Transmission Plant** or **Apparatus**, as the case may be, or the manner of its operation which has or may have a **Material Effect** on **The Company** or a **User**, as the case may be, at a particular **Connection Site**.
Mothballed DC Connected Power Park Module	A **DC Connected Power Park Module** that has previously generated which the **Generator** plans not to use to generate for the remainder of the current **Financial Year** but which could be returned to service.
Mothballed DC Converter at a DC Converter Station	A **DC Converter** at a **DC Converter Station** that has previously imported or exported power which the **DC Converter Station** owner plans not to use to import or export power for the remainder of the current **Financial Year** but which could be returned to service.
Mothballed HVDC System	An **HVDC System** that has previously imported or exported power which the **HVDC System Owner** plans not to use to import or export power for the remainder of the current **Financial Year** but which could be returned to service.
Mothballed HVDC Converter	An **HVDC Converter** which is part of an **HVDC System** that has previously imported or exported power which the **HVDC System Owner** plans not to use to import or export power for the remainder of the current **Financial Year** but which could be returned to service.
Mothballed Generating Unit	A **Generating Unit** that has previously generated which the **Generator** plans not to use to generate for the remainder of the current **Financial Year** but which could be returned to service. For the avoidance of doubt a **Mothballed Generating Unit** could be part of a **Power Generating Module**.
Mothballed Power Generating Module	A **Power Generating Module** that has previously generated which the **Generator** plans not to use to generate for the remainder of the current **Financial Year** but which could be returned to service.
Mothballed Power Park Module	A **Power Park Module** that has previously generated which the **Generator** plans not to use to generate for the remainder of the current **Financial Year** but which could be returned to service.

Multiple Point of Connection	A double (or more) **Point of Connection**, being two (or more) **Points of Connection** interconnected to each other through the **User's System**.
MSID	Has the meaning a set out in the **BSC**, covers Metering System Identifier
National Demand	The amount of electricity supplied from the **Grid Supply Points** plus:- • that supplied by **Embedded Large Power Stations**, and • **National Electricity Transmission System Losses**, minus:- • the **Demand** taken by **Station Transformers** and **Pumped Storage Units'** and, for the purposes of this definition, does not include:- • any exports from the **National Electricity Transmission System** across **External Interconnections**.
National Electricity Transmission System	The **Onshore Transmission System** and, where owned by **Offshore Transmission Licensees**, **Offshore Transmission Systems**.
National Electricity Transmission System Demand	The amount of electricity supplied from the **Grid Supply Points** plus:- • that supplied by **Embedded Large Power Stations**, and • exports from the **National Electricity Transmission System** across **External Interconnections**, and • **National Electricity Transmission System Losses**, and, for the purposes of this definition, includes:- • the **Demand** taken by **Station Transformers** and **Pumped Storage Units**.
National Electricity Transmission System Losses	The losses of electricity incurred on the **National Electricity Transmission System**.
National Electricity Transmission System Operator Area	Has the meaning set out in Schedule 1 of **The Company's Transmission Licence**.
National Electricity Transmission System Study Network Data File	A computer file produced by **The Company** which in **The Company's** view provides an appropriate representation of the **National Electricity Transmission System** for a specific point in time. The computer file will contain information and data on **Demand** on the **National Electricity Transmission System** and on **Large Power Stations** including **Genset** power output consistent with **Output Usable** and **The Company's** view of prevailing system conditions.

National Electricity Transmission System Warning	A warning issued by **The Company** to **Users** (or to certain **Users** only) in accordance with OC7.4.8.2, which provides information relating to **System** conditions or **Events** and is intended to : (a) alert **Users** to possible or actual **Plant** shortage, **System** problems and/or **Demand** reductions; (b) inform of the applicable period; (c) indicate intended consequences for **Users**; and (d) enable specified **Users** to be in a state of readiness to receive instructions from **The Company**.
National Electricity Transmission System Warning - Demand Control Imminent	A warning issued by **The Company**, in accordance with OC7.4.8.7, which is intended to provide short term notice, where possible, to those **Users** who are likely to receive **Demand** reduction instructions from **The Company** within 30 minutes.
National Electricity Transmission System Warning - High Risk of Demand Reduction	A warning issued by **The Company**, in accordance with OC7.4.8.6, which is intended to alert recipients that there is a high risk of **Demand** reduction being implemented and which may normally result from an **Electricity Margin Notice**.
National Electricity Transmission System Warning - Electricity Margin Notice	A warning issued by **The Company**, in accordance with OC7.4.8.5, which is intended to invite a response from and to alert recipients to a decreased **System Margin**.
National Electricity Transmission System Warning - Risk of System Disturbance	A warning issued by **The Company**, in accordance with OC7.4.8.8, which is intended to alert **Users** of the risk of widespread and serious **System** disturbance which may affect **Users**.
Network Data	The data to be provided by **The Company** to **Users** in accordance with the **PC**, as listed in Part 3 of the Appendix to the **PC**.
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**.
NGET	National Grid Electricity Transmission plc (NO: 2366977) whose registered office is at 1-3 Strand, London, WC2N 5EH
No-Load Field Voltage	Shall have the meaning ascribed to that term in **IEC** 34-16-1:1991 [equivalent to **British Standard BS**4999 Section 116.1 : 1992].
No System Connection	As defined in OC8A.1.6.2 and OC8B.1.7.2
Non-Synchronous Electricity Storage Module	A **Power Park Module** comprising soley of one or more **Non-Synchronous Electricity Storage Units**.

Notification of User's Intention to Operate	A notification from a **Network Operator** or **Non-Embedded Customer** to **The Company** informing **The Company** of the date upon which any **Network Operator's** or **Non-Embedded Customer's Plant** and **Apparatus** at an **EU Grid Supply Point** will be ready to be connected to the **Transmission System**.
Notification of User's Intention to Synchronise	A notification from a **Generator** or **DC Converter Station** owner or **HVDC System Owner** to **The Company** informing **The Company** of the date upon which any **OTSUA**, a **Generating Unit**(s), **CCGT Module**(s), **Power Park Module**(s), **Power Generating Module**(s) (including a **DC Connected Power Park Module**(s)), **HVDC System** or **DC Converter**(s) will be ready to be **Synchronised** to the **Total System**.
Non-Dynamic Frequency Response Service	A **Demand Response Service** in which the **Demand** is controlled through discrete switching rather than through continuous load changes in response to **System Frequency** changes.
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.
Non-Synchronous Generating Unit	An **Onshore Non-Synchronous Generating Unit** or **Offshore Non-Synchronous Generating Unit** which could form part of a **Power Generating Module**.
Normal CCGT Module	A **CCGT Module** other than a **Range CCGT Module**.
Novel Unit	A tidal, wave, wind, geothermal, or any similar, **Generating Unit**.
OC9 De-synchronised Island Procedure	Has the meaning set out in OC9.5.4.
Offshore	Means wholly or partly in **Offshore Waters**, and when used in conjunction with another term and not defined means that the associated term is to be read accordingly.
Offshore DC Converter	Any **User Apparatus** located **Offshore** used to convert alternating current electricity to direct current electricity, or vice versa. An **Offshore DC Converter** is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion.
Offshore HVDC Converter	Any **User Apparatus** located **Offshore** used to convert alternating current electricity to direct current electricity, or vice versa. An **Offshore HVDC Converter** is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion.
Offshore Development Information Statement	A statement prepared by **The Company** in accordance with Special Condition C4 of **The Company's Transmission Licence**.
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**..

Offshore Grid Entry Point	In the case of:- (a) an **Offshore Generating Unit** or an **Offshore Synchronous Power Generating Module** or an **Offshore DC Converter** or an **Offshore HVDC Converter**, as the case may be, which is directly connected to an **Offshore Transmission System**, the point at which it connects to that **Offshore Transmission System**, or; (b) an **Offshore Power Park Module** which is directly connected to an **Offshore Transmission System**, the point where one **Power Park String** (registered by itself as a **Power Park Module**) or the collection of points where a number of **Offshore Power Park Strings** (registered as a single **Power Park Module**) connects to that **Offshore Transmission System**, or; (c) an **External Interconnection** which is directly connected to an **Offshore Transmission System**, the point at which it connects to that **Offshore Transmission System.**
Offshore Non-Synchronous Generating Unit	An **Offshore Generating Unit** that is not an **Offshore Synchronous Generating Unit** including for the avoidance of doubt a **Power Park Unit** located **Offshore**.
Offshore Platform	A single structure comprising of **Plant** and **Apparatus** located **Offshore** which includes one or more **Offshore Grid Entry Points**.
Offshore Power Park Module	A collection of one or more **Offshore Power Park Strings** (registered as a **Power Park Module** under the **PC**). There is no limit to the number of **Power Park Strings** within the **Power Park Module**, so long as they either: (a) connect to the same busbar which cannot be electrically split; or (b) connect to a collection of directly electrically connected busbars of the same nominal voltage and are configured in accordance with the operating arrangements set out in the relevant **Bilateral Agreement**.
Offshore Power Park String	A collection of **Offshore Generating Units** or **Power Park Units** that are powered by an **Intermittent Power Source**, joined together by cables forming part of a **User System** with a single point of connection to an **Offshore Transmission System**. The connection to an **Offshore Transmission System** may include a **DC Converter** or **HVDC Converter**.
Offshore Synchronous Generating Unit	An **Offshore Generating Unit** which could be part of an **Offshore Synchronous Power Generating Module** in which, under all steady state conditions, the rotor rotates at a mechanical speed equal to the electrical frequency of the **National Electricity Transmission System** divided by the number of pole pairs of the **Generating Unit**.
Offshore Synchronous Power Generating Module	A **Synchronous Power Generating Module** located **Offshore**.
Offshore Tender Process	The process followed by the **Authority** to make, in prescribed cases, a determination on a competitive basis of the person to whom an offshore transmission licence is to be granted.

Offshore Transmission Distribution Connection Agreement	An agreement entered into by **The Company** and a **Network Operator** in respect of the connection to and use of a **Network Operator's User System** by an **Offshore Transmission System**.
Offshore Transmission Licensee	Such person in relation to whose **Transmission Licence** the standard conditions in Section E (offshore transmission owner standard conditions) of such **Transmission Licence** have been given effect, or any person in that prospective role who has acceded to the **STC**.
Offshore Transmission System	A system consisting (wholly or mainly) of high voltage electric lines and used for the transmission of electricity from one **Power Station** to a sub-station or to another **Power Station** or between sub-stations, and includes any **Plant** and **Apparatus** (including **OTSUA**) and meters in connection with the transmission of electricity but does not include any **Remote Transmission Assets**. An **Offshore Transmission System** extends from the **Interface Point**, or the **Offshore Grid Entry Point(s)** and may include **Plant** and **Apparatus** located **Onshore** and **Offshore** and, where the context permits, references to the **Offshore Transmission System** includes **OTSUA**.
Offshore Transmission System Development User Works or **OTSDUW**	In relation to a particular **User** where the **OTSDUW Arrangements** apply, means those activities and/or works for the design, planning, consenting and/or construction and installation of the **Offshore Transmission System** to be undertaken by the **User** as identified in Part 2 of Appendix I of the relevant **Construction Agreement**.
Offshore Transmission System User Assets or **OTSUA**	**OTSDUW Plant and Apparatus** constructed and/or installed by a **User** under the **OTSDUW Arrangements** which form an **Offshore Transmission System** that once transferred to a **Relevant Transmission Licensee** under an **Offshore Tender Process** will become part of the **National Electricity Transmission System**.
Offshore Waters	Has the meaning given to "offshore waters" in Section 90(9) of the Energy Act 2004.
Offshore Works Assumptions	In relation to a particular **User** means those assumptions set out in Appendix P of the relevant **Construction Agreement** as amended from time to time.
Onshore	Means within **Great Britain**, and when used in conjunction with another term and not defined means that the associated term is to be read accordingly.
Onshore DC Converter	Any **User Apparatus** located **Onshore** with a **Completion Date** after 1st April 2005 used to convert alternating current electricity to direct current electricity, or vice versa. An **Onshore DC Converter** is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion. In a bipolar arrangement, an **Onshore DC Converter** represents the bipolar configuration.
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**.

Onshore Grid Entry Point	A point at which a **Onshore Generating Unit** or a **CCGT Module** or a **CCGT Unit** or an **Onshore Power Generating Module** or a **Onshore DC Converter** or an **Onshore HVDC Converter** or a **Onshore Power Park Module** or an **External Interconnection**, as the case may be, which is directly connected to the **Onshore Transmission System** connects to the **Onshore Transmission System**.
Onshore HVDC Converter	Any **User Apparatus** located **Onshore** used to convert alternating current electricity to direct current electricity, or vice versa. An **Onshore HVDC Converter** is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion. In a bipolar arrangement, an **Onshore HVDC Converter** represents the bipolar configuration.
Onshore Non-Synchronous Generating Unit	A **Generating Unit** located **Onshore** that is not a **Synchronous Generating Unit** including for the avoidance of doubt a **Power Park Unit** located **Onshore**.
Onshore Power Park Module	A collection of **Non-Synchronous Generating Units** (registered as a **Power Park Module** under the **PC**) that are powered by an **Intermittent Power Source** or connected through power electronic conversion technology, joined together by a **System** with a single electrical point of connection directly to the **Onshore Transmission System** (or **User System** if **Embedded**) with no intermediate **Offshore Transmission System** connections. The connection to the **Onshore Transmission System** (or **User System** if **Embedded**) may include a **DC Converter** or **HVDC Converter**.
Onshore Synchronous Generating Unit	An **Onshore Generating Unit** (which could also be part of an **Onshore Power Generating Module**) including, for the avoidance of doubt, a **CCGT Unit** in which, under all steady state conditions, the rotor rotates at a mechanical speed equal to the electrical frequency of the **National Electricity Transmission System** divided by the number of pole pairs of the **Generating Unit**.
Onshore Synchronous Power Generating Module	A **Synnchronous Power Generating Module** located **Onshore**.
Onshore Transmission Licensee	**NGET**, **SPT**, or **SHETL**.
Onshore Transmission System	The system consisting (wholly or mainly) of high voltage electric lines owned or operated by **Onshore Transmission Licensees** or operated by **The Company** and used for the transmission of electricity from one **Power Station** to a substation or to another **Power Station** or between substations or to or from **Offshore Transmission Systems** or to or from any **External Interconnection**, and includes any **Plant** and **Apparatus** and meters owned or operated by any **Onshore Transmission Licensee** in connection with the transmission of electricity but does not include any **Remote Transmission Assets**.
On-Site Generator Site	A site which is determined by the **BSC Panel** to be a Trading Unit under the **BSC** by reason of having fulfilled the Class 1 or Class 2 requirements as such terms are used in the **BSC**.
Operating Code or **OC**	That portion of the Grid Code which is identified as the **Operating Code**.

Operating Margin	**Contingency Reserve** plus **Operating Reserve**.
Operating Reserve	The additional output from **Large Power Stations** or the reduction in **Demand**, which must be realisable in real-time operation to respond in order to contribute to containing and correcting any **System Frequency** fall to an acceptable level in the event of a loss of generation or a loss of import from an **External Interconnection** or mismatch between generation and **Demand**.
Operation	A scheduled or planned action relating to the operation of a **System** (including an **Embedded Power Station**).
Operational Data	Data required under the **Operating Codes** and/or **Balancing Codes**.
Operational Day	The period from 0500 hours on one day to 0500 on the following day.
Operation Diagrams	Diagrams which are a schematic representation of the **HV Apparatus** and the connections to all external circuits at a **Connection Site** (and in the case of **OTSDUW**, **Transmission Interface Site**), incorporating its numbering, nomenclature and labelling.
Operational Effect	Any effect on the operation of the relevant other **System** which causes the **National Electricity Transmission System** or the **System** of the other **User** or **Users**, as the case may be, to operate (or be at a materially increased risk of operating) differently to the way in which they would or may have operated in the absence of that effect.
Operational Intertripping	The automatic tripping of circuit-breakers to prevent abnormal system conditions occurring, such as over voltage, overload, **System** instability, etc. after the tripping of other circuit-breakers following power **System** fault(s) which includes **System** to **Generating Unit**, **System** to **CCGT Module**, **System** to **Power Park Module**, **System** to **DC Converter, System to Power Generating Module**, **System** to **HVDC Converter** and **System** to **Demand** intertripping schemes.
Operational Notifications	Any **Energisation Operational Notification**, **Interim Operational Notification**, **Final Operational Notification** or **Limited Operational Notification** issued from **The Company** to a **User**.
Operational Planning	Planning through various timescales the matching of generation output with forecast **National Electricity Transmission System Demand** together with a reserve of generation to provide a margin, taking into account outages of certain **Generating Units** or **Power Generating Modules**, of parts of the **National Electricity Transmission System** and of parts of **User Systems** to which **Power Stations** and/or **Customers** are connected, carried out to achieve, so far as possible, the standards of security set out in **The Company's Transmission Licence**, each **Relevant Transmission Licensee's Transmission Licence** or **Electricity Distribution Licence**, as the case may be.
Operational Planning Margin	An operational planning margin set by **The Company**.
Operational Planning Phase	The period from 8 weeks to the end of the 5^{th} year ahead of real time operation.

Operational Procedures	Management instructions and procedures, both in support of the **Safety Rules** and for the local and remote operation of **Plant** and **Apparatus**, issued in connection with the actual operation of **Plant** and/or **Apparatus** at or from a **Connection Site**.
Operational Switching	Operation of **Plant** and/or **Apparatus** to the instruction of the relevant **Control Engineer**. For the avoidance of doubt, the operation of **Transmission Plant** and/or **Apparatus** forming part of the **National Electricity Transmission System** will be to the instruction of the **Relevant Transmission Licensee**.
Other Relevant Data	The data listed in BC1.4.2(f) under the heading **Other Relevant Data**.
OTSDUW Arrangements	The arrangements whereby certain aspects of the design, consenting, construction, installation and/or commissioning of transmission assets are capable of being undertaken by a **User** prior to the transfer of those assets to a **Relevant Transmission Licensee** under an **Offshore Tender Process**.
OTSDUW Data and Information	The data and information to be provided by **Users** undertaking **OTSDUW**, to **The Company** in accordance with Appendix F of the **Planning Code**.
OTSDUW DC Converter	A **Transmission DC Converter** designed and/or constructed and/or installed by a **User** under the **OTSDUW Arrangements** and/or operated by the **User** until the **OTSUA Transfer Time**.
OTSDUW Development and Data Timetable	The timetable for both the delivery of **OTSDUW Data and Information** and **OTSDUW Network Data and Information** as referred to in Appendix F of the **Planning Code** and the development of the scope of the **OTSDUW**.
OTSDUW Network Data and Information	The data and information to be provided by **The Company** to **Users** undertaking **OTSDUW** in accordance with Appendix F of the **Planning Code**.
OTSDUW Plant and Apparatus	**Plant** and **Apparatus**, including any **OTSDUW DC Converter**, designed by the **User** under the **OTSDUW Arrangements**.
OTSUA Transfer Time	The time and date at which the **OTSUA** are transferred to a **Relevant Transmission Licensee**.
Out of Synchronism	The condition where a **System** or **Generating Unit** or **Power Generating Module** cannot meet the requirements to enable it to be **Synchronised**.
Output Usable or **OU**	The (daily or weekly) forecast value (in MW), at the time of the (daily or weekly) peak demand, of the maximum level at which the **Genset** can export to the **Grid Entry Point**, or in the case of **Embedded Power Stations**, to the **User System Entry Point**. In addition, for a **Genset** powered by an **Intermittent Power Source** the forecast value is based upon the **Intermittent Power Source** being at a level which would enable the **Genset** to generate at **Registered Capacity**. For the purpose of OC2 only, the term **Output Usable** shall include the terms **Interconnector Export Capacity** and **Interconnector Import Capacity** where the term **Output Usable** is being applied to an **External Interconnection**.
Over-excitation Limiter	Shall have the meaning ascribed to that term in **IEC** 34-16-1:1991 [equivalent to **British Standard BS**4999 Section 116.1 : 1992].

Panel Chairman	A person appointed as such in accordance with GR.4.1.
Panel Member	Any of the persons identified as such in GR.4.
Panel Members' Recommendation	The recommendation in accordance with the "**Grid Code Review Panel Recommendation Vote**"
Panel Secretary	A person appointed as such in accordance with GR.3.1.2(d).
Part 1 System Ancillary Services	**Ancillary Services** which are required for **System** reasons and which must be provided by **Users** in accordance with the **Connection Conditions**. An exhaustive list of **Part 1 System Ancillary Services** is included in that part of CC.8.1 headed Part 1.
Part 2 System Ancillary Services	**Ancillary Services** which are required for **System** reasons and which must be provided by a **User** if the **User** has agreed to provide them under a **Bilateral Agreement**. A non-exhaustive list of **Part 2 System Ancillary Services** is included in that part of CC.8.1 headed Part 2.
Part Load	The condition of a **Genset**, or **Cascade Hydro Scheme** which is **Loaded** but is not running at its Maximum Export Limit.
Permit for Work for proximity work	In respect of **E&W Transmission Systems**, a document issued by the **Relevant E&W Transmission Licensee** or an **E&W User** in accordance with its respective **Safety Rules** to enable work to be carried out in accordance with OC8A.8 and which provides for **Safety Precautions** to be applied and maintained. An example format of a **Relevant E&W Transmission Licensee**'s permit for work is attached as Appendix E to **OC8A**. In respect of **Scottish Transmission Systems**, a document issued by a **Relevant Scottish Transmission Licensee** or a **Scottish User** in accordance with its respective **Safety Rules** to enable work to be carried out in accordance with OC8B.8 and which provides for **Safety Precautions** to be applied and maintained. Example formats of **Relevant Scottish Transmission Licensees'** permits for work are attached as Appendix E to **OC8B**.
Partial Shutdown	The same as a **Total Shutdown** except that all generation has ceased in a separate part of the **Total System** and there is no electricity supply from **External Interconnections** or other parts of the **Total System** to that part of the **Total System** and, therefore, that part of the **Total System** is shutdown, with the result that it is not possible for that part of the **Total System** to begin to function again without **The Company's** directions relating to a **Black Start**.
Pending Grid Code Modification Proposal	A **Grid Code Modification Proposal** in respect of which, at the relevant time, the **Authority** has not yet made a decision as to whether to direct such **Grid Code Modification Proposal** to be made pursuant to the **Transmission Licence** (whether or not a **Grid Code Modification Report** has been submitted in respect of such **Grid Code Modification Proposal**) or, in the case of a **Grid Code Self Governance Proposals**, in respect of which the **Grid Code Review Panel** has not yet voted whether or not to approve.
Phase (Voltage) Unbalance	The ratio (in percent) between the rms values of the negative sequence component and the positive sequence component of the voltage.

Physical Notification	Data that describes the **BM Participant**'s best estimate of the expected input or output of **Active Power** of a **BM Unit** and/or (where relevant) **Generating Unit**, the accuracy of the **Physical Notification** being commensurate with **Good Industry Practice**.
Planning Code or **PC**	That portion of the Grid Code which is identified as the **Planning Code**.
Planned Maintenance Outage	An outage of **The Company's** electronic data communication facilities as provided for in CC.6.5.8 and **The Company's** associated computer facilities of which normally at least 5 days notice is given, but in any event of which at least twelve hours notice has been given by **The Company** to the **User** and which is anticipated to last no longer than 2 hours. The length of such an outage may in exceptional circumstances be extended where at least 24 hours notice has been given by **The Company** to the **User**. It is anticipated that normally any planned outage would only last around one hour.
Planned Outage	An outage of a **Large Power Station** or of part of the **National Electricity Transmission System**, or of part of a **User System**, co-ordinated by **The Company** under **OC2**.
Plant	Fixed and movable items used in the generation and/or supply and/or transmission of electricity, other than **Apparatus**.
Point of Common Coupling	That point on the **National Electricity Transmission System** electrically nearest to the **User** installation at which either **Demands** or **Loads** are, or may be, connected.
Point of Connection	An electrical point of connection between the **National Electricity Transmission System** and a **User's System**.
Point of Isolation	The point on **Apparatus** (as defined in OC8A.1.6.2 and OC8B.1.7.2) at which **Isolation** is achieved.
Post-Control Phase	The period following real time operation.
Power Available	A signal prepared in accordance with good industry practice, representing the instantaneous sum of the potential **Active Power** available from each individual **Power Park Unit** within the **Power Park Module** calculated using any applicable combination of meteorological (including wind speed), electrical or mechanical data measured at each **Power Park Unit** at a specified time. **Power Available** shall be a value between 0MW and **Registered Capacity** or **Maximum Capacity** which is the sum of the potential **Active Power** available of each **Power Park Unit** within the **Power Park Module.** A turbine that is not generating will be considered as not available. For the avoidance of doubt, the **Power Available** signal would be the **Active Power** output that a **Power Park Module** could reasonably be expected to export at the **Grid Entry Point** or **User System Entry Point** taking all the above criteria into account including **Power Park Unit** constraints such as optimisation modes but would exclude a reduction in the **Active Power** export of the **Power Park Module** instructed by **The Company** (for example) for the purposes selecting a **Power Park Module** to operate in **Frequency Sensitive Mode** or when an **Emergency Instruction** has been issued.
Power Factor	The ratio of **Active Power** to **Apparent Power**.

Power-Generating Module	Either a **Synchronous Power-Generating Module** or a **Power Park Module** owned or operated by an **EU Generator**.
Power-Generating Module Document (PGMD)	A document provided by the **Generator** to **The Company** for a **Type B** or **Type C Power Generating Module** which confirms that the **Power Generating Module's** compliance with the technical criteria set out in the Grid Code has been demonstrated and provides the necessary data and statements, including a statement of compliance.
Power Generating Module Performance Chart	A diagram showing the **Real Power** (MW) and **Reactive Power** (MVAr) capability limits within which a **Synchronous Power Generating Module** or **Power Park Module** at its **Grid Entry Point** or **User System Entry Point** will be expected to operate under steady state conditions.
Power Island	**Gensets** at an isolated **Power Station**, together with complementary local **Demand**. In Scotland a **Power Island** may include more than one **Power Station**.
Power Park Module	Any **Onshore Power Park Module** or **Offshore Power Park Module**.
Power Park Module Availability Matrix	The matrix described in Appendix 1 to BC1 under the heading **Power Park Module Availability Matrix**.
Power Park Module Planning Matrix	A matrix in the form set out in Appendix 4 of OC2 showing the combination of **Power Park Units** within a **Power Park Module** which would be expected to be running under normal conditions.
Power Park Unit	A **Generating Unit** within a **Power Park Module**.
Power Station	An installation comprising one or more **Generating Units** or **Power Park Modules** or **Power Generating Modules** (even where sited separately) owned and/or controlled by the same **Generator**, which may reasonably be considered as being managed as one **Power Station**.
Power System Stabiliser or **PSS**	Equipment controlling the **Exciter** output via the voltage regulator in such a way that power oscillations of the synchronous machines are dampened. Input variables may be speed, frequency or power (or a combination of these).
Preface	The preface to the Grid Code (which does not form part of the Grid Code and therefore is not binding).
Preliminary Notice	A notice in writing, sent by **The Company** both to all **Users** identified by it under OC12.4.2.1 and to the **Test Proposer**, notifying them of a proposed **System Test**.
Preliminary Project Planning Data	Data relating to a proposed **User Development** at the time the **User** applies for a **CUSC Contract** but before an offer is made and accepted.

Primary Response	The automatic increase in **Active Power** output of a **Genset** or, as the case may be, the decrease in **Active Power Demand** in response to a **System Frequency** fall. This increase in **Active Power** output or, as the case may be, the decrease in **Active Power Demand** must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** fall on the basis set out in the **Ancillary Services Agreement** and fully available by the latter, and sustainable for at least a further 20 seconds. The interpretation of the **Primary Response** to a – 0.5 Hz frequency change is shown diagrammatically in Figure CC.A.3.2 and Figure ECC.A.3.2
Private Network	A network which connects to a **Network Operator's System** and that network belongs to a **User** who is not classified as a **Generator**, **Network Operator** or **Non Embedded Customer**.
Programming Phase	The period between the **Operational Planning Phase** and the **Control Phase**. It starts at the 8 weeks ahead stage and finishes at 17:00 on the day ahead of real time.
Proposal Notice	A notice submitted to **The Company** by a **User** which would like to undertake a **System Test**.
Proposal Report	A report submitted by the **Test Panel** which contains: (a) proposals for carrying out a **System Test** (including the manner in which the **System Test** is to be monitored); (b) an allocation of costs (including un-anticipated costs) between the affected parties (the general principle being that the **Test Proposer** will bear the costs); and (c) such other matters as the **Test Panel** considers appropriate. The report may include requirements for indemnities to be given in respect of claims and losses arising from a **System Test**.
Proposed Implementation Date	The proposed date(s) for the implementation of a **Grid Code Modification Proposal** or **Workgroup Alternative Grid Code Modification** such date(s) to be either (i) described by reference to a specified period after a direction from the Authority approving the **Grid Code Modification Proposal** or **Workgroup Alternative Grid Code Modification** or (ii) a **Fixed Proposed Implementation Date**.
Protection	The provisions for detecting abnormal conditions on a **System** and initiating fault clearance or actuating signals or indications.
Protection Apparatus	A group of one or more **Protection** relays and/or logic elements designated to perform a specified **Protection** function.
Pump Storage	A a hydro unit in which water can be raised by means of pumps and stored to be used for the generation of electrical energy;
Pumped Storage Generator	A **Generator** which owns and/or operates any **Pumped Storage Plant**.
Pumped Storage Plant	The Dinorwig, Ffestiniog, Cruachan and Foyers **Power Stations**.
Pumped Storage Unit	A **Generating Unit** within a **Pumped Storage Plant**.

Purchase Contracts	A final and binding contract for the purchase of the **Main Plant and Apparatus**.
Q/Pmax	The ratio of **Reactive Power** to the **Maximum Capacity**. The relationship between **Power Factor** and **Q/Pmax** is given by the formula:- **Power Factor** = Cos $[\arctan[\frac{Q}{Pmax}]]$ For example, a **Power Park Module** with a Q/P value of +0.33 would equate to a **Power Factor** of Cos(arctan0.33) = 0.95 **Power Factor** lag.
Quick Resynchronisation Capability	The capability of a **Type C** or **Type D Power Generating Module** as defined in ECC.6.3.5.6. For the avoidance of doubt this requirement only applies to **EU Code Generators** who own or operate a **Type C** or **Type D Power Generating Module**.
Quick Resynchronisation Unit Test	A test undertaken on **Generating Unit** forming part of a **Type C** or **Type D Power Generating Module** as detailed in OC5.7.1 and OC5.7.4 necessary to determine its ability to demonstrate a **Quick Resynchronisation Capability**.
Range CCGT Module	A **CCGT Module** where there is a physical connection by way of a steam or hot gas main between that **CCGT Module** and another **CCGT Module** or other **CCGT Modules**, which connection contributes (if open) to efficient modular operation, and which physical connection can be varied by the operator.
Rated Field Voltage	Shall have the meaning ascribed to that term in **IEC** 34-16-1:1991 [equivalent to **British Standard BS**4999 Section 116.1 : 1992].
Rated MW	The "rating-plate" MW output of a **Power Generating Module**, **Generating Unit**, **Power Park Module**, **HVDC Converter** or **DC Converter**, being: (a) that output up to which the **Generating Unit** was designed to operate (Calculated as specified in **British Standard BS** EN 60034 – 1: 1995); or (b) the nominal rating for the MW output of a **Power Park Module** or **Power Generating Module** being the maximum continuous electric output power which the **Power Park Module** or **Power Generating Module** was designed to achieve under normal operating conditions; or (c) the nominal rating for the MW import capacity and export capacity (if at a **DC Converter Station** or **HVDC Converter Station**) of a **DC Converter** or **HVDC Converter**.
Reactive Despatch Instruction	Has the meaning set out in the **CUSC**.

Reactive Despatch Network Restriction	A restriction placed upon an **Embedded Power Generating Module**, **Embedded Generating Unit**, **Embedded Power Park Module** or **DC Converter** at an **Embedded DC Converter Station** or **HVDC Converter** at an **Embedded HVDC Converter Station** by the **Network Operator** that prevents the **Generator** or **DC Converter Station** owner or **HVDC System Owner** in question (as applicable) from complying with any **Reactive Despatch Instruction** with respect to that **Power Generating Module**, **Generating Unit**, **Power Park Module** or **DC Converter** at a **DC Converter Station** or **HVDC Converter** at a **HVDC Converter Station**, whether to provide Mvars over the range referred to in CC 6.3.2, ECC.6.3.2 or otherwise.
Reactive Energy	The integral with respect to time of the **Reactive Power**.
Reactive Power	The product of voltage and current and the sine of the phase angle between them measured in units of voltamperes reactive and standard multiples thereof, ie: 1000 VAr = 1 kVAr 1000 kVAr = 1 Mvar
Record of Inter-System Safety Precautions or **RISSP**	A written record of inter-system **Safety Precautions** to be compiled in accordance with the provisions of **OC8**.

Registered Capacity	(a) In the case of a **Generating Unit** other than that forming part of a **CCGT Module** or **Power Park Module** or **Power Generating Module**, the normal full load capacity of a **Generating Unit** as declared by the **Generator**, less the MW consumed by the **Generating Unit** through the **Generating Unit's Unit Transformer** when producing the same (the resultant figure being expressed in whole MW, or in MW to one decimal place). (b) In the case of a **CCGT Module** or **Power Park Module** owned or operated by a **GB Generator**, the normal full load capacity of the **CCGT Module** or **Power Park Module** (as the case may be) as declared by the **GB Generator**, being the **Active Power** declared by the **GB Generator** as being deliverable by the **CCGT Module** or **Power Park Module** at the **Grid Entry Point** (or in the case of an **Embedded CCGT Module** or **Power Park Module**, at the **User System Entry Point**), expressed in whole MW, or in MW to one decimal place. For the avoidance of doubt **Maximum Capacity** would apply to **Power Generating Modules** which form part of a **Large**, **Medium** or **Small Power Stations**. (c) In the case of a **Power Station**, the maximum amount of **Active Power** deliverable by the **Power Station** at the **Grid Entry Point** (or in the case of an **Embedded Power Station** at the **User System Entry Point**), as declared by the **Generator**, expressed in whole MW, or in MW to one decimal place. The maximum **Active Power** deliverable is the maximum amount deliverable simultaneously by the **Power Generating Modules** and/or **Generating Units** and/or **CCGT Modules** and/or **Power Park Modules** less the MW consumed by the **Power Generating Modules** and/or **Generating Units** and/or **CCGT Modules** in producing that **Active Power** and forming part of a **Power Station**. (d) In the case of a **DC Converter** at a **DC Converter Station** or **HVDC Converter** at an **HVDC Converter Station**, the normal full load amount of **Active Power** transferable from a **DC Converter** or **HVDC Converter** at the **Onshore Grid Entry Point** (or in the case of an **Embedded DC Converter Station** or an **Embedded HVDC Converter Station** at the **User System Entry Point**), as declared by the **DC Converter Station** owner or **HVDC System Owner**, expressed in whole MW, or in MW to one decimal place. (e) In the case of a **DC Converter Station** or **HVDC Converter Station**, the maximum amount of **Active Power** transferable from a **DC Converter Station** or **HVDC Converter Station** at the **Onshore Grid Entry Point** (or in the case of an **Embedded DC Converter Station** or **Embedded HVDC Converter Station** at the **User System Entry Point**), as declared by the **DC Converter Station** owner or **HVDC System Owner**, expressed in whole MW, or in MW to one decimal place.
Registered Data	Those items of **Standard Planning Data** and **Detailed Planning Data** which upon connection become fixed (subject to any subsequent changes).

Registered Import Capability	In the case of a **DC Converter Station** or **HVDC Converter Station** containing **DC Converters** or **HVDC Converters** connected to an **External System**, the maximum amount of **Active Power** transferable into a **DC Converter Station** or **HVDC Converter Station** at the **Onshore Grid Entry Point** (or in the case of an **Embedded DC Converter Station** or **Embedded HVDC Converter Station** at the **User System Entry Point**), as declared by the **DC Converter Station** owner or **HVDC System Owner**, expressed in whole MW. In the case of a **DC Converter** or **HVDC Converter** connected to an **External System** and in a **DC Converter Station** or **HVDC Converter Station**, the normal full load amount of **Active Power** transferable into a **DC Converter** or **HVDC Converter** at the **Onshore Grid Entry Point** (or in the case of an **Embedded DC Converter Station** or **Embedded HVDC Converter Station** at the **User System Entry Point**), as declared by the **DC Converter** owner or **HVDC System Owner**, expressed in whole MW.
Regulations	The Utilities Contracts Regulations 1996, as amended from time to time.
Reheater Time Constant	Determined at **Registered Capacity**, the reheater time constant will be construed in accordance with the principles of the IEEE Committee Report "Dynamic Models for Steam and Hydro Turbines in Power System Studies" published in 1973 which apply to such phrase.
Rejected Grid Code Modification Proposal	A **Grid Code Modification Proposal** in respect of which the **Authority** has decided not to direct **The Company** to modify the **Grid Code** pursuant to **The Company's Transmission Licence** in the manner set out herein or, in the case of a **Grid Code Self Governance Proposals**, in respect of which the **Grid Code Review Panel** has voted not to approve.
Related Person	means, in relation to an individual, any member of his immediate family, his employer (and any former employer of his within the previous 12 months), any partner with whom he is in partnership, and any company or Affiliate of a company in which he or any member of his immediate family controls more than 20% of the voting rights in respect of the shares of the company;
Relevant E&W Transmission Licensee	As the context requires **NGET** and/or an **E&W Offshore Transmission Licensee**.
Relevant Party	Has the meaning given in GR15.10(a).
Relevant Scottish Transmission Licensee	As the context requires **SPT** and/or **SHETL** and/or a **Scottish Offshore Transmission Licensee**.
Relevant Transmission Licensee	Means National Grid Electricity Transmission plc (**NGET)** in its **Transmission Area** or SP Transmission Ltd (**SPT**) in its **Transmission Area** or Scottish Hydro-Electric Transmission Ltd (**SHETL**) in its **Transmission Area** or any **Offshore Transmission Licensee** in its **Transmission Area**.
Relevant Unit	As defined in the **STC**, Schedule 3.
Remote End HVDC Converter Station	An **HVDC Converter Station** which forms part of an **HVDC System** and is not directly connected to the AC part of the **GB Synchronous Area**.

Remote Transmission Assets	Any **Plant** and **Apparatus** or meters owned by **NGET** which: (a) are **Embedded** in a **User System** and which are not directly connected by **Plant** and/or **Apparatus** owned by **NGET** to a sub-station owned by **NGET**; and (b) are by agreement between **NGET** and such **User** operated under the direction and control of such **User**.
Replacement Reserves (RR)	means, in the context of **Balancing Services,** the active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including generation reserves;
Requesting Safety Co-ordinator	The **Safety Co-ordinator** requesting **Safety Precautions**.
Responsible Engineer/ Operator	A person nominated by a **User** to be responsible for **System** control.
Responsible Manager	A manager who has been duly authorised by a **User** or a **Relevant Transmission Licensee** to sign **Site Responsibility Schedules** on behalf of that **User** or **Relevant Transmission Licensee** as the case may be.
Restoration Service Provider	A **Black Start Service Provider** or **User** with a legal or contractual obligation tp provide a service contributing to one or several measures of the **System Resoration Plan.**
Re-synchronisation	The bringing of parts of the **System** which have become **Out of Synchronism** with any other **System** back into **Synchronism**, and like terms shall be construed accordingly.
RR Acceptance	The results of the TERRE auction for each **BM Participant**
Restricted	Applies to a **TERRE Bid** which has been marked so that it will be passed to the **TERRE Central Platform** but will not be used in the auction
RR Instruction	Replacement Reserve Instruction – used for instructing **BM Participants** after the results of the **TERRE** auction. An **RR Instruction** has the same format as a **Bid-Offer Acceptance** but has type field indicating it is for **TERRE**
Safety Co-ordinator	A person or persons nominated by a **Relevant E&W Transmission Licensee** and each **E&W User** in relation to **Connection Points** (or in the case of **OTSUA** operational prior to the **OTSUA Transfer Time**, **Transmission Interface Points**) on an **E&W Transmission System** and/or by the **Relevant Scottish Transmission Licensee** and each **Scottish User** in relation to **Connection Points** (or in the case of **OTSUA** operational prior to the **OTSUA Transfer Time**, **Transmission Interface Points**) on a **Scottish Transmission System** to be responsible for the co-ordination of **Safety Precautions** at each **Connection Point** (or in the case of **OTSUA** operational prior to the **OTSUA Transfer Time**, **Transmission Interface Points**) when work (which includes testing) is to be carried out on a **System** which necessitates the provision of **Safety Precautions** on **HV Apparatus** (as defined in OC8A.1.6.2 and OC8B.1.7.2), pursuant to **OC8**.
Safety From The System	That condition which safeguards persons when work is to be carried out on or near a **System** from the dangers which are inherent in the **System**.

Safety Key	A key unique at the **Location** capable of operating a lock which will cause an **Isolating Device** and/or **Earthing Device** to be **Locked**.
Safety Log	A chronological record of messages relating to safety co-ordination sent and received by each **Safety Co-ordinator** under **OC8**.
Safety Precautions	**Isolation** and/or **Earthing**.
Safety Rules	The rules of the **Relevant Transmission Licensee** or a **User** that seek to ensure that persons working on **Plant** and/or **Apparatus** to which the rules apply are safeguarded from hazards arising from the **System**.
Scottish Offshore Transmission System	An **Offshore Transmission System** with an **Interface Point** in Scotland.
Scottish Offshore Transmission Licensee	A person who owns or operates a **Scottish Offshore Transmission System** pursuant to a **Transmission Licence**.
Scottish Transmission System	Collectively **SPT's Transmission System** and **SHETL's Transmission System** and any **Scottish Offshore Transmission Systems**.
Scottish User	A **User** in Scotland or any **Offshore User** who owns or operates **Plant** and/or **Apparatus** connected (or which will at the **OTSUA Transfer Time** be connected) to a **Scottish Offshore Transmission System**
Secondary BM Unit	Has the same meaning set out in the **BSC**
Secondary Response	The automatic increase in **Active Power** output of a **Genset** or, as the case may be, the decrease in **Active Power Demand** in response to a **System Frequency** fall. This increase in **Active Power** output or, as the case may be, the decrease in **Active Power Demand** must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be fully available by 30 seconds from the time of the start of the **Frequency** fall and be sustainable for at least a further 30 minutes. The interpretation of the **Secondary Response** to a -0.5 Hz frequency change is shown diagrammatically in Figure CC.A.3.2 or Figure ECC.A.3.2.
Secretary of State	Has the same meaning as in the **Act**.
Secured Event	Has the meaning set out in the **Security and Quality of Supply Standard**.
Security and Quality of Supply Standard (SQSS)	The version of the document entitled 'Security and Quality of Supply Standard' established pursuant to the **Transmission Licence** in force at the time of entering into the relevant **Bilateral Agreement**.

Self-Governance Criteria	A proposed **Modification** that, if implemented, (a) is unlikely to have a material effect on: (i) existing or future electricity consumers; and (ii) competition in the generation, distribution, or supply of electricity or any commercial activities connected with the generation, distribution or supply of electricity; and (iii) the operation of the **National Electricity Transmission System**; and (iv) matters relating to sustainable development, safety or security of supply, or the management of market or network emergencies; and (v) the **Grid Code**'s governance procedures or the **Grid Code**'s modification procedures, and (b) is unlikely to discriminate between different classes of Users.
Self-Governance Modifications	A **Grid Code Modification Proposal** that does not fall within the scope of a **Significant Code Review** and that meets the **Self-Governance Criteria** or which the **Authority** directs is to be treated as such any direction under GR.24.4.
Self-Governance Statement	The statement made by the **Grid Code Review Panel** and submitted to the **Authority**: (a) confirming that, in its opinion, the **Self-Governance Criteria** are met and the proposed **Grid Code Modification Proposal** is suitable for the Self-Governance route; and (b) providing a detailed explanation of the **Grid Code Review Panel**'s reasons for that opinion
Setpoint Voltage	The value of voltage at the **Grid Entry Point**, or **User System Entry Point** if **Embedded**, on the automatic control system steady state operating characteristic, as a percentage of the nominal voltage, at which the transfer of **Reactive Power** between a **Power Park Module**, **DC Converter**, **HVDC Converter** or **Non-Synchronous Generating Unit** and the **Transmission System**, or **Network Operator's** system if **Embedded**, is zero.
Settlement Period	A period of 30 minutes ending on the hour and half-hour in each hour during a day.
Seven Year Statement	A statement, prepared by **The Company** in accordance with the terms of **The Company's Transmission Licence**, showing for each of the seven succeeding **Financial Years**, the opportunities available for connecting to and using the **National Electricity Transmission System** and indicating those parts of the **National Electricity Transmission System** most suited to new connections and transport of further quantities of electricity.
SF_6 Gas Zone	A segregated zone surrounding electrical conductors within a casing containing SF_6 gas.
SHETL	Scottish Hydro-Electric Transmission Limited

Shutdown	In the case of a **Generating Unit** is the condition of a **Generating Unit** where the generator rotor is at rest or on barring. In the case of an **HVDC System** or **DC Converter Station**, is the condition of an **HVDC System** or **DC Converter Station** where the **HVDC System** or **DC Converter Station** is de-energised and therefore not importing or exporting **Apparent Power** to or from the **Total System**.
Significant Code Review	Means the period commencing on the start date of a **Significant Code Review** as stated in the notice issued by the **Authority**, and ending in the circumstances described in GR.16.6 or GR.16.7, as appropriate.
Significant Code Review Phase	Means the period commencing on the start date of a **Significant Code Review** as stated in the notice issued by the **Authority**, and ending in the circumstances described in GR.16.6 or GR.16.7, as appropriate.
Significant Incident	An **Event** which either: (a) was notified by a **User** to **The Company** under **OC7**, and which **The Company** considers has had or may have had a significant effect on the **National Electricity Transmission System**, and **The Company** requires the **User** to report that **Event** in writing in accordance with **OC10** and notifies the **User** accordingly; or (b) was notified by **The Company** to a **User** under **OC7**, and which that **User** considers has had or may have had a significant effect on that **User's System**, and that **User** requires **The Company** to report that **Event** in writing in accordance with the provisions of **OC10** and notifies **The Company** accordingly.
Simultaneous Tap Change	A tap change implemented on the generator step-up transformers of **Synchronised Gensets**, effected by **Generators** in response to an instruction from **The Company** issued simultaneously to the relevant **Power Stations**. The instruction, preceded by advance notice, must be effected as soon as possible, and in any event within one minute of receipt from **The Company** of the instruction.
Single Line Diagram	A schematic representation of a three-phase network in which the three phases are represented by single lines. The diagram shall include (but not necessarily be limited to) busbars, overhead lines, underground cables, power transformers and reactive compensation equipment. It shall also show where **Large Power Stations** are connected, and the points at which **Demand** is supplied.
Single Point of Connection	A single **Point of Connection**, with no interconnection through the **User's System** to another **Point of Connection**.
Site Common Drawings	Drawings prepared for each **Connection Site** (and in the case of **OTSDUW**, **Transmission Interface Site**) which incorporate **Connection Site** (and in the case of **OTSDUW**, **Transmission Interface Site**) layout drawings, electrical layout drawings, common protection/ control drawings and common services drawings.
Site Responsibility Schedule	A schedule containing the information and prepared on the basis of the provisions set out in Appendix 1 of the **CC** and Appendix E1 of the **ECC**.

Slope	The ratio of the steady state change in voltage, as a percentage of the nominal voltage, to the steady state change in **Reactive Power** output, in per unit of **Reactive Power** capability. For the avoidance of doubt, the value indicates the percentage voltage reduction that will result in a 1 per unit increase in **Reactive Power** generation.
Small Participant	Has the meaning given in the **CUSC**.
Small Power Station	A **Power Station** which is (a) directly connected to: (i) **NGET's Transmission System** where such **Power Station** has a **Registered Capacity** of less than 50MW; or (ii) **SPT's Transmission System** where such **Power Station** has a **Registered Capacity** of less than 30MW; or (iii) **SHETL's Transmission System** where such a **Power Station** has a **Registered Capacity** of less than 10 MW; or (iv) an **Offshore Transmission System** where such **Power Station** has a **Registered Capacity** of less than 10MW; or, (b) **Embedded** within a **User System** (or part thereof) where such **User System** (or part thereof) is connected under normal operating conditions to: (i) **NGET's Transmission System** and such **Power Station** has a **Registered Capacity** of less than 50MW; or (ii) **SPT's Transmission System** and such **Power Station** has a **Registered Capacity** of less than 30MW; or (iii) **SHETL's Transmission System** and such **Power Station** has a **Registered Capacity** of less than 10MW; or, (c) **Embedded** within a **User System** (or part thereof) where the **User System** (or part thereof) is not connected to the **National Electricity Transmission System**, although such **Power Station** is in: (i) **NGET's Transmission Area** and such **Power Station** has a **Registered Capacity** of less than 50MW; or (ii) **SPT's Transmission Area** and such **Power Station** has a **Registered Capacity** of less than 30MW; or (iii) **SHETL's Transmission Area** and such **Power Station** has a **Registered Capacity** of less than 10MW; For the avoidance of doubt a **Small Power Station** could comprise of **Type A**, **Type B**, **Type C** or **Type D Power Generating Modules**.
Speeder Motor Setting Range	The minimum and maximum no-load speeds (expressed as a percentage of rated speed) to which the turbine is capable of being controlled, by the speeder motor or equivalent, when the **Generating Unit** terminals are on open circuit.
SPT	SP Transmission Limited

Standard Contract Terms	The standard terms and conditions applicable to **Ancillary Services** provided by **Demand Response Providers** and published on the **Website** from time to time.
Standard Modifications	A **Grid Code Modification Proposal** that does not fall within the scope of a **Significant Code Review** subject to any direction by the **Authority** pursuant to GR.16.3 and GR.16.4, nor meets the **Self-Governance Criteria** subject to any direction by the **Authority** pursuant to GR.24.4 and in accordance with any direction under GR.24.2.
Standard Planning Data	The general data required by **The Company** under the **PC**. It is generally also the data which **The Company** requires from a new **User** in an application for a **CUSC Contract**, as reflected in the **PC**.
Standard Product	means a harmonised balancing product defined by all EU TSOs for the exchange of balance services.
Specific Product	Means in the context of Balancing Services a product that is not a standard product;
Start Time	The time named as such in an instruction issued by **The Company** pursuant to the **BC**.
Start-Up	In the case of a **Generating Unit** is the action of bringing a **Generating Unit** from **Shutdown** to **Synchronous Speed**. In the case of an **HVDC System** or **DC Converter Station**, is the action of bringing the **HVDC System** or **DC Converter Station** from **Shutdown** to a state where it is energised.
Statement of Readiness	Has the meaning set out in the **Bilateral Agreement** and/or **Construction Agreement**.
Station Board	A switchboard through which electrical power is supplied to the **Auxiliaries** of a **Power Station**, and which is supplied by a **Station Transformer**. It may be interconnected with a **Unit Board**.
Station Transformer	A transformer supplying electrical power to the **Auxiliaries** of (a) a **Power Station**, which is not directly connected to the **Generating Unit** terminals (typical voltage ratios being 132/11kV or 275/11kV),or (b) a **DC Converter Station** or **HVDC Converter Station**.
STC Committee	The committee established under the **STC**.
Steam Unit	A **Generating Unit** whose prime mover converts the heat-energy in steam to mechanical energy.
Subtransmission System	The part of a **User's System** which operates at a single transformation below the voltage of the relevant **Transmission System**.

Substantial Modification	A **Modification** in relation to modernisation or replacement of the **User's Main Plant and Apparatus** which impacts its technical capabilities, which, following notification by the relevant **User** to **The Company**, results in substantial amendment to the **Bilateral Agreement**.
Supergrid Voltage	Any voltage greater than 200kV.
Supplier	(a) A person supplying electricity under an **Electricity Supply Licence**; or (b) A person supplying electricity under exemption under the **Act**; in each case acting in its capacity as a supplier of electricity to **Customers** in **Great Britain**.
Surplus	A MW figure relating to a **System Zone** equal to the total **Output Usable** in the **System Zone:** (a) minus the forecast of **Active Power Demand** in the **System Zone**, and (b) minus the export limit in the case of an export limited **System Zone**, or plus the import limit in the case of an import limited **System Zone**, and (c) (only in the case of a **System Zone** comprising the **National Electricity Transmission System**) minus the **Operational Planning Margin**. For the avoidance of doubt, a **Surplus** of more than zero in an export limited **System Zone** indicates an excess of generation in that **System Zone**; and a **Surplus** of less than zero in an import limited **System Zone** indicates insufficient generation in that **System Zone.**
Synchronised	(a) The condition where an incoming **Power Generating Module**, **Generating Unit** or **Power Park Module** or **DC Converter** or **HVDC Converter** or **System** is connected to the busbars of another **System** so that the **Frequencies** and phase relationships of that **Power Generating Module**, **Generating Unit**, **Power Park Module**, **DC Converter**, **HVDC Converter** or **System**, as the case may be, and the **System** to which it is connected are identical, like terms shall be construed accordingly e.g. **"Synchronism"**. (b) The condition where an importing **BM Unit** is consuming electricity.

Synchronous Electricity Storage Module	A **Synchronous Power Generating Module** which can convert or re-convert electrical energy from another source of energy such that the frequency of the generated voltage, the rotor speed and the frequency of network voltage are in a constant ratio and thus in synchronism. For the avoidance of doubt a **Synchronous Electricity Storage Module** could comprise of one or more **Synchronous Electricity Storage Units**.
Synchronous Electricity Storage Unit	A **Synchronous Generating Unit** which can supply or absorb electrical energy such that the frequency of the generated voltage, the rotor speed and the frequency of the equipment are in constant ratio and thus in synchronism with the network.
Synchronising Generation	The amount of MW (in whole MW) produced at the moment of synchronising.
Synchronising Group	A group of two or more **Gensets**) which require a minimum time interval between their **Synchronising** or **De-Synchronising** times.
Synchronous Area	An area covered by synchronously interconnected **Transmission Licensees**, such as the **Synchronous Areas** of Continental Europe, Great Britain, Ireland-Northern Ireland and Nordic and the power systems of Lithuania, Latvia and Estonia, together referred to as 'Baltic' which are part of a wider **Synchronous Area**;
Synchronous Compensation	The operation of rotating synchronous **Apparatus** for the specific purpose of either the generation or absorption of **Reactive Power**.
Synchronous Generating Unit	Any **Onshore Synchronous Generating Unit** or **Offshore Synchronous Generating Unit**.
Synchronous Generating Unit Performance Chart	A diagram showing the **Real Power** (MW) and **Reactive Power** (MVAr) capability limits within which a **Synchronous Generating Unit** at its stator terminals (which is part of a **Synchronous Power Generating Module**) will be expected to operate under steady state conditions.
Synchronous Power-Generating Module	An indivisible set of installations which can generate electrical energy such that the frequency of the generated voltage, the generator speed and the frequency of network voltage are in a constant ratio and thus in synchronism. For the avoidance of doubt a **Synchronous Power Generating Module** could comprise of one or more **Synchronous Generating Units**
Synchronous Power Generating Module Matrix	The matrix described in Appendix 1 to BC1 under the heading **Synchronous Power Generating Module Matrix**.
Synchronous Power Generating Module Planning Matrix	A matrix in the form set out in Appendix 5 of OC2 showing the combination of **Synchronous Generating Units** within a **Synchronous Power Generating Module** which would be running in relation to any given MW output.
Synchronous Power Generating Unit	Has the same meaning as a **Synchronous Generating Unit** and would be considered to be part of a **Power Generating Module.**
Synchronous Speed	That speed required by a **Generating Unit** to enable it to be **Synchronised** to a **System**.
System	Any **User System** and/or the **National Electricity Transmission System**, as the case may be.

System Ancillary Services	Collectively **Part 1 System Ancillary Services** and **Part 2 System Ancillary Services**.
System Constraint	A limitation on the use of a **System** due to lack of transmission capacity or other **System** conditions.
System Constrained Capacity	That portion of **Registered Capacity** or Regis**tered Import Capacity** not available due to a **System Constraint**.
System Constraint Group	A part of the **National Electricity Transmission System** which, because of **System Constraints**, is subject to limits of **Active Power** which can flow into or out of (as the case may be) that part.
System Defence Plan	A document prepared by **The Company**, as published on its **Website**, outlining how the requirements of the "defence plan" (as provided for **European Regulation (EU) 2017/2196**) has been implemented within the **GB Synchronous Area**.
System Fault Dependability Index or **Dp**	A measure of the ability of **Protection** to initiate successful tripping of circuit-breakers which are associated with a faulty item of **Apparatus**. It is calculated using the formula: **Dp** = $1 - F_1/A$ Where: A = Total number of **System** faults F_1 = Number of **System** faults where there was a failure to trip a circuit-breaker.
System Margin	The margin in any period between (a) the sum of Maximum Export Limits and (b) forecast **Demand** and the **Operating Margin**, for that period.
System Negative Reserve Active Power Margin or **System NRAPM**	That margin of **Active Power** sufficient to allow the largest loss of **Load** at any time.
System Operator - Transmission Owner Code or **STC**	Has the meaning set out in **The Company's Transmission Licence**
System Restoration Plan	A document prepared by **The Company**, as published on its **Website**, outlining how the requirements of the "restoration plan" (as defined in **European Regulation (EU) 2017/2196**) has been implemented within the **GB Synchronous Area**.
System Telephony	An alternative method by which a **User's Responsible Engineer/Operator** and **The Company's Control Engineer(s)** speak to one and another for the purposes of control of the **Total System** in both normal operating conditions and where practicable, emergency operating conditions.

System Tests	Tests which involve simulating conditions, or the controlled application of irregular, unusual or extreme conditions, on the **Total System**, or any part of the **Total System**, but which do not include commissioning or recommissioning tests or any other tests of a minor nature.
System to Demand Intertrip Scheme	An intertrip scheme which disconnects **Demand** when a **System** fault has arisen to prevent abnormal conditions occurring on the **System**.
System to Generator Operational Intertripping	A **Balancing Service** involving the initiation by a **System to Generator Operational Intertripping Scheme** of automatic tripping of the **User's** circuit breaker(s), or **Relevant Transmission Licensee's** circuit breaker(s) where agreed by **The Company**, the **User** and the **Relevant Transmission Licensee**, resulting in the tripping of **BM Unit(s)** or (where relevant) **Generating Unit(s)** comprised in a **BM Unit** to prevent abnormal system conditions occurring, such as over voltage, overload, **System** instability, etc, after the tripping of other circuit-breakers following power **System** fault(s).
System to Generator Operational Intertripping Scheme	A **System** to **Generating Unit** or **System** to **CCGT Module** or **System** to **Power Park Module** or **System** to **Power Generating Module Intertripping Scheme** forming a condition of connection and specified in Appendix F3 of the relevant **Bilateral Agreement**, being either a **Category 1 Intertripping Scheme**, **Category 2 Intertripping Scheme**, **Category 3 Intertripping Scheme** or C**ategory 4 Intertripping Scheme**.
System Zone	A region of the **National Electricity Transmission System** within a described boundary or the whole of the **National Electricity Transmission System**, as further provided for in OC2.2.4, and the term "**Zonal**" will be construed accordingly.
Target Frequency	That **Frequency** determined by **The Company**, in its reasonable opinion, as the desired operating **Frequency** of the **Total System**. This will normally be 50.00Hz plus or minus 0.05Hz, except in exceptional circumstances as determined by **The Company**, in its reasonable opinion when this may be 49.90 or 50.10Hz. An example of exceptional circumstances may be difficulties caused in operating the **System** during disputes affecting fuel supplies.
Technical Specification	In relation to **Plant** and/or **Apparatus**, (a) the relevant **European Specification**; or (b) if there is no relevant **European Specification**, other relevant standards which are in common use in the European Community.
TERRE	Trans European Replacement Reserves Exchange – a market covering the procurement of replacement reserves across Europe as described European Regulation (EU) 2017/2195 (EBGL) and European Regulation (EU) 2017/1485
TERRE Activation Period	A period of time lasting 15 minutes and starting at either 0, 15, 30 or 45 minutes past the hour (e.g. 10:00 to 10:15). There are 4 **TERRE Activation Periods** in one **TERRE Auction Period**
TERRE Auction Period	A period of time lasting one hour and starting and ending on the hour (e.g. from 10:00 to 11:00). Hence there are 24 **TERRE Auction Periods** in a day

TERRE Bid	A submission by a **BM Participant** covering the price and MW deviation offered into the **TERRE** auction (please note – in the **Balancing Mechanism** the term bid has a different meaning – in this case a bid can be an upward or downward MW change)
TERRE Central Platform	IT system which implements the **TERRE** auction
TERRE Gate Closure	60 minutes before the start of the TERRE Auction period (note still ongoing discussions if this may become 55 minutes)
TERRE Instruction Guide	Details specific rules for creating an RR Instruction from an RR Acceptance
TERRE Data Validation and Consistency Rules	A document produced by the central **TERRE** project detailing the correct format of submissions for **TERRE**
Test Co-ordinator	A person who co-ordinates **System Tests**.
Test Panel	A panel, whose composition is detailed in **OC12**, which is responsible, inter alia, for considering a proposed **System Test**, and submitting a **Proposal Report** and a **Test Programme**.
Test Programme	A programme submitted by the **Test Panel** to **The Company**, the **Test Proposer**, and each **User** identified by **The Company** under OC12.4.2.1, which states the switching sequence and proposed timings of the switching sequence, a list of those staff involved in carrying out the **System Test** (including those responsible for the site safety) and such other matters as the **Test Panel** deems appropriate.
Test Proposer	The person who submits a **Proposal Notice**.
The Company	National Grid Electricity System Operator Limited (NO: 11014226) whose registered office is at 1-3 Strand, London, WC2N 5EH as the person whose **Transmission Licence** Section C of such **Transmission Licence** has been given effect.
The Company Control Engineer	The nominated person employed by **The Company** to direct the operation of the **National Electricity Transmission System** or such person as nominated by **The Company**.
The Company Operational Strategy	**The Company's** operational procedures which form the guidelines for operation of the **National Electricity Transmission System**.
Total Shutdown	The situation existing when all generation has ceased and there is no electricity supply from **External Interconnections** and, therefore, the **Total System** has shutdown with the result that it is not possible for the **Total System** to begin to function again without **The Company's** directions relating to a **Black Start**.
Total System	The **National Electricity Transmission System** and all **User Systems** in the **National Electricity Transmission System Operator Area**.
Trading Point	A commercial and, where so specified in the Grid Code, an operational interface between a **User** and **The Company**, which a **User** has notified to **The Company**.

Transfer Date	Such date as may be appointed by the **Secretary of State** by order under section 65 of the **Act**.
Transmission	Means, when used in conjunction with another term relating to equipment or a site, whether defined or not, that the associated term is to be read as being part of or directly associated with the **National Electricity Transmission System**, and not of or with the **User System**.
Transmission Area	Has the meaning set out in the **Transmission Licence** of a **Transmission Licensee**.
Transmission Connected Demand Facilities	A **Demand Facility** which has a **Grid Supply Point** to the **National Electricity Transmission System**
Transmission DC Converter	Any **Transmission Licensee Apparatus** (or **OTSUA** that will become **Transmission Licensee Apparatus** at the **OTSUA Transfer Time**) used to convert alternating current electricity to direct current electricity, or vice versa. A **Transmission Network DC Converter** (which could include an **HVDC System** owned by an **Offshore Transmission Licensee** or **Generator** in respect of **OTSUA**) is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion.
Transmission Entry Capacity	Has the meaning set out in the **CUSC**.
Transmission Interface Circuit	In **NGET's Transmission Area**, a **Transmission** circuit which connects a **System** operating at a voltage above 132kV to a **System** operating at a voltage of 132kV or below In **SHETL's Transmission Area** and **SPT's Transmission Area**, a **Transmission** circuit which connects a **System** operating at a voltage of 132kV or above to a **System** operating at a voltage below 132kV.
Transmission Interface Point	means the electrical point of connection between the **Offshore Transmission System** and an **Onshore Transmission System**.
Transmission Interface Site	the site at which the **Transmission Interface Point** is located.
Transmission Licence	A licence granted under Section 6(1)(b) of the **Act**.
Transmission Licensee	**The Company** and any **Onshore Transmission Licensee** or **Offshore Transmission Licensee**
Transmission Site	Means a site owned (or occupied pursuant to a lease, licence or other agreement) by a **Relevant Transmission Licensee** in which there is a **Connection Point**. For the avoidance of doubt, a site owned by a **User** but occupied by the **Relevant Transmission Licensee** as aforesaid, is a **Transmission Site**.
Transmission System	Has the same meaning as the term "licensee's transmission system" in the **Transmission Licence** of a **Transmission Licensee**.

Turbine Time Constant	Determined at **Registered Capacity**, the turbine time constant will be construed in accordance with the principles of the IEEE Committee Report "Dynamic Models for Steam and Hydro Turbines in Power System Studies" published in 1973 which apply to such phrase.
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 10MW or greater but less than 50MW;
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 50MW or greater
Unbalanced Load	The situation where the **Load** on each phase is not equal.
Under-excitation Limiter	Shall have the meaning ascribed to that term in **IEC** 34-16-1:1991 [equivalent to **British Standard BS**4999 Section 116.1 : 1992].
Under Frequency Relay	An electrical measuring relay intended to operate when its characteristic quantity (**Frequency**) reaches the relay settings by decrease in **Frequency**.
Unit Board	A switchboard through which electrical power is supplied to the **Auxiliaries** of a **Generating Unit** and which is supplied by a **Unit Transformer**. It may be interconnected with a **Station Board**.
Unit Transformer	A transformer directly connected to a **Generating Unit's** terminals, and which supplies power to the **Auxiliaries** of a **Generating Unit**. Typical voltage ratios are 23/11kV and 15/6.6Kv.
Unit Load Controller Response Time Constant	The time constant, expressed in units of seconds, of the power output increase which occurs in the **Secondary Response** timescale in response to a step change in **System Frequency**.
Unresolved Issues	Any relevant Grid Code provisions or **Bilateral Agreement** requirements identified by **The Company** with which the relevant **User** has not demonstrated compliance to **The Company's** reasonable satisfaction at the date of issue of the **Preliminary Operational Notification** and/or **Interim Operational Notification** and/or **Limited Operational Notification** and which are detailed in such **Preliminary Operational Notification** and/or **Interim Operational Notification** and/or **Limited Operational Notification**.
Urgent Modification	A **Grid Code Modification Proposal** treated or to be treated as an **Urgent Modification** in accordance with GR.23.

User	A term utilised in various sections of the Grid Code to refer to the persons using the **National Electricity Transmission System**, as more particularly identified in each section of the Grid Code concerned. In the **Preface** and the **General Conditions** the term means any person to whom the Grid Code applies. The term **User** includes an **EU Code User** and a **GB Code User**.
User Data File Structure	The file structure given at **DRC 18** which will be specified by **The Company** which a **Generator** or **DC Converter Station** owner or **HVDC System Onwer** must use for the purposes of **CP** to submit **DRC** data Schedules and information demonstrating compliance with the Grid Code and, where applicable, with the **CUSC Contract(s)**, unless otherwise agreed by **The Company**.
User Development	In the **PC** means either **User's Plant** and/or **Apparatus** to be connected to the **National Electricity Transmission System**, or a **Modification** relating to a **User's Plant** and/or **Apparatus** already connected to the **National Electricity Transmission System**, or a proposed new connection or **Modification** to the connection within the **User System**.
User Self Certification of Compliance	A certificate, in the form attached at CP.A.2.(1) or ECP.A.2.(1) completed by a **Generator** or **DC Converter Station** owner or **HVDC System Owner** to which the **Compliance Statement** is attached which confirms that such **Plant** and **Apparatus** complies with the relevant Grid Code provisions and where appropriate, with the **CUSC Contract**(s), as identified in the **Compliance Statement** and, if appropriate, identifies any **Unresolved Issues** and/or any exceptions to such compliance and details the derogation(s) granted in respect of such exceptions.
User Site	A site owned (or occupied pursuant to a lease, licence or other agreement) by a **User** in which there is a **Connection Point**. For the avoidance of doubt, a site owned by a **Relevant Transmission Licensee** but occupied by a **User** as aforesaid, is a **User Site**.
User System	Any system owned or operated by a **User** comprising:- (a) **Power Generating Modules** or **Generating Units**; and/or (b) Systems consisting (wholly or mainly) of electric lines used for the distribution of electricity from **Grid Supply Points** or **Generating Units** or **Power Generating Modules** or other entry points to the point of delivery to **Customers**, or other **Users**; and **Plant** and/or **Apparatus** (including prior to the **OTSUA Transfer Time**, any **OTSUA**) connecting:- (c) The system as described above; or (d) **Non-Embedded Customers** equipment; to the **National Electricity Transmission System** or to the relevant other **User System**, as the case may be. The **User System** includes any **Remote Transmission Assets** operated by such **User** or other person and any **Plant** and/or **Apparatus** and meters owned or operated by the **User** or other person in connection with the distribution of electricity but does not include any part of the **National Electricity Transmission System**.

User System Entry Point	A point at which a **Power Generating Module**, **Generating Unit**, a **CCGT Module** or a **CCGT Unit** or a **Power Park Module** or a **DC Converter** or an **HVDC Converter**, as the case may be, which is **Embedded** connects to the **User System**.
Water Time Constant	Bears the meaning ascribed to the term "Water inertia time" in **IEC**308.
Website	The site established by **The Company** on the World-Wide Web for the exchange of information among **Users** and other interested persons in accordance with such restrictions on access as may be determined from time to time by **The Company**.
Weekly ACS Conditions	Means that particular combination of weather elements that gives rise to a level of peak **Demand** within a week, taken to commence on a Monday and end on a Sunday, which has a particular chance of being exceeded as a result of weather variation alone. This particular chance is determined such that the combined probabilities of **Demand** in all weeks of the year exceeding the annual peak **Demand** under **Annual ACS Conditions** is 50%, and in the week of maximum risk the weekly peak **Demand** under **Weekly ACS Conditions** is equal to the annual peak **Demand** under **Annual ACS Conditions**.
WG Consultation Alternative Request	Any request from an **Authorised Electricity Operator**; the **Citizens Advice** or the **Citizens Advice Scotland**, **The Company** or a **Materially Affected Party** for a **Workgroup Alternative Grid Code Modification** to be developed by the **Workgroup** expressed as such and which contains the information referred to at GR.20.13. For the avoidance of doubt any **WG Consultation Alternative Request** does not constitute either a **Grid Code Modification Proposal** or a **Workgroup Alternative Grid Code Modification**
Workgroup	a **Workgroup** established by the **Grid Code Review Panel** pursuant to GR.20.1;
Workgroup Consultation	as defined in GR.20.10, and any further consultation which may be directed by the **Grid Code Review Panel** pursuant to GR.20.17;
Workgroup Alternative Grid Code Modification	an alternative modification to the **Grid Code Modification Proposal** developed by the **Workgroup** under the **Workgroup** terms of reference (either as a result of a **Workgroup Consultation** or otherwise) and which is believed by a majority of the members of the **Workgroup** or by the chairman of the **Workgroup** to better facilitate the **Grid Code Objectives** than the **Grid Code Modification Proposal** or the current version of the **Grid Code;**
Zonal System Security Requirements	That generation required, within the boundary circuits defining the **System Zone**, which when added to the secured transfer capability of the boundary circuits exactly matches the **Demand** within the **System Zone**.

A number of the terms listed above are defined in other documents, such as the **Balancing and Settlement Code** and the **Transmission Licence**. Appendix 1 sets out the current definitions from the other documents of those terms so used in the Grid Code and defined in other documents for ease of reference, but does not form part of the Grid Code.

GD.2 Construction of References

GD.2.1 In the Grid Code:

(i) a table of contents, a Preface, a Revision section, headings, and the Appendix to this **Glossary and Definitions** are inserted for convenience only and shall be ignored in construing the Grid Code;

(ii) unless the context otherwise requires, all references to a particular paragraph, sub-paragraph, Appendix or Schedule shall be a reference to that paragraph, sub-paragraph Appendix or Schedule in or to that part of the Grid Code in which the reference is made;

(iii) unless the context otherwise requires, the singular shall include the plural and vice versa, references to any gender shall include all other genders and references to persons shall include any individual, body corporate, corporation, joint venture, trust, unincorporated association, organisation, firm or partnership and any other entity, in each case whether or not having a separate legal personality;

(iv) references to the words "include" or "including" are to be construed without limitation to the generality of the preceding words;

(v) unless there is something in the subject matter or the context which is inconsistent therewith, any reference to an Act of Parliament or any Section of or Schedule to, or other provision of an Act of Parliament shall be construed at the particular time, as including a reference to any modification, extension or re-enactment thereof then in force and to all instruments, orders and regulations then in force and made under or deriving validity from the relevant Act of Parliament;

(vi) where the **Glossary and Definitions** refers to any word or term which is more particularly defined in a part of the Grid Code, the definition in that part of the Grid Code will prevail (unless otherwise stated) over the definition in the **Glossary & Definitions** in the event of any inconsistency;

(vii) a cross-reference to another document or part of the Grid Code shall not of itself impose any additional or further or co-existent obligation or confer any additional or further or co-existent right in the part of the text where such cross-reference is contained;

(viii) nothing in the Grid Code is intended to or shall derogate from **The Company's** statutory or licence obligations;

(ix) a "holding company" means, in relation to any person, a holding company of such person within the meaning of section 736, 736A and 736B of the Companies Act 1985 as substituted by section 144 of the Companies Act 1989 and, if that latter section is not in force at the **Transfer Date**, as if such latter section were in force at such date;

(x) a "subsidiary" means, in relation to any person, a subsidiary of such person within the meaning of section 736, 736A and 736B of the Companies Act 1985 as substituted by section 144 of the Companies Act 1989 and, if that latter section is not in force at the **Transfer Date**, as if such latter section were in force at such date;

(xi) references to time are to London time; and

(xii) (a) Save where (b) below applies, where there is a reference to an item of data being expressed in a whole number of MW, fractions of a MW below 0.5 shall be rounded down to the nearest whole MW and fractions of a MW of 0.5 and above shall be rounded up to the nearest whole MW;

(b) In the case of the definition of **Registered Capacity** or **Maximum Capacity**, fractions of a MW below 0.05 shall be rounded down to one decimal place and fractions of a MW of 0.05 and above shall be rounded up to one decimal place.

(xiii) For the purposes of the Grid Code, physical quantities such as current or voltage are not defined terms as their meaning will vary depending upon the context of the obligation. For example, voltage could mean positive phase sequence root mean square voltage, instantaneous voltage, phase to phase voltage, phase to earth voltage. The same issue equally applies to current, and therefore the terms current and voltage should remain undefined with the meaning depending upon the context of the application. European Regulation (EU) 2016/631 defines requirements of current and voltage but they have not been adopted as part of EU implementation for the reasons outlined above.

< END OF GLOSSARY & DEFINITIONS >

OPERATING CODE NO. 5
(OC5)

TESTING AND MONITORING

CONTENTS

(This contents page does not form part of the Grid Code)

OC5.1 INTRODUCTION

Operating Code No. 5 ("**OC5**") specifies the procedures to be followed by **The Company** in carrying out:

(a) monitoring

(i) of **BM Units** against their expected input or output;

(ii) of compliance by **Users** with the **CC** or **ECC** as applicable and in the case of response to **Frequency**, **BC3**; and

(iii) of the provision by **Users** of **Ancillary Services** which they are required or have agreed to provide; and

(b) the following tests (which are subject to **System** conditions prevailing on the day):

(i) tests on **Gensets**, **CCGT Modules**, **Power Generating Modules, Power Park Modules**, **DC Converters, HVDC Equipment**, **OTSUA** (prior to the **OTSUA Transfer Time**) and **Generating Units** (excluding **Power Park Units**) to test that they have the capability to comply with the **CC** and **ECC**, and in the case of response to **Frequency**, **BC3** and to provide the **Ancillary Services** that they are either required or have agreed to provide;

(ii) tests on **BM Units**, to ensure that the **BM Units** are available in accordance with their submitted **Export and Import Limits** and **Dynamic Parameters**.

The **OC5** tests include the **Black Start Test** procedure.

OC5 also specifies in OC5.8 the procedures which apply to the monitoring and testing of **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** and **Embedded DC Converter Stations (or Embedded HVDC Equipment)** not subject to a **Bilateral Agreement**.

In respect of a **Cascade Hydro Scheme** the provisions of **OC5** shall be applied as follows:

(a) in respect of the **BM Unit** for the **Cascade Hydro Scheme** the parameters referred to at OC5.4.1 (a) and (c) in respect of **Commercial Ancillary Services** will be monitored and tested;

(b) in respect of each **Genset** forming part of the **Cascade Hydro Scheme** the parameters referred to at OC5.4.1 (a), (b) and (c) will be tested and monitored. In respect of OC5.4.1 (a) the performance of the **Gensets** will be tested and monitored against their expected input or output derived from the data submitted under BC1.4.2(a)(2). Where necessary to give effect to the requirements for **Cascade Hydro Schemes** in the following provisions of **OC5** the term **Genset** will be read and construed in the place of **BM Unit.**

In respect of **Embedded Exemptable Large Power Stations** the provisions of **OC5** shall be applied as follows:

(a) where there is a **BM Unit** registered in the **BSC** in respect of **Generating Units** the provisions of **OC5** shall apply as written;

(b) in all other cases, in respect of each **Power Generating Module,** and/or **Generating Unit** and **HVDC Equipment** the parameters referred to at OC5.4.1(a), (b) and (c) will be tested and monitored. In respect of OC5.4.1(a) the performance of the **Power Generating Module** and/or **Generating Unit** and **HVDC Equipment** will be tested and monitored against their expected input or output derived from the data submitted under BC1.4.2(a)(2). Where necessary to give effect to the requirements for such **Embedded Exemptable Large Power Stations** in the provisions of **OC5** the term **Generating Unit** will be read and construed in place of **BM Unit**.

OC5.2 OBJECTIVE

The objectives of **OC5** are to establish:

(a) that **Users** comply with the **CC** or **ECC** as applicable (including in the case of **OTSUA** prior to the **OTSUA Transfer Time**);

(b) whether **BM Units** operate in accordance with their expected input or output derived from their **Final Physical Notification Data** and agreed **Bid-Offer Acceptances** issued under **BC2**;

(c) whether each **BM Unit** is available as declared in accordance with its submitted **Export and Import Limits** and **Dynamic Parameters**; and

(d) whether **Generators**, **DC Converter Station** owners, **HVDC Equipment Owners** and **Suppliers** can provide those **Ancillary Services** which they are either required or have agreed to provide.

In certain limited circumstances as specified in this **OC5** the output of **CCGT Units** may be verified, namely the monitoring of the provision of **Ancillary Services** and the testing of **Reactive Power** and automatic **Frequency Sensitive Operation**.

OC5.3 SCOPE

OC5 applies to **The Company** and to **Users**, which in **OC5** means:

(a) **Generators** (including those undertaking **OTSDUW**);

(b) **Network Operators**;

(c) **Non-Embedded Customers**;

(d) **Suppliers**; and

(e) **DC Converter Station** owners or **HVDC Equipment Owners**.

OC5.4 MONITORING

OC5.4.1 Parameters To Be monitored

The Company will monitor the performance of:

(a) **BM Units** against their expected input or output derived from their **Final Physical Notification Data** and agreed **Bid-Offer Acceptances** issued under **BC2**;

(b) compliance by **Users** with the **CC** or **ECC** as applicable; and

(c) the provision by **Users** of **Ancillary Services** which they are required or have agreed to provide.

OC5.4.2 Procedure For Monitoring

OC5.4.2.1 In the event that a **BM Unit** fails persistently, in **The Company's** reasonable view, to follow, in any material respect, its expected input or output or a **User** fails persistently to comply with the **CC** or **ECC** as applicable and in the case of response to **Frequency**, **BC3** or to provide the **Ancillary Services** it is required, or has agreed, to provide, **The Company** shall notify the relevant **User** giving details of the failure and of the monitoring that **The Company** has carried out.

OC5.4.2.2 The relevant **User** will, as soon as possible, provide **The Company** with an explanation of the reasons for the failure and details of the action that it proposes to take to:

(a) enable the **BM Unit** to meet its expected input or output or to provide the **Ancillary Services** it is required or has agreed to provide, within a reasonable period, or

(b) in the case of a **Power Generating Module**, **Generating Unit** (excluding a **Power Park Unit**), **CCGT Module**, **Power Park Module**, **OTSUA** (prior to the **OTSUA Transfer Time**), **HVDC Equipment** or **DC Converter** to comply with the **CC** or **ECC** as applicable and in the case of response to **Frequency**, **BC3** or to provide the **Ancillary Services** it is required or has agreed to provide, within a reasonable period.

OC5.4.2.3 **The Company** and the **User** will then discuss the action the **User** proposes to take and will endeavour to reach agreement as to:

(a) any short term operational measures necessary to protect other **Users**; and

(b) the parameters which are to be submitted for the **BM Unit** and the effective date(s) for the application of the agreed parameters.

OC5.4.2.4 In the event that agreement cannot be reached within 10 days of notification of the failure by **The Company** to the **User**, **The Company** or the **User** shall be entitled to require a test, as set out in OC5.5 and OC5.6, to be carried out.

OC5.5 PROCEDURE FOR TESTING

OC5.5.1 The Company's Instruction For Testing

OC5.5.1.1 **The Company** may at any time (although not normally more than twice in any calendar year in respect of any particular **BM Unit**) issue an instruction requiring a **User** to carry out a test, provided **The Company** has reasonable grounds of justification based upon:

(a) a failure to agree arising from the process in CP.8.1 or ECP.8.1; or

(b) monitoring carried out in accordance with OC5.4.2.

OC5.5.1.2 The test, referred to in OC5.5.1.1 and carried out at a time no sooner than 48 hours from the time that the instruction was issued, on any one or more of the **User's BM Units** should only be to demonstrate that the relevant **BM Unit**:

(a) if active in the **Balancing Mechanism**, meets the ability to operate in accordance with its submitted **Export and Import Limits** and **Dynamic Parameters** and achieve its expected input or output which has been monitored under OC5.4; and

(b) meets the requirements of the paragraphs in the **CC** which are applicable to such **BM Units**; and

in the case of a **BM Unit** comprising a **Generating Unit**, a **CCGT Module**, a **Power Park Module**, a **Power Generating Module**, **HVDC System** or a **DC Converter** meets,

(c) the requirements for operation in **Frequency Sensitive Mode** and compliance with the requirements for operation in **Limited Frequency Sensitive Mode** in accordance with CC.6.3.3, ECC.6.3.3, CC.6.3.7, ECC.6.3.7, BC3.5.2 and BC3.7.2; or

(d) the terms of the applicable **Bilateral Agreement** agreed with the **Generator** to have a **Fast Start Capability**; or

(e) the **Reactive Power** capability registered with **The Company** under **OC2** which shall meet the requirements set out in CC.6.3.2 or ECC.6.3.2 as applicable. In the case of a test on a **Generating Unit** within a **CCGT Module** the instruction need not identify the particular **CCGT Unit** within the **CCGT Module** which is to be tested, but instead may specify that a test is to be carried out on one of the **CCGT Units** within the **CCGT Module**.

OC5.5.1.3 (a) The instruction referred to in OC5.5.1.1 may only be issued if the relevant **User** has submitted **Export and Import Limits** which notify that the relevant **BM Unit** is available in respect of the **Operational Day** current at the time at which the instruction is issued. The relevant **User** shall then be obliged to submit **Export and Import Limits** with a magnitude greater than zero for that **BM Unit** in respect of the time and the duration that the test is instructed to be carried out, unless that **BM Unit** would not then be available by reason of forced outage or **Planned Outage** expected prior to this instruction.

(b) In the case of a **CCGT Module** the **Export and Import Limits** data must relate to the same **CCGT Units** which were included in respect of the **Operational Day** current at the time at which the instruction referred to in OC5.5.1.1 is issued and must include, in relation to each of the **CCGT Units** within the **CCGT Module**, details of the various data set out in BC1.A.1.3 and BC1.A.1.5, which parameters **The Company** will utilise in instructing in accordance with this **OC5** in issuing **Bid-Offer Acceptances**. The parameters shall reasonably reflect the true operating characteristics of each **CCGT Unit**.

(c) The test referred to in OC5.5.1.1 will be initiated by the issue of instructions, which may be accompanied by a **Bid-Offer Acceptance**, under **BC2** (in accordance with the **Export and Import Limits** and **Dynamic Parameters** which have been submitted for the day on which the test was called, or in the case of a **CCGT Unit**, in accordance with the parameters submitted under OC5.5.1.3(b)). The instructions in respect of a **CCGT Unit** within a **CCGT Module** will be in respect of the **CCGT Unit**, as provided in BC2.

OC5.5.2 User Request For Testing

OC5.5.2.1 Where a **GB Code User** undertakes a test to demonstrate compliance with the **Grid Code** and **Bilateral Agreement** in accordance with CP.6 or CP.7 or CP.8 (other than a failure between **The Company** and a **GB Code User** to agree in CP.8.1 where OC5.5.1.1 applies) the **GB Code User** shall request permission to test using the process laid out in OC7.5.

OC5.5.2.2 Where an **EU Code User** undertakes a test to demonstrate compliance with the **Grid Code** and **Bilateral Agreement** in accordance with ECP.6.1, ECP.6.2, ECP.6.3 or ECP.7 or ECP.8 (other than a failure between **The Company** and a **EU Code User** to agree in ECP.8.1 where OC5.5.1.1 applies) the **EU Code User** shall request permission to test using the process laid out in OC7.5.

OC5.5.3 Conduct Of Test

OC5.5.3.1 The performance of the **BM Unit** will be recorded at **Transmission Control Centres** notified by **The Company** with monitoring at site when necessary, from voltage and current signals provided by the **User** for each **BM Unit** under CC.6.6.1 or ECC.6.6.1 as applicable.

OC5.5.3.2 If monitoring at site is undertaken, the performance of the **BM Unit** will be recorded on a suitable recorder (with measurements, in the case of a **Synchronous Generating Unit** (which could be part of a **Synchronous Power Generating Module**), taken on the **Generating Unit** Stator Terminals / on the **LV** side of the generator transformer) or in the case of a **Non-Synchronous Generating Unit** (excluding **Power Park Units**), **Power Generating Module**, **Power Park Module** or **HVDC Equipment** or **DC Converter** at the point of connection (including where the **OTSUA** is operational prior to the **OTSUA Transfer Time**, the **Transmission Interface Point**) in the relevant **User's Control Room**, in the presence of a reasonable number of representatives appointed and authorised by **The Company**. If **The Company** or the **User** requests, monitoring at site will include measurement of the parameters set out in OC5.A.1.2 or OC5.A.1.3 or ECP.A4.2 or ECP.A.4.3 as appropriate.

OC5.5.3.3 The **User** is responsible for carrying out the test and retains the responsibility for the safety of personnel and plant during the test.

OC5.5.4 Test And Monitoring Assessment

The criteria must be read in conjunction with the full text under the Grid Code reference. The **BM Unit**, **Power Generating Module**, **CCGT Module**, **Power Park Module** or **Generating Unit** (excluding **Power Park Units**), **HVDC Equipment** and **DC Converters** and **OTSUA** will pass the test the criteria below are met:

Parameter to be Tested		Criteria against which the test results will be assessed by The Company.
Voltage Quality	Harmonic Content	CC.6.1.5(a) or ECC.6.1.5(a) Measured harmonic emissions do not exceed the limits specified in the **Bilateral Agreement** or where no such limits are specified, the relevant planning level specified in G5/4.
	Phase Unbalance	CC.6.1.5(b) or ECC.6.1.5(b), The measured maximum **Phase (Voltage) Unbalance** on the **National Electricity Transmission System** should remain, in England and Wales, below 1% and, in Scotland, below 2% and **Offshore** will be defined in relevant **Bilateral Agreement**. CC.6.1.6 or ECC.6.1.6 In England and Wales, measured infrequent short duration peaks in **Phase (Voltage) Unbalance** should not exceed the maximum value stated in the **Bilateral Agreement**.
	Rapid Voltage Change	CC.6.1.7(a) or ECC.6.1.7(a) The measured Rapid Voltage Change at the **Point of Common Coupling** shall not exceed the Planning Levels specified in CC.6.1.7(a) or ECC 6.1.7.(i)
	Flicker Severity	CC.6.1.7(j) or ECC.6.1.7(j) The measured Flicker Severity at the **Point of Common Coupling** shall not exceed the limits specified in the table of CC.6.1.7(j) or ECC 6.1.7(j).
	Voltage Fluctuation	CC.6.1.8 or ECC.6.1.8 **Offshore**, measured voltage fluctuations at the **Point of Common Coupling** shall not exceed the limits set out in the **Bilateral Agreement**.
Fault Clearance	Fault Clearance Times	CC.6.2.2.2.2(a), CC.6.2.3.1.1(a), ECC.6.2.2.2.2(a), ECC.6.2.3.1.1(a), **Bilateral Agreement**
	Back Up Protection	CC.6.2.2.2.2(b), CC.6.2.3.1.1(b), ECC.6.2.2.2.2(a), ECC.6.2.3.1.1(a), **Bilateral Agreement**
	Circuit Breaker Fail **Protection**	CC.6.2.2.2.2(c), CC.6.2.3.1.1(c), ECC.6.2.2.2.2(c), ECC.6.2.3.1.1(c)

Parameter to be Tested		Criteria against which the test results will be assessed by The Company.
	Reactive Capability	CC.6.3.2 or ECC.6.3.2 (and in the case of CC.6.3.2(e)(iii) and ECC.6.3.2.5 and ECC.6.3.2.6, the **Bilateral Agreement**), CC.6.3.4 or ECC.6.3.4, **Ancillary Services Agreement**. For a test initiated under OC.5.5.1.1 the **Power Generating Module**, **Generating Unit**, **HVDC Equipment**, **DC Converter** or **Power Park Module** or (prior to the **OTSUA Transfer Time**) **OTSUA** will pass the test if it is within ±5% of the reactive capability registered with **The Company** under **OC2**. the duration of the test will be for a period of upto 60 minutes during which period the system voltage at the **Grid Entry Point** for the relevant **Power Generating Module**, **Generating Unit**, **HVDC Equipment**, **DC Converter** or **Power Park Module** or **Interface Point** in the case of **OTSUA** will be maintained by the **Generator** or or **HVDC System Owner**, **DC Converter Station** owner at the voltage specified pursuant to BC2.8 by adjustment of **Reactive Power** on the remaining **Power Generating Module**, **Generating Unit**, **HVDC Equipment**, **DC Converter** or **Power Park Modules** or **OTSUA**, if necessary. Any test performed in respect of an **Embedded Medium Power Station** not subject to a **Bilateral Agreement** or, an **Embedded DC Converter Station** or **Embedded HVDC System** not subject to a **Bilateral Agreement** shall be as confirmed pursuant to OC5.8.3. Measurements of the **Reactive Power** output under steady state conditions should be consistent with Grid Code requirements i.e. fully available within the voltage range ±5% at 400kV, 275kV and 132kV and lower voltages.
Governor / Frequency Control	Primary Secondary and High **Frequency** Response	**Ancillary Services Agreement**, CC.6.3.7 and where applicable CC.A.3 or ECC.6.3.7 and where applicable ECC.A.3. For a test initiated under OC.5.5.1.1 the measured response in MW/Hz is within ±5% of the level of response specified in the **Ancillary Services Agreement** for that **Genset**.
	Stability with Voltage	CC.6.3.4 or ECC.6.3.4
	Governor / Load / **Frequency** Controller **System** Compliance	CC.6.3.6(a), CC.6.3.7, CC.6.3.9, CC8.1, where applicable CC.A.3, BC3.5, BC3.6, BC3.7 or ECC.6.3.6, ECC.6.3.7, ECC.6.3.9, ECC8.1, where applicable ECC.A.3, BC3.5, BC3.6, BC3.7

Parameter to be Tested		Criteria against which the test results will be assessed by The Company.
	Output at Reduced **System Frequency**	CC.6.3.3 or ECC.6.3.3 - For variations in **System Frequency** exceeding 0.1Hz within a period of less than 10 seconds, the **Active Power** output is within ±0.2% of the requirements of CC.6.3.3 or ECC.6.3.3 when monitored at prevailing external air temperatures of up to 25ºC., BC3.5.1
	Fast Start	**Ancillary Services Agreement** requirements
	Black Start	OC5.7
	Excitation/Voltage **Control System**	CC.6.3.6(b), CC.6.3.8, CC.A.6 or CC.A.7 as applicable, BC2.11.2, and the **Bilateral Agreement** or ECC.6.3.6, ECC.6.3.8, ECC.A.6 or ECC.A.7 or ECC.A.8 as applicable
	Fault Ride Through and Fast Fault Current Injection	CC.6.3.15, CC.A.4.A or CC.A.4.B as applicable or ECC.6.3.15, ECC.6.3.16, ECC.A.4. or ECC.A.4EC as applicable
Dynamic Parameters	**Export and Import Limits**, and **Dynamic Parameters**	BC2 The **Export and Import Limits Dynamic Parameters** under test are within 2½% of the declared value being tested.
	Synchronisation time	BC2.5.2.3 **Synchronisation** takes place within ±5 minutes of the time it should have achieved **Synchronisation**.
	Run-up rates	BC2 Achieves the instructed output and, where applicable, the first and/or second intermediate breakpoints, each within ±3 minutes of the time it should have reached such output and breakpoints from **Synchronisation** (or break point, as the case may be), calculated from the run-up rates in its **Dynamic Parameters**.
	Run-down rates	BC2 Achieves the instructed output and, where applicable, the first and/or second intermediate breakpoints, each within ±5 minutes of the time it should have reached such output and breakpoints from **Synchronisation** (or break point, as the case may be), calculated from the run-up rates in its **Dynamic Parameters**.

Parameter to be Tested		Criteria against which the test results will be assessed by The Company.
	Demand Response	DRSC.11.7 **Non-Embedded Customers** and **BM Participants** who are also **Demand Response Providers** shall execute a demand modification test when requested as per DRSC.11.7 to ensure the requirements of the **Ancillary Services** agreement and **Demand Response Services Code** are satisfied.

OC5.5.4.1 The duration of the **Dynamic Parameter** tests in the above table will be consistent with and sufficient to measure the relevant expected input or output derived from the **Final Physical Notification Data** and **Bid-Offer Acceptances** issued under **BC2** which are still in dispute following the procedure in OC5.4.2.

OC5.5.4.2 Due account will be taken of any conditions on the **System** which may affect the results of the test. The relevant **User** must, if requested, demonstrate, to **The Company's** reasonable satisfaction, the reliability of the suitable recorders, disclosing calibration records to the extent appropriate.

OC5.5.5 Test Failure / Re-test

OC5.5.5.1 If the **BM Unit**, **Power Generating Module**, **CCGT Modules**, **Power Park Module**, **OTSUA**, or **Generating Unit** (excluding **Power Park Units**), **HVDC Equipment** or **DC Converter Station** concerned fails to pass the test instructed by **The Company** under OC5.5.1.1 the **User** must provide **The Company** with a written report specifying in reasonable detail the reasons for any failure of the test so far as they are then known to the **User** after due and careful enquiry. This must be provided within five **Business Days** of the test.

OC5.5.5.2 If in **The Company's** reasonable opinion the failure to pass the test relates to compliance with the **CC** or **ECC** as applicable then **The Company** may invoke the process detailed in CP.8.2 to CP.9, or ECP.8.2 to ECP.9

OC5.5.5.3 If a dispute arises relating to the failure, **The Company** and the relevant **User** shall seek to resolve the dispute by discussion, and, if they fail to reach agreement, the **User** may by notice require **The Company** to carry out a re-test on 48 hours' notice which shall be carried out following the procedure set out in OC5.5.3 and OC5.5.4 and subject as provided in OC5.5.1.3, as if **The Company** had issued an instruction at the time of notice from the **User**.

OC5.5.6 Dispute Following Re-Test

If the **BM Unit**, **Power Generating Module**, **CCGT Module**, **Power Park Module**, **OTSUA**, or **Generating Unit** (excluding **Power Park Units**), **HVDC Equipment** or **DC Converter** in **The Company's** view fails to pass the re-test and a dispute arises on that re-test, either party may use the **Disputes Resolution Procedure** for a ruling in relation to the dispute, which ruling shall be binding.

OC5.6 DISPUTE RESOLUTION

OC5.6.1 If following the procedure set out in OC5.5 it is accepted that the **BM Unit**, **Power Generating Module, CCGT Module**, **Power Park Module**, **OTSUA** (prior to the **OTSUA Transfer Time**) or **Generating Unit** (excluding **Power Park Units**)), **HVDC Equipment** or **DC Converter** has failed the test or re-test (as applicable), the **User** shall within 14 days, or such longer period as **The Company** may reasonably agree, following such failure, submit in writing to **The Company** for approval the date and time by which the **User** shall have brought the **BM Unit** concerned to a condition where it complies with the relevant requirement. **The Company** will not unreasonably withhold or delay its approval of the **User's** proposed date and time submitted. Should **The Company** not approve the **User's** proposed date or time (or any revised proposal), the **User** should amend such proposal having regard to any comments **The Company** may have made and re-submit it for approval.

OC5.6.2 If a **BM Unit** fails the test, the **User** shall submit revised **Export and Import Limits** and/or **Dynamic Parameters**, or in the case of a **BM Unit** comprising a **Generating Unit**, **Power Generating Module, CCGT Module**, **HVDC Equipment**, **DC Converter**, **OTSUA** (prior to the **OTSUA Transfer Time**) or **Power Park Module**, the **User** may amend, with **The Company's** approval, the relevant registered parameters of that **Generating Unit**, **Power Generating Module**, **CCGT Module**, **HVDC Equipment**, **DC Converter**, **OTSUA** (prior to the **OTSUA Transfer Time**) or **Power Park Module**, as the case may be, relating to the criteria, for the period of time until the **BM Unit** can achieve the parameters previously registered, as demonstrated in a re-test.

OC5.6.3 Once the **User** has indicated to **The Company** the date and time that the **BM Unit**, **Power Generating Module**, **CCGT Module**, **Power Park Module**, **Generating Unit** (excluding **Power Park Units**) or **OTSUA** (prior to the **OTSUA Transfer Time**), **HVDC Equipment** or **DC Converter Station** can achieve the parameters previously registered or submitted, **The Company** shall either accept this information or require the **User** to demonstrate the restoration of the capability by means of a repetition of the test referred to in OC5.5.3 by an instruction requiring the **User** on 48 hours notice to carry out such a test. The provisions of this OC5.6 will apply to such further test.

OC5.7 BLACK START TESTING

OC5.7.1 General

(a) **The Company** shall require a **Black Start Service Provider** to carry out a **Black Start Test** in order to demonstrate that a **Black Start Station** or **Black Start HVDC System** has a **Black Start Capability**.

(i) In the case of a **Generator**, **The Company** shall require a **Generator** with a **Black Start Station** to carry out a test (either a "**Black Start Unit Test"** or a **Black Start Station Test**") in order to demonstrate that a **Black Start Station** has a **Black Start Capability**.

(ii) In the case of an **HVDC System Owner** or **DC Converter Station Owner**, **The Company** shall require an **HVDC System Owner** or **DC Converter Station Owner** with a **Black Start HVDC System** to carry out a test (a "**Black Start HVDC Test**") on a **HVDC System** or **DC Converter**, in order to demonstrate that a **Black Start HVDC System** has a **Black Start Capability**.

(iii) In the case of an **EU Generator**, **The Company** may also require a **Generator** with a **Black Start Station** to carry out a test (a **Quick Resynchronisation Unit Test**) in order to demonstrate that a **Black Start Station** has a **Quick Re-Synchronisation Capability**.

(b) Where **The Company** requires a **Black Start Service Provider** to undertake testing, the following requirements shall apply:-

(i) Where **The Company** requires a **Generator** with a **Black Start Station** to carry out a **Black Start Unit Test**, on each **Genset,** which has **Black Start Capability**, within such a **Black Start Station**, the **Generator** shall execute such a test at least once every three years. **The Company** shall not require the **Black Start Test Unit** to be carried out on more than one **Genset** at that **Black Start Station** at the same time, and would not, in the absence of exceptional circumstances, expect any of the other **Gensets** at the **Black Start Station** to be directly affected by the **Black Start Unit Test**.

(ii) **The Company** may occasionally require the **Generator** to carry out a **Black Start Station Test** at any time (but will not require a **Black Start Station Test** to be carried out more than once in every three calendar years in respect of any particular **Genset** unless it can justify on reasonable grounds the necessity for further tests or unless the further test is a re-test). If successful, this **Black Start Station Test** shall count as a successful **Black Start Unit Test** for the **Genset** used in the test.

(iii) **The Company** may require the **HVDC System Owner** or **DC Converter Station Owner** to carry out a **Black Start HVDC Test** at any time (but will not require such a test to be carried out more than once in every three calendar years unless it can justify on reasonable grounds the necessity for further tests or unless the further test is a re-test).

(iv) The **Company** may occasionally require the **EU Generator** to carry out a **Quick Re-Synchronisation Test** at any time, but will generally only be required where the **EU Generator** has made a change to its **Plant** and **Apparatus** which has an impact on its **Houseload Operation** or after two unsuccessful tripping **Events** in the operational environment.

The above tests will be deemed a success where starting from **Shutdown** is achieved within a time frame specified by **The Company** and which may be agreed in the **Black Start Contract**.

c) **The Company** may require a **Generator** to carry out a **Black Start Unit Test** at any time (but will not require a **Black Start Unit Test** to be carried out more than once in each calendar year in respect of any particular **Genset** unless it can justify on reasonable grounds the necessity for further tests or unless the further test is a re-test).

(d) When **The Company** wishes a **Black Start Service Provider** to carry out a **Black Start Test**, it shall notify the relevant **Black Start Service Provider** at least 7 days prior to the time of the **Black Start Test** with details of the proposed **Black Start Test**.

OC5.7.2 <u>Procedure for a Black Start Test</u>

The following procedure will, so far as practicable, be carried out in the following sequence for **Black Start Tests**:

OC5.7.2.1 <u>Black Start Unit Tests</u>

(a) The relevant **Generating Unit** shall be **Synchronised** and **Loaded**;

(b) All the **Auxiliary Gas Turbines** and/or **Auxiliary Diesel Engines** in the **Black Start Station** in which that **Generating Unit** is situated, shall be **Shutdown**.

(c) The **Generating Unit** shall be **De-Loaded** and **De-Synchronised** and all alternating current electrical supplies to its **Auxiliaries** shall be disconnected.

(d) The **Auxiliary Gas Turbine(s)** or **Auxiliary Diesel Engine(s)** to the relevant **Generating Unit** shall be started, and shall re-energise the **Unit Board** of the relevant **Generating Unit**.

(e) The **Auxiliaries** of the relevant **Generating Unit** shall be fed by the **Auxiliary Gas Turbine(s)** or **Auxiliary Diesel Engine(s)**, via the **Unit Board**, to enable the relevant **Generating Unit** to return to **Synchronous Speed**.

(f) The relevant **Generating Unit** shall be **Synchronised** to the **System** but not **Loaded**, unless the appropriate instruction has been given by **The Company** under **BC2** which would also be in accordance with the requirements of the **Black Start Contract**.

(g) In respect of **EU Generators**, the above tests defined in OC5.7.2.1(a) – (e) shall be in accordance with the requirements of ECC.6.3.5.3.

OC5.7.2.2 Black Start Station Test

(a) All **Generating Units** at the **Black Start Station**, other than the **Generating Unit** on which the **Black Start Test** is to be carried out, and all the **Auxiliary Gas Turbines** and/or **Auxiliary Diesel Engines** at the **Black Start Station**, shall be **Shutdown**.

(b) The relevant **Generating Unit** shall be **Synchronised** and **Loaded**.

(c) The relevant **Generating Unit** shall be **De-Loaded** and **De-Synchronised**.

(d) All external alternating current electrical supplies to the **Unit Board** of the relevant **Generating Unit**, and to the **Station Board** of the relevant **Black Start Station**, shall be disconnected.

(e) An **Auxiliary Gas Turbine** or **Auxiliary Diesel Engine** at the **Black Start Station** shall be started, and shall re-energise either directly, or via the **Station Board**, the **Unit Board** of the relevant **Generating Unit**.

(f) The provisions of OC5.7.2.1 (e) and (f) shall thereafter be followed.

(g) In respect of **EU Generators**, the above tests defined in OC5.7.2.2(a) – (e) shall be in accordance with the requirements of ECC.6.3.5.3.

OC5.7.2.3 Procedure for a **Black Start HVDC Test**

a) The **HVDC System** or **DC Converter Station** shall demonstrate its technical capability to energise the busbar of the de-energised AC substation to which it is connected, within the **GB Synchronous Area** within a timeframe specified by **The Company**. In the case of **HVDC Systems** this shall be in accordance with the requirements of ECC.6.3.5.4. As part of this test, all **Auxiliaries** are required to be derived from within the **HVDC System** or **DC Converter Station**.

b) The test shall be carried out while the **HVDC System** or **DC Converter Station** starts from **Shutdown**;

c) The test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

i) The **HVDC System Owner** has demonstrated its **HVDC System** or **DC Converter Station** is able to energise the busbar of the isolated AC-substation to which it is connected within the **GB Synchronous Area**

ii) The **HVDC System** or **DC Converter Station** can achieve a stable operating point at an agreed capacity as agreed with **The Company**The relevant **HVDC System** or **DC Converter Station** can be connected to the **System** but not **Loaded**, unless appropriate instructions are given by **The Company** under **BC2** which would also be in accordance with the requirements of the **Black Start Contract**.

iii) In respect of **HVDC Systems** and **Remote End HVDC Converter Stations**, the above tests defined in OC5.7.2.3(a) – (c) shall be in accordance with the requirements of, ECC.6.1.2, ECC.6.1.4, ECC.6.2.2.9.4 and ECC.6.3.5.4.

iv) In respect of **DC Converter Stations**, the above tests defined in OC5.7.2.3(a) – (c) shall be in accordance with the requirements of, CC.6.1.2, CC.6.1.3 and CC.6.1.4.

OC5.7.2.4 All **Black Start Tests** shall be carried out at the time specified by **The Company** in the notice given under OC5.7.1 and shall be undertaken in the presence of a reasonable number of representatives appointed and authorised by **The Company**, who shall be given access to all information relevant to the **Black Start Test**.

OC5.7.2.5 Failure of a Black Start Test

A **Black Start Station** or **Black Start HVDC System** shall fail a **Black Start Test** if the **Black Start Test** shows that it does not have a **Black Start Capability** (ie. if the relevant **Generating Unit** or **HVDC System** or **DC Converter** fails to be **Synchronised** to the **System** within two hours of the **Auxiliary Gas Turbine(s)** or **Auxiliary Diesel Engine(s)** being required to start unless this is part of a **Local Joint Restoration Plan** where the times will be adjusted accordingly).

OC5.7.2.6 If a **Black Start Station** or **Black Start HVDC System** fails to pass a **Black Start Test** the **Black Start Service Provider** must provide **The Company** with a written report specifying in reasonable detail the reasons for any failure of the test so far as they are then known to the **Black Start Service Provider** after due and careful enquiry. This must be provided within five **Business Days** of the test. If a dispute arises relating to the failure, **The Company** and the relevant **Black Start Service Provider**shall seek to resolve the dispute by discussion, and if they fail to reach agreement, the **Black Start Service Provider** may require **The Company** to carry out a further **Black Start Test** on 48 hours notice which shall be carried out following the procedure set out in OC5.7.2.1 or OC5.7.2.2 or OC5.7.2.3 as the case may be, as if **The Company** had issued an instruction at the time of notice from the **Black Start Service Provider.**

OC5.7.2.7 If the **Black Start Station** or **Black Start HVDC System** concerned fails to pass the re-test and a dispute arises on that re-test, either party may use the **Disputes Resolution Procedure** for a ruling in relation to the dispute, which ruling shall be binding.

OC5.7.2.8 If following the procedure in OC5.7.2.6 and OC5.7.2.7 it is accepted that the **Black Start Station** or **Black Start HVDC System** has failed the **Black Start Test** (or a re-test carried out under OC5.7.2.5), within 14 days, or such longer period as **The Company** may reasonably agree, following such failure, the relevant **Black Start Service Provider** shall submit to **The Company** in writing for approval, the date and time by which that **Black Start Service Provider**shall have brought that **Black Start Station** or **Black Start HVDC System** to a condition where it has a **Black Start Capability** and would pass the **Black Start Test**, and **The Company** will not unreasonably withhold or delay its approval of the **Black Start Service Provider's** proposed date and time submitted. Should **The Company** not approve the **Black Start Service Provider's** proposed date and time (or any revised proposal) the **Black Start Service Provider**shall revise such proposal having regard to any comments **The Company** may have made and resubmit it for approval.

OC5.7.2.9 Once the **Black Start Service Provider** has indicated to **The Company** that the **PowerStation** or **HVDC System** or **DC Converter Station** has a **Black Start Capability**, **The Company** shall either accept this information or require the **Black Start Service Provider** to demonstrate that the relevant **Black Start Station** or **Black Start HVDC System** has its **Black Start Capability** restored, by means of a repetition of the **Black Start Test** referred to in OC5.7.1(d) following the same procedure as for the initial **Black Start Test**. The provisions of this OC5.7.2 will apply to such test.

OC5.7.4 Quick Re-synchronisation UnitTest

(a) The relevant **Generating Unit** shall be **Synchronised** and **Loaded**;

(b) All the **Auxiliary Gas Turbines** and/or **Auxiliary Diesel Engines** in the **Black Start Station** in which that **Generating Unit** is situated, shall be **Shutdown**.

(c) The **Generating Unit** shall tripped to house load**.**

(d) The relevant **Generating Unit** shall be **Synchronised** to the **System** but not **Loaded**, unless the appropriate instruction has been given by **The Company** under **BC2** which would also be in accordance with the requirements of the **Black Start Contract**.

In respect of **EU Generators**, the above tests defined in OC5.7.2.3(a) – (e) shall be in accordance with the requirements of ECC.6.3.5.6.

OC5.8 PROCEDURES APPLYING TO EMBEDDED MEDIUM POWER STATIONS NOT SUBJECT TO A BILATERAL AGREEMENT AND EMBEDDED DC CONVERTER STATIONS NOT SUBJECT TO A BILATERAL AGREEMENT

OC5.8.1 Compliance Statement

Each **Network Operator** shall ensure that each **Embedded Person** provides to the **Network Operator** upon **The Company's** request:

(a) written confirmation that each such **Power Generating Module**, **Generating Unit**, **Power Park Module**, **HVDC Equipment**, or **DC Converter** complies with the requirements of the **CC**; and

(b) evidence, where requested, reasonably satisfactory to **The Company**, of such compliance. Such a request shall not normally be made by **The Company** more than twice in any calendar year in respect of any **Generator's Power Generating Module**, **Generating Unit** or **Power Park Module** or **HVDC System Owner's HVDC System**, or **DC Converter** owner's **DC Converter**.

The **Network Operator** shall provide the evidence or written confirmation required under OC5.8.1 (a) and (b) forthwith upon receipt to **The Company**.

OC5.8.2 Network Operator's Obligations To Facilitate Tests

If:

(a) the **Network Operator** fails to procure the confirmation referred to at OC5.8.1(a); or

(b) the evidence of compliance is not to **The Company's** reasonable satisfaction,

then, **The Company** shall be entitled to require the **Network Operator** to procure access upon terms reasonably satisfactory to **The Company** to enable **The Company** to witness the **Embedded Person** carrying out the tests referred to in OC5.8.3 in respect of the relevant **Embedded Medium Power Station** or **Embedded DC Converter Station** or **Embedded HVDC System**.

OC5.8.3 Testing Of Embedded Medium Power Stations Not Subject To A Bilateral Agreement Or Embedded DC Converter Stations Not Subject To A Bilateral Agreement or Embedded HVDC Equipment Not Subject To A Bilateral Agreement

The Company may, in accordance with the provisions of OC5.8.2, at any time (although not normally more than twice in any calendar year in respect of any particular **Embedded Medium Power Station** not subject to a **Bilateral Agreement** or **Embedded DC Converter Station** or **Embedded HVDC Equipment** not subject to a **Bilateral Agreement**) issue an instruction requiring the **Network Operator** within whose **System** the relevant **Medium Power Station** not subject to a **Bilateral Agreement** or **DC Converter Station** or **HVDC Equipment** not subject to a **Bilateral Agreement** is **Embedded**, to require the **Embedded Person** to carry out a test.

Such test shall be carried out at a time no sooner than 48 hours from the time that the instruction was issued, on any one or more of the **Generating Units**, **Power Generating Module, Power Park Module** or **DC Converter** or **HVDC Equipment** comprising part of the relevant **Embedded Medium Power Station** or **Embedded DC Converter Station or HVDC System** and should only be to demonstrate that:

(a) the relevant **Generating Unit**, **Power Generating Module, Power Park Module** or **DC Converter** or **HVDC Equipment** meets the requirements of the paragraphs in the **CC** or **ECC** which are applicable to such **Generating Units**, **Power Generating Modules**, **Power Park Module** or **DC Converter** or **HVDC Equipment**;

(b) the **Reactive Power** capability registered with **The Company** under **OC2** meets the requirements set out in CC.6.3.2 or ECC.6.3.2 as applicable.

The instruction may only be issued where, following consultation with the relevant **Network Operator**, **The Company** has:

(a) confirmed to the relevant **Network Operator** the manner in which the test will be conducted, which shall be consistent with the principles established in OC5.5.3; and

(b) received confirmation from the relevant **Network Operator** that the relevant **Generating Unit**, **Power Generating Module**, **Power Park Module** or **DC Converter** or **HVDC Equipment** would not then be unavailable by reason of forced outage or **Planned Outage** expected prior to the instruction.

The relevant **Network Operator** is responsible for ensuring the performance of any test so required by **The Company** and the **Network Operator** shall ensure that the **Embedded Person** retains the responsibility for ensuring the safety of personnel and plant during the test.

OC5.8.4 Test Failures/Re-Tests And Disputes

The relevant **Network Operator** shall:

(a) ensure that provisions equivalent to OC5.5.5, OC5.5.6 and OC5.6 apply to **Embedded Medium Power Stations** not the subject of a **Bilateral Agreement, Embedded DC Converter Stations** not the subject of a **Bilateral Agreement** or **Embedded HVDC Equipment** not the subject of a **Bilateral Agreement** within its **System** in respect of test failures, re-tests and disputes as to test failures and re-tests;

(b) ensure that the provisions equivalent to OC5.5.5, OC5.5.6 and OC5.6 referred to in OC5.8.4(a) are effective so that **The Company** may require, if it so wishes, the provision to it of any reports or other information equivalent to those or that to which **The Company** would be entitled in relation to test failures, re-tests and disputes as to test failures and re-tests under the provisions of OC5.5.5, OC5.5.6 and OC5.6; and

(c) the provisions equivalent to OC5.5.5, OC5.5.6 and OC5.6 referred to in OC5.8.4(a) are effective to permit **The Company** to conduct itself and take decisions in such a manner in relation to test failures, re-tests and disputes as to test failures and re-tests in respect of **Embedded Medium Power Stations** not the subject of a **Bilateral Agreement**, **Embedded DC Converter Stations** not the subject of a **Bilateral Agreement** or **Embedded HVDC Equipment** not the subject of a **Bilateral Agreement** as it is able to conduct itself and take decisions in relation to test failures, re-tests and disputes as to test failures and re-tests under OC5.5.5, OC5.5.6 and OC5.6.

APPENDIX 1 - ONSITE SIGNAL PROVISION FOR WITNESSING TESTS

OC5.A.1.1 During tests witnessed on-site by **The Company**, the following signals shall be provided to **The Company** by the **GB Generator**, GB **Generator** undertaking **OTSDUW or DC Converter Station** owner in accordance with CC.6.6.2:

OC5.A.1.2 Synchronous Generating Units

(a) All Tests

- MW - **Active Power** at **Generating Unit** terminals

(b) Reactive & Excitation System

- MVAr - **Reactive Power** at **Generating Unit** terminals
- Vt - **Generating Unit** terminal voltage
- Efd- **Generating Unit** field voltage and/or main exciter field voltage
- Ifd – **Generating Unit** field current (where possible)
- **Power System Stabiliser** output, where applicable.
- Noise – Injected noise signal (where applicable and possible)

(c) Governor System & Frequency Response

- Fsys - **System Frequency**
- Finj - Injected Speed Reference
- Logic - Stop / Start Logic Signal

For Gas Turbines:

- GT Fuel Demand
- GT Fuel Valve Position
- GT Inlet Guide Vane Position
- GT Exhaust Gas Temperature

For Steam Turbines at >= 1Hz:

- Pressure before Turbine Governor Valves
- Turbine Governor Valve Positions
- Governor Oil Pressure*
- Boiler Pressure Set Point *
- Superheater Outlet Pressure *
- Pressure after Turbine Governor Valves*
- Boiler Firing Demand*

*Where applicable (typically not in CCGT module)

For Hydro Plant:

- Speed Governor Demand Signal
- Actuator Output Signal
- Guide Vane / Needle Valve Position

(d) Compliance with CC.6.3.3	• Fsys - **System Frequency** • Finj - Injected Speed Reference • Appropriate control system parameters as agreed with **The Company** (See OC5.A.2.9)

OC5.A.1.3 Power Park Modules, OTSUA and DC Converters

	Each **Power Park Module** and **DC Converters** at **Grid Entry Point** or **User System Entry Point**
(a) Real Time on site.	• Total **Active Power** (MW) • Total **Reactive Power** (MVAr) • Line-line Voltage (kV) • **System Frequency** (Hz)
(b) Real Time on site or Downloadable	• Injected frequency signal (Hz) or test logic signal (Boolean) when appropriate • Injected voltage signal (per unit voltage) or test logic signal (Boolean) when appropriate • In the case of an **Onshore Power Park Module** the **Onshore Power Park Module** site voltage (MV) (kV) • **Power System Stabiliser** output, where appropriate • In the case of a **Power Park Module** or **DC Converter** where the **Reactive Power** is provided by from more than one **Reactive Power** source, the individual **Reactive Power** contributions from each source, as agreed with **The Company**. • In the case of **DC Converters** appropriate control system parameters as agreed with **The Company** (See OC5.A.4) • In the case of an **Offshore Power Park Module** the Total **Active Power** (MW) and the Total **Reactive Power** (MVAr) at the **Offshore Grid Entry Point**
(c) Real Time on site or Downloadable	• Available power for **Power Park Module** (MW) • Power source speed for **Power Park Module** (e.g. wind speed) (m/s) when appropriate • Power source direction for **Power Park Module** (degrees) when appropriate See OC5.A.1.3.1

OC5.A.1.3.1 **The Company** accept that the signals specified in OC5.A.1.3(c) may have lower effective sample rates than those required in CC.6.6.2 although any signals supplied for connection to **The Company's** recording equipment which do not meet at least the sample rates detailed in CC.6.6.2 should have the actual sample rates indicated to **The Company** before testing commences.

OC5.A.1.3.2 For all **The Company** witnessed testing either;

(i) the **Generator** or **DC Converter Station** owner shall provide to **The Company** all signals outlined in OC5.A.1.3 direct from the **Power Park Module** control system without any attenuation, delay or filtering which would result in the inability to fully demonstrate the objectives of the test, or identify any potential safety or plant instability issues, and with a signal update rate corresponding to CC.6.6.2.1; or

(ii) in the case of **Onshore Power Park Modules** the **Generator** or **DC Converter Station** owner shall provide signals OC5.A.1.3(a) direct from one or more transducer(s) connected to current and voltage transformers for monitoring in real time on site; or,

(iii) In the case of **Offshore Power Park Modules** and **OTSUA** signals OC5.A.1.3(a) will be provided at the **Interface Point** by the **Offshore Transmission Licensee** pursuant to the STC or by the **Generator** when **OTSDUW Arrangements** apply.

OC5.A.1.3.3 Options OC5.A.1.3.2 (ii) and (iii) will only be available on condition that;

(a) all signals outlined in OC5.A.1.3 are recorded and made available to **The Company** by the **Generator** or **DC Converter Station** owner from the **Power Park Module** or **OTSUA** or **DC Converter** control systems as a download once the testing has been completed; and

(b) the full test results are provided by the **Generator** or **DC Converter Station** owner within 2 working days of the test date to **The Company** unless **The Company** agrees otherwise; and

(c) all data is provided with a sample rate in accordance with CC.6.6.2.2 unless **The Company** agrees otherwise; and

(d) in **The Company's** reasonable opinion the solution does not unreasonably add a significant delay between tests or impede the volume of testing which can take place on the day.

OC5.A.1.3.4 In the case of where transducers connected to current and voltage transformers are installed (OC5.A.1.3.3 (ii) and (iii)), the transducers shall meet the following specification

(a) The transducer(s) shall be permanently installed to easily allow safe testing at any point in the future, and to avoid a requirement for recalibration of the current transformers and voltage transformers.

(b) The transducer(s) should be directly connected to the metering quality current transformers and voltage transformers or similar.

(c) The transducers shall either have a response time no greater than 50ms to reach 90% of output, or no greater than 300ms to reach 99.5%.

APPENDIX 2 - COMPLIANCE TESTING OF SYNCHRONOUS PLANT

OC5.A.2.1 Scope

OC5.A.2.1.1 This Appendix sets out the tests contained therein to demonstrate compliance with the relevant clauses of the **Connection Conditions** of the Grid Code and apply only to **GB Generators**. This Appendix shall be read in conjunction with the **CP** with regard to the submission of the reports to **The Company**. The testing requirements applicable to **EU Generators** are specified in ECP.A.5.

OC5.A.2.1.2 The tests specified in this Appendix will normally be sufficient to demonstrate compliance however **The Company** may:

(i) agree an alternative set of tests provided **The Company** deem the alternative set of tests sufficient to demonstrate compliance with the **Grid Code** and **Bilateral Agreement**; and/or

(ii) require additional or alternative tests if information supplied to **The Company** during the compliance process suggests that the tests in this Appendix will not fully demonstrate compliance with the relevant section of the **Grid Code** or **Bilateral Agreement**.

(iii) Agree a reduced set of tests for subsequent **Generating Units** following successful completion of the first **Generating Unit** tests in the case of a **Power Station** comprised of two or more **Generating Units** which **The Company** reasonably considers to be identical.

If:

(a) the tests performed pursuant to OC5.A.2.1.2(iii) in respect of subsequent **Generating Units** do not replicate the full tests for the first **Generating Unit**, or

(b) any of the tests performed pursuant to OC5.A.2.1.2(iii) do not fully demonstrate compliance with the relevant aspects of the **Grid Code**, **Ancillary Services Agreement** and / or **Bilateral Agreement**,

then notwithstanding the provisions above, the full testing requirements set out in this Appendix will be applied.

OC5.A.2.1.3 The **Generator** is responsible for carrying out the tests set out in and in accordance with this Appendix and the **Generator** retains the responsibility for the safety of personnel and plant during the test. **The Company** will witness all of the tests outlined or agreed in relation to this Appendix unless **The Company** decides and notifies the **Generator** otherwise. Reactive Capability tests may be witnessed by **The Company** remotely from the **The Company** control centre. For all on site **The Company** witnessed tests the **Generator** should ensure suitable representatives from the **Generator** and manufacturer (if appropriate) are available on site for the entire testing period. In all cases the **Generator** shall provide suitable monitoring equipment to record all relevant test signals as outlined below in OC5.A.3.1.5.

OC5.A.2.1.6 The **Generator** shall submit a schedule of tests to **The Company** in accordance with CP.4.3.1

OC5.A.2.1.7 Prior to the testing of a **Generating Unit** the **Generator** shall complete the **Integral Equipment Test** procedure in accordance with OC.7.5

OC5.A.2.1.8 Full **Generating Unit** testing as required by CP.7.2 is to be completed as defined in OC5.A.2.2 through to OC5.A.2.9

OC5.A.2.2 Excitation System Open Circuit Step Response Tests

OC5.A.2.2.1 The open circuit step response of the **Excitation System** will be tested by applying a voltage step change from 90% to 100% of the nominal **Generating Unit** terminal voltage, with the **Generating Unit** on open circuit and at rated speed.

OC5.A.2.2.1 The test shall be carried out prior to synchronisation in accordance with CP.6.4. This is not witnessed by **The Company** unless specifically requested by **The Company**. Where **The Company** is not witnessing the tests, the **Generator** shall supply the recordings of the following signals to **The Company** in an electronic spreadsheet format:

Vt - **Generating Unit** terminal voltage

Efd - **Generating Unit** field voltage or main exciter field voltage

Ifd- **Generating Unit** field current (where possible)

Step injection signal

OC5.A.2.2.3 Results shall be legible, identifiable by labelling, and shall have appropriate scaling.

OC5.A.2.3 Open & Short Circuit Saturation Characteristics

OC5.A.2.3.1 The test shall normally be carried out prior to synchronisation in accordance with CP.6.4. Manufacturer factory test results may be used where appropriate or manufacturers factory type test results may be used if agreed by **The Company**.

OC5.A.2.3.2 This is not witnessed by **The Company**. Graphical and tabular representations of the results in an electronic spreadsheet format showing per unit open circuit terminal voltage and short circuit current versus per unit field current shall be submitted to **The Company**.

OC5.A.2.3.3 Results shall be legible, identifiable by labelling, and shall have appropriate scaling.

OC5.A.2.4 Excitation System On-Load Tests

OC5.A.2.4.1 The time domain performance of the **Excitation System** shall be tested by application of voltage step changes corresponding to 1% and 2% of the nominal terminal voltage.

OC5.A.2.4.2 Where a **Power System Stabiliser** is present:

(i) The **PSS** must only be commissioned in accordance with BC2.11.2. When a **PSS** is switched on for the first time as part of on-load commissioning or if parameters have been adjusted the **Generator** should consider reducing the **PSS** output gain by at least 50% and should consider reducing the limits on **PSS** output by at least a factor of 5 to prevent unexpected PSS action affecting the stability of the **Generating Unit** or the **National Electricity Transmission System**.

(ii) The time domain performance of the **Excitation System** shall be tested by application of voltage step changes corresponding to 1% and 2% of the nominal terminal voltage, repeating with and without the **PSS** in service.

(iii) The frequency domain tuning of the **PSS** shall also be demonstrated by injecting a 0.2Hz-3Hz band limited random noise signal into the **Automatic Voltage Regulator** reference with the **Generating Unit** operating at points specified by **The Company** (up to rated MVA output).

(iv) The **PSS** gain margin shall be tested by increasing the **PSS** gain gradually to threefold and observing the **Generating Unit** steady state **Active Power** output.

(v) The interaction of the **PSS** with changes in **Active Power** shall be tested by application of a +0.5Hz frequency injection to the governor while the **Generating Unit** is selected to **Frequency Sensitive Mode**.

(vi) If the **Generating Unit** is of the pump storage type then the step tests shall be carried out, with and without the **PSS**, in the pumping mode in addition to the generating mode.

(vii) Where the **Bilateral Agreement** requires that the **PSS** is in service at a specified loading level additional testing witnessed by **The Company** will be required during the commissioning process before the **Generating Unit** or **CCGT Module** may exceed this output level.

(viii) Where the **Excitation System** includes a **PSS**, the **Generator** shall provide a suitable noise source to facilitate noise injection testing.

OC5.A.2.4.3 The following typical procedure is provided to assist **Generators** in drawing up their own site specific procedures for the **The Company** witnessed **PSS** Tests.

Test	**Injection**	**Notes**
	Synchronous Generator running rated MW, unity pf, PSS Switched Off	
1	• Record steady state for 10 seconds • Inject +1% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
2	• Record steady state for 10 seconds • Inject +2% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
3	• Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. • Remove noise injection.	
	Switch On Power System Stabiliser	
4	• Record steady state for 10 seconds • Inject +1% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
5	• Record steady state for 10 seconds • Inject +2% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
6	• Increase PSS gain at 30 second intervals. i.e. x1 – x1.5 – x2 – x2.5 – x3 • Return PSS gain to initial setting	
7	• Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. • Remove noise injection.	

8	• Select the governor to FSM • Inject +0.5 Hz step into governor. • Hold until generator MW output is stabilised • Remove step	

OC5.A.2.5 Under-excitation Limiter Performance Test

OC5.A.2.5.1 Initially the performance of the **Under-excitation Limiter** should be checked by moving the limit line close to the operating point of the **Generating Unit** when operating close to unity power factor. The operating point of the **Generating Unit** is then stepped into the limit by applying a 2% decrease in **Automatic Voltage Regulator** reference voltage.

OC5.A.2.5.2 The final performance of the **Under-excitation Limiter** shall be demonstrated by testing its response to a step change corresponding to a 2% decrease in **Automatic Voltage Regulator** reference voltage when the **Generating Unit** is operating just off the limit line, at the designed setting as indicated on the **Performance Chart** submitted to **The Company** under OC2.

OC5.A.2.5.3 Where possible the **Under-excitation Limiter** should also be tested by operating the tap-changer when the **Generating Unit** is operating just off the limit line, as set up.

OC5.A.2.5.4 The **Under-excitation Limiter** will normally be tested at low **Active Power** output and at maximum **Active Power** output (**Registered Capacity**).

OC5.A.2.5.5 The following typical procedure is provided to assist **Generators** in drawing up their own site specific procedures for the **The Company** witnessed **Under-excitation Limiter** Tests.

Test	Injection	Notes
	Synchronous generator running rated MW at unity power factor. Under-excitation limit temporarily moved close to the operating point of the generator.	
1	• PSS on. • Inject -2% voltage step into AVR voltage reference and hold at least for 10 seconds until stabilised • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	Under-excitation limit moved to normal position. Synchronous generator running at rated MW and at leading MVArs close to Under-excitation limit.	
2	• PSS on. • Inject -2% voltage step into AVR voltage reference and hold at least for 10 seconds until stabilised • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	

OC5.A.2.6 Over-excitation Limiter Performance Test

Description & Purpose of Test

OC5.A.2.6.1 The performance of the **Over-excitation Limiter**, where it exists, shall be demonstrated by testing its response to a step increase in the **Automatic Voltage Regulator** reference voltage that results in operation of the **Over-excitation Limiter**. Prior to application of the step the **Generating Unit** shall be generating **Rated Active Power** and operating within its continuous **Reactive Power** capability. The size of the step will be determined by the minimum value necessary to operate the **Over-excitation Limiter** and will be agreed by **The Company** and the **Generator**. The resulting operation beyond the **Over-excitation Limit** shall be controlled by the **Over-excitation Limiter** without the operation of any protection that could trip the **Generating Unit**. The step shall be removed immediately on completion of the test.

OC5.A.2.6.2 If the **Over-excitation Limiter** has multiple levels to account for heating effects, an explanation of this functionality will be necessary and if appropriate, a description of how this can be tested.

OC5.A.2.6.3 The following typical procedure is provided to assist **Generators** in drawing up their own site specific procedures for the **The Company** witnessed **Under-excitation Limiter** Tests.

Test	Injection	Notes
	Synchronous Generator running rated MW and maximum lagging MVAr.	
	Over-excitation Limit temporarily set close to this operating point. PSS on.	
1	• Inject positive voltage step into AVR voltage reference and hold • Wait till Over-excitation Limiter operates after sufficient time delay to bring back the excitation back to the limit. • Remove step returning AVR Voltage Reference to nominal.	
	Over-excitation Limit restored to its normal operating value. PSS on.	

OC5.A.2.7 Reactive Capability

OC5.A.2.7.1 The leading and lagging **Reactive Power** capability on each **Generating Unit** will normally be demonstrated by operation of the **Generating Unit** at 0.85 power factor lagging for 1 hour and 0.95 power factor leading for 1 hour.

OC5.A.2.7.2 In the case of an **Embedded Generating Unit** where distribution network considerations restrict the **Generating Unit Reactive Power** Output then the maximum leading and lagging capability will be demonstrated without breaching the host network operators limits.

OC5.A.2.7.3 The test procedure, time and date will be agreed with **The Company** and will be to the instruction of **The Company** control centre and shall be monitored and recorded at both the **The Company** control centre and by the **Generator**.

OC5.A.2.7.4 Where the **Generator** is recording the voltage and **Reactive Power** at the **Generating Unit** terminals the results shall be supplied in an electronic spreadsheet format.

OC5.A.2.7.5 The ability of the **Generating Unit** to comply with the operational requirements specified in BC2.A.2.6 and CC.6.1.7 will normally be demonstrated by changing the tap position and, where agreed in the **Bilateral Agreement**, the **Generating Unit** terminal voltage.

OC5.A.2.8 Governor and Load Controller Response Performance

OC5.A.2.8.1 The governor and load controller response performance will be tested by injecting simulated frequency deviations into the governor and load controller systems. Such simulated frequency deviation signals must be injected simultaneously at both speed governor and load controller references. For **CCGT modules**, simultaneous injection into all gas turbines, steam turbine governors and module controllers is required.

OC5.A.2.8.2 Prior to witnessing the governor tests set out in OC5.A.2.8.6, **The Company** requires the **Generator** to conduct the preliminary tests detailed in OC5.A.2.8.4 and send the results to **The Company** for assessment unless agreed otherwise by **The Company**. The results should be supplied in an electronic spreadsheet format. These tests shall be completed at least two weeks prior to the witnessed governor response tests.

OC5.A.2.8.3 Where **CCGT module** or **Generating Unit** is capable of operating on alternative fuels, tests will be required to demonstrate performance when operating on each fuel. **The Company** may agree a reduction from the tests listed in OC5.A.2.8.6 for demonstrating performance on the alternative fuel. This includes the case where a main fuel is supplemented by bio-fuel.

<u>Preliminary Governor Frequency Response Testing</u>

OC5.A.2.8.4 Prior to conducting the full set of tests as per OC5.A.2.8.6, **Generators** are required to conduct a preliminary set of tests below to confirm the frequency injection method is correct and the plant control performance is within expectation. The test numbers refer to Figure 1 below. With the plant running at 80% of full load, the following frequency injections shall be applied.

Test No (Figure 1)	**Frequency Injection**	**Notes**
8	• Inject - 0.5Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injected signal	
14	• Inject +0.5Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injected signal	
13	• Inject -0.5Hz frequency fall over 10 sec • Hold for a further 20 sec • At 30 sec from the start of the test, Inject a +0.3Hz frequency rise over 30 sec. • Hold until conditions stabilise • Remove the injected signal	

OC5.A.2.8.5 The recorded results (e.g. Finj, MW and control signals) should be sampled at a minimum rate of 1 Hz to allow **The Company** to assess the plant performance from the initial transients (seconds) to the final steady state conditions (5-15 minutes depending on the plant design). This is not witnessed by **The Company**. The Generator shall supply the recordings including data to **The Company** in an electronic spreadsheet format. Results shall be legible, identifiable by labelling, and shall have appropriate scaling.

Full Frequency Response Testing Schedule Witnessed by The Company

OC5.A.2.8.6 The tests are to be conducted at a number of different Module Load Points (MLP). The load points are conducted as shown below unless agreed otherwise by **The Company**.

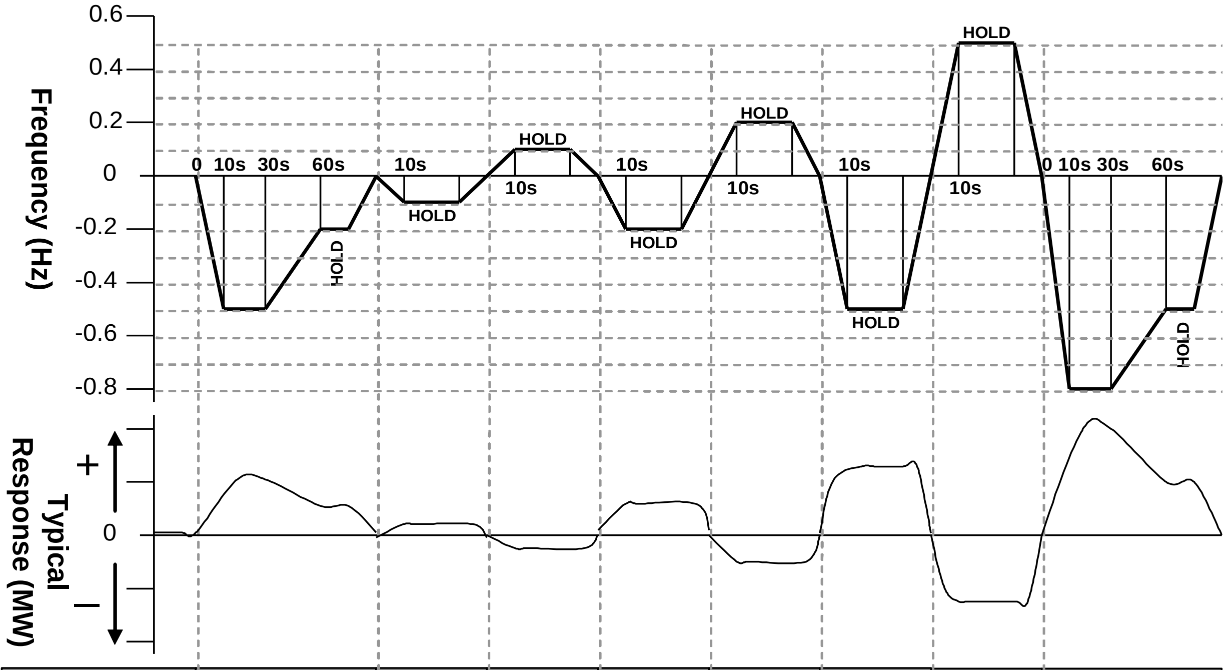
Module Load Point 6 (**Maximum Export Limit**)	100% MEL
Module Load Point 5	95% MEL
Module Load Point 4 (Mid point of Operating Range)	80% MEL
Module Load Point 3	70% MEL
Module Load Point 2 (**Minimum Generation**)	MG
Module Load Point 1 (**Design Minimum Operating Level**)	DMOL

OC5.A.2.8.7 The tests are divided into the following two types;

(i) **Frequency** response volume tests as per OC5.A.2.8. Figure 1. These tests consist of **Frequency** profile and ramp tests.

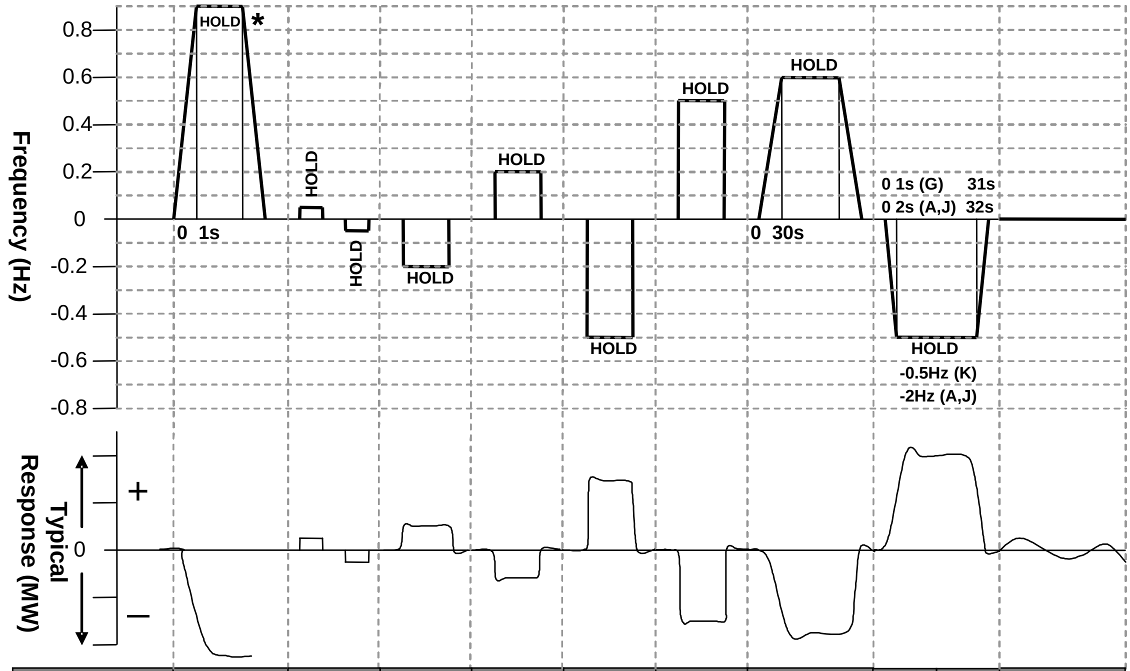
(ii) **System** islanding and step response tests as shown by OC5.A.2.8. Figure 2.

OC5.A.2.8.8 There should be sufficient time allowed between tests for control systems to reach steady state. Where the diagram states 'HOLD' the current injection should be maintained until the **Active Power** (MW) output of the **Generating Unit or CCGT Module** has stabilised. The frequency response capability test (see Figure 1) injection signal shall be returned to zero at the same rate at which it was applied. **The Company** may require repeat tests should the tests give unexpected results.



Load Point	LF Event Profile 1	LF Ramp -0.1Hz	HF Ramp +0.1Hz	LF Ramp -0.2Hz	HF Ramp +0.2Hz	LF Ramp -0.5Hz	HF Ramp +0.5Hz	LF Event Profile 2
MLP6			1	2	3		4	
MLP5	5			6			7	
MLP4	8	9	10	11	12	13	14	
MLP3	15						16	17
MLP2	18			19	20	21		22
MLP1	23			24	25			26

Figure 1: Frequency Response Capability Tests



Load Point	+2.0*	±0.02	-0.2	+0.2	-0.5	+0.5	+0.6	-0.5	-2.0	± 0**
MLP6	BC1						BC2			L
MLP6 LFSM	BC3						BC4			
MLP5								A		
MLP4		D/E	F	G	H	I		J		M
MLP4 LFSM										N
MLP3										
MLP2										
MLP1								K		

Figure 2: System islanding and step response tests

* This will generally be +2.0Hz unless an injection of this size causes a reduction in plant output that takes the operating point below **Designed Minimum Operating Level** in which case an appropriate injection should be calculated in accordance with the following:

For example 0.9Hz is needed to take an initial output 65% to a final output of 20%. If the initial output was not 65% and the **Designed Minimum Operating Level** is not 20% then the injected step should be adjusted accordingly as shown in the example given below

Initial Output	65%
Designed Minimum Operating Level	20%
Frequency Controller Droop	4%
Frequency to be injected =	(0.65 - 0.20) x 0.04 x 50 = 0.9Hz

** Tests L and M in Figure 2 shall be conducted if in this range of tests the system frequency feedback signal is replaced by the injection signal rather than the injection signal being added to the system frequency signal. The tests will consist of monitoring the **Generating Unit and CCGT Module** in **Frequency Sensitive Mode** during normal system frequency variations without applying any injection. Test N in figure 2 shall be conducted in all cases. All three tests should be conducted for a period of at least 10 minutes.

OC5.A.2.9 Compliance with CC.6.3.3 Functionality Test

OC5.A.2.9.1 Where the plant design includes active control function or functions to deliver CC.6.3.3 compliance, the **Generator** will propose and agree a test procedure with **The Company**, which will demonstrate how the **Generating Unit Active Power** output responds to changes in **System Frequency** and ambient conditions (e.g. by **Frequency** and temperature injection methods).

OC5.A.2.9.2 The **Generator** shall inform **The Company** if any load limiter control is additionally employed.

OC5.A.2.9.3 With reference to the signals specified in OC5.A.1, **The Company** will agree with the **Generator** which additional control system parameters shall be monitored to demonstrate the functionality of CC.6.3.3 compliance systems. Where **The Company** recording equipment is not used results shall be supplied to **The Company** in an electronic spreadsheet format.

APPENDIX 3 - COMPLIANCE TESTING OF POWER PARK MODULES (AND OTSUA)

OC5.A.3.1 Scope

OC5.A.3.1.1 This Appendix outlines the general testing requirements for **Power Park Modules** and **OTSUA** to demonstrate compliance with the relevant aspects of the **Grid Code**, **Ancillary Services Agreement** and **Bilateral Agreement** and apply only to **GB Generators**. The testing requirements applicable to **EU Generators** are specified in ECP.A.6. The tests specified in this Appendix will normally be sufficient to demonstrate compliance however **The Company** may:

(i) agree an alternative set of tests provided **The Company** deem the alternative set of tests sufficient to demonstrate compliance with the **Grid Code**, **Ancillary Services Agreement** and **Bilateral Agreement**; and/or

(ii) require additional or alternative tests if information supplied to **The Company** during the compliance process suggests that the tests in this Appendix will not fully demonstrate compliance with the relevant section of the **Grid Code**, **Ancillary Services Agreement** or **Bilateral Agreement**; and/or

(ii) require additional tests if a **Power System Stabiliser** is fitted; and/or

(iv) agree a reduced set of tests if a relevant **Manufacturer's Data & Performance Report** has been submitted to and deemed to be appropriate by **The Company**; and/or

(v) agree a reduced set of tests for subsequent **Power Park Modules** or **OTSUA** following successful completion of the first **Power Park Module** or **OTSUA** tests in the case of a **Power Station** comprised of two or more **Power Park Modules** or **OTSUA** which **The Company** reasonably considers to be identical.

If:

(a) the tests performed pursuant to OC5.A.3.1.1(iv) do not replicate the results contained in the **Manufacturer's Data & Performance Report** or

(b) the tests performed pursuant to OC5.A.3.1.1(v) in respect of subsequent **Power Park Modules** or **OTSUA** do not replicate the full tests for the first **Power Park Module** or **OTSUA**, or

(c) any of the tests performed pursuant to OC5.A.3.1.1(iv) or OC5.A.3.1.1(v) do not fully demonstrate compliance with the relevant aspects of the **Grid Code**, **Ancillary Services Agreement** and / or **Bilateral Agreement**,

then notwithstanding the provisions above, the full testing requirements set out in this Appendix will be applied.

OC5.A.3.1.2 The **Generator** is responsible for carrying out the tests set out in and in accordance with this Appendix and the **Generator** retains the responsibility for the safety of personnel and plant during the test. **The Company** will witness all of the tests outlined or agreed in relation to this Appendix unless **The Company** decides and notifies the **Generator** owner otherwise. Reactive Capability tests may be witnessed by **The Company** remotely from the **The Company** control centre. For all on site **The Company** witnessed tests the **Generator** must ensure suitable representatives from the **Generator** and / or **Power Park Module** manufacturer (if appropriate) and/or **OTSUA** manufacturer (if appropriate) are available on site for the entire testing period. In all cases and in addition to any recording of signals conducted by **The Company** the **Generator** shall record all relevant test signals as outlined in OC5.A.1.

OC5.A.3.1.3 In addition to the dynamic signals supplied in OC5.A.1 the **Generator** shall inform **The Company** of the following information prior to the commencement of the tests and any changes to the following, if any values change during the tests:

(i) All relevant transformer tap numbers; and

(ii) Number of **Power Park Units** in operation

OC5.A.3.1.4 The **Generator** shall submit a detailed schedule of tests to **The Company** in accordance with CP.6.3.1, and this Appendix.

OC5.A.3.1.5 Prior to the testing of a **Power Park Module** or **OTSUA** the **Generator** shall complete the **Integral Equipment Tests** procedure in accordance with OC.7.5.

OC5.A.3.1.6 Partial **Power Park Module** or **OTSUA** testing as defined in OC5.A.3.2 and OC5.A.3.3 is to be completed at the appropriate stage in accordance with CP.6.

OC5.A.3.1.7 Full **Power Park Module** or **OTSUA** testing as required by CP.7.2 is to be completed as defined in OC5.A.3.4 through to OC5.A.3.7.

OC5.A.3.1.8 Where **OTSDUW Arrangements** apply and prior to the **OTSUA Transfer Time** any relevant **OTSDUW Plant and Apparatus** shall be considered within the scope of testing described in this Appendix. Performance shall be assessed against the relevant Grid Code requirements for **OTSDUW Plant and Apparatus** at the **Interface Point** and other **Generator Plant** and **Apparatus** at the **Offshore Grid Entry Point**. This Appendix should be read accordingly.

OC5.A.3.2 Pre 20% (or <50MW) **Synchronised Power Park Module** Basic Voltage Control Tests

OC5.A.3.2.1 Before 20% of the **Power Park Module** (or 50MW if less) has commissioned, either voltage control test OC5.A.3.5.6(i) or (ii) must be completed in accordance with CP.6.

OC5.A.3.2.2 In the case of an **Offshore Power Park Module** which provides all or a portion of the **Reactive Power** capability as described in CC.6.3.2(e)(iii) and / or voltage control requirements as described in CC.6.3.8(b)(ii) to enable an **Offshore Transmission Licensee** to meet the requirements of **STC** Section K, the **Generator** is required to cooperate with the **Offshore Transmission Licensee** to conduct the 20% voltage control test. The results in relation to the **Offshore Power Park Module** will be assessed against the requirements in the **Bilateral Agreement**. In the case of **OTSUA** prior to the **OTSUA Transfer Time**, the **Generator** shall conduct the testing by reference to the entire control system responding to changes at the **Interface Point.**

OC5.A.3.3 For **Power Park Modules** with **Registered Capacity** ≥100MW Pre 70% **Power Park Module** Tests

OC5.A.3.3.1 Before 70% but with at least 50% of the **Power Park Module** commissioned the following **Limited Frequency Sensitive** tests as detailed in OC5.A.3.6.2 must be completed.

(a) BC3

(b) BC4

OC5.A.3.4 <u>Reactive Capability Test</u>

OC5.A.3.4.1 This section details the procedure for demonstrating the reactive capability of an **Onshore Power Park Module** or an **Offshore Power Park Module** or **OTSUA** which provides all or a portion of the **Reactive Power** capability as described in CC.6.3.2(e)(iii) (for the avoidance of doubt, an **Offshore Power Park Module** which does not provide part of the **Offshore Transmission Licensee Reactive Power** capability as described in CC6.3.2(e)(i) and CC6.3.2(e)(ii) should complete the reactive power transfer / voltage control tests as per section OC5.A.3.8). These tests should be scheduled at a time where there are at least 95% of the **Power Park Units** within the **Power Park Module** in service. There should be sufficient MW resource forecasted in order to generate at least 85% of **Registered Capacity** of the **Power Park Module**.

OC5.A.3.4.2 The tests shall be performed by modifying the voltage set-point of the voltage control scheme of the **Power Park Module** or **OTSUA** by the amount necessary to demonstrate the required reactive range. This is to be conducted for the operating points and durations specified in OC5.A.3.4.5.

OC5.A.3.4.3 **Embedded Generator** should liaise with the relevant **Network Operator** to ensure the following tests will not have an adverse impact upon the **Network Operator's System** as per OC.7.5. In situations where the tests have an adverse impact upon the **Network Operator's System The Company** will only require demonstration within the acceptable limits of the **Network Operator**. For the avoidance of doubt, these tests do not negate the requirement to produce a complete **Power Park Module** performance chart as specified in OC2.4.2.1

OC5.A.3.4.4 In the case where the **Reactive Power** metering point is not at the same location as the **Reactive Power** capability requirement, then an equivalent **Reactive Power** capability for the metering point shall be agreed between the **Generator** and **The Company**.

OC5.A.3.4.5 The following tests shall be completed:

(i) Operation in excess of 50% **Rated MW** and maximum continuous lagging **Reactive Power** for 60 minutes.

(ii) Operation in excess of 50% **Rated MW** and maximum continuous leading **Reactive Power** for 60 minutes.

(iii) Operation at 50% **Rated MW** and maximum continuous leading **Reactive Power** for 5 minutes.

(iv) Operation at 20% **Rated MW** and maximum continuous leading **Reactive Power** for 5 minutes.

(v) Operation at 20% **Rated MW** and maximum continuous lagging **Reactive Power** for 5 minutes.

(vi) Operation at less than 20% **Rated MW** and unity **Power Factor** for 5 minutes. This test only applies to systems which do not offer voltage control below 20% of **Rated MW**.

(vii) Operation at 0% **Rated MW** and maximum continuous leading **Reactive Power** for 5 minutes. This test only applies to systems which offer voltage control below 20% and hence establishes actual capability rather than required capability.

(viii) Operation at 0% **Rated MW** and maximum continuous lagging **Reactive Power** for 5 minutes. This test only applies to systems which offer voltage control below 20% and hence establishes actual capability rather than required capability.

OC5.A.3.4.6 Within this OC lagging **Reactive Power** is the export of **Reactive Power** from the **Power Park Module** to the **Total System** and leading **Reactive Power** is the import of **Reactive Power** from the **Total System** to the **Power Park Module** or **OTSUA**.

OC5.A.3.4.7 Where the **Generator** provides a report from a **Power Park Unit** manufacturer validating the full **Reactive Power** capability envelope of the **Power Park Unit** by test results acceptable to **The Company**, **The Company** may agree a reduction from the set of tests detailed in OC5.A.3.4.5. The validation testing detailed in the report must fully demonstrate the **Reactive Power** capability across both the **Active Power** range and the range of unit terminal voltages.

OC5.A.3.5 Voltage Control Tests

OC5.A.3.5.1 This section details the procedure for conducting voltage control tests on **Onshore Power Park Modules** or **OTSUA** or an **Offshore Power Park Module** which provides all or a portion of the voltage control capability as described in CC.6.3.8(b)(ii) (for the avoidance of doubt, **Offshore Power Park Modules** which do not provide part of the **Offshore Transmission Licensee** voltage control capability as described in CC6.3.8(b)(i) should complete the reactive power transfer / voltage control tests as per section OC5.A.3.8). These tests should be scheduled at a time when there are at least 95% of the **Power Park Units** within the **Power Park Module** in service. There should be sufficient MW resource forecasted in order to generate at least 65% of **Registered Capacity** of the **Onshore Power Park Module**. An **Embedded Generator** should also liaise with the relevant **Network Operator** to ensure all requirements covered in this section will not have a detrimental effect on the **Network Operator's System**.

OC5.A.3.5.2 The voltage control system shall be perturbed with a series of step injections to the **Power Park Module** voltage reference, and where possible, multiple up-stream transformer taps. In the case of an **Offshore Power Park Module** providing part of the **Offshore Transmission Licensee** voltage control capability this may require a series of step injections to the voltage reference of the **Offshore Transmission Licensee** control system.

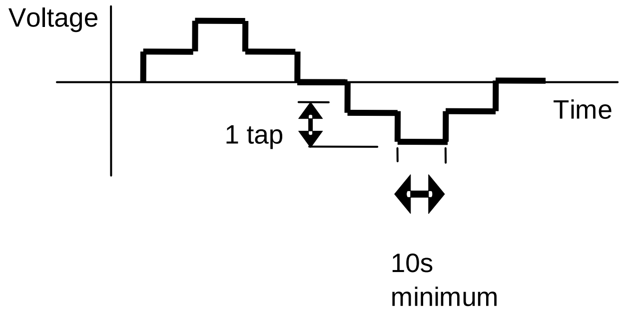
OC5.A.3.5.3 For steps initiated using network tap changers the **Generator** will need to coordinate with **The Company** or the relevant **Network Operator** as appropriate. The time between transformer taps shall be at least 10 seconds as per OC5.A.3.5 Figure 1.

OC5.A.3.5.4 For step injection into the **Power Park Module** or **OTSUA** voltage reference, steps of ±1% and ±2% shall be applied to the voltage control system reference summing junction. The injection shall be maintained for 10 seconds as per OC5.A.3.5 Figure 2.

OC5.A.3.5.5 Where the voltage control system comprises of discretely switched plant and apparatus additional tests will be required to demonstrate that its performance is in accordance with Grid Code and **Bilateral Agreement** requirements.

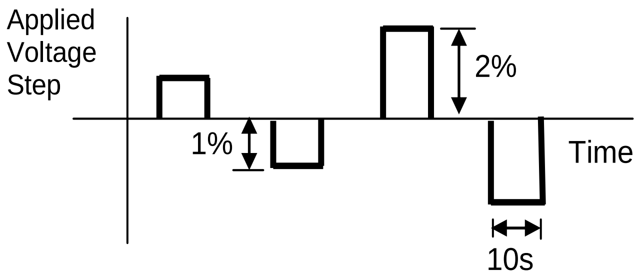
OC5.A.3.5.6 Tests to be completed:

(i)



OC5.A.3.5 Figure 1 – Transformer tap sequence for voltage control tests

(ii)



OC5.A.3.5 Figure 2 – Step injection sequence for voltage control tests

OC.A.3.5.7 In the case of **OTSUA** where the **Bilateral Agreement** specifies additional damping facilities, additional testing to demonstrate these damping facilities may be required.

OC5.A.3.6 <u>Frequency Response Tests</u>

OC5.A.3.6.1 This section describes the procedure for performing frequency response testing on an **Power Park Module**. These tests should be scheduled at a time where there are at least 95% of the **Power Park Units** within the **Power Park Module** in service. There should be sufficient MW resource forecasted in order to generate at least 65% of **Registered Capacity** of the **Power Park Module**.

OC5.A.3.6.2 The frequency controller shall be in **Frequency Sensitive Mode** or **Limited Frequency Sensitive Mode** as appropriate for each test. Simulated frequency deviation signals shall be injected into the frequency controller reference/feedback summing junction. If the injected frequency signal replaces rather than sums with the real system frequency signal then the additional tests outlined in OC5.A.3.6.6 shall be performed with the **Power Park Module** or **Power Park Unit** in normal **Frequency Sensitive Mode** monitoring actual system frequency, over a period of at least 10 minutes. The aim of this additional test is to verify that the control system correctly measures the real system frequency for normal variations over a period of time.

OC5.A.3.6.3 In addition to the frequency response requirements it is necessary to demonstrate the **Power Park Module** ability to deliver a requested steady state power output which is not impacted by power source variation as per CC.6.3.9. This test shall be conducted in **Limited Frequency Sensitive Mode** at a part-loaded output for a period of 10 minutes as per OC5.A.3.6.6.

Preliminary Frequency Response Testing

OC5.A.3.6.4 Prior to conducting the full set of tests as per OC5.A.3.6.6, **Generators** are required to conduct the preliminary set of tests below to confirm the frequency injection method is correct and the plant control performance is within expectation. The test numbers refer to Figure 1 below. The test should be conducted when sufficient MW resource is forecasted in order to generate at least 65% of **Registered Capacity** of the **Power Park Module**. The following frequency injections shall be applied when operating at module load point 4.

Test No (Figure 1)	Frequency Injection	Notes
8	• Inject - 0.5Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injected signal	
14	• Inject +0.5Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injected signal	
13	• Inject -0.5Hz frequency fall over 10 sec • Hold for a further 20 sec • At 30 sec from the start of the test, Inject a +0.3Hz frequency rise over 30 sec. • Hold until conditions stabilise • Remove the injected signal	

OC5.A.3.6.5 The recorded results (e.g. Finj, MW and control signals) should be sampled at a minimum rate of 1 Hz to allow **The Company** to assess the plant performance from the initial transients (seconds) to the final steady state conditions (5-15 minutes depending on the plant design). This is not witnessed by **The Company**. The **Generator** shall supply the recordings including data to **The Company** in an electronic spreadsheet format. Results shall be legible, identifiable by labelling, and shall have appropriate scaling.

Full Frequency Response Testing Schedule Witnessed by The Company

OC5.A.3.6.6 The tests are to be conducted at a number of different Module Load Points (MLP). In the case of a **Power Park Module** the module load points are conducted as shown below unless agreed otherwise by **The Company**.

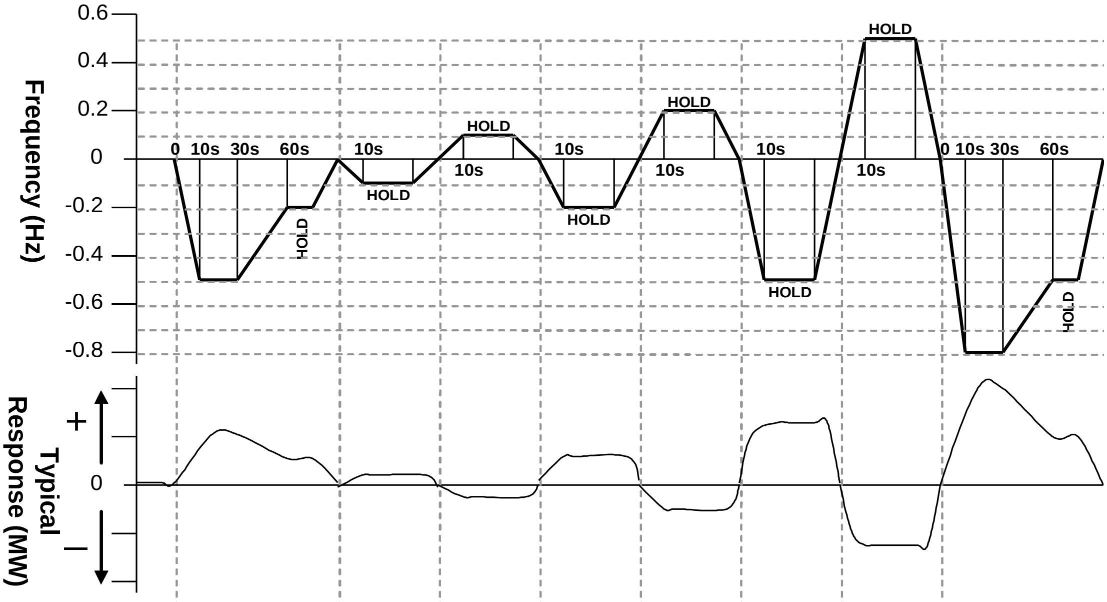
Module Load Point 6 (**Maximum Export Limit**)	100% MEL
Module Load Point 5	90% MEL
Module Load Point 4 (Mid point of Operating Range)	80% MEL
Module Load Point 3	DMOL + 20%
Module Load Point 2	DMOL + 10%
Module Load Point 1 (**Design Minimum Operating Level**)	DMOL

OC5.A.3.6.7 The tests are divided into the following two types;

(i) Frequency response volume tests as per OC5.A.3.6. Figure 1. These tests consist of frequency profile and ramp tests.

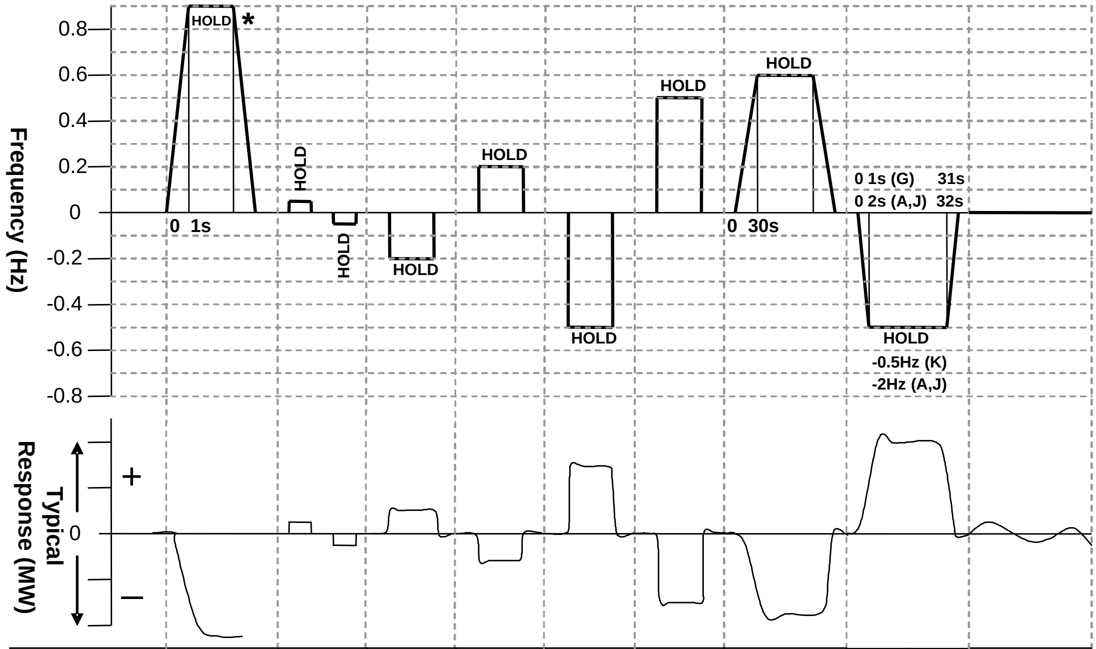
(ii) System islanding and step response tests as shown by OC5.A.3.6 Figure 2

OC5.A.3.6.8 There should be sufficient time allowed between tests for control systems to reach steady state (depending on available power resource). Where the diagram states 'HOLD' the current injection should be maintained until the **Active Power** (MW) output of the **Power Park Module** has stabilised. All frequency response tests should be removed over the same timescale for which they were applied. **The Company** may require repeat tests should the response volume be affected by the available power, or if tests give unexpected results.



Load Point	LF Event Profile 1	LF Ramp -0.1Hz	HF Ramp +0.1Hz	LF Ramp -0.2Hz	HF Ramp +0.2Hz	LF Ramp -0.5Hz	HF Ramp +0.5Hz	LF Event Profile 2
MLP6			1	2	3		4	
MLP5	5			6			7	
MLP4	8	9	10	11	12	13	14	
MLP3	15						16	17
MLP2	18			19	20	21		22
MLP1	23			24	25			26

OC5.A.3.6. Figure 1 – Frequency response volume tests



Load Point	+2.0*	±0.02	-0.2	+0.2	-0.5	+0.5	+0.6	-0.5	-2.0	± 0**
MLP6	BC1						BC2			L
MLP6 LFSM	BC3						BC4			
MLP5								A		
MLP4		D/E	F	G	H	I		J		M
MLP4 LFSM										N
MLP3										
MLP2										
MLP1								K		

OC5.A.3.6. Figure 2 – System islanding and step response tests

* This will generally be +2.0Hz unless an injection of this size causes a reduction in plant output that takes the operating point below **Designed Minimum Operating Level** in which case an appropriate injection should be calculated in accordance with the following:

For example 0.9Hz is needed to take an initial output 65% to a final output of 20%. If the initial output was not 65% and the **Designed Minimum Operating Level** is not 20% then the injected step should be adjusted accordingly as shown in the example given below

Initial Output	65%
Designed Minimum Operating Level	20%
Frequency Controller Droop	4%
Frequency to be injected =	(0.65 - 0.20) x 0.04 x 50 = 0.9Hz

** Tests L and M in Figure 2 shall be conducted if in this range of tests the system frequency feedback signal is replaced by the injection signal rather than the injection signal being added to the system frequency signal. The tests will consist of monitoring the **Power Park Module** in **Frequency Sensitive Mode** during normal system frequency variations without applying any injection. Test N in Figure 2 shall be conducted in all cases. All three tests should be conducted for a period of at least 10 minutes.

OC5.A.3.7 <u>Fault Ride Through Testing</u>

OC5.A.3.7.1 This section describes the procedure for conducting fault ride through tests on a single **Power Park Unit**.

OC5.A.3.7.2 The test circuit will utilise the full **Power Park Unit** with no exclusions (e.g. in the case of a wind turbine it would include the full wind turbine structure) and shall be conducted with sufficient resource available to produce at least 95% of the **Registered Capacity** of the **Power Park Unit**. The test will comprise of a number of controlled short circuits applied to a test network to which the **Power Park Unit** is connected, typically comprising of the **Power Park Unit** transformer and a test impedance to shield the connected network from voltage dips at the **Power Park Unit** terminals.

OC5.A.3.7.3 In each case the tests should demonstrate the minimum voltage at the **Power Park Unit** terminals or **High Voltage** side of the **Power Park Unit** transformer which the **Power Park Unit** can withstand for the length of time specified in OC5.A.3.7.5. Any test results provided to **The Company** should contain sufficient data pre and post fault in order to determine steady state values of all signals, and the power recovery timescales.

OC5.A.3.7.4 In addition to the signals outlined in OC5.A.1.2. the following signals from either the **Power Park Unit** terminals or **High Voltage** side of the **Power Park Unit** transformer should be provided for this test only:

(i) Phase voltages

(ii) Positive phase sequence and negative phase sequence voltages

(iii) Phase currents

(iv) Positive phase sequence and negative phase sequence currents

(v) Estimate of **Power Park Unit** negative phase sequence impedance

(vi) MW – **Active Power** at the generating unit.

(vii) MVAr – **Reactive Power** at the generating unit.

(viii) Mechanical Rotor Speed

(ix) Real / reactive, current / power reference as appropriate

(x) Fault ride through protection operation (e.g. a crowbar in the case of a doubly fed induction generator)

(xi) Any other signals relevant to the control action of the fault ride through control deemed applicable for model validation.

At a suitable frequency rate for fault ride through tests as agreed with **The Company**.

OC5.A.3.7.5 The tests should be conducted for the times and fault types indicated in OC5.A.3.7 Table 1.

3 Phase	Phase to Phase	2 Phase to Earth	1 Phase to Earth	Grid Code Ref
0.14s	0.14s	0.14s	0.14s	CC.6.3.15a
0.384s				CC.6.3.15b
0.710s				
2.5s				
180.0s				

OC5.A.3.7 Table 1 – Types of fault for fault ride through **testing**

OC5.A.3.8 <u>Reactive Power Transfer / Voltage Control Tests for Offshore Power Park Modules</u>

OC5.A.3.8.1 In the case of an **Offshore Power Park Module** which provides all or a portion of the **Reactive Power** capability as described in CC.6.3.2(e)(iii) and / or voltage control requirements as described in CC.6.3.8(b)(ii) to enable an **Offshore Transmission Licensee** to meet the requirements of STC Section K, the testing, will comprise of the entire control system responding to changes at the onshore **Interface Point**. Therefore the tests in this section OC5.A.3.8 will not apply. The **Generator** shall cooperate with the relevant **Offshore Transmission Licensee** to facilitate these tests as required by **The Company**. The testing may be combined with testing of the corresponding **Offshore Transmission Licensee** requirements under the STC. The results in relation to the **Offshore Power Park Module** will be assessed against the requirements in the **Bilateral Agreement**.

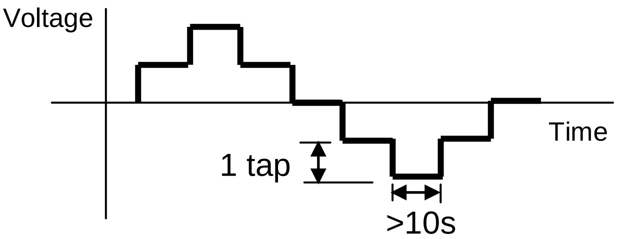
OC5.A.3.8.2 In the case of an **Offshore Power Park Module** which does not provide part of the **Offshore Transmission Licensee Reactive Power** capability the following procedure for conducting reactive power transfer control tests on **Offshore Power Park Modules** and / or voltage control system as per CC6.3.2(e)(i) and CC6.3.2(e)(ii) apply. These tests should be carried out prior to 20% of the **Power Park Units** within the **Offshore Power Park Module** being synchronised, and again when at least 95% of the **Power Park Units** within the **Offshore Power Park Module** in service. There should be sufficient power resource forecast to generate at least 85% of the **Registered Capacity** of the **Offshore Power Park Module**.

OC5.A.3.8.3 The **Reactive Power** control system shall be perturbed by a series of system voltage changes and changes to the **Active Power** output of the **Offshore Power Park Module**.

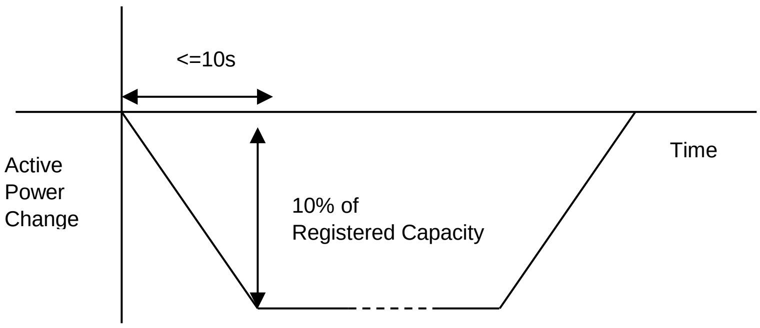
OC5.A.3.8.4 System voltage changes should be created by a series of multiple upstream transformer taps. The **Generator** should coordinate with **The Company** or the relevant **Network Operator** in order to conduct the required tests. The time between transformer taps should be at least 10 seconds as per OC5.A.3.8 Figure 1.

OC5.A.3.8.5 The active power output of the **Offshore Power Park Module** should be varied by applying a sufficiently large step to the frequency controller reference/feedback summing junction to cause a 10% change in output of the **Registered Capacity** of the **Offshore Power Park Module** in a time not exceeding 10 seconds. This test does not need to be conducted provided that the frequency response tests as outlined in OC5.A.3.6 are completed.

OC5.A.3.8.6 The following diagrams illustrate the tests to be completed:



OC5.A.3.8 Figure 1 – Transformer tap sequence for reactive transfer tests



OC5.A.3.8 Figure 2 – Active Power ramp for reactive transfer tests

APPENDIX 4 - COMPLIANCE TESTING FOR DC CONVERTERS AT A DC CONVERTER STATION

OC5.A.4.1 Scope

OC5.A.4.1.1 This Appendix outlines the general testing requirements for **DC Converter Station** owners to demonstrate compliance with the relevant aspects of the **Grid Code**, **Ancillary Services Agreement** and **Bilateral Agreement** and apply only to **DC Converter Station** owners. The testing requirements applicable to **HVDC System Owners** are specified in ECP.A.7. The tests specified in this Appendix will normally be sufficient to demonstrate compliance however **The Company** may:

(i) agree an alternative set of tests provided **The Company** deem the alternative set of tests sufficient to demonstrate compliance with the **Grid Code**, **Ancillary Services Agreement** and **Bilateral Agreement**; and/or

(ii) require additional or alternative tests if information supplied to **The Company** during the compliance process suggests that the tests in this Appendix will not fully demonstrate compliance with the relevant section of the **Grid Code**, **Ancillary Services Agreement** or **Bilateral Agreement**; and/or

(iii) require additional tests if control functions to improve damping of power system oscillations and/or subsynchronous resonance torsional oscillations required by the **Bilateral Agreement** or included in the control scheme and active; and/or

(iv) agree a reduced set of tests for subsequent **DC Converters** following successful completion of the first **DC Converter** tests in the case of a **Power Station** comprised of two or more **DC Converters** which **The Company** reasonably considers to be identical.

If:

(a) the tests performed pursuant to OC5.A.4.1.1(iv) in respect of subsequent **DC Converters** do not replicate the full tests for the first **DC Converter**, or

(b) any of the tests performed pursuant to OC5.A.4.1.1(iv) do not fully demonstrate compliance with the relevant aspects of the **Grid Code**, **Ancillary Services Agreement** and / or **Bilateral Agreement**,

then notwithstanding the provisions above, the full testing requirements set out in this Appendix will be applied.

OC5.A.4.1.2 The **DC Converter Station** owner is responsible for carrying out the tests set out in and in accordance with this Appendix and the **DC Converter Station** owner retains the responsibility for the safety of personnel and plant during the test. The **DC Converter Station** owner is responsible for ensuring that suitable arrangements are in place with the **Externally Interconnected System Operator** to facilitate testing. **The Company** will witness all of the tests outlined or agreed in relation to this Appendix unless **The Company** decides and notifies the **DC Converter Station** owner otherwise. Reactive Capability tests if required, may be witnessed by **The Company** remotely from the **The Company** control centre. For all on site **The Company** witnessed tests the **DC Converter Station** owner must ensure suitable representatives from the **DC Converter Station** owner and / or **DC Converter** manufacturer (if appropriate) are available on site for the entire testing period. In all cases and in addition to any recording of signals conducted by **The Company** the **DC Converter Station** owner shall record all relevant test signals as outlined in OC5.A.1.

OC5.A.4.1.3 In addition to the dynamic signals supplied in OC5.A.1 the **DC Converter Station** owner shall inform **The Company** of the following information prior to the commencement of the tests and any changes to the following, if any values change during the tests:

(i) All relevant transformer tap numbers.

OC5.A.4.1.4 The **DC Converter Station** owner shall submit a detailed schedule of tests to **The Company** in accordance with CP.6.3.1, and this Appendix.

OC5.A.4.1.5 Prior to the testing of a **DC Converter** the **DC Converter Station** owner shall complete the **Integral Equipment Tests** procedure in accordance with OC.7.5

OC5.A.4.1.6 Full **DC Converter** testing as required by CP.7.2 is to be completed as defined in OC5.A.4.2 through to OC5.A.4.5

OC5.A.4.2 Reactive Capability Test

OC5.A.4.2.1 This section details the procedure for demonstrating the reactive capability of an **Onshore DC Converter**. These tests should be scheduled at a time where there are sufficient MW resource forecasted in order to import and export full **Registered Capacity** of the **DC Converter**.

OC5.A.4.2.2 The tests shall be performed by modifying the voltage set-point of the voltage control scheme of the **DC Converter** by the amount necessary to demonstrate the required reactive range. This is to be conducted for the operating points and durations specified in OC5.A.4.2.5.

OC5.A.4.2.3 **Embedded DC Converter Station** owner should liaise with the relevant **Network Operator** to ensure the following tests will not have an adverse impact upon the **Network Operator's System** as per OC.7.5. In situations where the tests have an adverse impact upon the **Network Operator's System The Company** will only require demonstration within the acceptable limits of the **Network Operator**. For the avoidance of doubt, these tests do not negate the requirement to produce a complete **DC Converter** performance chart as specified in OC2.4.2.1.

OC5.A.4.2.4 In the case where the **Reactive Power** metering point is not at the same location as the **Reactive Power** capability requirement, then an equivalent **Reactive Power** capability for the metering point shall be agreed between the **DC Converter Station** owner and **The Company**.

OC5.A.4.2.5 The following tests shall be completed for both importing and exporting of Active Power for a **DC Converter** (excluding current source technology):

(i) Operation at **Rated MW** and maximum continuous lagging **Reactive Power** for 60 minutes.

(ii) Operation at **Rated MW** and maximum continuous leading **Reactive Power** for 60 minutes.

(iii) Operation at 50% **Rated MW** and maximum continuous leading **Reactive Power** for 5 minutes.

(iv) Operation at 20% **Rated MW** and maximum continuous leading **Reactive Power** for 5 minutes.

(v) Operation at 20% **Rated MW** and maximum continuous lagging **Reactive Power** for 5 minutes.

(vi) Operation at less than 20% **Rated MW** and unity **Power Factor** for 5 minutes. This test only applies to systems which do not offer voltage control below 20% of **Rated MW**.

(vii) Operation at 0% **Rated MW** and maximum continuous leading **Reactive Power** for 5 minutes. This test only applies to systems which offer voltage control below 20% and hence establishes actual capability rather than required capability.

(viii) Operation at 0% **Rated MW** and maximum continuous lagging **Reactive Power** for 5 minutes. This test only applies to systems which offer voltage control below 20% and hence establishes actual capability rather than required capability.

OC5.A.4.2.6 For the avoidance of doubt, lagging **Reactive Power** is the export of **Reactive Power** from the **DC Converter** to the **Total System** and leading **Reactive Power** is the import of **Reactive Power** from the **Total System** to the **DC Converter**.

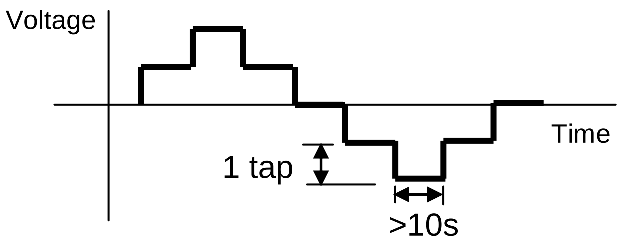
OC5.A.4.3 <u>Reactive Control Testing For DC Converters (Current Source Technology)</u>

OC5.A.4.3.1 The Reactive control testing for **DC Converters** employing current source technology shall be for both importing and exporting of Active Power and shall demonstrate that the reactive power transfer limits specified in the **Bilateral Agreement** are not exceeded. The **Reactive Power** control system shall be perturbed by a series of system voltage changes to the **Active Power** output of the **DC Converter** and changes of system voltage where possible. The **DC Converter Station** owner is responsible for ensuring that suitable arrangements are in place with the **Externally Interconnected System Operator** to facilitate the active power changes required by these tests

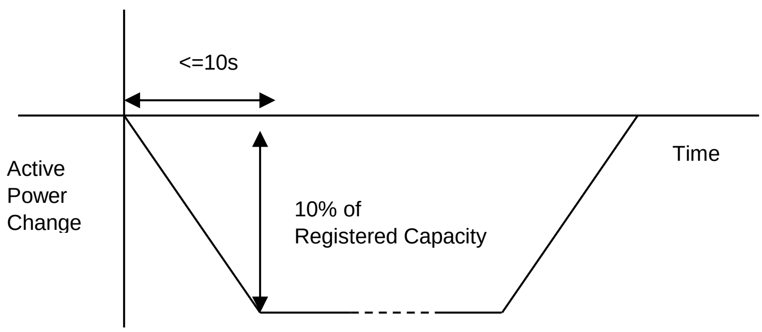
OC5.A.4.3.2 The active power output of the **DC Converter** should be varied by applying a sufficiently large step to the frequency controller reference/feedback summing junction to cause at least a 10% change in output of the **Registered Capacity** of the **DC Converter** in a time not exceeding 10 seconds. This test does not need to be conducted provided that the frequency response tests as outlined in OC5.A.4.3 are completed.

OC5.A.4.3.3 Where possible system voltage changes should be created by a series of multiple upstream transformer taps. The **DC Converter station** owner should coordinate with **The Company** or the relevant **Network Operator** in order to conduct the required tests. The time between transformer taps should be at least 10 seconds as per OC5.A.4.3 Figure 1.

OC5.A.4.3.4 The following diagrams illustrate the tests to be completed:



OC5.A.4.3 Figure 1 – Transformer tap sequence for reactive transfer tests



OC5.A.4.3 Figure 2 – Active Power ramp for reactive transfer tests

OC5.A.4.4 <u>Voltage Control Tests</u>

OC5.A.4.4.1 This section details the procedure for conducting voltage control tests on **DC Converters** (excluding current source technology). These tests should be scheduled at a time where there are sufficient MW resource in order to import and export full **Registered Capacity** of the **DC Converter**. An **Embedded DC Converter Station** owner should also liaise with the relevant **Network Operator** to ensure all requirements covered in this section will not have a detrimental effect on the **Network Operator's System**.

OC5.A.4.4.2 The voltage control system shall be perturbed with a series of step injections to the **DC Converter** voltage reference, and where possible, multiple up-stream transformer taps.

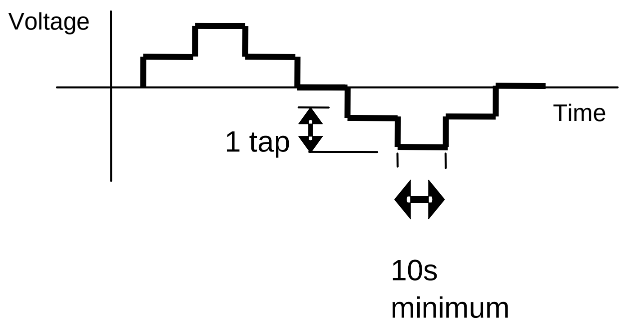
OC5.A.4.4.3 For steps initiated using network tap changers the **DC Converter Station** owner will need to coordinate with **The Company** or the relevant **Network Operator** as appropriate. The time between transformer taps shall be at least 10 seconds as per OC5.A.4.4 Figure 1.

OC5.A.4.4.4 For step injection into the **DC Converter** voltage reference, steps of ±1% and ±2% shall be applied to the voltage control system reference summing junction. The injection shall be maintained for 10 seconds as per OC5.A.4.4 Figure 2.

OC5.A.4.4.5 Where the voltage control system comprises of discretely switched plant and apparatus additional tests will be required to demonstrate that its performance is in accordance with **Grid Code** and **Bilateral Agreement** requirements.

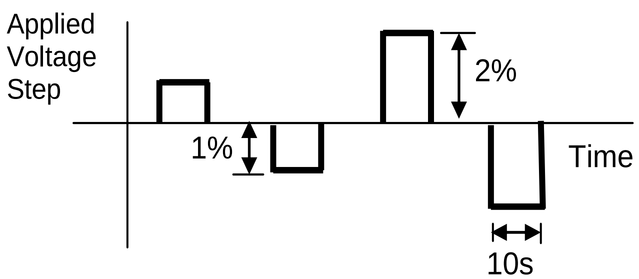
OC5.A.4.4.6 Tests to be completed:

(i)



OC5.A.4.4 Figure 1 – Transformer tap sequence for voltage control tests

(ii)



OC5.A.4.4 Figure 2 – Step injection sequence for voltage control tests

OC5.A.4.5 Frequency Response Tests

OC5.A.4.5.1 This section describes the procedure for performing frequency response testing on a **DC Converter**. These tests should be scheduled at a time where there are sufficient MW resource in order to import and export full **Registered Capacity** of the **DC Converter**. The **DC Converter Station** owner is responsible for ensuring that suitable arrangements are in place with the **Externally Interconnected System Operator** to facilitate the active power changes required by these tests

OC5.A.4.5.2 The frequency controller shall be in **Frequency Sensitive Mode** or **Limited Frequency Sensitive Mode** as appropriate for each test. Simulated frequency deviation signals shall be injected into the frequency controller reference/feedback summing junction. If the injected frequency signal replaces rather than sums with the real system frequency signal then the additional tests outlined in OC5.A.4.5.6 shall be performed with the **DC Converter** in normal **Frequency Sensitive Mode** monitoring actual system frequency, over a period of at least 10 minutes. The aim of this additional test is to verify that the control system correctly measures the real system frequency for normal variations over a period of time.

OC5.A.4.5.3 In addition to the frequency response requirements it is necessary to demonstrate the **DC Converter** ability to deliver a requested steady state power output which is not impacted by power source variation as per CC.6.3.9. This test shall be conducted in **Limited Frequency Sensitive Mode** at a part-loaded output for a period of 10 minutes as per OC5.A.4.5.6.

Preliminary Frequency Response Testing

OC5.A.4.5.4 Prior to conducting the full set of tests as per OC5.A.4.5.6, **DC Converter Station** owners are required to conduct a preliminary set of tests below to confirm the frequency injection method is correct and the plant control performance is within expectation. The test numbers refer to Figure 1 below. These tests should be scheduled at a time where there are sufficient MW resource in order to export full **Registered Capacity** from the **DC Converter**. The following frequency injections shall be applied when operating at module load point 4.

Test No (Figure 1)	**Frequency Injection**	**Notes**
8	• Inject - 0.5Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injected signal	
14	• Inject +0.5Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injected signal	
13	• Inject -0.5Hz frequency fall over 10 sec • Hold for a further 20 sec • At 30 sec from the start of the test, Inject a +0.3Hz frequency rise over 30 sec. • Hold until conditions stabilise • Remove the injected signal	

OC5.A.4.5.5 The recorded results (e.g. Finj, MW and control signals) should be sampled at a minimum rate of 1 Hz to allow **The Company** to assess the plant performance from the initial transients (seconds) to the final steady state conditions (5-15 minutes depending on the plant design). This is not witnessed by **The Company**. The **DC Converter Station** owner shall supply the recordings including data to **The Company** in an electronic spreadsheet format. Results shall be legible, identifiable by labelling, and shall have appropriate scaling.

Full Frequency Response Testing Schedule Witnessed by **The Company**

OC5.A.4.5.6 The tests are to be conducted at a number of different Module Load Points (MLP). In the case of a **DC Converter** the module load points are conducted as shown below unless agreed otherwise by **The Company**.

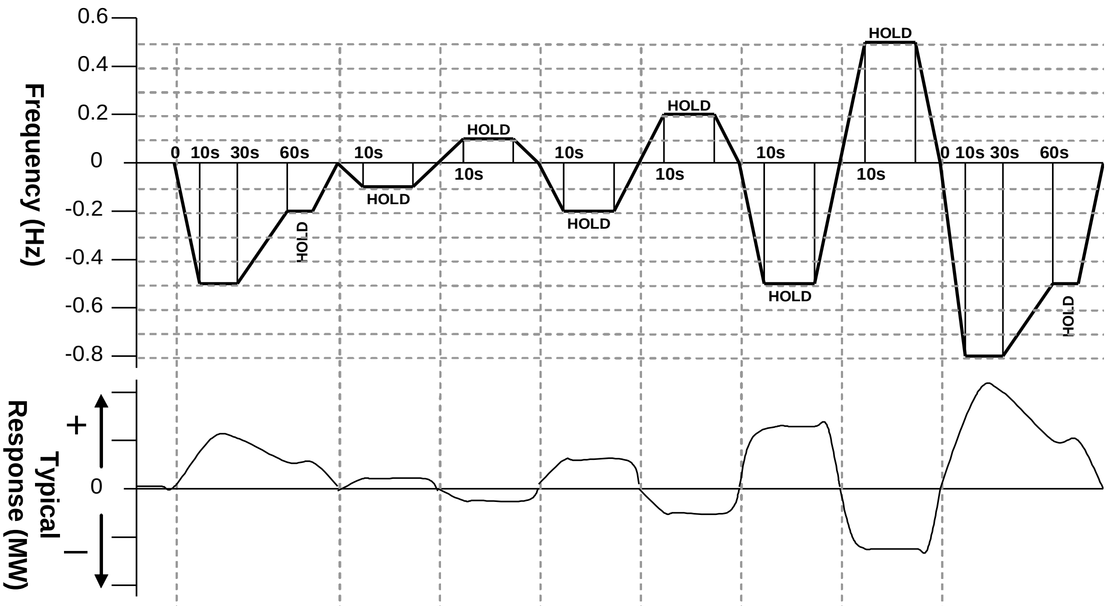
Module Load Point 6 (**Maximum Export Limit**)	100% MEL
Module Load Point 5	90% MEL
Module Load Point 4 (Mid point of Operating Range)	80% MEL
Module Load Point 3	DMOL + 20%
Module Load Point 2	DMOL + 10%
Module Load Point 1 (**Design Minimum Operating Level**)	DMOL

OC5.A.4.5.7 The tests are divided into the following two types;

(i) Frequency response volume tests as per OC5.A.4.5. Figure 1. These tests consist of frequency profile and ramp tests.

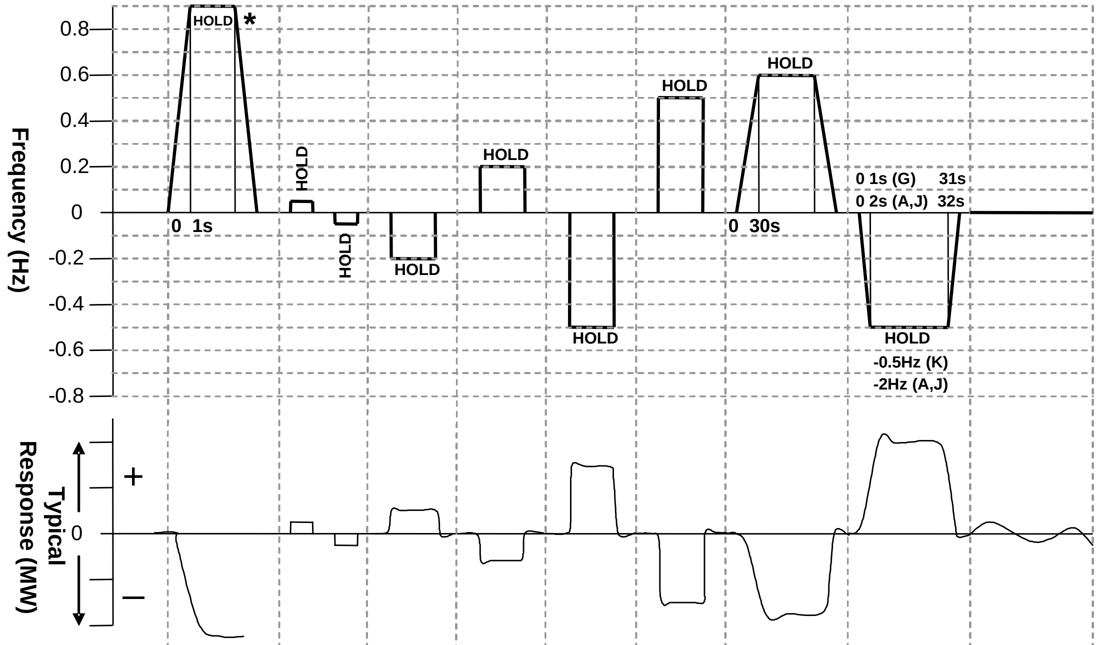
(ii) System islanding and step response tests as shown by OC5.A.4.5 Figure 2

OC5.A.4.5.8 There should be sufficient time allowed between tests for control systems to reach steady state (depending on available power resource). Where the diagram states 'HOLD' the current injection should be maintained until the **Active Power** (MW) output of the **DC Converter** has stabilised. All frequency response tests should be removed over the same timescale for which they were applied. **The Company** may require repeat tests should the response volume be affected by the available power, or if tests give unexpected results.



Load Point	LF Event Profile 1	LF Ramp -0.1Hz	HF Ramp +0.1Hz	LF Ramp -0.2Hz	HF Ramp +0.2Hz	LF Ramp -0.5Hz	HF Ramp +0.5Hz	LF Event Profile 2
MLP6			1	2	3		4	
MLP5	5			6			7	
MLP4	8	9	10	11	12	13	14	
MLP3	15						16	17
MLP2	18			19	20	21		22
MLP1	23			24	25			26

OC5.A.4.5. Figure 1 – Frequency response volume tests



Load Point	+2.0*	±0.02	-0.2	+0.2	-0.5	+0.5	+0.6	-0.5	-2.0	± 0**
MLP6	BC1						BC2			L
MLP6 LFSM	BC3						BC4			
MLP5								A		
MLP4		D/E	F	G	H	I		J		M
MLP4 LFSM										N
MLP3										
MLP2										
MLP1								K		

OC5.A.4.5. Figure 2 – System islanding and step response tests

* This will generally be +2.0Hz unless an injection of this size causes a reduction in plant output that takes the operating point below **Designed Minimum Operating Level** in which case an appropriate injection should be calculated in accordance with the following:

For example 0.9Hz is needed to take an initial output 65% to a final output of 20%. If the initial output was not 65% and the **Designed Minimum Operating Level** is not 20% then the injected step should be adjusted accordingly as shown in the example given below

Initial Output	65%
Designed Minimum Operating Level	20%
Frequency Controller Droop	4%
Frequency to be injected =	(0.65 - 0.20) x 0.04 x 50 = 0.9Hz

** Tests L and M in Figure 2 shall be conducted if in this range of tests the system frequency feedback signal is replaced by the injection signal rather than the injection signal being added to the system frequency signal. The tests will consist of monitoring the **DC Converter** in **Frequency Sensitive Mode** during normal system frequency variations without applying any injection. Test N in Figure 2 shall be conducted in all cases. All three tests should be conducted for a period of at least 10 minutes.

< END OF OPERATING CODE NO. 5 >

BALANCING CODE NO. 1
(BC1)

PRE GATE CLOSURE PROCESS

CONTENTS

(This contents page does not form part of the Grid Code)

BC1.1 INTRODUCTION

Balancing Code No1 (BC1) sets out the procedure for:

(a) the submission of **BM Unit Data** and/or **Generating Unit Data** (which could be part of a **Power Generating Module**) by each **BM Participant**;

(b) the submission of certain **System** data by each **Network Operator**; and

(c) the provision of data by **The Company**,

in the period leading up to **Gate Closure**.

BC1.2 OBJECTIVE

The procedure for the submission of **BM Unit Data** and/or **Generating Unit Data** is intended to enable **The Company** to assess which **BM Units** and **Generating Units** (which could be part of a **Power Generating Module**) are expected to be operating in order that **The Company** can ensure (so far as possible) the integrity of the **National Electricity Transmission System**, and the security and quality of supply.

Where reference is made in this **BC1** to **Generating Units** and/or **Power Generating Modules** (unless otherwise stated) it only applies:

(a) to each **Generating Unit** which forms part of the **BM Unit** of a **Cascade Hydro Scheme**; and

(b) at an **Embedded Exemptable Large Power Station** where the relevant **Bilateral Agreement** specifies that compliance with **BC1** is required:

(i) to each **Generating Unit** which could be part of a **Synchronous Power Generating Module**, or

(ii) to each **Power Park Module** where the **Power Station** comprises **Power Park Modules**.

BC1.3 SCOPE

BC1 applies to **The Company** and to **Users**, which in this **BC1** means:-

(a) **BM Participants**;

(b) **Externally Interconnected System Operators**; and

(c) **Network Operators**.

BC1.4 SUBMISSION OF DATA

In the case of **Additional BM Units** or **Secondary BM Units** any data submitted by **Users** under this **BC1** must represent the value of the data at the relevant **GSP Group**.

In the case of all other **BM Units** or **Generating Units Embedded** in a **User System**, any data submitted by **Users** under this **BC1** must represent the value of the data at the relevant **Grid Supply Point**.

BC1.4.1 Communication With Users

(a) Submission of **BM Unit Data** and **Generating Unit Data** by **Users** to **The Company** specified in BC1.4.2 to BC1.4.4 (with the exception of BC1.4.2(f)) is to be by use of electronic data communications facilities, as provided for in CC.6.5.8 or ECC.6.5.8 (as applicable). However, data specified in BC1.4.2(c) and BC1.4.2(e) only, may be submitted by telephone or fax.

(b) In the event of a failure of the electronic data communication facilities, the data to apply in relation to a pre-**Gate Closure** period will be determined in accordance with the **Data Validation**, **Consistency and Defaulting Rules**, based on the most recent data received and acknowledged by **The Company**.

(c) **Planned Maintenance Outages** will normally be arranged to take place during periods of low data transfer activity.

(d) Upon any **Planned Maintenance Outage**, or following an unplanned outage described in BC1.4.1(b) (where it is termed a "failure") in relation to a pre-**Gate Closure** period:

(i) **BM Participants** should continue to act in relation to any period of time in accordance with the **Physical Notifications** current at the time of the start of the **Planned Maintenance Outage** or the computer system failure in relation to each such period of time subject to the provisions of BC2.5.1. Depending on when in relation to **Gate Closure** the planned or unplanned maintenance outage arises such operation will either be operation in preparation for the relevant output in real time, or will be operation in real time. No further submissions of **BM Unit Data** and/or **Generating Unit Data** (other than data specified in BC1.4.2(c) and BC1.4.2(e)) should be attempted. Plant failure or similar problems causing significant deviation from **Physical Notification** should be notified to **The Company** by the submission of a revision to **Export and Import Limits** in relation to the **BM Unit** and /or **Generating Unit** so affected;

(ii) during the outage, revisions to the data specified in BC1.4.2(c) and BC1.4.2(e) may be submitted. Communication between **Users Control Points** and **The Company** during the outage will be conducted by telephone; and

(iii) no data will be transferred from **The Company** to the **BMRA** until the communication facilities are re-established.

BC1.4.2 Day Ahead Submissions

Data for any **Operational Day** may be submitted to **The Company** up to several days in advance of the day to which it applies, as provided in the **Data Validation, Consistency and Defaulting Rules**. However, **Interconnector Users** must submit **Physical Notifications**, and any associated data as necessary, each day by 11:00 hours in respect of the next following **Operational Day** in order that the information used in relation to the capability of the respective **External Interconnection** is expressly provided. **The Company** shall not by the inclusion of this provision be prevented from utilising the provisions of BC1.4.5 if necessary.

The data may be modified by further data submissions at any time prior to **Gate Closure**, in accordance with the other provisions of **BC1**. The data to be used by **The Company** for operational planning will be determined from the most recent data that has been received by **The Company** by 11:00 hours on the day before the **Operational Day** to which the data applies, or from the data that has been defaulted at 11:00 hours on that day in accordance with BC1.4.5. Any subsequent revisions received by **The Company** under the Grid Code will also be utilised by **The Company**. In the case of all data items listed below, with the exception of item (e), **Dynamic Parameters** (Day Ahead), the latest submitted or defaulted data, as modified by any subsequent revisions, will be carried forward into operational timescales. The individual data items are listed below:

(a) Physical Notifications

Physical Notifications, being the data listed in **BC1** Appendix 1 under that heading, are required by **The Company** at 11:00 hours each day for each **Settlement Period** of the next following **Operational Day**, in respect of;

(1) **BM Units**:

(i) with a **Demand Capacity** with a magnitude of 50MW or more in **NGET's Transmission Area** or 10MW or more in **SHETL's Transmission Area** or 30MW or more in **SPT's Transmission Area**; or

(ii) comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC1.2) and/or **Power Generating Modules** and/or **CCGT Modules** and/or **Power Park Modules** in each case at **Large Power Stations**, **Medium Power Stations** and **Small Power Stations** where such **Small Power Stations** are directly connected to the **Transmission System**; or

(iii) where the **BM Participant** chooses to submit **Bid-Offer Data** in accordance with BC1.4.2(d) for **BM Units** not falling within (i) or (ii) above,

and

(2) each **Generating Unit** where applicable under BC1.2.

Physical Notifications may be submitted to **The Company** by **BM Participants**, for the **BM Units**, and **Generating Units**, specified in this BC1.4.2(a) at an earlier time, or **BM Participants** may rely upon the provisions of BC1.4.5 to create the **Physical Notifications** by data defaulting pursuant to the **Grid Code** utilising the rules referred to in that paragraph at 11:00 hours in any day.

Physical Notifications (which must comply with the limits on maximum rates of change listed in **BC1** Appendix 1) must, subject to the following operating limits, represent the **Users** best estimate of expected input or output of **Active Power** and shall be prepared in accordance with **Good Industry Practice**. **Physical Notifications** for any **BM Unit**, and any **Generating Units**, should normally be consistent with the **Dynamic Parameters** and **Export and Import Limits** and must not reflect any **BM Unit** or any **Generating Units**, proposing to operate outside the limits of its **Demand Capacity** and (and in the case of **BM Units**) **Generation Capacity** and, in the case of a **BM Unit** comprising a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC1.2) and/or **Power Generating Module** and/or **CCGT Module** and/or **Power Park Module**, its **Registered Capacity**.

These **Physical Notifications** provide, amongst other things, indicative **Synchronising** and **De-Synchronising** times to **The Company** in respect of any **BM Unit** comprising a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC1.2) and/or **Power Generating Module** and/or **CCGT Module** and/or **Power Park Module**, and for any **Generating Units**, and provide an indication of significant **Demand** changes in respect of other **BM Units**.

(b) Not Used.

(c) Export and Import Limits

Each **BM Participant** may, in respect of each of its **BM Units** and its **Generating Units** submit to **The Company** for any part or for the whole of the next following **Operational Day** the data listed in **BC1** Appendix 1 under the heading of "**Export and Import Limits**" to amend the data already held by **The Company** in relation to **Export and Import Limits**, which would otherwise apply for those **Settlement Periods**.

Export and Import Limits respectively represent the maximum export to or import from the **National Electricity Transmission System** for a **BM Unit** and a **Generating Unit** and are the maximum levels that the **BM Participant** wishes to make available and must be prepared in accordance with **Good Industry Practice**.

(d) Bid-Offer Data

Each **BM Participant** may, in respect of each of its **BM Units**, but must not in respect of its **Generating Units** submit to **The Company** for any **Settlement Period** of the next following **Operational Day** the data listed in **BC1** Appendix 1 under the heading of "**Bid-Offer Data**" to amend the data already held by **The Company** in relation to **Bid-Offer Data**, which would otherwise apply to those **Settlement Periods**. The submitted **Bid-Offer Data** will be utilised by **The Company** in the preparation and analysis of its operational plans for the next following **Operational Day**. **Bid-Offer Data** may not be submitted unless an automatic logging device has been installed at the **Control Point** for the **BM Unit** in accordance with CC.6.5.8(b) or ECC.6.5.8(b) (as applicable).

(e) Dynamic Parameters (Day Ahead)

Each **BM Participant** may, in respect of each of its **BM Units**, but must not in respect of its **Generating Units** submit to **The Company** for the next following **Operational Day** the data listed in **BC1** Appendix 1 under the heading of "**Dynamic Parameters**" to amend that data already held by **The Company**.

These **Dynamic Parameters** shall reasonably reflect the expected true operating characteristics of the **BM Unit** and shall be prepared in accordance with **Good Industry Practice**.

The **Dynamic Parameters** applicable to the next following **Operational Day** will be utilised by **The Company** in the preparation and analysis of its operational plans for the next following **Operational Day** and may be used to instruct certain **Ancillary Services**. For the avoidance of doubt, the **Dynamic Parameters** to be used in the current **Operational Day** will be those submitted in accordance with BC2.5.3.1.

(f) Other Relevant Data

By 11:00 hours each day, each **BM Participant**, in respect of each of its **BM Units** and **Generating Units** for which **Physical Notifications** are being submitted, shall, if it has not already done so, submit to **The Company** (save in respect of item (vi) and (vii) where the item shall be submitted only when reasonably required by **The Company**), in respect of the next following **Operational Day** the following:

(i) in the case of a **CCGT Module** and/or a **Synchronous Power Generating Module**, a **CCGT Module Matrix** and/or a **Synchronous Power Generating Module Matrix** as described in **BC1** Appendix 1;

(ii) details of any special factors which in the reasonable opinion of the **BM Participant** may have a material effect or present an enhanced risk of a material effect on the likely output (or consumption) of such **BM Unit(s)**. Such factors may include risks, or potential interruptions, to **BM Unit** fuel supplies, or developing plant problems, details of tripping tests, etc. This information will normally only be used to assist in determining the appropriate level of **Operating Margin** that is required under OC2.4.6;

(iii) in the case of **Generators**, any temporary changes, and their possible duration, to the **Registered Data** of such **BM Unit**;

(iv) in the case of **Suppliers**, details of **Customer Demand Management** taken into account in the preparation of its **BM Unit Data**;

(v) details of any other factors which **The Company** may take account of when issuing **Bid-Offer Acceptances** for a **BM Unit** (e.g., **Synchronising** or **De-Synchronising** Intervals);

(vi) in the case of a **Cascade Hydro Scheme**, the **Cascade Hydro Scheme Matrix** as described in **BC1** Appendix 1;

(vii) in the case of a **Power Park Module**, a **Power Park Module Availability Matrix** as described in **BC1** Appendix 1;

(viii) in the case of an **Additional BM Unit** or a **Secondary BM Unit** an **Aggregator Impact Matrix** as described in **BC1** Appendix 1.

BC1.4.3 Data Revisions

The **BM Unit Data**, and **Generating Unit Data**, derived at 1100 hours each day under BC1.4.2 above may need to be revised by the **BM Participant** for a number of reasons, including for example, changes to expected output or input arising from revised contractual positions, plant breakdowns, changes to expected **Synchronising** or **De-Synchronising** times, etc, occurring before **Gate Closure**. **BM Participants** should use reasonable endeavours to ensure that the data held by **The Company** in relation to its **BM Units** and **Generating Units**, is accurate at all times. Revisions to **BM Unit Data**, and **Generating Unit Data** for any period of time up to **Gate Closure** should be submitted to **The Company** as soon as reasonably practicable after a change becomes apparent to the **BM Participant**. **The Company** will use reasonable endeavours to utilise the most recent data received from **Users**, subject to the application of the provisions of BC1.4.5, for its preparation and analysis of operational plans.

BC1.4.4 Receipt Of BM Unit Data Prior To Gate Closure

BM Participants submitting **Bid-Offer Data**, in respect of any **BM Unit** for use in the **Balancing Mechanism** for any particular **Settlement Period** in accordance with the **BSC**, must ensure that **Physical Notifications** and **Bid-Offer Data** for such **BM Units** are received in their entirety and logged into **The Company's** computer systems by the time of **Gate Closure** for that **Settlement Period**. In all cases the data received will be subject to the application under the **Grid Code** of the provisions of BC1.4.5.

For the avoidance of doubt, no changes to the **Physical Notification** or **Bid-Offer Data** for any **Settlement Period** may be submitted to **The Company** after **Gate Closure** for that **Settlement Period**.

BC1.4.5 BM Unit Data Defaulting, Validity And Consistency Checking

In the event that no submission of any or all of the **BM Unit Data** and **Generating Unit Data** in accordance with BC1.4.2 in respect of an **Operational Day**, is received by **The Company** by 11:00 hours on the day before that **Operational Day**, **The Company** will apply the **Data Validation**, **Consistency and Defaulting Rules**, with the default rules applicable to **Physical Notifications** and **Export and Import Limits** data selected as follows:

(a) for an **Interconnector Users BM Unit**, the defaulting rules will set some or all of the data for that **Operational Day** to zero, unless the relevant Interconnector arrangements, as agreed with **The Company**, state otherwise (in which case (b) applies); and

(b) for all other **BM Units** or **Generating Units**, the defaulting rules will set some or all of the data for that **Operational Day** to the values prevailing in the current **Operational Day**.

A subsequent submission by a **User** of a data item which has been so defaulted under the **Grid Code** will operate as an amendment to that defaulted data and thereby replace it. Any such subsequent submission is itself subject to the application under the **Grid Code** of the **Data Validation**, **Consistency and Defaulting Rules**.

BM Unit Data and **Generating Unit Data** submitted in accordance with the provisions of BC1.4.2 to BC1.4.4 will be checked under the **Grid Code** for validity and consistency in accordance with the **Data Validation**, **Consistency and Defaulting Rules**. If any **BM Unit Data** and **Generating Unit Data** so submitted fails the data validity and consistency checking, this will result in the rejection of all data submitted for that **BM Unit** or **Generating Unit** included in the electronic data file containing that data item and that **BM Unit's** or **Generating Unit's** data items will be defaulted under the **Grid Code** in accordance with the **Data Validation**, **Consistency and Defaulting Rules**. Data for other **BM Units** and **Generating Units** included in the same electronic data file will not be affected by such rejection and will continue to be validated and checked for consistency prior to acceptance. In the event that rejection of any **BM Unit Data** and **Generating Unit Data** occurs, details will be made available to the relevant **BM Participant** via the electronic data communication facilities. In the event of a difference between the **BM Unit Data** for the **Cascade Hydro Scheme** and sum of the data submitted for the **Generating Units** forming part of such **Cascade Hydro Scheme**, the **BM Unit Data** shall take precedence.

BC1.4.6 Special Provisions Relating To Interconnector Users

(a) The total of the relevant **Physical Notifications** submitted by **Interconnector Users** in respect of any period of time should not exceed the capability (in MW) of the respective **External Interconnection** for that period of time. In the event that it does, then **The Company** shall advise the **Externally Interconnected System Operator** accordingly. In the period between such advice and **Gate Closure**, one or more of the relevant **Interconnector Users** would be expected to submit revised **Physical Notifications** to **The Company** to eliminate any such over-provision.

(b) In any case where, as a result of a reduction in the capability (in MW) of the **External Interconnection** in any period during an **Operational Day** which is agreed between **The Company** and an **Externally Interconnected System Operator** after 0900 hours on the day before the beginning of such **Operational Day**, the total of the **Physical Notifications** in the relevant period using that **External Interconnection**, as stated in the **BM Unit Data** exceeds the reduced capability (in MW) of the respective **External Interconnection** in that period then **The Company** shall notify the **Externally Interconnected System Operator** accordingly.

BC1.5 INFORMATION PROVIDED BY THE COMPANY

The Company shall provide data to the **Balancing Mechanism Reporting Agent** or **BSCCo** each day in accordance with the requirements of the **BSC** in order that the data may be made available to **Users** via the **Balancing Mechanism Reporting Service** (or by such other means) in each case as provided in the **BSC**. Where **The Company** provides such information associated with the secure operation of the **System** to the **Balancing Mechanism Reporting Agent**, the provision of that information is additionally provided for in the following sections of this BC1.5. **The Company** shall be taken to have fulfilled its obligations to provide data under BC1.5.1, BC1.5.2, and BC1.5.3 by so providing such data to the **Balancing Mechanism Reporting Agent**.

BC1.5.1 Demand Estimates

Normally by 0900 hours each day, **The Company** will make available to **Users** a forecast of **National Demand** and the **Demand** for a number of pre-determined constraint groups (which may be updated from time to time, as agreed between **The Company** and **BSCCo**) for each **Settlement Period** of the next following **Operational Day**. Normally by 1200 hours each day, **The Company** will make available to **Users** a forecast of **National Electricity Transmission System Demand** for each **Settlement Period** of the next **Operational Day**. Further details are provided in Appendix 2.

BC1.5.2 Indicated Margin And Indicated Imbalance

Normally by 1200 hours each day, **The Company** will make available to **Users** an **Indicated Margin** and an **Indicated Imbalance** for each **Settlement Period** of the next following **Operational Day**. **The Company** will use reasonable endeavours to utilise the most recent data received from **Users** in preparing for this release of data. Further details are provided in Appendix 2.

BC1.5.3 Provision Of Updated Information

The Company will provide updated information on **Demand** and other information at various times throughout each day, as detailed in Appendix 2. **The Company** will use reasonable endeavours to utilise the most recent data received from **Users** in preparing for this release of data.

BC1.5.4 Reserve And System Margin

Contingency Reserve

(a) The amount of **Contingency Reserve** required at the day ahead stage and in subsequent timescales will be decided by **The Company** on the basis of historical trends in the reduction in availability of **Large Power Stations** and increases in forecast **Demand** up to real time operation. Where **Contingency Reserve** is to be allocated to thermal **Gensets**, **The Company** will instruct through a combination of **Ancillary Services** instructions and **Bid-Offer Acceptances**, the time at which such **Gensets** are required to synchronise, such instructions to be consistent with **Dynamic Parameters** and other contractual arrangements.

Operating Reserve

(b) The amount of **Operating Reserve** required at any time will be determined by **The Company** having regard to the **Demand** levels, **Large Power Station** availability shortfalls and the greater of the largest secured loss of generation (ie, the loss of generation against which, as a requirement of the **Licence Standards**, the **National Electricity Transmission System** must be secured) or loss of import from or sudden export to **External Interconnections**. **The Company** will allocate **Operating Reserve** to the appropriate **BM Units** and **Generating Units** so as to fulfil its requirements according to the **Ancillary Services** available to it and as provided in the **BC**.

System Margin

(c) In the period following 1200 hours each day and in relation to the following **Operational Day**, **The Company** will monitor the total of the Maximum Export Limit component of the **Export and Import Limits** received against forecast **National Electricity Transmission System Demand** and the **Operating Margin** and will take account of **Dynamic Parameters** to see whether the anticipated level of the **System Margin** for any period is insufficient.

(d) Where the level of the **System Margin** for any period is, in **The Company's** reasonable opinion, anticipated to be insufficient, **The Company** will send (by such data transmission facilities as have been agreed) a **National Electricity Transmission System Warning** - **Electricity Margin Notice** in accordance with OC7.4.8 to each **Generator**, **Supplier**, **Externally Interconnected System Operator**, **Network Operator** and **Non-Embedded Customer**.

(e) Where, in **The Company's** judgement the **System Margin** at any time during the current **Operational Day** is such that there is a high risk of **Demand** reduction being instructed, a **National Electricity Transmission System Warning** - **High Risk of Demand Reduction** will be issued, in accordance with OC7.4.8.

(f) The monitoring will be conducted on a regular basis and a revised **National Electricity Transmission System Warning** - **Electricity Margin Notice** or **High Risk of Demand Reduction** may be sent out from time to time, including within the post **Gate Closure** phase. This will reflect any changes in **Physical Notifications** and **Export and Import Limits** which have been notified to **The Company**, and will reflect any **Demand Control** which has also been so notified. This will also reflect generally any changes in the forecast **Demand** and the relevant **Operating Margin**.

(g) To reflect changing conditions, a **National Electricity Transmission System Warning - Electricity Margin Notice** may be superseded by a **National Electricity Transmission System Warning - High Risk of Demand Reduction** and vice-versa.

(h) If the continuing monitoring identifies that the **System Margin** is anticipated, in **The Company's** reasonable opinion, to be sufficient for the period for which previously a **National Electricity Transmission System Warning** had been issued, **The Company** will send (by such data transmission facilities as have been agreed) a **Cancellation of National Electricity Transmission System Warning** to each **User** who had received a **National Electricity Transmission System Warning - Electricity Margin Notice** or **High Risk of Demand Reduction** for that period. The issue of a **Cancellation of National Electricity Transmission System Warning** is not an assurance by **The Company** that in the event, the **System Margin** will be adequate, but reflects **The Company's** reasonable opinion that the insufficiency is no longer anticipated.

(i) If continued monitoring indicates the **System Margin** becoming reduced **The Company** may issue further **National Electricity Transmission System Warnings - Electricity Margin Notice** or **High Risk of Demand Reduction**.

(j) **The Company** may issue a **National Electricity Transmission System Warning - Electricity Margin Notice** or **High Risk of Demand Reduction** for any period, not necessarily relating to the following **Operational Day**, where it has reason to believe there will be a reduced **System Margin** over a period (for example in periods of protracted **Plant** shortage, the provisions of OC7.4.8.6 apply).

BC1.5.5 System And Localised NRAPM (Negative Reserve Active Power Margin)

(a) (i) System Negative Reserve Active Power Margin

Synchronised Gensets must at all times be capable of reducing output such that the total reduction in output of all **Synchronised Gensets** is sufficient to offset the loss of the largest secured demand on the **System** and must be capable of sustaining this response;

(ii) Localised Negative Reserve Active Power Margin

Synchronised Gensets must at all times be capable of reducing output to allow transfers to and from the **System Constraint Group** (as the case may be) to be contained within such reasonable limit as **The Company** may determine and must be capable of sustaining this response.

(b) **The Company** will monitor the total of **Physical Notifications** of exporting **BM Units** and **Generating Units** (where appropriate) received against forecast **Demand** and, where relevant, the appropriate limit on transfers to and from a **System Constraint Group** and will take account of **Dynamic Parameters** and **Export and Import Limits** received to see whether the level of **System NRAPM** or **Localised NRAPM** for any period is likely to be insufficient. In addition, **The Company** may increase the required margin of **System NRAPM** or **Localised NRAPM** to allow for variations in forecast **Demand**. In the case of **System NRAPM**, this may be by an amount (in **The Company's** reasonable discretion) not exceeding five per cent of forecast **Demand** for the period in question. In the case of **Localised NRAPM**, this may be by an amount (in **The Company's** reasonable discretion) not exceeding ten per cent of the forecast **Demand** for the period in question;

(c) Where the level of **System NRAPM** or **Localised NRAPM** for any period is, in **The Company's** reasonable opinion, likely to be insufficient **The Company** may contact all **Generators** in the case of low **System NRAPM** and may contact **Generators** in relation to relevant **Gensets** in the case of low **Localised NRAPM**. **The Company** will raise with each **Generator** the problems it is anticipating due to low **System NRAPM** or **Localised NRAPM** and will discuss whether, in advance of **Gate Closure**:-

(i) any change is possible in the **Physical Notification** of a **BM Unit** which has been notified to **The Company**; or

(ii) any change is possible to the **Physical Notification** of a **BM Unit** within an **Existing AGR Plant** within the **Existing AGR Plant Flexibility Limit**;

in relation to periods of low **System NRAPM** or (as the case may be) low **Localised NRAPM**. **The Company** will also notify each **Externally Interconnected System Operator** of the anticipated low **System NRAPM** or **Localised NRAPM** and request assistance in obtaining changes to **Physical Notifications** from **BM Units** in that **External System**.

(d) Following **Gate Closure**, the procedure of BC2.9.4 will apply.

BC1.6 SPECIAL PROVISIONS RELATING TO NETWORK OPERATORS

BC1.6.1 User System Data From Network Operators

(a) By 1000 hours each day each **Network Operator** will submit to **The Company** in writing, confirmation or notification of the following in respect of the next **Operational Day**:

(i) constraints on its **User System** which **The Company** may need to take into account in operating the **National Electricity Transmission System**. In this BC1.6.1 the term "constraints" shall include restrictions on the operation of **Embedded Power Generating Modules**, and/or **Embedded CCGT Units**, and/or **Embedded Power Park Modules** as a result of the **User System** to which the **Power Generating Module** and/or **CCGT Unit** and/or **Power Park Module** is connected at the **User System Entry Point** being operated or switched in a particular way, for example, splitting the relevant busbar. It is a matter for the **Network Operator** and the **Generator** to arrange the operation or switching, and to deal with any resulting consequences. The **Generator**, after consultation with the **Network Operator**, is responsible for ensuring that no **BM Unit Data** submitted to **The Company** can result in the violation of any such constraint on the **User System**.

(ii) the requirements of voltage control and MVAr reserves which **The Company** may need to take into account for **System** security reasons.

(iii) where applicable, updated best estimates of **Maximum Export Capacity** and **Maximum Import Capacity** and **Interface Point Target Voltage/Power Factor** for any **Interface Point** connected to its **User System** including any requirement for post-fault actions to be implemented on the relevant **Offshore Transmission System** by **The Company**.

(iv) constraints on its **User System** which **The Company** may need to take into account when issuing **Bid-Offer Acceptances** to **Additional BM units** or **Secondary BM units**.

(b) The form of the submission will be:

(i) that of a **BM Unit** output or consumption (for MW and for MVAr, in each case a fixed value or an operating range, on the **User System** at the **User System Entry Point**, namely in the case of a **BM Unit** comprising a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC1.2) on the higher voltage side of the generator step-up transformer, and/or in the case of a **Power Generating**

Module, at the point of connection and/or in the case of a **Power Park Module**, at the point of connection) required for particular **BM Units** (identified in the submission) connected to that **User System** for each **Settlement Period** of the next **Operational Day**;

(ii) adjusted in each case for MW by the conversion factors applicable for those **BM Units** to provide output or consumption at the relevant **Grid Supply Points**.

(c) At any time and from time to time, between 1000 hours each day and the expiry of the next **Operational Day**, each **Network Operator** must submit to **The Company** in writing any revisions to the information submitted under this BC1.6.1.

BC1.6.2 Notification Of Times To Network Operators

The Company will make available indicative **Synchronising** and **De-Synchronising** times to each **Network Operator**, but only relating to **BM Units** comprising a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC1.2) or a **Power Park Module** or a **CCGT Module** and/or a **Power Generating Module**, **Embedded** within that **Network Operator's User System** and those **Gensets** directly connected to the **National Electricity Transmission System** which **The Company** has identified under **OC2** as being those which may, in the reasonable opinion of **The Company**, affect the integrity of that **User System**. If in preparing for the operation of the **Balancing Mechanism**, **The Company** becomes aware that a **BM Unit** directly connected to the **National Electricity Transmission System** may, in its reasonable opinion, affect the integrity of that other **User System** which, in the case of a **BM Unit** comprising a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC1.2) and/or a **Power Generating Module** and/or a **CCGT Module** and/or a **Power Park Module**, it had not so identified under **OC2**, then **The Company** may make available details of its indicative **Synchronising** and **De-Synchronising** times to that other **User** and shall inform the relevant **BM Participant** that it has done so, identifying the **BM Unit** concerned.

BC1.7 SPECIAL ACTIONS

BC1.7.1 **The Company** may need to identify special actions (either pre- or post-fault) that need to be taken by specific **Users** in order to maintain the integrity of the **National Electricity Transmission System** in accordance with the **Licence Standards** and **The Company Operational Strategy**.

(a) For a **Generator** special actions will generally involve a **Load** change or a change of required Notice to Deviate from Zero NDZ, in a specific timescale on individual or groups of **Gensets**.

(b) For **Network Operators** these special actions will generally involve **Load** transfers between **Grid Supply Points** or arrangements for **Demand** reduction by manual or automatic means.

(c) For **Externally Interconnected System Operators** (in their co-ordinating role for **Interconnector Users** using their **External System**) these special actions will generally involve an increase or decrease of net power flows across an **External Interconnection** by either manual or automatic means.

BC1.7.2 These special actions will be discussed and agreed with the relevant **User** as appropriate. The actual implementation of these special actions may be part of an "emergency circumstances" procedure described under **BC2**. If not agreed, generation or **Demand** may be restricted or may be at risk.

BC1.7.3 **The Company** will normally issue the list of special actions to the relevant **Users** by 1700 hours on the day prior to the day to which they are to apply.

BC1.8 PROVISION OF REACTIVE POWER CAPABILITY

BC1.8.1 Under certain operating conditions **The Company** may identify through its **Operational Planning** that an area of the **National Electricity Transmission System** may have insufficient **Reactive Power** capability available to ensure that the operating voltage can be maintained in accordance with **The Company's Licence Standards**.

In respect of **Onshore Synchronous Generating Unit(s)** belonging to **GB Code Users**

(i) that have a **Connection Entry Capacity** in excess of **Rated MW** (or the **Connection Entry Capacity** of the **CCGT Module** exceeds the sum of **Rated MW** of the **Generating Units** comprising the **CCGT Module**); and

(ii) that are not capable of continuous operation at any point between the limits 0.85 **Power Factor** lagging and 0.95 **Power Factor** leading at the **Onshore Synchronous Generating Unit** terminals at **Active Power** output levels higher than **Rated MW**; and

(iii) that have either a **Completion Date** on or after 1st May 2009, or where its **Connection Entry Capacity** has been increased above **Rated MW** (or the **Connection Entry Capacity** of the **CCGT Module** has increased above the sum of **Rated MW** of the **Generating Units** comprising the **CCGT Module**) such increase takes effect on or after 1st May 2009 but only in respect of **GB Generators** that are classified as **GB Code Users** ; and

(iv) that are in an area of potentially insufficient **Reactive Power** capability as described in this clause BC1.8.1,

The Company may instruct the **Onshore Synchronous Generating Unit(s)** to limit its submitted **Physical Notifications** to no higher than **Rated MW** (or the **Active Power** output at which it can operate continuously between the limits 0.85 **Power Factor** lagging to 0.95 **Power Factor** leading at its terminals if this is higher) for a period specified by **The Company**. Such an instruction must be made at least 1 hour prior to **Gate Closure**, although **The Company** will endeavour to give as much notice as possible. The instruction may require that a **Physical Notification** is re-submitted. The period covered by the instruction will not exceed the expected period for which the potential deficiency has been identified. Compliance with the instruction will not incur costs to **The Company** in the **Balancing Mechanism**. The detailed provisions relating to such instructions will normally be set out in the relevant **Bilateral Agreement.**

BC1.8.2 BC1.8.1 shall not apply to **EU Code Users** where the obligations under CC.6.3.2(a) apply only to **GB Generators**. For the avoidance of doubt, **EU Code User's** are only required to satisfy the requirements of the **ECC's** and not the **CC's**.

APPENDIX 1 - BM UNIT DATA

BC1.A.1 More detail about valid values required under the **Grid Code** for **BM Unit Data** and **Generating Unit Data** may be identified by referring to the **Data Validation**, **Consistency and Defaulting Rules**. In the case of **Embedded BM Units** and **Generating Units** the **BM Unit Data** and the **Generating Unit Data** shall represent the value at the relevant **Grid Supply Point**. Where data is submitted on a **Generating Unit** basis, the provisions of this Appendix 1 shall in respect of such data submission apply as if references to **BM Unit** were replaced with **Generating Unit**. Where **The Company** and the relevant **User** agree, submission on a **Generating Unit** basis (in whole or in part) may be otherwise than in accordance with the provisions of the Appendix 1.

BC1.A.1.1 Physical Notifications

For each **BM Unit**, the **Physical Notification** is a series of MW figures and associated times, making up a profile of intended input or output of **Active Power** at the **Grid Entry Point** or **Grid Supply Point**, as appropriate. For each **Settlement Period**, the first "from time" should be at the start of the **Settlement Period** and the last "to time" should be at the end of the **Settlement Period.**

The input or output reflected in the **Physical Notification** for a single **BM Unit** (or the aggregate **Physical Notifications** for a collection of **BM Units** at a **Grid Entry Point** or **Grid Supply Point** or to be transferred across an **External Interconnection**, owned or controlled by a single **BM Participant**) must comply with the following limits regarding maximum rates of change, either for a single change or a series of related changes :

- for a change of up to 300MW — no limit;
- for a change greater than 300MW and less than 1000MW — 50MW per minute;
- for a change of 1000MW or more — 40MW per minute,

unless prior arrangements have been discussed and agreed with **The Company**. This limitation is not intended to limit the Run-Up or Run-Down Rates provided as **Dynamic Parameters**.

An example of the format of **Physical Notification** is shown below. The convention to be applied is that where it is proposed that the **BM Unit** will be importing, the **Physical Notification** is negative.

Data Name		BMU name	Time From	From level (MW)	Time To	To Level MW)
PN ,	TAGENT ,	BMUNIT01 ,	2001-11-03 06:30 ,	77 ,	2001-11-03 07:00 ,	100
PN ,	TAGENT ,	BMUNIT01 ,	2001-11-03 07:00 ,	100 ,	2001-11-03 07:12 ,	150
PN ,	TAGENT ,	BMUNIT01 ,	2001-11-03 07:12 ,	150 ,	2001-11-03 07:30 ,	175

A linear interpolation will be assumed between the **Physical Notification** From and To levels specified for the **BM Unit** by the **BM Participant**.

BC1.A.1.2 Not Used.

BC1.A.1.3 Export And Import Limits

BC1.A.1.3.1 Maximum Export Limit (MEL)

A series of MW figures and associated times, making up a profile of the maximum level at which the **BM Unit** may be exporting (in MW) to the **National Electricity Transmission System** at the **Grid Entry Point** or **Grid Supply Point** or **GSP Group**, as appropriate.

For a **Power Park Module,** the Maximum Export Limit should reflect the maximum possible **Active Power** output from each **Power Park Module** consistent with the data submitted within the **Power Park Module Availability Matrix** as defined under BC.1.A.1.8. For the avoidance of doubt, in the case of a **Power Park Module** this would equate to the **Registered Capacity** less the unavailable **Power Park Units** within the **Power Park Module** and not include weather corrected MW output from each **Power Park Unit**.

BC1.A.1.3.2 Maximum Import Limit (MIL)

A series of MW figures and associated times, making up a profile of the maximum level at which the **BM Unit** may be importing (in MW) from the **National Electricity Transmission System** at the **Grid Entry Point** or **Grid Supply Point** or **GSP Group**, as appropriate.

An example format of data is shown below. MEL must be positive or zero, and MIL must be negative or zero.

Data Name				BMU name		Time From		From level (MW)		Time To		To level (MW)
MEL	,	TAGENT	,	BMUNIT01	,	2001-11-03 05:00	,	410	,	2001-11-03 09:35	,	410
MEL	,	TAGENT	,	BMUNIT01	,	2001-11-03 09:35	,	450	,	2001-11-03 12:45	,	450
MIL	,	TAGENT	,	BMUNIT04	,	2001-11-03 06:30	,	-200	,	2001-11-03 07:00	,	-220

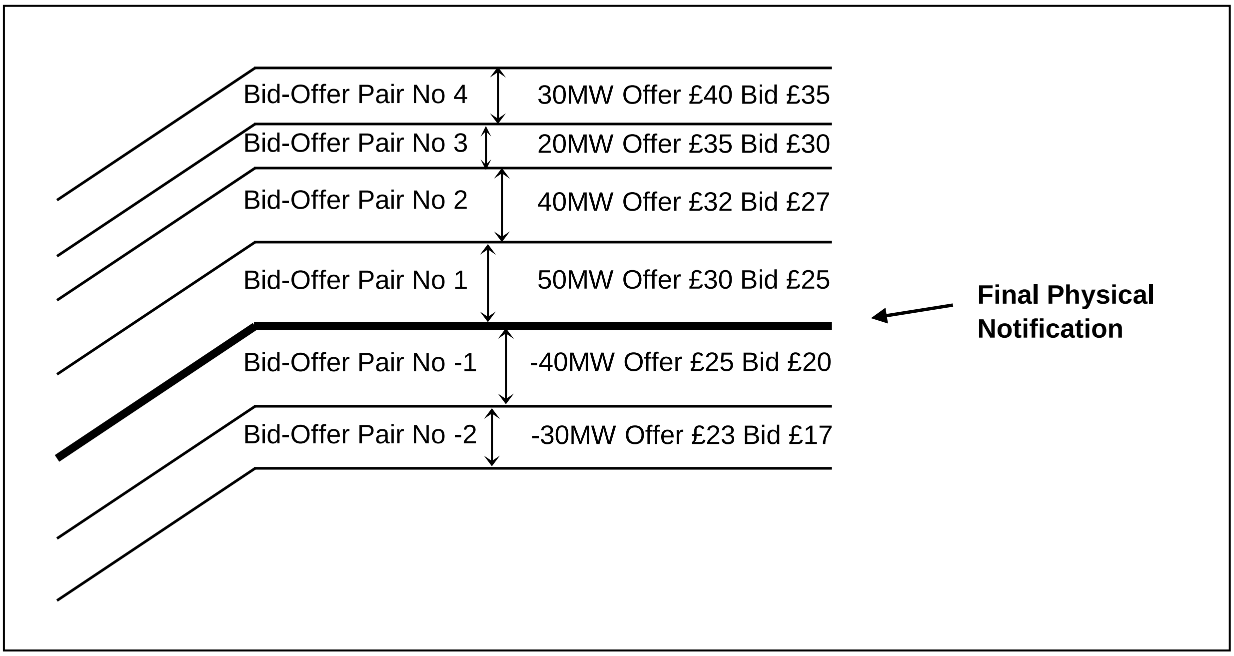
BC1.A.1.4 Bid-Offer Data

For each **BM Unit** for each **Settlement Period**:	Up to 10 Bid-Offer Pairs as defined in the **BSC**.

An example of the format of data is shown below.

Data	Name	BMU name	Time from	Time to	Pair ID	From Level (MW)	To Level (MW)	Offer (£/ MWh)	Bid (£/ MWh)
BOD,	TAGENT ,	BMUNIT01 ,	2000-10-28 12:00 ,	2000-10-28 13:30 ,	4 ,	30 ,	30 ,	40 ,	35
BOD,	TAGENT ,	BMUNIT01 ,	2000-10-28 12:00 ,	2000-10-28 13:30 ,	3 ,	20 ,	20 ,	35 ,	30
BOD,	TAGENT ,	BMUNIT01 ,	2000-10-28 12:00 ,	2000-10-28 13:30 ,	2 ,	40 ,	40 ,	32 ,	27
BOD,	TAGENT ,	BMUNIT01 ,	2000-10-28 12:00 ,	2000-10-28 13:30 ,	1 ,	50 ,	50 ,	30 ,	25
BOD,	TAGENT ,	BMUNIT01 ,	2000-10-28 12:00 ,	2000-10-28 13:30 ,	-1 ,	-40 ,	-40 ,	25 ,	20
BOD,	TAGENT ,	BMUNIT01 ,	2000-10-28 12:00 ,	2000-10-28 13:30 ,	-2 ,	-30 ,	-30 ,	23 ,	17

This example of Bid-Offer data is illustrated graphically below:



BC1.A.1.5 Dynamic Parameters

The **Dynamic Parameters** comprise:

- Up to three Run-Up Rate(s) and up to three Run-Down Rate(s), expressed in MW/minute and associated Run-Up Elbow(s) and Run-Down Elbow(s), expressed in MW for output and the same for input. It should be noted that Run-Up Rate(s) are applicable to a MW figure becoming more positive;
- Notice to Deviate from Zero (NDZ) output or input, being the notification time required for a **BM Unit** to start importing or exporting energy, from a zero **Physical Notification** level as a result of a **Bid-Offer Acceptance**, expressed in minutes;
- Notice to Deliver Offers (NTO) and Notice to Deliver Bids (NTB), expressed in minutes, indicating the notification time required for a **BM Unit** to start delivering Offers and Bids respectively from the time that the **Bid-Offer Acceptance** is issued. In the case of a **BM Unit** comprising a **Genset**, NTO and NTB will be set to a maximum period of two minutes;
- Minimum Zero Time (MZT), being either the minimum time that a **BM Unit** which has been exporting must operate at zero or be importing, before returning to exporting or the minimum time that a **BM Unit** which has been importing must operate at zero or be exporting before returning to importing, as a result of a **Bid-Offer Acceptance**, expressed in minutes;
- Minimum Non-Zero Time (MNZT), expressed in minutes, being the minimum time that a **BM Unit** can operate at a non-zero level as a result of a **Bid-Offer Acceptance**;
- Stable Export Limit (SEL) expressed in MW at the **Grid Entry Point** or **Grid Supply Point** or **GSP Group**, as appropriate, being the minimum value at which the **BM Unit** can, under stable conditions, export to the **National Electricity Transmission System**;
- Stable Import Limit (SIL) expressed in MW at the **Grid Entry Point** or **Grid Supply Point** or **GSP Group**, as appropriate, being the minimum value at which the **BM Unit** can, under stable conditions, import from the **National Electricity Transmission System**;
- Maximum Delivery Volume (MDV), expressed in MWh, being the maximum number of MWh of Offer (or Bid if MDV is negative) that a particular **BM Unit** may deliver within the associated Maximum Delivery Period (MDP), expressed in minutes, being the maximum period over which the MDV applies.
- Last Time to Cancel Synchronisation, expressed in minutes with an upper limit of 60 minutes, being the notification time required to cancel a **BM Unit's** transition from operation at zero. This parameter is only applicable where the transition arises either from a **Physical Notification** or, in the case where the **Physical Notification** is zero, a **Bid-Offer Acceptance**. There can be up to three Last Time to Cancel Synchronisation(s) each applicable for a range of values of Notice to Deviate from Zero.

BC1.A.1.6 CCGT Module Matrix

BC1.A.1.6.1 **CCGT Module Matrix** showing the combination of **CCGT Units** running in relation to any given MW output, in the form of the diagram illustrated below. The **CCGT Module Matrix** is designed to achieve certainty in knowing the number of **CCGT Units** synchronised to meet the **Physical Notification** and to achieve a **Bid-Offer Acceptance**.

BC1.A.1.6.2 In the case of a **Range CCGT Module**, and if the **Generator** so wishes, a request for the single **Grid Entry Point** at which power is provided from the **Range CCGT Module** to be changed in accordance with the provisions of BC1.A.1.6.4 below:

CCGT Module Matrix example form

CCGT MODULE ACTIVE POWER	**CCGT GENERATING UNITS*** AVAILABLE								
	1st GT	2nd GT	3rd GT	4th GT	5th GT	6th GT	1st ST	2nd ST	3rd ST
MW	**ACTIVE POWER OUTPUT**								
	150	150	150				100		
0MW to 150MW	/								
151MW to 250MW	/						/		
251MW to 300MW	/	/							
301MW to 400MW	/	/					/		
401MW to 450MW	/	/	/						
451MW to 550MW	/	/	/				/		

* as defined in the Glossary and Definitions and not limited by BC1.2

BC1.A.1.6.3 In the absence of the correct submission of a **CCGT Module Matrix** the last submitted (or deemed submitted) **CCGT Module Matrix** shall be taken to be the **CCGT Module Matrix** submitted hereunder.

BC1.A.1.6.4 The data may also include in the case of a **Range CCGT Module**, a request for the **Grid Entry Point** at which the power is provided from the **Range CCGT Module** to be changed with effect from the beginning of the following **Operational Day** to another specified single **Grid Entry Point** (there can be only one) to that being used for the current **Operational Day**. **The Company** will respond to this request by 1600 hours on the day of receipt of the request. If **The Company** agrees to the request (such agreement not to be unreasonably withheld), the **Generator** will operate the **Range CCGT Module** in accordance with the request. If **The Company** does not agree, the **Generator** will, if it produces power from that **Range CCGT Module**, continue to provide power from the **Range CCGT Module** to the **Grid Entry Point** being used at the time of the request. The request can only be made up to 1100 hours in respect of the following **Operational Day**. No subsequent request to change can be made after 1100 hours in respect of the following **Operational Day**. Nothing in this paragraph shall prevent the busbar at the **Grid Entry Point** being operated in separate sections.

BC1.A.1.6.5 The principles set out in PC.A.3.2.3 apply to the submission of a **CCGT Module Matrix** and accordingly the **CCGT Module Matrix** can only be amended as follows:

(a) Normal CCGT Module

if the **CCGT Module** is a **Normal CCGT Module**, the **CCGT Units** within that **CCGT Module** can only be amended such that the **CCGT Module** comprises different **CCGT Units** if **The Company** gives its prior consent in writing. Notice of the wish to amend the **CCGT Units** within such a **CCGT Module** must be given at least 6 months before it is wished for the amendment to take effect;

(b) Range CCGT Module

if the **CCGT Module** is a **Range CCGT Module**, the **CCGT Units** within that **CCGT Module** can only be amended such that the **CCGT Module** comprises different **CCGT Units** for a particular **Operational Day** if the relevant notification is given by 1100 hours on the day prior to the **Operational Day** in which the amendment is to take effect. No subsequent amendment may be made to the **CCGT Units** comprising the **CCGT Module** in respect of that particular **Operational Day**.

BC1.A.1.6.6 In the case of a **CCGT Module Matrix** submitted (or deemed to be submitted) as part of the other data for **CCGT Modules**, the output of the **CCGT Module** at any given instructed MW output must reflect the details given in the **CCGT Module Matrix**. It is accepted that in cases of change in MW in response to instructions issued by **The Company** there may be a transitional variance to the conditions reflected in the **CCGT Module Matrix**. In achieving an instruction the range of number of **CCGT Units** envisaged in moving from one MW output level to the other must not be departed from. Each **Generator** shall notify **The Company** as soon as practicable after the event of any such variance. It should be noted that there is a provision above for the **Generator** to revise the **CCGT Module Matrix**, subject always to the other provisions of this **BC1**;

BC1.A.1.6.7 Subject as provided above, **The Company** will rely on the **CCGT Units** specified in such **CCGT Module Matrix** running as indicated in the **CCGT Module Matrix** when it issues an instruction in respect of the **CCGT Module**;

BC1.A.1.6.8 Subject as provided in BC1.A.1.6.5 above, any changes to the **CCGT Module Matrix** must be notified immediately to **The Company** in accordance with the relevant provisions of **BC1**.

BC1.A.1.7 Cascade Hydro Scheme Matrix

BC1.A.1.7.1 A **Cascade Hydro Scheme Matrix** showing the performance of individual **Generating Units** forming part of a **Cascade Hydro Scheme** in response to **Bid-Offer Acceptance**. An example table is shown below:

Cascade Hydro Scheme Matrix example form

Plant	Synchronises when offer is greater than……..
Generating Unit 1	......MW
Generating Unit 2	......MW
Generating Unit 3	......MW
Generating Unit 4	......MW
Generating Unit 5	......MW

BC1.A.1.8 Power Park Module Availability Matrix

BC1.A.1.8.1 **Power Park Module Availability Matrix** showing the number of each type of **Power Park Units** expected to be available is illustrated in the example form below. The **Power Park Module Availability Matrix** is designed to achieve certainty in knowing the number of **Power Park Units Synchronised** to meet the **Physical Notification** and to achieve a **Bid-Offer Acceptance** by specifying which **BM Unit** each **Power Park Module** forms part of. The **Power Park Module Availability Matrix** may have as many columns as are required to provide information on the different make and model for each type of **Power Park Unit** in a **Power Park Module** and as many rows as are required to provide information on the **Power Park Modules** within each **BM Unit**. The description is required to assist identification of the **Power Park Units** within the **Power Park Module** and correlation with data provided under the **Planning Code**.

Power Park Module Availability Matrix example form

BM Unit Name				
Power Park Module [unique identifier]				
POWER PARK UNIT AVAILABILITY	**POWER PARK UNITS**			
	Type A	Type B	Type C	Type D
Description (Make/Model)				
Number of units				
Power Park Module [unique identifier]				
POWER PARK UNIT AVAILABILITY	**POWER PARK UNITS**			
	Type A	Type B	Type C	Type D
Description (Make/Model)				
Number of units				

BC1.A.1.8.2 In the absence of the correct submission of a **Power Park Module Availability Matrix** the last submitted (or deemed submitted) **Power Park Module Availability Matrix** shall be taken to be the **Power Park Module Availability Matrix** submitted hereunder.

BC1.A.1.8.3 **The Company** will rely on the **Power Park Units**, **Power Park Modules** and **BM Units** specified in such **Power Park Module Availability Matrix** running as indicated in the **Power Park Module Availability Matrix** when it issues an instruction in respect of the **BM Unit**.

BC1.A.1.8.4 Subject as provided in PC.A.3.2.4 any changes to **Power Park Module** or **BM Unit** configuration, or availability of **Power Park Units** which affects the information set out in the **Power Park Module Availability Matrix** must be notified immediately to **The Company** in accordance with the relevant provisions of **BC1**. Initial notification may be by telephone. In some circumstances, such as a significant re-configuration of a **Power Park Module** due to an unplanned outage, a revised **Power Park Module Availability Matrix** must be supplied on **The Company's** request.

BC1.A.1.9 **Synchronous Power Generating Module Matrix**

BC1.A.1.9.1 **Synchronous Power Generating Module Matrix** showing the combination of **Synchronous Power Generating Units** running in relation to any given MW output, in the form of the table illustrated below. The **Synchronous Power Generating Module Matrix** is designed to achieve certainty in knowing the number of **Synchronous Power Generating Units** synchronised to meet the **Physical Notification** and to achieve a **Bid-Offer Acceptance**.

BC1.A.1.9.2 This data need not be provided where a submission has been made in respect of BC1.A.1.6, BC1.A.1.7 or BC1.A.1.8

Synchronous Power Generating Module Matrix example form

SYNCHRONOUS POWER GENERATING MODULE MATRIX	SYNCHRONOUS POWER GENERATING UNITS* AVAILABLE								
	1st GT	2nd GT	3rd GT	4th GT	5th GT	6th GT	1st ST	2nd ST	3rd ST
MW	**ACTIVE POWER OUTPUT**								
	150	150	150				100		
0MW to 150MW	/								
151MW to 250MW	/						/		
251MW to 300MW	/	/							
301MW to 400MW	/	/					/		
401MW to 450MW	/	/	/						
451MW to 550MW	/	/	/				/		

* as defined in the Glossary and Definitions and not limited by BC1.2

BC1.A.1.9.3 In the absence of the correct submission of a **Synchronous Power Generating Module Matrix** the last submitted (or deemed submitted) **Synchronous Power Generating Module Matrix** shall be taken to be the **Synchronous Power Generating Module Matrix** submitted hereunder.

BC1.A.1.9.4 The principles set out in PC.A.3.2.5 apply to the submission of a **Synchronous Power Generating Module Matrix** and accordingly the **Synchronous Power Generating Module Matrix** can only be amended as if the **Synchronous Power Generating Units** within that **Synchronous Power Generating Module** can only be amended such that the **Synchronous Power Generating Module** comprises different **Synchronous Power Generating Units** if **The Company** gives its prior consent in writing. Notice of the wish to amend the **Synchronous Power Generating Units** within such a **Synchronous Power Generating Module** must be given at least 6 months before it is wished for the amendment to take effect;

BC1.A.1.9.5 In the case of a **Synchronous Power Generating Module Matrix** submitted (or deemed to be submitted) as part of the other data for **Synchronous Power Generating Modules**, the output of the **Synchronous Power Generating Module** at any given instructed MW output must reflect the details given in the **Synchronous Power Generating Module Matrix**. It is accepted that in cases of change in MW in response to instructions issued by **The Company** there may be a transitional variance to the conditions reflected in the **Synchronous Power Generating Module Matrix**. In achieving an instruction the range of number of **Synchronous Power Generating Units** envisaged in moving from one MW output level to the other must not be departed from. Each **Generator** shall notify **The Company** as soon as practicable after the event of any such variance. It should be noted that there is a provision above for the **Generator** to revise the **Synchronous Power Generating Module Matrix**, subject always to the other provisions of this **BC1**;

BC1.A.1.9.6 Subject as provided above, **The Company** will rely on the **Synchronous Power Generating Units** specified in such **Synchronous Power Generating Module Matrix** running as indicated in the **Synchronous Power Generating Module Matrix** when it issues an instruction in respect of the **Synchronous Power Generating Module**;

BC1.A.1.9.7 Subject as provided in BC1.A.1.9.4 above, any changes to the **Synchronous Power Generating Module Matrix** must be notified immediately to **The Company** in accordance with the relevant provisions of **BC1**.

BC1.A.10 Aggregator Impact Matrix

BC1.A.10.1 For each **Additional BM Unit** and **Secondary BM Unit** the relevant **BM Participant** will submit data relating to the effect of a Bid-Off Acceptance on each **Grid Supply Point** within the **GSP Group** over which the **Additional BM Unit** or **Secondary BM Unit** was defined.

BC1.A.10.2 For each **Additional BM Unit** and **Secondary BM Unit** the relevant BM Participant will also provide the post-codes and MSIDs that make up the **Additional BM Unit** or **Secondary BM Unit**

Aggregator Impact Matrix example form

BMU Name			
Operational Day from which values apply			
Grid Supply Point	% Impact	Grid Supply Point	% Impact

APPENDIX 2 - DATA TO BE MADE AVAILABLE BY THE COMPANY

BC1.A.2.1 Initial Day Ahead Demand Forecast

Normally by 09:00 hours each day, values (in MW) for each **Settlement Period** of the next following **Operational Day** of the following data items:-

(i) Initial forecast of **National Demand**;

(II) Initial forecast of **Demand** for a number of predetermined constraint groups.

BC1.A.2.2 Initial Day Ahead Market Information

Normally by 12:00 hours each day, values (in MW) for each **Settlement Period** of the next following **Operational Day** of the following data items:-

(i) Initial National **Indicated Margin**

This is the difference between the sum of **BM Unit** MELs and the forecast of **National Electricity Transmission System Demand**.

(ii) Initial National **Indicated Imbalance**

This is the difference between the sum of **Physical Notifications** for **BM Units** comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC1.2) and/or **Power Generating Modules** and/or **CCGT Modules** and/or **Power Park Modules** and the forecast of **National Electricity Transmission System Demand**.

(iii) Forecast of **National Electricity Transmission System Demand**.

BC1.A.2.3 Current Day And Day Ahead Updated Market Information

Data will normally be made available by the times shown below for the associated periods of time:

Target Data Release Time	Period Start Time	Period End Time
02:00	02:00 D0	05:00 D+1
10:00	10:00 D0	05:00 D+1
16:00	05:00 D+1	05:00 D+2
16:30	16:30 D0	05:00 D+1
22:00	22:00 D0	05:00 D+2

In this table, D0 refers to the current day, D+1 refers to the next day and D+2 refers to the day following D+1.

In all cases, data will be ½ hourly average MW values calculated by **The Company**. Information to be released includes:

National Information

(i) National **Indicated Margin**;

(ii) National **Indicated Imbalance**;

(iii) Updated forecast of **National Electricity Transmission System Demand**.

Constraint Boundary Information (For Each Constraint Boundary)

(i) **Indicated Constraint Boundary Margin**;

This is the difference between the Constraint Boundary Transfer limit and the difference between the sum of **BM Unit** MELs and the forecast of local **Demand** within the constraint boundary.

(ii) Local **Indicated Imbalance**;

This is the difference between the sum of **Physical Notifications** for **BM Units** comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC1.2) and/or **Power Generating Modules** and/or **CCGT Modules** and/or **Power Park Modules** and the forecast of local **Demand** within the constraint boundary.

(iii) Updated forecast of the local **Demand** within the constraint boundary.

< END OF BALANCING CODE NO. 1 >

BALANCING CODE NO. 2
(BC2)

POST GATE CLOSURE PROCESS

CONTENTS

(This contents page does not form part of the Grid Code)

BC2.1 INTRODUCTION

Balancing Code No 2 (**BC2**) sets out the procedure for:

(a) the physical operation of **BM Units** and **Generating Units** (which could be part of a **Power Generating Module**) in the absence of any instructions from **The Company**;

(b) the acceptance by **The Company** of **Balancing Mechanism** Bids and Offers,

(c) the calling off by **The Company** of **Ancillary Services**;

(d) the issuing and implementation of **Emergency Instructions**; and

(e) the issuing by **The Company** of other operational instructions and notifications.

In addition, **BC2** deals with any information exchange between **The Company** and **BM Participants** or specific **Users** that takes place after **Gate Closure**.

In this **BC2**, “consistent” shall be construed as meaning to the nearest integer MW level.

In this **BC2**, references to “a **BM Unit** returning to its **Physical Notification**” shall take account of any **Bid-Offer Acceptances** already issued to the **BM Unit** in accordance with BC2.7 and any **Emergency Instructions** already issued to the **BM Unit** or **Generating Unit** (which could be part of a **Power Generating Module**) in accordance with BC2.9.

BC2.2 OBJECTIVE

The procedure covering the operation of the **Balancing Mechanism** and the issuing of instructions to **Users** is intended to enable **The Company** as far as possible to maintain the integrity of the **National Electricity Transmission System** together with the security and quality of supply.

Where reference is made in this **BC2** to **Power Generating Modules** or **Generating Units** (unless otherwise stated) it only applies:

(a) to each **Generating Unit** which forms part of the **BM Unit** of **a Cascade Hydro Scheme**; and

(b) at an **Embedded Exemptable Large Power Station** where the relevant **Bilateral Agreement** specifies that compliance with **BC2** is required:

(i) to each **Generating Unit** which could be part of a **Synchronous Power Generating Module**, or

(ii) to each **Power Park Module** where the **Power Station** comprises **Power Park Modules**.

BC2.3 SCOPE

BC2 applies to **The Company** and to **Users**, which in this **BC2** means:-

(a) **BM Participants**;

(b) **Externally Interconnected System Operators**, and

(c) **Network Operators**.

BC2.4 INFORMATION USED

BC2.4.1 The information which **The Company** shall use, together with the other information available to it, in assessing:

(a) which bids and offers to accept;

(b) which **BM Units** and/or **Generating Units** to instruct to provide **Ancillary Services**;

(c) the need for and formulation of **Emergency Instructions**; and

(d) other operational instructions and notifications which **The Company** may need to issue

will be:

(a) the **Physical Notification** and **Bid-Offer Data** submitted under **BC1**;

(b) **Export and Import Limits** in respect of that **BM Unit** and/or **Generating Unit** supplied under **BC1** (and any revisions under **BC1** and **BC2** to the data); and

(c) **Dynamic Parameters** submitted or revised under this **BC2**.

BC2.4.2 As provided for in BC1.5.4, **The Company** will monitor the total of the Maximum Export Limit component of the **Export and Import Limits** against forecast **Demand** and the **Operating Margin** and will take account of **Dynamic Parameters** to see whether the anticipated level of **System Margin** is insufficient. This will reflect any changes in **Export and Import Limits** which have been notified to **The Company**, and will reflect any **Demand Control** which has also been so notified. **The Company** may issue new or revised **National Electricity Transmission System Warnings – Electricity Margin Notice** or **High Risk of Demand Reduction** in accordance with BC1.5.4.

BC2.5 PHYSICAL OPERATION OF BM UNITS

BC2.5.1 Accuracy Of Physical Notifications

As described in BC1.4.2(a), **Physical Notifications** must represent the **BM Participant's** best estimate of expected input or output of **Active Power** and shall be prepared in accordance with **Good Industry Practice**.

Each **BM Participant** must, applying **Good Industry Practice**, ensure that each of its **BM Units** follows the **Physical Notification** in respect of that **BM Unit** (and each of its **Generating Units** follows the **Physical Notification** in the case of **Physical Notifications** supplied under BC1.4.2(a)(2)) that is prevailing at **Gate Closure** (the data in which will be utilised in producing the **Final Physical Notification Data** in accordance with the **BSC**) subject to variations arising from:

(a) the issue of **Bid-Offer Acceptances** which have been confirmed by the **BM Participant**; or

(b) instructions by **The Company** in relation to that **BM Unit** (or a **Generating Unit**) which require, or compliance with which would result in, a variation in output or input of that **BM Unit** (or a **Generating Unit**); or

(c) compliance with provisions of **BC1**, **BC2** or **BC3** which provide to the contrary.

Except where variations from the **Physical Notification** arise from matters referred to at (a),(b or (c) above, in respect only of **BM Units** (or **Generating Units**) powered by an **Intermittent Power Source**, where there is a change in the level of the **Intermittent Power Source** from that forecast and used to derive the **Physical Notification**, variations from the **Physical Notification** prevailing at **Gate Closure** may, subject to remaining within the **Registered Capacity**, occur providing that the **Physical Notification** prevailing at **Gate Closure** was prepared in accordance with **Good Industry Practice**.

If variations and/or instructions as described in (a),(b) or (c) apply in any instance to **BM Units** (or **Generating Units**) powered by an **Intermittent Power Source** (e.g. a **Bid Offer Acceptance** is issued in respect of such a **BM Unit** and confirmed by the **BM Participant**) then such provisions will take priority over the third paragraph of BC2.5.1 above such that the **BM Participant** must ensure that the **Physical Notification** as varied in accordance with (a), (b) or (c) above applies and must be followed, subject to this not being prevented as a result of an unavoidance event as described below.

For the avoidance of doubt, this gives rise to an obligation on each **BM Participant** (applying **Good Industry Practice**) to ensure that each of its **BM Units** (and **Generating Units**), follows the **Physical Notifications** prevailing at **Gate Closure** as amended by such variations and/or instructions unless in relation to any such obligation it is prevented from so doing as a result of an unavoidable event (existing or anticipated) in relation to that **BM Unit** (or a **Generating Unit**) which requires a variation in output or input of that **BM Unit** (or a **Generating Unit**).

Examples (on a non-exhaustive basis) of such an unavoidable event are:

- plant breakdowns;
- events requiring a variation of input or output on safety grounds (relating to personnel or plant);
- events requiring a variation of input or output to maintain compliance with the relevant Statutory Water Management obligations; and
- uncontrollable variations in output of **Active Power**.

Any anticipated variations in input or output post **Gate Closure** from the **Physical Notification** for a **BM Unit** (or a **Generating Unit**) prevailing at **Gate Closure** (except for those arising from instructions as outlined in (a), (b) or (c) above) must be notified to **The Company** without delay by the relevant **BM Participant** (or the relevant person on its behalf). For the avoidance of doubt, where a change in the level of the **Intermittent Power Source** from that forecast and used to derive the **Physical Notification** results in the **Shutdown** or **Shutdown** of part of the **BM Unit** (or **Generating Unit**), the change must be notified to **The Company** without delay by the relevant **BM Participant** (or the relevant person on its behalf).

Implementation of this notification should normally be achieved by the submission of revisions to the **Export and Import Limits** in accordance with BC2.5.3 below.

BC2.5.2 Synchronising And De-Synchronising Times

BC2.5.2.1 The **Final Physical Notification Data** provides indicative **Synchronising** and **De-Synchronising** times to **The Company** in respect of any **BM Unit** which is **De-Synchronising** or is anticipated to be **Synchronising** post **Gate Closure**.

Any delay of greater than five minutes to the **Synchronising** or any advancement of greater than five minutes to the **De-Synchronising** of a **BM Unit** must be notified to **The Company** without delay by the submission of a revision of the **Export and Import Limits**.

BC2.5.2.2 Except in the circumstances provided for in BC2.5.2.3, BC2.5.2.4, BC2.5.5.1 or BC2.9, no **BM Unit** (nor a **Generating Unit**) is to be **Synchronised** or **De-Synchronised** unless:-

(a) a **Physical Notification** had been submitted to **The Company** prior to **Gate Closure** indicating that a **Synchronisation** or **De-Synchronisation** is to occur; or

(b) **The Company** has issued a **Bid-Offer Acceptance** requiring **Synchronisation** or **De-Synchronisation** of that **BM Unit** (or a **Generating Unit**).

BC2.5.2.3 **BM Participants** must only **Synchronise** or **De-Synchronise BM Units** (or a **Generating Unit**);

(a) at the times indicated to **The Company**, or

(b) at times consistent with variations in output or input arising from provisions described in BC2.5.1,

(within a tolerance of +/- 5 minutes) or unless that occurs automatically as a result of **Operational Intertripping** or **Low Frequency Relay** operations or an **Ancillary Service** pursuant to an **Ancillary Services Agreement**

BC2.5.2.4 **De-Synchronisation** may also take place without prior notification to **The Company** as a result of plant breakdowns or if it is done purely on safety grounds (relating to personnel or plant). If that happens **The Company** must be informed immediately that it has taken place and a revision to **Export and Import Limits** must be submitted in accordance with BC2.5.3.3. Following any **De-Synchronisation** occurring as a result of plant failure, no **Synchronisation** of that **BM Unit** (or a **Generating Unit**) is to take place without **The Company's** agreement, such agreement not to be unreasonably withheld.

In the case of **Synchronisation** following an unplanned **De-Synchronisation** within the preceding 15 minutes, a minimum of 5 minutes notice of its intention to **Synchronise** should normally be given to **The Company** (via a revision to **Export and Import Limits**). In the case of any other unplanned **De-Synchronisation** where the **User** plans to **Synchronise** before the expiry of the current **Balancing Mechanism** period, a minimum of 15 minutes notice of **Synchronisation** should normally be given to **The Company** (via a revision to **Export and Import Limits**). In addition, the rate at which the **BM Unit** is returned to its **Physical Notification** is not to exceed the limits specified in **BC1**, Appendix 1 without **The Company's** agreement.

The Company will either agree to the **Synchronisation** or issue a **Bid-Offer Acceptance** in accordance with BC2.7 to delay the **Synchronisation**. **The Company** may agree to an earlier **Synchronisation** if **System** conditions allow.

BC2.5.2.5 Notification Of Times To Network Operators

The Company will make changes to the **Synchronising** and **De-Synchronising** times available to each **Network Operator**, but only relating to **BM Units Embedded** within its **User System** and those **BM Units** directly connected to the **National Electricity Transmission System** which **The Company** has identified under **OC2** and/or **BC1** as being those which may, in the reasonable opinion of **The Company**, affect the integrity of that **User System** and shall inform the relevant **BM Participant** that it has done so, identifying the **BM Unit** concerned.

Each **Network Operator** must notify **The Company** of any changes to its **User System** Data as soon as practicable in accordance with BC1.6.1(c).

BC2.5.3 Revisions To BM Unit Data

Following **Gate Closure** for any **Settlement Period**, no changes to the **Physical Notification** or to **Bid-Offer Data** for that **Settlement Period** may be submitted to **The Company**.

BC2.5.3.1 At any time, any **BM Participant** (or the relevant person on its behalf) may, in respect of any of its **BM Units**, submit to **The Company** the data listed in **BC1**, Appendix 1 under the heading of **Dynamic Parameters** from the **Control Point** of its **BM Unit** to amend the data already held by **The Company** (including that previously submitted under this BC2.5.3.1) for use in preparing for and operating the **Balancing Mechanism**. The change will take effect from the time that it is received by **The Company**. For the avoidance of doubt, the **Dynamic Parameters** submitted to **The Company** under BC1.4.2(e) are not used within the current **Operational Day**. The **Dynamic Parameters** submitted under this BC2.5.3.1 shall reasonably reflect the true current operating characteristics of the **BM Unit** and shall be prepared in accordance with **Good Industry Practice**.

Following the **Operational Intertripping** of a **System** to **Generating Unit** or a **System** to **CCGT Module** and/or a **System** to **Power Generating Module**, the **BM Participant** shall as soon as reasonably practicable re-declare its MEL to reflect more accurately its output capability.

BC2.5.3.2 Revisions to **Export and Import Limits** or **Other Relevant Data** supplied (or revised) under **BC1** must be notified to **The Company** without delay as soon as any change becomes apparent to the **BM Participant** (or the relevant person on its behalf) via the **Control Point** for the **BM Unit** (or a **Generating Unit**) to ensure that an accurate assessment of **BM Unit** (or a **Generating Unit**) capability is available to **The Company** at all times. These revisions should be prepared in accordance with **Good Industry Practice** and may be submitted by use of electronic data communication facilities or by telephone.

BC2.5.3.3 Revisions to **Export and Import Limits** must be made by a **BM Participant** (or the relevant person on its behalf) via the **Control Point** in the event of any **De-Synchronisation** of a **BM Unit** (or a **Generating Unit**) in the circumstances described in BC2.5.2.4 if the **BM Unit** (or a **Generating Unit**) is no longer available for any period of time. Revisions must also be submitted in the event of plant failures causing a reduction in input or output of a **BM Unit** (or a **Generating Unit**) even if that does not lead to **De-Synchronisation**. Following the correction of a plant failure, the **BM Participant** (or the relevant person on its behalf) must notify **The Company** via the **Control Point** of a revision to the **Export and Import Limits**, if appropriate, of the **BM Unit** (or a **Generating Unit**), using reasonable endeavours to give a minimum of 5 minutes notice of its intention to return to its **Physical Notification**. The rate at which the **BM Unit** (or a **Generating Unit**) is returned to its **Physical Notification** is not to exceed the limits specified in **BC1**, Appendix 1 without **The Company's** agreement.

BC2.5.4 Operation In The Absence Of Instructions From The Company

In the absence of any **Bid-Offer Acceptances**, **Ancillary Service** instructions issued pursuant to BC2.8 or **Emergency Instructions** issued pursuant to BC2.9:

(a) as provided for in BC3, each **Synchronised Genset** producing **Active Power** must operate at all times in **Limited Frequency Sensitive Mode** (unless instructed in accordance with BC3.5.4 to operate in **Frequency Sensitive Mode**);

(b) (i) in the absence of any MVAr **Ancillary Service** instructions, the MVAr output of each **Synchronised Genset** located **Onshore** should be 0 MVAr upon **Synchronisation** at the circuit-breaker where the **Genset** is **Synchronised**. For the avoidance of doubt, in the case of a **Genset** located **Onshore** comprising of **Non-Synchronous Generating Units**, **Power Park Modules, HVDC Systems** or **DC Converters** the steady state tolerance allowed in CC.6.3.2(b) or ECC.6.3.2.4.4 may be applied

(ii) In the absence of any MVAr **Ancillary Service** instructions, the MVAr output of each **Synchronised Genset** comprising **Synchronous Generating Units** located **Offshore** (which could be part of a **Synchronous Power Generating Module**) should be 0MVAr at the **Grid Entry Point** upon **Synchronisation**. For the avoidance of doubt, in the case of a **Genset** located **Offshore** comprising of **Non-Synchronous Generating Units**, **Power Park Modules**, **HVDC Systems** or **DC Converters** the steady state tolerance allowed in CC.6.3.2(e) or ECC.6.3.2.5.1 or ECC.6.3.2.6.2 (as applicable) may be applied;

(c) (i) subject to the provisions of 2.5.4(c) (ii) and 2.5.4 (c) (iii) below, the excitation system or the voltage control system of a **Genset** located **Offshore** which has agreed an alternative **Reactive Power** capability range under CC.6.3.2 (e) (iii) or ECC.6.3.2.5.2 or ECC.6.3.2.6.3 (as applicable) or a **Genset** located **Onshore**, unless otherwise agreed with **The Company**, must be operated only in its constant terminal voltage mode of operation with VAR limiters in service, with any constant **Reactive Power** output control mode or constant **Power Factor** output control mode always disabled, unless agreed otherwise with **The Company**. In the event of any change in **System** voltage, a **Generator** must not take any action to override automatic MVAr response which is produced as a result of constant terminal voltage mode of operation of the automatic excitation control system unless instructed otherwise by **The Company** or unless immediate action is necessary to comply with **Stability Limits** or unless constrained by plant operational limits or safety grounds (relating to personnel or plant);

(ii) In the case of all **Gensets** comprising **Non-Synchronous Generating Units**, **DC Converters**, **HVDC Systems** and **Power Park Modules** that are located **Offshore** and which have agreed an alternative **Reactive Power** capability range under CC.6.3.2 (e) (iii), or ECC.6.3.2.5.2 or ECC.6.3.2.6.3 (as applicable) or that are located **Onshore** only when operating below 20 % of the **Rated MW** output, the voltage control system shall maintain the reactive power transfer at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**) to 0 MVAr. For the avoidance of doubt the relevant steady state tolerance allowed for **GB Generators** in

CC.6.3.2(b) or CC.6.3.2 (e) and for **EU Generators** in ECC.6.3.2.4.4, ECC.6.3.2.5.1 and ECC.6.3.2.6.2 and ECC.6.3.2.8.2.may be applied. In the case of any such **Gensets** owned or operated by **GB Code Users** comprising current source **DC Converter** technology or comprising **Power Park Modules** connected to the **Total System** by a current source **DC Converter** when operating at any power output the voltage control system shall maintain the reactive power transfer at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**) to 0 MVAr. For the avoidance of doubt the relevant steady state tolerance allowed in CC.6.3.2(b) or CC.6.3.2 (c) (i) may be applied.

(iii) In the case of all **Gensets** located **Offshore** which are not subject to the requirements of BC2.5.4 (c) (i) or BC2.5.4 (c) (ii) the control system shall maintain the **Reactive Power** transfer at the **Offshore Grid Entry Point** at 0MVAr. For the avoidance of doubt the steady state tolerance allowed by CC.6.3.2 (e) or ECC.6.3.2.4.4, ECC.6.3.2.5.1 and ECC.6.3.2.6.2 may be applied.

(d) In the absence of any MVAr **Ancillary Service** instructions,

(i) the MVAr output of each **Genset** located **Onshore** should be 0 MVAr immediately prior to **De-Synchronisation** at the circuit-breaker where the **Genset** is **Synchronised**, other than in the case of a rapid unplanned **De-Synchronisation** or in the case of a **Genset** comprising of **Power Generating Modules** and/or **Non-Synchronous Generating Units** and/or **Power Park Modules** and/or **HVDC Converters** or **DC Converters** which is operating at less than 20% of its **Rated MW** output where the requirements of BC2.5.4 (c) part (ii) apply, or;

(ii) the MVAr output of each **Genset** located **Offshore** should be 0MVAr immediately prior to **De-Synchronisation** at the **Offshore Grid Entry Point**, other than in the case of a rapid unplanned **De-Synchronisation** or in the case of a **Genset** comprising of **Non-Synchronous Generating Units**, **Power Park Modules**, **HVDC Converters** or **DC Converters** which is operating at less than 20% of its **Rated MW** output and which has agreed an alternative **Reactive Power** capability range (for **GB Code Users**) under CC.6.3.2 (e) (iii) or ECC.6.3.2.4.4, ECC.6.3.2.5.1 and ECC.6.3.2.6.2 (for EU **Code Users**) where the requirements of BC2.5.4 (c) (ii) apply.

(e) a **Generator** should at all times operate its **CCGT Units** in accordance with the applicable **CCGT Module Matrix**;

(f) in the case of a **Range CCGT Module**, a **Generator** must operate that **CCGT Module** so that power is provided at the single **Grid Entry Point** identified in the data given pursuant to PC.A.3.2.1 or at the single **Grid Entry Point** to which **The Company** has agreed pursuant to BC1.4.2(f);

(g) in the event of the **System Frequency** being above 50.3Hz or below 49.7Hz, **BM 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 50Hz without first using reasonable endeavours to discuss the proposed actions with **The Company**. **The Company** shall either agree to these changes in input or output or issue a **Bid-Offer Acceptance** in accordance with BC2.7 to delay the change.

(h) a **Generator** should at all times operate its **Power Park Units** in accordance with the applicable **Power Park Module Availability Matrix**.

BC2.5.5 Commencement Or Termination Of Participation In The Balancing Mechanism

BC2.5.5.1 In the event that a **BM Participant** in respect of a **BM Unit** with a **Demand Capacity** with a magnitude of less than 50MW in **NGET's Transmission Area** or less than 10MW in **SHETL's Transmission Area** or less than 30MW in **SPT's Transmission Area** or comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC2.2) and/or **Power Generating Modules** and/or **CCGT Modules** and/or **Power Park Modules** at a **Small Power Station** notifies **The Company** at least 30 days in advance that from a specified **Operational Day** it will:

(a) no longer submit **Bid-Offer Data** under BC1.4.2(d), then with effect from that **Operational Day** that **BM Participant** no longer has to meet the requirements of BC2.5.1 nor the requirements of CC.6.5.8(b) or ECC.6.5.8(b) (as applicable) in relation to that **BM Unit**. Also, with effect from that **Operational Day**, any defaulted **Physical Notification** and defaulted **Bid-Offer Data** in relation to that **BM Unit** arising from the **Data Validation**, **Consistency and Defaulting Rules** will be disregarded and the provisions of BC2.5.2 will not apply;

(b) submit **Bid-Offer Data** under BC1.4.2(d), then with effect from that **Operational Day** that **BM Participant** will need to meet the requirements of BC2.5.1 and the requirements of CC.6.5.8(b) or ECC.6.5.8(b) (as applicable) in relation to that **BM Unit**.

BC2.5.5.2 In the event that a **BM Participant** in respect of a **BM Unit** with a **Demand Capacity** with a magnitude of 50MW or more in **NGET's Transmission Area** or 10MW or more in **SHETL's Transmission Area** or 30MW or more in **SPT's Transmission Area** or comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC2.2) and/or **Power Generating Modules** and/or **CCGT Modules** and/or **Power Park Modules** at a **Medium Power Station** or **Large Power Station** notifies **The Company** at least 30 days in advance that from a specified **Operational Day** it will:

(a) no longer submit **Bid-Offer Data** under BC1.4.2(d), then with effect from that **Operational Day** that **BM Participant** no longer has to meet the requirements of CC.6.5.8(b) or ECC.6.5.8(b) (as applicable) in relation to that **BM Unit**; Also, with effect from that **Operational Day**, any defaulted **Bid-Offer Data** in relation to that **BM Unit** arising from the **Data Validation**, **Consistency and Defaulting Rules** will be disregarded;

(b) submit **Bid-Offer Data** under BC1.4.2(d), then with effect from that **Operational Day** that **BM Participant** will need to meet the requirements of CC.6.5.8(b) or ECC.6.5.8(b) (as applicable) in relation to that **BM Unit**.

BC2.6 COMMUNICATIONS

Electronic communications are always conducted in GMT. However, the input of data and display of information to **Users** and **The Company** and all other communications are conducted in London time.

BC2.6.1 Normal Communication With Control Points

(a) With the exception of BC2.6.1(c) below, **Bid-Offer Acceptances** and, unless otherwise agreed with **The Company**, **Ancillary Service** instructions shall be given by automatic logging device and will be given to the **Control Point** for the **BM Unit**. For all **Planned Maintenance Outages** the provisions of BC2.6.5 will apply. For **Generating Units** (including **DC Connected Power Park Modules** (if relevant)) communications under **BC2** shall be by telephone unless otherwise agreed by **The Company** and the **User**.

(b) **Bid-Offer Acceptances** and **Ancillary Service** instructions must be formally acknowledged immediately by the **BM Participant** (or the relevant person on its behalf) via the **Control Point** for the **BM Unit** or **Generating Unit** in respect of that **BM Unit** or that **Generating Unit**. The acknowledgement and subsequent confirmation or rejection, within two minutes of receipt, is normally given electronically by automatic logging device. If no confirmation or rejection is received by **The Company** within two minutes of the issue of the **Bid-Offer Acceptance**, then **The Company** will contact the **Control Point** for the **BM Unit** by telephone to determine the reason for the lack of confirmation or rejection. Any rejection must be given in accordance with BC2.7.3 or BC2.8.3.

(c) In the event of a failure of the logging device or a **The Company** computer system outage, **Bid-Offer Acceptances** and instructions will be given, acknowledged, and confirmed or rejected by telephone. The provisions of BC2.9.7 are also applicable.

(d) In the event that in carrying out the **Bid-Offer Acceptances** or providing the **Ancillary Services**, or when operating at the level of the **Final Physical Notification Data** as provided in BC2.5.1, an unforeseen problem arises, caused on safety grounds (relating to personnel or plant), **The Company** must be notified without delay by telephone.

(e) The provisions of BC2.5.3 are also relevant.

(f) Submissions of revised MVAr capability may be made by facsimile transmission, using the format given in Appendix 3 to **BC2**.

(g) Communication will normally be by telephone for any purpose other than **Bid-Offer Acceptances**, in relation to **Ancillary Services** or for revisions of MVAr Data.

(h) Submissions of revised availability of **Frequency Sensitive Mode** may be made by facsimile transmission, using the format given in Appendix 4 to **BC2**. This process should only be used for technical restrictions to the availability of **Frequency Sensitive Mode**.

BC2.6.2 <u>Communication With Control Points In Emergency Circumstances</u>

The Company will issue **Emergency Instructions** direct to the **Control Point** for each **BM Unit** [or **Generating Unit**] in **Great Britain**. **Emergency Instructions** to a **Control Point** will normally be given by telephone (and will include an exchange of operator names).

BC2.6.3 <u>Communication With Network Operators In Emergency Circumstances</u>

The Company will issue **Emergency Instructions** direct to the **Network Operator** at each **Control Centre** in relation to special actions and **Demand Control**. **Emergency Instructions** to a **Network Operator** will normally be given by telephone (and will include an exchange of operator names). **OC6** contains further provisions relating to **Demand Control** instructions.

BC2.6.4 <u>Communication With Externally Interconnected System Operators In Emergency Circumstances</u>

The Company will issue **Emergency Instructions** directly to the **Externally Interconnected System Operator** at each **Control Centre**. **Emergency Instructions** to an **Externally Interconnected System Operator** will normally be given by telephone (and will include an exchange of operator names).

BC2.6.5 <u>Communications During Planned Outages Of Electronic Data Communication Facilities</u>

Planned Maintenance Outages will normally be arranged to take place during periods of low data transfer activity. Upon any such **Planned Maintenance Outage** in relation to a post **Gate Closure** period:-

(a) **BM Participants** should operate in relation to any period of time in accordance with the **Physical Notification** prevailing at **Gate Closure** current at the time of the start of the **Planned Maintenance Outage** in relation to each such period of time. Such operation shall be subject to the provisions of BC2.5.1, which will apply as if set out in this BC2.6.5. No further submissions of **BM Unit Data** (other than data specified in BC1.4.2(c) and BC1.4.2(e)) should be attempted or **Generating Unit Data**. Plant failure or similar problems causing significant deviation from **Physical Notification** should be notified to **The Company** by the submission of a revision to **Export and Import Limits** in relation to the **BM Unit** or **Generating Unit** so affected;

(b) during the outage, revisions to the data specified in BC1.4.2(c) and BC1.4.2(e) may be submitted. Communication between **Users Control Points** and **The Company** during the outage will be conducted by telephone;

(c) **The Company** will issue **Bid-Offer Acceptances** by telephone; and

(d) no data will be transferred from **The Company** to the **BMRA** until the communication facilities are re-established.

(e) The provisions of BC2.9.7 may also be relevant.

BC2.7 <u>BID-OFFER ACCEPTANCES</u>

BC2.7.1 Acceptance Of Bids And Offers By The Company

Bid-Offer Acceptances may be issued to the **Control Point** at any time following **Gate Closure**. Any **Bid-Offer Acceptance** will be consistent with the **Dynamic Parameters** and **Export and Import Limits** of the **BM Unit** in so far as the **Balancing Mechanism** timescales will allow (see BC2.7.2).

(a) **The Company** is entitled to assume that each **BM Unit** is available in accordance with the **BM Unit Data** submitted unless and until it is informed of any changes.

(b) **Bid-Offer Acceptances** sent to the **Control Point** will specify the data necessary to define a MW profile to be provided (ramp rate break-points are not normally explicitly sent to the **Control Point**) and to be achieved consistent with the respective **BM Unit's Export and Import Limits** provided or modified under **BC1** or **BC2**, and **Dynamic Parameters** given under BC2.5.3 or, if agreed with the relevant **User**, such rate within those **Dynamic Parameters** as is specified by **The Company** in the **Bid-Offer Acceptances**.

(c) All **Bid-Offer Acceptances** will be deemed to be at the current "**Target Frequency**", namely where a **Genset** is in **Frequency Sensitive Mode** they refer to target output at **Target Frequency**.

(d) The form of and terms to be used by **The Company** in issuing **Bid-Offer Acceptances** together with their meanings are set out in Appendix 1 in the form of a non-exhaustive list of examples.

BC2.7.2 Consistency With Export And Import Limits And Dynamic Parameters

(a) **Bid-Offer Acceptances** will be consistent with the **Export and Import Limits** provided or modified under **BC1** or **BC2** and the **Dynamic Parameters** provided or modified under **BC2**. **Bid-Offer Acceptances** may also recognise **Other Relevant Data** provided or modified under **BC1** or **BC2**

(b) In the case of consistency with **Dynamic Parameters** this will be limited to the time until the end of the **Settlement Period** for which **Gate Closure** has most recently occurred. If **The Company** intends to issue a **Bid-Offer Acceptance** covering a period after the end of the **Settlement Period** for which **Gate Closure** has most recently occurred, based upon the then submitted **Dynamic Parameters**, **Export and Import Limits**, and **Bid-Offer Data** applicable to that period, **The Company** will indicate this to the **BM Participant** at the **Control Point** for the **BM Unit**. The intention will then be reflected in the issue of a **Bid-Offer Acceptance** to return the **BM Unit** to its previously notified **Physical Notification** after the relevant **Gate Closure** provided the submitted data used to formulate this intention has not changed and subject to **System** conditions which may affect that intention. Subject to that, assumptions regarding **Bid-Offer Acceptances** may be made by **BM Participants** for **Settlement Periods** for which **Gate Closure** has not yet occurred when assessing consistency with **Dynamic Parameters** in **Settlement Periods** for which **Gate Closure** has occurred. If no such subsequent **Bid–Offer Acceptance** is issued, the original **Bid-Offer Acceptance** will include an instantaneous return to **Physical Notification** at the end of the **Balancing Mechanism** period.

BC2.7.3 Confirmation And Rejection Of Acceptances

Bid-Offer Acceptances may only be rejected by a **BM Participant** :

(a) on safety grounds (relating to personnel or plant) as soon as reasonably possible and in any event within five minutes; or

(b) because they are not consistent with the **Export and Import Limits** or **Dynamic Parameters** applicable at the time of issue of the **Bid-Offer Acceptance**.

A reason must always be given for rejection by telephone.

Where a **Bid-Offer Acceptance** is not confirmed within two minutes or is rejected, **The Company** will seek to contact the **Control Point** for the **BM Unit**. **The Company** must then, within 15 minutes of issuing the **Bid-Offer Acceptance**, withdraw the **Bid-Offer Acceptance** or log the **Bid-Offer Acceptance** as confirmed. **The Company** will only log a rejected **Bid-Offer Acceptance** as confirmed following discussion and if the reason given is, in **The Company's** reasonable opinion, not acceptable and **The Company** will inform the **BM Participant** accordingly.

BC2.7.4 Action Required From BM Participants

(a) Each **BM Participant** in respect of its **BM Units** will comply in accordance with BC2.7.1 with all **Bid-Offer Acceptances** given by **The Company** with no more than the delay allowed for by the **Dynamic Parameters** unless the **BM Unit** has given notice to **The Company** under the provisions of BC2.7.3 regarding non-acceptance of a **Bid-Offer Acceptance**.

(b) Where a **BM Unit's** input or output changes in accordance with a **Bid-Offer Acceptance** issued under BC2.7.1, such variation does not need to be notified to **The Company** in accordance with BC2.5.1.

(c) In the event that while carrying out the **Bid-Offer Acceptance** an unforeseen problem arises caused by safety reasons (relating to personnel or plant), **The Company** must be notified immediately by telephone and this may lead to revision of **BM Unit Data** in accordance with BC2.5.3

BC2.7.5 Additional Action Required when responding to Bid-Offer Acceptances

(a) When complying with **Bid-Offer Acceptances** for a **CCGT Module** a **Generator** will operate its **CCGT Units** in accordance with the applicable **CCGT Module Matrix**.

(b) When complying with **Bid-Offer Acceptances** for a **CCGT Module** which is a **Range CCGT Module**, a **Generator** must operate that **CCGT Module** so that power is provided at the single **Grid Entry Point** identified in the data given pursuant to PC.A.3.2.1 or at the single **Grid Entry Point** to which **The Company** has agreed pursuant to BC1.4.2 (f).

(c) On receiving a new MW **Bid-Offer Acceptance**, no tap changing shall be carried out to change the MVAr output unless there is a new MVAr **Ancillary Service** instruction issued pursuant to BC2.8.

(d) When complying with **Bid-Offer Acceptances** for a **Power Park Module** a **Generator** will operate its **Power Park Units** in accordance with the applicable **Power Park Module Availability Matrix**.

(e) When complying with **Bid-Offer Acceptances** for a **Synchronous Power Generating Module** a **Generator** will operate its **Generating Units** in accordance with the applicable **Synchronous Power Generating Module Availability Matrix**.

(f) When complying with **Bid-Offer Acceptances** for an **Additional BM** unit or **Secondary BM Unit** they will operate in accordance with the applicable **Aggregator Impact Matrix**.

BC2.8 ANCILLARY SERVICES

This section primarily covers the call-off of **System Ancillary Services**. The provisions relating to **Commercial Ancillary Services** will normally be covered in the relevant **Ancillary Services Agreement**.

BC2.8.1 Call-Off Of Ancillary Services By The Company

(a) **Ancillary Service** instructions may be issued at any time.

(b) **The Company** is entitled to assume that each **BM Unit** (or **Generating Unit**) is available in accordance with the **BM Unit Data** (or the **Generating Unit Data**) and data contained in the **Ancillary Services Agreement** unless and until it is informed of any changes.

(c) **Frequency** control instructions may be issued in conjunction with, or separate from, a **Bid-Offer Acceptance**.

(d) The form of and terms to be used by **The Company** in issuing **Ancillary Service** instructions together with their meanings are set out in Appendix 2 in the form of a non-exhaustive list of examples including **Reactive Power** and associated instructions.

(e) In the case of **Generating Units** that do not form part of a **BM Unit** any change in **Active Power** as a result of, or required to enable, the provision of an **Ancillary Service** will be dealt with as part of that **Ancillary Service Agreement** and/or provisions under the **CUSC**.

(f) A **System to Generator Operational Intertripping Scheme** will be armed in accordance with BC2.10.2(a).

BC2.8.2 Consistency With Export And Import Limits And Dynamic Parameters

Ancillary Service instructions will be consistent with the **Export and Import Limits** provided or modified under **BC1** or **BC2** and the **Dynamic Parameters** provided or modified under **BC2**. **Ancillary Service** instructions may also recognise **Other Relevant Data** provided or modified under **BC**1 or **BC2**.

BC2.8.3 Rejection Of Ancillary Service Instructions

(a) **Ancillary Service** instructions may only be rejected, by automatic logging device or by telephone, on safety grounds (relating to personnel or plant) or because they are not consistent with the applicable **Export and Import Limits**, **Dynamic Parameters**, **Other Relevant Data** or data contained in the **Ancillary Services Agreement** and a reason must be given immediately for non-acceptance.

(b) The issue of **Ancillary Service** instructions for **Reactive Power** will be made with due regard to any resulting change in **Active Power** output. The instruction may be rejected if it conflicts with any **Bid-Offer Acceptance** issued in accordance with BC2.7 or with the **Physical Notification**.

(c) Where **Ancillary Service** instructions relating to **Active Power** and **Reactive Power** are given together, and to achieve the **Reactive Power** output would cause the **BM Unit** to operate outside **Dynamic Parameters** as a result of the **Active Power** instruction being met at the same time, then the timescale of implementation of the **Reactive Power** instruction may be extended to be no longer than the timescale for implementing the **Active Power** instruction but in any case to achieve the MVAr **Ancillary Service** instruction as soon as possible.

BC2.8.4 Action Required From BM Units

(a) Each **BM Unit** (or **Generating Unit**) will comply in accordance with BC2.8.1 with all **Ancillary Service** instructions relating to **Reactive Power** properly given by **The Company** within 2 minutes or such longer period as **The Company** may instruct, and all other **Ancillary Service** instructions without delay, unless the **BM Unit** or **Generating Unit** has given notice to **The Company** under the provisions of BC2.8.3 regarding non-acceptance of **Ancillary Service** instructions.

(b) Each **BM Unit** may deviate from the profile of its **Final Physical Notification Data**, as modified by any **Bid-Offer Acceptances** issued in accordance with BC2.7.1, only as a result of responding to **Frequency** deviations when operating in **Frequency Sensitive Mode** in accordance with the **Ancillary Services Agreement**.

(c) Each **Generating Unit** that does not form part of a **BM Unit** may deviate from the profile of its **Final Physical Notification Data** where agreed by **The Company** and the **User**, including but not limited to, as a result of providing **an Ancillary Service** in accordance with the **Ancillary Service Agreement**.

(d) In the event that while carrying out the **Ancillary Service** instructions an unforeseen problem arises caused by safety reasons (relating to personnel or plant), **The Company** must be notified immediately by telephone and this may lead to revision of **BM Unit Data** or **Generating Unit Data** in accordance with BC2.5.3.

BC2.8.5 Reactive Despatch Network Restrictions

Where **The Company** has received notification pursuant to the Grid Code that a **Reactive Despatch to Zero MVAr Network Restriction** is in place with respect to any **Embedded Power Generating Module** and/or **Embedded Generating Unit** and/or **Embedded Power Park Module** or **HVDC Converter** at an **Embedded HVDC Converter Station** or **DC Converter** at an **Embedded DC Converter Station**, then **The Company** will not issue any **Reactive Despatch Instruction** with respect to that **Power Generating Module** and/or **Generating Unit** and/or **Power Park Module** or **DC Converter or HVDC Converter** until such time as notification is given to **The Company** pursuant to the Grid Code that such **Reactive Despatch to Zero MVAr Network Restriction** is no longer affecting that **Power Generating Module** and/or **Generating Unit** and/or **Power Park Module** or **DC Converter** or **HVDC Converter**.

BC2.9 EMERGENCY CIRCUMSTANCES

BC2.9.1 Emergency Actions

BC2.9.1.1 In certain circumstances (as determined by **The Company** in its reasonable opinion) it will be necessary, in order to preserve the integrity of the **National Electricity Transmission System** and any synchronously connected **External System**, for **The Company** to issue **Emergency Instructions**. In such circumstances, it may be necessary to depart from normal **Balancing Mechanism** operation in accordance with BC2.7 in issuing **Bid-Offer Acceptances**. **BM Participants** must also comply with the requirements of **BC3**.

BC2.9.1.2 Examples of circumstances that may require the issue of **Emergency Instructions** include:-

(a) **Events** on the **National Electricity Transmission System** or the **System** of another **User**; or

(b) the need to maintain adequate **System** and **Localised NRAPM** in accordance with BC2.9.4 below; or

(c) the need to maintain adequate frequency sensitive **Gensets** in accordance with BC2.9.5 below; or

(d) the need to implement **Demand Control** in accordance with OC6; or

(e) (i) the need to invoke the **Black Start** process or the **Re-Synchronisation of De-Synchronised Island** process in accordance with OC9; or

(ii) the need to request provision of a **Maximum Generation Service**; or

(iii) the need to issue an **Emergency Deenergisation Instruction** in circumstances where the condition or manner of operation of any **Transmission Plant** and/or **Apparatus** is such that it may cause damage or injury to any person or to the **National Electricity Transmission System**.

BC2.9.1.3 In the case of **BM Units** and **Generating Units** in **Great Britain**, **Emergency Instructions** will be issued by **The Company** direct to the **User** at the **Control Point** for the **BM Unit** or **Generating Unit** and may require an action or response which is outside its **Other Relevant Data**or **Export and Import Limits** submitted under **BC1**, or revised under **BC1** or **BC2**, or **Dynamic Parameters** submitted or revised under **BC2**.

BC2.9.1.4 In the case of a **Network Operator** or an **Externally Interconnected System Operator**, **Emergency Instructions** will be issued to its **Control Centre**.

BC2.9.2 Implementation Of Emergency Instructions

BC2.9.2.1 **Users** will respond to **Emergency Instructions** issued by **The Company** without delay and using all reasonable endeavours to so respond. **Emergency Instructions** may only be rejected by an **User** on safety grounds (relating to personnel or plant) and this must be notified to **The Company** immediately by telephone.

BC2.9.2.2 **Emergency Instructions** will always be prefixed with the words "This is an **Emergency Instruction**" except in the case of:

(i) **Maximum Generation Service** instructed by electronic data communication facilities where the instruction will be issued in accordance with the provisions of the **Maximum Generation Service Agreement**; and

(ii) an **Emergency Deenergisation Instruction**, where the **Emergency Deenergisation Instruction** will be pre-fixed with the words 'This is an **Emergency Deenergisation Instruction'**; and

(iii) during a **Black Start** situation where the **Balancing Mechanism** has been suspended, any instruction given by **The Company** will (unless **The Company** specifies otherwise) be deemed to be an **Emergency Instruction** and need not be pre-fixed with the words 'This is an **Emergency Instruction**'; and

(iv) during a **Black Start** situation where the **Balancing Mechanism** has not been suspended, any instruction in relation to **Black Start Stations Black Start HVDC Systems** and to **Network Operators** which are part of an invoked **Local Joint Restoration Plan** will (unless **The Company** specifies otherwise) be deemed to be an **Emergency Instruction** and need not be prefixed with the words 'This is an **Emergency Instruction**'.

In Scotland, any instruction in relation to **Gensets** that are not at **Black Start Stations** or to **HVDC Systems** or **DC Converter Stations** that are not part of **Black Start HVDC Systems**, but which are part of an invoked **Local Joint Restoration Plan** and are instructed in accordance with the provisions of that **Local Joint Restoration Plan,** will be deemed to be an **Emergency Instruction** and need not be prefixed with the words 'This is an **Emergency Instruction**'.

BC2.9.2.3 In all cases under this BC2.9 except BC2.9.1.2 (e) where **The Company** issues an **Emergency Instruction** to a **BM Participant** which is not rejected under BC2.9.2.1, the **Emergency Instruction** shall be treated as a **Bid-Offer Acceptance**. For the avoidance of doubt, any **Emergency Instruction** issued to a **Network Operator** or to an **Externally Interconnected System Operator** or in respect of a **Generating Unit** that does not form part of a **BM Unit**, will not be treated as a **Bid-Offer Acceptance**.

BC2.9.2.4 In the case of BC2.9.1.2 (e) (ii) where **The Company** issues an **Emergency Instruction** pursuant to a **Maximum Generation Service Agreemen**t payment will be dealt with in accordance with the **CUSC** and the **Maximum Generation Service Agreement**.

BC2.9.2.5 In the case of BC2.9.1.2 (e) (iii) where **The Company** issues an **Emergency Deenergisation Instruction** payment will be dealt with in accordance with the **CUSC**, Section 5.

BC2.9.2.6 In the of BC2.9.1.2 (e) (i) upon receipt of an **Emergency Instruction** by a **Generator** during a **Black Start** the provisions of Section G of the **BSC** relating to compensation shall apply.

BC2.9.3 Examples Of Emergency Instructions

BC2.9.3.1 In the case of a **BM Unit** or a **Generating Unit**, **Emergency Instructions** may include an instruction for the **BM Unit** or the **Generating Unit** to operate in a way that is not consistent with the **Dynamic Parameters** and/or **Export and Import Limits**.

BC2.9.3.2 In the case of a **Generator**, **Emergency Instructions** may include:

(a) an instruction to trip one or more **Gensets** (excluding **Operational Intertripping**); or

(b) an instruction to trip **Mills** or to **Part Load** a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC2.2); or

(c) an instruction to **Part Load** a **Power Generating Module** and/or **CCGT Module** or **Power Park Module**; or

(d) an instruction for the operation of **CCGT Units** within a **CCGT Module** (on the basis of the information contained within the **CCGT Module Matrix**) when emergency circumstances prevail (as determined by **The Company** in **The Company's** reasonable opinion); or

(e) an instruction to generate outside normal parameters, as allowed for in 4.2 of the **CUSC**; or

(f) an instruction for the operation of **Generating Units** within a **Cascade Hydro Scheme** (on the basis of the additional information supplied in relation to individual **Generating Units**) when emergency circumstances prevail (as determined by **The Company** in **The Company's** reasonable opinion); or

(g) an instruction for the operation of a **Power Park Module** (on the basis of the information contained within the **Power Park Module Availability Matrix**) when emergency circumstances prevail (as determined by **The Company** in **The Company's** reasonable opinion).

BC2.9.3.3 Instructions to **Network Operators** relating to the **Operational Day** may include:

(a) a requirement for **Demand** reduction and disconnection or restoration pursuant to **OC6**;

(b) an instruction to effect a load transfer between **Grid Supply Points**;

(c) an instruction to switch in a **System to Demand Intertrip Scheme**;

(d) an instruction to split a network;

(e) an instruction to disconnect an item of **Plant** or **Apparatus** from the **System.**

BC2.9.4 <u>Maintaining Adequate System And Localised NRAPM (Negative Reserve Active Power Margin)</u>

BC2.9.4.1 Where **The Company** is unable to satisfy the required **System NRAPM** or **Localised NRAPM** by following the process described in BC1.5.5, **The Company** will issue an **Emergency Instruction** to exporting **BM Units** for **De-Synchronising** on the basis of **Bid-Offer Data** submitted to **The Company** in accordance with BC1.4.2(d).

BC2.9.4.2 In the event that **The Company** is unable to differentiate between exporting **BM Units** according to **Bid-Offer Data**, **The Company** will instruct a **BM Participant** to **Shutdown** a specified exporting **BM Unit** for such period based upon the following factors:

(a) effect on power flows (resulting in the minimisation of transmission losses);

(b) reserve capability;

(c) **Reactive Power** worth;

(d) **Dynamic Parameters**;

(e) in the case of **Localised NRAPM**, effectiveness of output reduction in the management of the **System Constraint.**

BC2.9.4.3 Where **The Company** is still unable to differentiate between exporting **BM Units**, having considered all the foregoing, **The Company** will decide which exporting **BM Unit** to **Shutdown** by the application of a quota for each **BM Participant** in the ratio of each **BM Participant's Physical Notifications**.

BC2.9.4.4 Other than as provided in BC2.9.4.5 and BC2.9.4.6 below, in determining which exporting **BM Units** to **De-Synchronise** under this BC2.9.4, **The Company** shall not consider in such determination (and accordingly shall not instruct to **De-Synchronise**) any **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC2.2) within an **Existing Gas Cooled Reactor Plant**.

BC2.9.4.5 **The Company** shall be permitted to instruct a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC2.2) within an **Existing AGR Plant** to **De-Synchronise** if the relevant **Generating Unit** within the **Existing AGR Plant** has failed to offer to be flexible for the relevant instance at the request of **The Company** within the **Existing AGR Plant Flexibility Limit**.

BC2.9.4.6 Notwithstanding the provisions of BC2.9.4.5 above, if the level of **System NRAPM** (taken together with **System** constraints) or **Localised NRAPM** is such that it is not possible to avoid instructing a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC2.2) within an **Existing Magnox Reactor Plant** and/or an **Existing AGR Plant** whether or not it has met requests within the **Existing AGR Flexibility Limit** to **De-Synchronise The Company** may, provided the power flow across each **External Interconnection** is either at zero or results in an export of power from the **Total System**, so instruct a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC2.2) within an **Existing Magnox Reactor Plant** and/or an **Existing AGR Plant** to **De-Synchronise** in the case of **System NRAPM**, in all cases and in the case of **Localised NRAPM**, when the power flow would have a relevant effect.

BC2.9.4.7 When instructing exporting **BM Units** which form part of an **On-Site Generator Site** to reduce generation under this BC2.9.4, **The Company** will not issue an instruction which would reduce generation below the reasonably anticipated **Demand** of the **On-Site Generator Site**. For the avoidance of doubt, it should be noted that the term "**On-Site Generator Site**" only relates to Trading Units which have fulfilled the Class 1 or Class 2 requirements.

BC2.9.5 <u>Maintaining Adequate Frequency Sensitive Generation</u>

BC2.9.5.1 If, post **Gate Closure**, **The Company** determines, in its reasonable opinion, from the information then available to it (including information relating to a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC2.2) breakdown) that the number of and level of **Primary**, **Secondary** and **High Frequency Response** available from **Gensets** (other than those units within **Existing Gas Cooled Reactor Plant**, which are permitted to operate in **Limited Frequency Sensitive Mode** at all times under BC3.5.3) available to operate in **Frequency Sensitive Mode** is such that it is not possible to avoid **De-Synchronising Existing Gas Cooled Reactor Plant** then provided that:

(a) there are (or, as the case may be, that **The Company** anticipates, in its reasonable opinion, that at the time that the instruction is to take effect there will be) no other **Gensets** generating and exporting on to the **Total System** which are not operating in **Frequency Sensitive Mode** (or which are operating with only a nominal amount in terms of level and duration) (unless, in **The Company's** reasonable opinion, necessary to assist the relief of **System** constraints or necessary as a result of other **System** conditions); and

(b) the power flow across each **External Interconnection** is (or, as the case may be, is anticipated to be at the time that the instruction is to take effect) either at zero or result in an export of power from the **Total System**,

then **The Company** may instruct such of the **Existing Gas Cooled Reactor Plant** to **De-Synchronise** as it is, in **The Company's** reasonable opinion, necessary to **De-Synchronise** and for the period for which the **De-Synchronising** is, in **The Company's** reasonable opinion, necessary.

BC2.9.5.2 If in **The Company's** reasonable opinion it is necessary for both the procedure in BC2.9.4 and that set out in BC2.9.5.1 to be followed in any given situation, the procedure in BC2.9.4 will be followed first, and then the procedure set out in BC2.9.5.1. For the avoidance of doubt, nothing in this sub-paragraph shall prevent either procedure from being followed separately and independently of the other.

BC2.9.6 Emergency Assistance To And From External Systems

(a) An **Externally Interconnected System Operator** (in its role as operator of the **External System**) may request that **The Company** takes any available action to increase the **Active Energy** transferred into its **External System**, or reduce the **Active Energy** transferred into the **National Electricity Transmission System** by way of emergency assistance if the alternative is to instruct a demand reduction on all or part of its **External System** (or on the system of an **Interconnector User** using its **External System**). Such request must be met by **The Company** providing this does not require a reduction of **Demand** on the **National Electricity Transmission System**, or lead to a reduction in security on the **National Electricity Transmission System**.

(b) **The Company** may request that an **Externally Interconnected System Operator** takes any available action to increase the **Active Energy** transferred into the **National Electricity Transmission System**, or reduce the **Active Energy** transferred into its **External System** by way of emergency assistance if the alternative is to instruct a **Demand** reduction on all or part of the **National Electricity Transmission System**. Such request must be met by the **Externally Interconnected System Operator** providing this does not require a reduction of **Demand** on its **External System** (or on the system of **Interconnector Users** using its **External System**), or lead to a reduction in security on such **External System** or system.

BC2.9.7 Unplanned Outages Of Electronic Communication And Computing Facilities

BC2.9.7.1 In the event of an unplanned outage of the electronic data communication facilities or of **The Company's** associated computing facilities or in the event of a **Planned Maintenance Outage** lasting longer than the planned duration, in relation to a post-**Gate Closure** period **The Company** will, as soon as it is reasonably able to do so, issue a **The Company** Computing System Failure notification by telephone or such other means agreed between **Users** and **The Company** indicating the likely duration of the outage.

BC2.9.7.2 During the period of any such outage, the following provisions will apply:

(a) **The Company** will issue further **The Company** Computing System Failure notifications by telephone or such other means agreed between **Users** and **The Company** to all **BM Participants** to provide updates on the likely duration of the outage;

(b) **BM Participants** should operate in relation to any period of time in accordance with the **Physical Notification** prevailing at **Gate Closure** current at the time of the computer system failure in relation to each such period of time. Such operation shall be subject to the provisions of BC2.5.1, which will apply as if set out in this BC2.9.7.2. No further submissions of **BM Unit Data** or **Generating Unit Data** (other than data specified in BC1.4.2(c) (**Export and Import Limits**) and BC1.4.2(e) (**Dynamic Parameters**) should be attempted. Plant failure or similar problems causing significant deviation from **Physical Notification** should be notified to **The Company** by telephone by the submission of a revision to **Export and Import Limits** in relation to the **BM Unit** or **Generating Unit Data** so affected;

(c) Revisions to **Export and Import Limits** and to **Dynamic Parameters** should be notified to **The Company** by telephone and will be recorded for subsequent use;

(d) **The Company** will issue **Bid-Offer Acceptances** by telephone which will be recorded for subsequent use;

(e) No data will be transferred from **The Company** to the **BMRA** until the communication facilities are re-established.

BC2.9.7.3 **The Company** will advise **BM Participants** of the withdrawal of **The Company** Computing System Failure notification following the re-establishment of the communication facilities.

BC2.10 OTHER OPERATIONAL INSTRUCTIONS AND NOTIFICATIONS

BC2.10.1 **The Company** may, from time to time, need to issue other instructions or notifications associated with the operation of the **National Electricity Transmission System**.

BC2.10.2 Such instructions or notifications may include:

Intertrips

(a) an instruction to arm or disarm an **Operational Intertripping** scheme;

Tap Positions

(b) a request for a **Genset** step-up transformer tap position (for security assessment);

Tests

(c) an instruction to carry out tests as required under **OC5**, which may include the issue of an instruction regarding the operation of **CCGT Units** within a **CCGT Module** at a **Large Power Station**;

Future BM Unit Requirements

(d) a reference to any implications for future **BM Unit** requirements and the security of the **National Electricity Transmission System**, including arrangements for change in output to meet post fault security requirements;

Changes to Target Frequency

(e) a notification of a change in **Target Frequency**, which will normally only be 49.95, 50.00, or 50.05Hz but in exceptional circumstances as determined by **The Company** in its reasonable opinion, may be 49.90 or 50.10Hz.

BC2.10.3 Where an instruction or notification under BC2.10.2 (c) or (d) results in a change to the input or output level of the **BM Unit** then **The Company** shall issue a **Bid-Offer Acceptance** or **Emergency Instruction** as appropriate.

BC2.11 LIAISON WITH GENERATORS FOR RISK OF TRIP AND AVR TESTING

BC2.11.1 A **Generator** at the **Control Point** for any of its **Large Power Stations** may request **The Company's** agreement for one of the **Gensets** at that **Power Station** to be operated under a risk of trip. **The Company's** agreement will be dependent on the risk to the **National Electricity Transmission System** that a trip of the **Genset** would constitute.

BC2.11.2 (a) Each **Generator** at the **Control Point** for any of its **Large Power Stations** will operate its **Synchronised Gensets** (excluding **Power Park Modules**) with:

(i) **AVRs** in constant terminal voltage mode with VAR limiters in service at all times. **AVR** constant **Reactive Power** or **Power Factor** mode should, if installed, be disabled; and

(ii) its generator step-up transformer tap changer selected to manual mode,

unless released from this obligation in respect of a particular **Genset** by **The Company**.

(b) Each **Generator** at the **Control Point** for any of its **Large Power Stations** will operate its **Power Park Modules** with a **Completion Date** before 1st January 2006 at unity power factor at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**).

(c) Each **Generator** at the **Control Point** for any of its **Large Power Stations** will operate its **Power Park Modules** with a **Completion Date** on or after 1st January 2006 in voltage control mode at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**). Constant **Reactive Power** or **Power Factor** mode should, if installed, be disabled.

(d) Where a **Power System Stabiliser** is fitted as part of the excitation system or voltage control system of a **Genset**, it requires on-load commissioning which must be witnessed by **The Company**. Only when the performance of the **Power System Stabiliser** has been approved by **The Company** shall it be switched into service by a **Generator** and then it will be kept in service at all times unless otherwise agreed with **The Company**. Further reference is made to this in CC.6.3.8.

BC2.11.3 A **Generator** at the **Control Point** for any of its **Power Stations** may request **The Company's** agreement for one of its **Gensets** at that **Power Station** to be operated with the **AVR** in manual mode, or **Power System Stabiliser** switched out, or VAR limiter switched out. **The Company's** agreement will be dependent on the risk that would be imposed on the **National Electricity Transmission System** and any **User System**. Provided that in any event a **Generator** may take such action as is reasonably necessary on safety grounds (relating to personnel or plant) .

BC2.11.4 Each **Generator** shall operate its dynamically controlled **OTSDUW Plant and Apparatus** to ensure that the reactive capability and voltage control performance requirements as specified in CC.6.3.2, CC.6.3.8, CC.A.7 or ECC.6.3.2, ECC.6.3.8, ECC.A.7, ECC.A.8 and the **Bilateral Agreement** can be satisfied in response to the Setpoint Voltage and Slope as instructed by **The Company** at the **Transmission Interface Point**.

BC2.12 LIAISON WITH EXTERNALLY INTERCONNECTED SYSTEM OPERATORS

BC2.12.1 Co-Ordination Role Of Externally Interconnected System Operators

(a) The **Externally Interconnected System Operator** will act as the **Control Point** for **Bid-Offer Acceptances** on behalf of **Interconnector Users** and will co-ordinate instructions relating to **Ancillary Services** and **Emergency Instructions** on behalf of **Interconnector Users** using its **External System** in respect of each **Interconnector Users BM Units**.

(b) **The Company** will issue **Bid-Offer Acceptances** and instructions for **Ancillary Services** relating to **Interconnector Users BM Units** to each **Externally Interconnected System Operator** in respect of each **Interconnector User** using its **External System**.

(c) If, as a result of a reduction in the capability (in MW) of the **External Interconnection**, the total of the **Physical Notifications** and **Bid-Offer Acceptances** issued for the relevant period using that **External Interconnection**, as stated in the **BM Unit Data** exceeds the reduced capability (in MW) of the respective **External Interconnection** in that period then **The Company** shall notify the **Externally Interconnected System Operator** accordingly. The **Externally Interconnected System Operator** should seek a revision of **Export and Import Limits** from one or more of its **Interconnector Users** for the remainder of the **Balancing Mechanism** period during which **Physical Notifications** cannot be revised.

BC2.13 LIAISON WITH INTERCONNECTOR OWNERS

(a) Calculate the Interconnector Scheduled Transfer

i) **Interconnector Owners** shall use best endeavours to deliver an updated **Interconnector Scheduled Transfer** to **NGET** by 10 minutes after each **Intraday Cross-Zonal Gate Closure Time**.

ii) The updated **Interconnector Scheduled Transfer** shall fully reflect the results of the **Single Intraday Coupling**.

iii) **Interconnector Owners** must ensure that the updated **Interconnector Scheduled Transfer** is received in its entirety and logged into **NGET's** computer systems by the time of 10 minutes after each **Intraday Cross-zonal Gate Closure Time**.

APPENDIX 1 - FORM OF BID-OFFER ACCEPTANCES

BC2.A.1.1 This Appendix describes the forms of **Bid-Offer Acceptances**. As described in BC2.6.1 **Bid-Offer Acceptances** are normally given by an automatic logging device, but in the event of failure of the logging device, **Bid-Offer Acceptances** will be given by telephone.

BC2.A.1.2 For each **BM Unit** the **Bid-Offer Acceptance** will consist of a series of MW figures and associated times.

BC2.A.1.3 The **Bid-Offer Acceptances** relating to **CCGT Modules** will assume that the **CCGT Units** within the **CCGT Module** will operate in accordance with the **CCGT Module Matrix**, as required by **BC1**. The **Bid-Offer Acceptances** relating to **Cascade Hydro Schemes** will assume that the **Generating Unit** forming part of the **Cascade Hydro Scheme** will operate, where submitted, in accordance with the **Cascade Hydro Scheme Matrix** submitted under **BC1**. The **Bid-Offer Acceptances** relating to **Synchronous Power Generating Modules** will assume that the **Synchronous Generating Units** within the **Synchronous Power Generating Module** will operate in accordance with the **Synchronous Power Generating Module Matrix**, as required by **BC1**.

BC2.A.1.4 <u>Bid-Offer Acceptances Given By Automatic Logging Device</u>

(a) The complete form of the **Bid-Offer Acceptance** is given in the EDL Message Interface Specification which can be made available to **Users** on request.

(b) **Bid-Offer Acceptances** will normally follow the form:

(i) **BM Unit** Name

(ii) Instruction Reference Number

(iii) Time of instruction

(iv) Type of instruction

(v) **BM Unit Bid-Offer Acceptance** number

(vi) Number of MW/Time points making up instruction (minimum 2, maximum 5)

(vii) MW value and Time value for each point identified in (vi)

The times required in the instruction are input and displayed in London time, but communicated electronically in GMT.

BC2.A.1.5 <u>Bid-Offer Acceptances Given By Telephone</u>

(a) All run-up/run-down rates will be assumed to be constant and consistent with **Dynamic Parameters**. Each **Bid-Offer Acceptance** will, wherever possible, be kept simple, drawing as necessary from the following forms and BC2.7

(b) **Bid-Offer Acceptances** given by telephone will normally follow the form:

(i) an exchange of operator names;

(ii) **BM Unit** Name;

(iii) Time of instruction;

(iv) Type of instruction;

(v) Number of MW/Time points making up instruction (minimum 2, maximum 5)

(vi) MW value and Time value for each point identified in (v)

The times required in the instruction are expressed in London time.

For example, for a **BM Unit** ABCD-1 acceptance logged with a start time at 1400 hours and with a FPN at 300MW:

"**BM Unit** ABCD-1 **Bid-Offer Acceptance** timed at 1400 hours. Acceptance consists of 4 MW/Time points as follows:

300MW at 1400 hours

400MW at 1415 hours

400MW at 1450 hours

300MW at 1500 hours"

BC2.A.1.6 Submission Of Bid-Offer Acceptance Data To The Bmra

The relevant information contained in **Bid-Offer Acceptances** issued by **The Company** will be converted into "from" and "to" MW levels and times before they are submitted to the **BMRA** by **The Company**.

APPENDIX 2 - TYPE AND FORM OF ANCILLARY SERVICE INSTRUCTIONS

BC2.A.2.1 This part of the Appendix consists of a non-exhaustive list of the forms and types of instruction for a **Genset** to provide **System Ancillary Services**. There may be other types of **Commercial Ancillary Services** and these will be covered in the relevant **Ancillary Services Agreement**. In respect of the provision of **Ancillary Services** by **Generating Units** the forms and types of instruction will be in the form of this Appendix 2 unless amended in the **Ancillary Services Agreement**.

As described in CC.8, **System Ancillary Services** consist of Part 1 and Part 2 **System Ancillary Services**.

<u>Part 1 System Ancillary Services Comprise:</u>

(a) **Reactive Power** supplied other than by means of synchronous or static compensators. This is required to ensure that a satisfactory **System** voltage profile is maintained and that sufficient **Reactive Power** reserves are maintained under normal and fault conditions. **Ancillary Service** instructions in relation to **Reactive Power** may include:

(i) MVAr Output

(ii) Target Voltage Levels

(iii) Tap Changes

(iv) Maximum MVAr Output ('maximum excitation')

(v) Maximum MVAr Absorption ('minimum excitation')

(b) **Frequency** Control by means **of Frequency** sensitive generation. **Gensets** may be required to move to or from **Frequency Sensitive Mode** in the combinations agreed in the relevant **Ancillary Services Agreement**. They will be specifically requested to operate so as to provide **Primary Response** and/or **Secondary Response** and/or **High Frequency Response**.

<u>Part 2 System Ancillary Services Comprise:</u>

(c) **Frequency** Control by means of **Fast Start**.

(d) **Black Start Capability**

(e) **System to Generator Operational Intertripping**

BC2.A.2.2 As **Ancillary Service** instructions are not part of **Bid-Offer Acceptances** they do not need to be closed instructions and can cover any period of time, not just limited to the period of the **Balancing Mechanism**.

BC2.A.2.3 As described in BC2.6.1, unless otherwise agreed with **The Company**, **Ancillary Service** instructions are normally given by automatic logging device, but in the absence of, or in the event of failure of the logging device, instructions will be given by telephone.

BC2.A.2.4 <u>Instructions Given By Automatic Logging Device</u>

(a) The complete form of the **Ancillary Service** instruction is given in the EDL Message Interface Specification which is available to **Users** on request from **The Company**.

(b) **Ancillary Service** instructions for **Frequency** Control will normally follow the form:

(i) **BM Unit** Name

(ii) Instruction Reference Number

(iii) Time of instruction

(iv) Type of instruction (REAS)

(v) Reason Code

(vi) Start Time

(c) **Ancillary Service** instructions for **Reactive Power** will normally follow the form:

(i) **BM Unit** Name

(ii) Instruction Reference Number

(iii) Time of instruction

(iv) Type of instruction (MVAr, VOLT or TAPP)

(v) Target Value

(vi) Target Time

The times required in the instruction are input and displayed in London time, but communicated electronically in GMT.

BC2.A.2.5 Instructions Given By Telephone

(a) **Ancillary Service** instructions for **Frequency** Control will normally follow the form:

(i) an exchange of operator names;

(ii) **BM Unit** Name;

(iii) Time of instruction;

(iv) Type of instruction;

(v) Start Time.

The times required in the instruction are expressed in London time.

For example, for **BM Unit** ABCD-1 instructed at 1400 hours to provide **Primary** and **High Frequency** response starting at 1415 hours:

"**BM Unit** ABCD-1 message timed at 1400 hours. Unit to **Primary and High Frequency Response** at 1415 hours"

(b) **Ancillary Service** instructions for **Reactive Power** will normally follow the form:

(a) an exchange of operator names;

(b) **BM Unit** Name;

(c) Time of instruction;

(d) Type of instruction (MVAr, VOLT, SETPOINT, **SLOPE** or TAPP)

(e) Target Value

(f) Target Time.

The times required in the instruction are expressed as London time.

For example, for **BM Unit** ABCD-1 instructed at 1400 hours to provide 100MVAr by 1415 hours:

"**BM Unit** ABCD-1 message timed at 1400 hours. MVAr instruction. Unit to plus 100 MVAr target time 1415 hours."

BC2.A.2.6 Reactive Power

As described in BC2.A.2.4 and BC2.A.2.5 instructions for **Ancillary Services** relating to **Reactive Power** may consist of any of several specific types of instruction. The following table describes these instructions in more detail:

Instruction Name	Description	Type of Instruction
MVAr Output	The individual MVAr output from the **Genset** onto the **National Electricity Transmission System** at the **Grid Entry Point** (or onto the **User System** at the **User System Entry Point** in the case of **Embedded Power Stations**), namely on the higher voltage side of the generator step-up transformer or **Grid Entry Point** or **User System Entry Point** in the case of a **Power Generating Module**. In relation to each **Genset**, where there is no HV indication, **The Company** and the **Generator** will discuss and agree equivalent MVAr levels for the corresponding LV indication. Where a **Genset** is instructed to a specific MVAr output, the **Generator** must achieve that output within a tolerance of +/- 25 MVAr (for **Gensets** in England and Wales) or the lesser of +/-5% of rated output or 25MVAr (for **Gensets** in Scotland) (or such other figure as may be agreed with **The Company**) by tap changing on the generator step-up transformer, or adjusting the **Genset** terminal voltage, subject to compliance with CC.6.3.8 (a) (v), or ECC.6.3.8.3.3 (as applicable) to a value that is equal to or higher than 1.0p.u. of the rated terminal voltage, or a combination of both. Once this has been achieved, the **Generator** will not tap again and will not readjust the **Genset** terminal voltage without prior consultation with and the agreement of **The Company**, on the basis that MVAr output will be allowed to vary with **System** conditions.	MVAr

Instruction Name	Description	Type of Instruction
Target Voltage Levels	Target voltage levels to be achieved by the **Genset** on the **National Electricity Transmission System** at the **Grid Entry Point** (or on the **User System** at the **User System Entry Point** in the case of **Embedded Power Stations**, namely on the higher voltage side of the generator step-up transformer or **Grid Entry Point** or **User System Entry Point** in the case of a **Power Generating Module**. Where a **Genset** is instructed to a specific target voltage, the **Generator** must achieve that target within a tolerance of ±1 kV (or such other figure as may be agreed with **The Company**) by tap changing on the generator step-up transformer, or adjusting the **Genset** terminal voltage, subject to compliance with CC.6.3.8 (a) (v) or ECC.6.3.8.3.3 (as applicable), to a value that is equal to or higher than 1.0p.u. of the rated terminal voltage, or a combination of both. In relation to each **Genset**, where there is no HV indication, **The Company** and the **Generator** will discuss and agree equivalent voltage levels for the corresponding LV indication. Under normal operating conditions, once this target voltage level has been achieved the **Generator** will not tap again and will not readjust the **Genset** terminal voltage without prior consultation with, and with the agreement of, **The Company**. However, under certain circumstances the **Generator** may be instructed to maintain a target voltage until otherwise instructed and this will be achieved by tap changing on the generator step-up transformer, or adjusting the **Genset** terminal voltage, subject to compliance with CC.6.3.8 (a) (v) or ECC.6.3.8.3.3 (as applicable), to a value that is equal to or higher than 1.0p.u. of the rated terminal voltage, or a combination of both without reference to **The Company**.	VOLT
Setpoint Voltage	Where a **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** or **HVDC Converter** is instructed to a specific **Setpoint Voltage**, the **Generator** must achieve that **Setpoint Voltage** within a tolerance of ±0.25% (or such other figure as may be agreed with **The Company**). The **Generator** must maintain the specified **Setpoint Voltage** target until an alternative target is received from **The Company**.	SETPOINT

Instruction Name	Description	Type of Instruction
Slope	Where a **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** or **HVDC Converter** is instructed to a specific **Slope**, the **Generator** must achieve that **Slope** within a tolerance of ±0.5% (or such other figure as may be agreed with **The Company**). The **Generator** must maintain the specified **Slope** target until an alternative target is received from **The Company**. The **Generator** will not be required to implement a new **Slope** setting in a time of less than 1 week from the time of the instruction.	SLOPE
Tap Changes	Details of the required generator step-up transformer tap changes in relation to a **Genset**. The instruction for tap changes may be a **Simultaneous Tap Change** instruction, whereby the tap change must be effected by the **Generator** in response to an instruction from **The Company** issued simultaneously to relevant **Power Stations**. The instruction, which is normally preceded by advance notice, must be effected as soon as possible, and in any event within one minute of receipt from **The Company** of the instruction. For a **Simultaneous Tap Change**, change **Genset** generator step-up transformer tap position by one [two] taps to raise or lower (as relevant) **System** voltage, to be executed at time of instruction.	TAPP
Maximum MVAr Output ("maximum excitation")	Under certain conditions, such as low **System** voltage, an instruction to maximum MVAr output at instructed MW output ("maximum excitation") may be given, and a **Generator** should take appropriate actions to maximise MVAr output unless constrained by plant operational limits or safety grounds (relating to personnel or plant).	
Maximum MVAr Absorption ("minimum excitation")	Under certain conditions, such as high **System** voltage, an instruction to maximum MVAr absorption at instructed MW output ("minimum excitation") may be given, and a **Generator** should take appropriate actions to maximise MVAr absorption unless constrained by plant operational limits or safety grounds (relating to personnel or plant).	

BC2.A.2.7 In addition, the following provisions will apply to **Reactive Power** instructions:

(a) In circumstances where **The Company** issues new instructions in relation to more than one **BM Unit** at the same **Power Station** at the same time, tapping will be carried out by the **Generator** one tap at a time either alternately between (or in sequential order, if more than two), or at the same time on, each **BM Unit**.

(b) Where the instructions require more than two taps per **BM Unit** and that means that the instructions cannot be achieved within 2 minutes of the instruction time (or such longer period at **The Company** may have instructed), the instructions must each be achieved with the minimum of delay after the expiry of that period.

(c) It should be noted that should **System** conditions require, **The Company** may need to instruct maximum MVAr output to be achieved as soon as possible, but (subject to the provisions of paragraph (BC2.A.2.7(b) above) in any event no later than 2 minutes after the instruction is issued.

(d) An **Ancillary Service** instruction relating to **Reactive Power** may be given in respect of **CCGT Units** within a **CCGT Module** at a **Power Station** or **Generating Units** within a **Synchronous Power Generating Module** at a **Power Station** where running arrangements and/or **System** conditions require, in both cases where exceptional circumstances apply and connection arrangements permit.

(e) In relation to MVAr matters, MVAr generation/output is an export onto the **System** and is referred to as "lagging MVAr", and MVAr absorption is an import from the **System** and is referred to as "leading MVAr".

(f) It should be noted that the excitation control system constant **Reactive Power** output control mode or constant **Power Factor** output control mode will always be disabled, unless agreed otherwise with **The Company**.

APPENDIX 3 - SUBMISSION OF REVISED MVAr CAPABILITY

BC2.A.3.1 For the purpose of submitting revised MVAr data the following terms shall apply:

Full Output: In the case of a **Synchronous Generating Unit** (as defined in the Glossary and Definitions ((which could be part of a **Synchronous Power Generating Module**) and not limited by BC2.2) is the MW output measured at the generator stator terminals representing the LV equivalent of the **Registered Capacity** at the **Grid Entry Point**, and in the case of a **Non-Synchronous Generating Unit** (excluding **Power Park Units**), **HVDC Converter** or **DC Converter** or **Power Park Module** is the **Registered Capacity** at the **Grid Entry Point**

Minimum Output: In the case of a **Synchronous Generating Unit** (as defined in the Glossary and Definitions ((which could be part of a **Synchronous Power Generating Module**) and not limited by BC2.2) is the MW output measured at the generator stator terminals representing the LV equivalent of the **Minimum Generation** or **Minimum Stable Operating Level** at the **Grid Entry Point**, and in the case of a **Non-Synchronous Generating Unit** (excluding **Power Park Units**), **HVDC Converter** or **DC Converter** or **Power Park Module** is the **Minimum Generation** or **Minimum Stable Operating Level** or **Minimum Active Power Transmission Capacity** at the **Grid Entry Point**

BC2.A.3.2 The following provisions apply to faxed submission of revised MVAr data:

(a) The fax must be transmitted to **The Company** (to the relevant location in accordance with GC6) and must contain all the sections from the relevant part of Annexure 1 and from either Annexure 2 or 3 (as applicable) but with only the data changes set out. The "notification time" must be completed to refer to the time of transmission, where the time is expressed as London time.

(b) Upon receipt of the fax, **The Company** will acknowledge receipt by sending a fax back to the **User**. The acknowledgement will either state that the fax has been received and is legible or will state that it (or part of it) is not legible and will request re-transmission of the whole (or part) of the fax.

(c) Upon receipt of the acknowledging fax the **User** will, if requested, re-transmit the whole or the relevant part of the fax.

(d) The provisions of paragraphs (b) and (c) then apply to that re-transmitted fax.

APPENDIX 3 - ANNEXURE 1

Optional Logo

Company name REVISED REACTIVE POWER CAPABILITY DATA

TO: National Electricity Transmission System Control Centre

Fax telephone No.

Number of pages inc. header:.............................

Sent By : ....

Return Acknowledgement Fax to ....

For Retransmission or Clarification ring..

Acknowledged by **The Company**: (Signature)

....

Acknowledgement time and date
....

Legibility of FAX :

Acceptable		
Unacceptable (List pages if appropriate)		(Resend FAX)

APPENDIX 3 - ANNEXURE 2

To: National Electricity Transmission System Control Centre

From : [Company Name & Location]

REVISED REACTIVE POWER CAPABILITY DATA – GENERATING UNITS EXCLUDING POWER PARK MODULES AND DC CONVERTERS

Notification Time (HH:MM):	Notification Date (DD/MM/YY):
Start Time (HH:MM):	Start Date (DD/MM/YY):
Generating Unit*	

* For a **Synchronous Power Generating Module** and/or **CCGT Module** and/or a **Cascade Hydro Scheme**, the redeclaration is for a **Generating Unit** within a **Synchronous Power Generating Module** and/or **CCGT Module** and/or **Cascade Hydro Scheme**. For **BM Units** quote **The Company** BM Unit id, for other units quote the **Generating Unit** id used for OC2.4.1.2 Outage Planning submissions. **Generating Unit** has the meaning given in the Glossary and Definitions and is not limited by BC2.2.

REVISION TO THE REACTIVE POWER CAPABILITY AT THE GENERATING UNIT STATOR TERMINALS (at rated terminal volts) **AS STATED IN THE RELEVANT ANCILLARY SERVICES AGREEMENT:**

	MW	MINIMUM (MVAr +ve for lag, -ve for lead)	MAXIUM (MVAr +ve for lag, -ve for lead)
AT **RATED MW**			
AT FULL OUTPUT (MW)			
AT MINIMUM OUTPUT (MW)			

COMMENTS *e.g. generator transformer tap restrictions, predicted end time if known*

____

____

Redeclaration made by (Signature)

____

APPENDIX 3 - ANNEXURE 3

To: National Electricity Transmission System Control Centre

From : [Company Name & Location]

REVISED REACTIVE POWER CAPABILITY DATA – POWER PARK MODULES, HVDC CONVERTERS AND DC CONVERTERS

Notification Time (HH:MM):	Notification Date (DD/MM/YY):
Start Time (HH:MM):	Start Date (DD/MM/YY):
Power Park Module / DC Converter*	

* For BM Units quote **The Company** BM Unit id, for other units quote the id used for OC2.4.1.2 Outage Planning submissions

Start Time/Date (if not effective immediately)

REVISION TO THE REACTIVE POWER CAPABILITY AT THE COMMERCIAL BOUNDARY AS STATED IN THE RELEVANT ANCILLARY SERVICES AGREEMENT:

	MINIMUM (MVAr +ve for lag, -ve for lead)	MAXIMUM (MVAr +ve for lag, -ve for lead)
AT RATED MW		
AT 50% OF RATED MW		
AT 20% OF RATED MW		
BELOW 20% OF RATED MW		
AT 0% OF RATED MW		

COMMENTS *e.g. generator transformer tap restrictions, predicted end time if known*

____

____

Redeclaration made by (Signature)

APPENDIX 4 - SUBMISSION OF AVAILABILITY OF FREQUENCY SENSITIVE MODE

BC2.A.4.1 For the purpose of submitting availability of **Frequency Sensitive Mode**, this process only relates to the provision of response under the **Frequency Sensitive Mode** and does not cover the provision of response under the **Limited Frequency Sensitive Mode**.

BC2.A.4.2 The following provisions apply to the faxed submission of the **Frequency Sensitive Mode availability**;

(a) The fax must be transmitted to **The Company** (to the relevant location in accordance with GC6) and must contain all the sections relevant to Appendix 4 - Annexure1 but with only the data changes set out. The "notification time" must be completed to refer to the time and date of transmission, where the time is expressed in London time.

(b) Upon receipt of the fax, **The Company** will acknowledge receipt by sending a fax back to the **User**. This acknowledging fax should be in the format of Appendix 4 – Annexure 1. The acknowledgement will either state that the fax has been received and is legible or will state that it (or part of it) is not legible and will request re-transmission of the whole (or part) of the fax.

(c) Upon receipt of the acknowledging fax the **User** will, if requested re-transmit the whole or the relevant part of the fax.

(d) The provisions of paragraph (b) and (c) then apply to the re-transmitted fax.

BC2.A.4.3 The **User** shall ensure the availability of operating in the **Frequency Sensitive Mode** is restored as soon as reasonably practicable and will notify **The Company** using the format of Appendix 4 – Annexure 1. In the event of a sustained unavailability of **Frequency Sensitive Mode The Company** may seek to confirm compliance with the relevant requirements in the **CC** or **ECC** through the process in **OC5** or **ECP**.

APPENDIX 4 - ANNEXURE 1

To: National Electricity Transmission System Control Centre

From : [Company Name & Location]

Submission of availability of Frequency Sensitive Mode

Notification Time (HH:MM):	Notification Date (DD/MM/YY):
Start Time (HH:MM):	Start Date (DD/MM/YY):
Genset or DC Converter	

The availability of the above unit to operate in **Frequency Sensitive Mode** is as follows:

All contract modes: Available / Unavailable *[delete as applicable];* or

Change to the availability of individual contract modes:

Contract Mode e.g. *A*	**Availability for operation in Frequency Sensitive Mode** *[Y/N]*

COMMENTS *e.g. reason for submission, predicted end time if known*

____

____

Redeclaration made by (Signature)____

Receipt Acknowledgement from **The Company**

Legible (tick box)		Illegible (tick box)	
Explanation:			
Time: Date: Signature:			

< END OF BALANCING CODE 2 >

DATA REGISTRATION CODE
(DRC)

CONTENTS

(This contents page does not form part of the Grid Code)

DRC.1 INTRODUCTION

DRC.1.1 The **Data Registration Code** ("**DRC**") presents a unified listing of all data required by **The Company** from **Users** and by **Users** from **The Company**, from time to time under the **Grid Code**. The data which is specified in each section of the **Grid Code** is collated here in the **RC**. Where there is any inconsistency in the data requirements under any particular section of the **Grid Code** and the **Data Registration Code** the provisions of the particular section of the **Grid Code** shall prevail.

DRC.1.2 The **DRC** identifies the section of the **Grid Code** under which each item of data is required .

DRC.1.3 The Code under which any item of data is required specifies procedures and timings for the supply of that data, for routine updating and for recording temporary or permanent changes to that data. All timetables for the provision of data are repeated in the **DRC.**

DRC.1.4 Various sections of the **Grid Code** also specify information which **Users** will receive from **The Company**. This information is summarised in a single schedule in the **DRC** (Schedule 9).

DRC.1.5 The categorisation of data into **DPD I** and **DPD II** is indicated in the **DRC** below.

DRC.2 OBJECTIVE

The objective of the **DRC** is to:

DRC.2.1 List and collate all the data to be provided by each category of **User** to **The Company** under the **Grid Code**.

DRC.2.2 List all the data to be provided by **The Company** to each category of **User** under the **Grid Code**.

DRC.3 SCOPE

DRC.3.1 The **DRC** applies to **The Company** and to **Users**, which in this **DRC** means:-

(a) **Generators** (including those undertaking **OTSDUW** and/or those who own and/or operate **DC Connected Power Park Modules**);

(b) **Network Operators**;

(c) **DC Converter Station** owners and **HVDC System Owners**;

(d) **Suppliers**;

(e) **Non-Embedded Customers** (including, for the avoidance of doubt, a **Pumped Storage Generator** in that capacity);

(f) **Externally Interconnected System Operators**;

(g) **Interconnector Users**; and

(h) **BM Participants**.

DRC.3.2 For the avoidance of doubt, the **DRC** applies to both **GC Code Users** and **EU Code Users User's**.

DRC.4 DATA CATEGORIES AND STAGES IN REGISTRATION

DRC.4.1.1 Within the **DRC** each data item is allocated to one of the following three categories:

(a) **Standard Planning Data** (**SPD**)

(b) **Detailed Planning Data** (**DPD**)

(c) **Operational Data**

DRC.4.2 Standard Planning Data (SPD)

DRC.4.2.1 The **Standard Planning Data** listed and collated in this **DRC** is that data listed in Part 1 of the Appendix to the **PC**.

DRC.4.2.2 **Standard Planning Data** will be provided to **The Company** in accordance with PC.4.4 and PC.A.1.2.

DRC.4.3 Detailed Planning Data (DPD)

DRC.4.3.1 The **Detailed Planning Data** listed and collated in this **DRC** is categorised as **DPD I** and **DPD II** and is that data listed in Part 2 of the Appendix to the **PC**.

DRC.4.3.2 **Detailed Planning Data** will be provided to **The Company** in accordance with PC.4.4, PC.4.5 and PC.A.1.2.

DRC.4.4 Operational Data

DRC.4.4.1 **Operational Data** is data which is required by the **Operating Codes** and the **Balancing Codes**. Within the **DRC**, **Operational Data** is sub-categorised according to the Code under which it is required, namely **OC1**, **OC2**, **BC1** or **BC2**.

DRC.4.4.2 **Operational Data** is to be supplied in accordance with timetables set down in the relevant **Operating Codes** and **Balancing Codes** and repeated in tabular form in the schedules to the **DRC**.

DRC.5 PROCEDURES AND RESPONSIBILITIES

DRC.5.1 Responsibility For Submission And Updating Of Data

In accordance with the provisions of the various sections of the **Grid Code**, each **User** must submit data as summarised in DRC.6 and listed and collated in the attached schedules.

DRC.5.2 Methods Of Submitting Data

DRC.5.2.1 Wherever possible the data schedules to the **DRC** are structured to serve as standard formats for data submission and such format must be used for the written submission of data to **The Company**.

DRC.5.2.2 Data must be submitted to the **Transmission Control Centre** notified by **The Company** or to such other department or address as **The Company** may from time to time advise. The name of the person at the **User Site** who is submitting each schedule of data must be included.

DRC.5.2.3 Where a computer data link exists between a **User** and **The Company**, data may be submitted via this link. **The Company** will, in this situation, provide computer files for completion by the **User** containing all the data in the corresponding **DRC** schedule.

Data submitted can be in an electronic format using a proforma to be supplied by **The Company** or other format to be agreed annually in advance with **The Company.** In all cases the data must be complete and relate to, and relate only to, what is required by the relevant section of the **Grid Code**.

DRC.5.2.4 Other modes of data transfer, such as magnetic tape, may be utilised if **The Company** gives its prior written consent.

DRC.5.2.5 **Generators**, **HVDC System Owners** and **DC Converter Station** owners submitting data for a **Power Generating Module, Generating Unit**, **DC Converter**, **HVDC System**, **Power Park Module** (including **DC Connected Power Park Modules**) or **CCGT Module** before the issue of a **Final Operational Notification** should submit the **DRC** data schedules and compliance information required under the **CP** electronically using the **User Data File Structure** unless otherwise agreed with **The Company**.

DRC.5.3 Changes To Users' Data

DRC.5.3.1 Whenever a **User** becomes aware of a change to an item of data which is registered with **The Company** the **User** must notify **The Company** in accordance with each section of the Grid Code. The method and timing of the notification to **The Company** is set out in each section of the Grid Code.

DRC.5.4 Data Not Supplied

DRC.5.4.1 **Users** and **The Company** are obliged to supply data as set out in the individual sections of the **Grid Code** and repeated in the **DRC**. If a **User** fails to supply data when required by any section of the **Grid Code**, **The Company** will estimate such data if and when, in **The Company's** view, it is necessary to do so. If **The Company** fails to supply data when required by any section of the **Grid Code**, the **User** to whom that data ought to have been supplied, will estimate such data if and when, in that **User's** view, it is necessary to do so. Such estimates will, in each case, be based upon data supplied previously for the same **Plant** or **Apparatus** or upon corresponding data for similar **Plant** or **Apparatus** or upon such other information as **The Company** or that **User**, as the case may be, deems appropriate.

DRC.5.4.2 **The Company** will advise a **User** in writing of any estimated data it intends to use pursuant to DRC.5.4.1 relating directly to that **User's Plant** or **Apparatus** in the event of data not being supplied.

DRC.5.4.3 A **User** will advise **The Company** in writing of any estimated data it intends to use pursuant to DRC.5.4.1 in the event of data not being supplied.

DRC.5.5 Substituted Data

DRC.5.5.1 In the case of PC.A.4 only, if the data supplied by a **User** does not in **The Company's** reasonable opinion reflect the equivalent data recorded by **The Company**, **The Company** may estimate such data if and when, in the view of **The Company**, it is necessary to do so. Such estimates will, in each case, be based upon data supplied previously for the same **Plant** or **Apparatus** or upon corresponding data for similar **Plant** or **Apparatus** or upon such other information as **The Company** deems appropriate.

DRC.5.5.2 **The Company** will advise a **User** in writing of any estimated data it intends to use pursuant to DRC.5.5.1 relating directly to that **User's Plant** or **Apparatus** where it does not in **The Company's** reasonable opinion reflect the equivalent data recorded by **The Company**. Such estimated data will be used by **The Company** in place of the appropriate data submitted by the **User** pursuant to PC.A.4 and as such shall be deemed to accurately represent the **User's** submission until such time as the **User** provides data to **The Company's** reasonable satisfaction.

DRC.6 DATA TO BE REGISTERED

DRC.6.1 Schedules 1 to 19 attached cover the following data areas.

DRC.6.1.1 Schedule 1 – Power Generating Module, Generating Unit (or CCGT Module), Power Park Module (including DC Connected Power Park Module and Power Park Unit), HVDC System and DC Converter Technical Data.

Comprising **Power Generating Module**, **Generating Unit** (and **CCGT Module**), **Power Park Module** (including **DC Connected Power Park Module** and **Power Park Unit**) and **DC Converter** fixed electrical parameters.

DRC.6.1.2 Schedule 2 - Generation Planning Parameters

Comprising the **Genset** parameters required for **Operational Planning** studies.

DRC.6.1.3 Schedule 3 - Large Power Station Outage Programmes, Output Usable And Inflexibility Information.

Comprising generation outage planning, **Output Usable** and inflexibility information at timescales down to the daily **BM Unit Data** submission.

DRC.6.1.4 Schedule 4 - Large Power Station Droop And Response Data.

Comprising data on governor **Droop** settings and **Primary**, **Secondary** and **High Frequency Response** data for **Large Power Stations**.

DRC.6.1.5 Schedule 5 – User's System Data.

Comprising electrical parameters relating to **Plant** and **Apparatus** connected to the **National Electricity Transmission System**.

DRC.6.1.6 Schedule 6 – Users Outage Information.

Comprising the information required by **The Company** for outages on the **User System**, including outages at **Power Stations** other than outages of **Gensets**

DRC.6.1.7 Schedule 7 - Load Characteristics.

Comprising the estimated parameters of load groups in respect of, for example, harmonic content and response to frequency.

DRC.6.1.8 Schedule 8 - BM Unit Data.

DRC.6.1.9 Schedule 9 - Data Supplied By The Company To Users.

DRC.6.1.10 Schedule 10 - Demand Profiles And Active Energy Data

Comprising information relating to the **Network Operators'** and **Non-Embedded Customers'** total **Demand** and **Active Energy** taken from the **National Electricity Transmission System**

DRC.6.1.11 Schedule 11 - Connection Point Data

Comprising information relating to **Demand**, demand transfer capability and the **Small Power Station**, **Medium Power Station** and **Customer** generation connected to the **Connection Point**

DRC.6.1.12 Schedule 12 - Demand Control Data

Comprising information related to **Demand Control**

DRC.6.1.13 Schedule 13 - Fault Infeed Data

Comprising information relating to the short circuit contribution to the **National Electricity Transmission System** from **Users** other than **Generators**, **HVDC System Owners** and **DC Converter Station** owners.

DRC.6.1.14 Schedule 14 - Fault Infeed Data (Generators Including Unit And Station Transformers)

Comprising information relating to the Short Circuit contribution to the **National Electricity Transmission System** from **Generators**, **HVDC System Owners** and **DC Converter Station** owners.

DRC.6.1.15 Schedule 15 – Mothballed Power Generating Module, Mothballed Generating Unit, Mothballed Power Park Module (including Mothballed DC Connected Power Park Modules), Mothballed HVDC Systems, Mothballed HVDC Converters, Mothballed DC Converters at a DC Converter Station and Alternative Fuel Data

Comprising information relating to estimated return to service times for **Mothballed Power Generating Modules**, **Mothballed Generating Units**, **Mothballed Power Park Modules (**including **Mothballed DC Connected Power Park Modules**), **Mothballed HVDC Systems**, **Mothballed HVDC Converters** and **Mothballed DC Converters at a DC Converter Station** and the capability of gas-fired **Generating Units** to operate using alternative fuels.

DRC.6.1.16 Schedule 16 – Black Start Information

Comprising information relating to **Black Start**.

DRC.6.1.17 Schedule 17 – Access Period Schedule

Comprising **Access Period** information for **Transmission Interface Circuits** within an **Access Group**.

DRC.6.1.18 Schedule 18 – Generators Undertaking OTSDUW Arrangements

Comprising electrical parameters relating to **OTSDUW Plant and Apparatus** between the **Offshore Grid Entry Point** and **Transmission Interface Point**.

DRC.6.1.19 Schedule 19 – User Data File Structure

Comprising information relating to the **User Data File Structure**.

DRC.6.2 The **Schedules** applicable to each class of **User** are as follows:

User	Schedule
Generators with **Large Power Stations**	1, 2, 3, 4, 9, 14, 15, 16, 19
Generators with **Medium Power Stations** (see notes 2, 3, 4)	1, 2 (part), 9, 14, 15, 19
Generators with **Small Power Stations** directly connected to the **National Electricity Transmission System**	1, 6, 14, 15, 19
Generators undertaking **OTSDUW** (see note 5)	18, 19
All **Users** connected directly to the **National Electricity Transmission System**	5, 6, 9
All **Users** connected directly to the **National Electricity Transmission System** other than **Generators**	10,11,13,17
All **Users** connected directly to the **National Electricity Transmission System** with **Demand**	7, 9
A **Pumped Storage Generator**, **Externally Interconnected System Operator** and **Interconnector Users**	12 (as marked)
All **Suppliers**	12
All **Network Operators**	12
All **BM Participants**	8
All **DC Converter Station** owners	1, 4, 9, 14, 15, 19

Notes:

(1) **Network Operators** must provide data relating to **Small Power Stations** and/or **Customer Generating Plant Embedded** in their **Systems** when such data is requested by **The Company** pursuant to PC.A.3.1.4 or PC.A.5.1.4.

(2) The data in schedules 1, 14 and 15 need not be supplied in relation to **Medium Power Stations** connected at a voltage level below the voltage level of the **Subtransmission System** except in connection with a **CUSC Contract** or unless specifically requested by **The Company**.

(3) Each **Network Operator** within whose **System** an **Embedded Medium Power Station** not subject to a **Bilateral Agreement** or **Embedded DC Converter Station** not subject to a **Bilateral Agreement** is situated shall provide the data to **The Company** in respect of each such **Embedded Medium Power Station** or **Embedded DC Converter Station** or **HVDC System**.

(4) In the case of Schedule 2, **Generators**, **HVDC System Owners**, **DC Converter Station** owners or **Network Operators** in the case of **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** or **Embedded DC Converter Stations** not subject to a **Bilateral Agreement**, would only be expected to submit data in relation to **Standard Planning Data** as required by the **Planning Code**.

(5) In the case of **Generators** undertaking **OTSDUW**, the **Generator** will need to supply **User** data in accordance with the requirements of **Large** or **Small Power Stations** (as defined in DRC.6.2) up to the **Offshore Grid Entry Point**. In addition, the **User** will also need to submit **Offshore Transmission System** data in between the **Interface Point** and its **Connection Points** in accordance with the requirements of Schedule 18.

ABBREVIATIONS:

SPD = **Standard Planning Data**	**DPD** = **Detailed Planning Data**
% on MVA = % on Rated MVA	**RC** = **Registered Capacity** **MC = Maximum Capacity**
% on 100 = % on 100 MVA	**OC1**, **BC1**, etc = Grid Code for which data is required
CUSC Contract = **User** data which may be submitted to the **Relevant Transmission Licensees** by **The Company**, following the acceptance by a **User** of a **CUSC Contract**.	CUSC App. Form = **User** data which may be submitted to the **Relevant Transmission Licensees** by **The Company**, following an application by a **User** for a **CUSC Contract**.

Note:

All parameters, where applicable, are to be measured at nominal **System Frequency**

+ these **SPD** items should only be given in the data supplied with the application for a **CUSC Contract**.

* Asterisk items are not required for **Small Power Stations** and **Medium Power Stations**

Information is to be given on a **Unit** basis, unless otherwise stated. Where references to **CCGT Modules** are made, the columns "G1" etc should be amended to read "M1" etc, as appropriate

□ These data items may be submitted to the **Relevant Transmission Licensees** from **The Company** in respect of the **National Electricity Transmission System**. The data may be submitted to the **Relevant Transmission Licensees** in a summarised form e.g. network model; the data transferred will have been originally derived from data submitted by **Users** to **The Company**.

■ these data items may be submitted to the **Relevant Transmission Licensee** from **The Company** in respect to **Relevant Units** only. The data may be submitted to the **Relevant Transmission Licensee** in a summarised form e.g. network model; the data transferred will have been originally derived from data submitted by **Users** to **The Company**.

POWER STATION NAME: ______________________ DATE: ___________

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CAT.	**GENERATING UNIT** OR STATION DATA						
		CUSC Contract	CUSC App. Form		F.Yr. 0	F.Yr. 1	F.Yr. 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6
GENERATING STATION DEMANDS: **Demand** associated with the **Power Station** supplied through the **National Electricity Transmission System** or the **Generator's User System** *(PC.A.5.2)*											
- The maximum **Demand** that could occur.	MW MVAr	□ □		**DPD I** **DPD I**							
- **Demand** at specified time of annual peak half hour of **National Electricity Transmission System Demand** at **Annual ACS Conditions**.	MW MVAr	□ □		**DPD II** **DPD II**							
- **Demand** at specified time of annual minimum half-hour of **National Electricity Transmission System Demand**.	MW MVAr	□ □		**DPD II** **DPD II**							
(Additional **Demand** supplied through the unit transformers to be provided below)											
INDIVIDUAL **GENERATING UNIT** (OR AS THE CASE MAY BE, **SYCNHRONOUS POWER GENERATING MODULE** OR **CCGT MODULE**) DATA					G1	G2	G3	G4	G5	G6	STN
Point of connection to the **National Electricity Transmission System** (or the **Total System** if embedded) of the **Generating Unit** or **Synchronous Power Generating Module** (other than a **CCGT Unit**) or the **CCGT Module**, as the case may be in terms of geographical and electrical location and system voltage *(PC.A.3.4.1)*	Text	□	■	**SPD**							
If the busbars at the **Connection Point** are normally run in separate sections identify the section to which the **Generating Unit** (other than a **CCGT Unit**) or **Synchronous Power Generating Module** or **CCGT Module**, as the case may be is connected *(PC.A.3.1.5)*	Section Number	□	■	**SPD**							

Type of **Unit** (steam, **Gas Turbine Combined Cycle Gas Turbine Unit**, tidal, wind, etc.) *(PC.A.3.2.2 (h))*		□										

SCHEDULE 1 – POWER GENERATING MODULE, GENERATING UNIT (OR CCGT MODULE), POWER PARK MODULE, DC CONNECTED POWER PARK MODULE, HVDC SYSTEM AND DC CONVERTER TECHNICAL DATA

					G1	G2	G3	G4	G5	G6	STN
INDIVIDUAL **SYNCHRONOUS POWER GENERATING MODULE GENERATING UNIT** (OR AS THE CASE MAY BE, **CCGT MODULE**) DATA											
A list of the Generating Units and **CCGT Units** within a **Synchronous Power Generating Module** or **CCGT Module**, identifying each **CCGT Unit**, and the **Power Generating Module** or **CCGT Module** of which it forms part, unambiguously. In the case of a **Range CCGT Module**, details of the possible configurations should also be submitted. *(PC.A.3.2.2 (g))*		□	■	**SPD**							

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DATA DESCRIPTION	UNITS	DATA to **RTL** CUSC Contract	DATA to **RTL** CUSC App. Form	DATA CAT.	**GENERATING UNIT** (OR CCGT MODULE, AS THE CASE MAY BE) G1	G2	G3	G4	G5	G6	STN
Rated MVA *(PC.A.3.3.1)*	MVA	□	■	**SPD+**							
Rated MW *(PC.A.3.3.1)*	MW	□	■	**SPD+**							
Rated terminal voltage *(PC.A.5.3.2.(a) & PC.A.5.4.2 (b))*	kV	□		**DPD I**							
*Performance Chart at **Onshore Synchronous Generating Unit** stator terminals *(PC.A.3.2.2(f)(i))* * Performance Chart of the **Offshore Synchronous Generating Unit** at the **Offshore Grid Entry Point** *(PC.A.3.2.2(f)(ii))* * *Synchronous Generating Unit Performance Chart (PC.A.3.2.2(f))* * *Power Generating Module Performance Chart of the Synchronous Power Generating Module (PC.A.3.2.2(f))*				**SPD**	(see **OC2** for specification)						
* Maximum terminal voltage set point*(PC.A.5.3.2.(a) & PC.A.5.4.2 (b))*	kV	□		**DPD I**							
* Terminal voltage set point step resolution – if not continuous *(PC.A.5.3.2.(a) & PC.A.5.4.2 (b))*	kV	□		**DPD I**							
***Output Usable** (on a monthly basis) *(PC.A.3.2.2(b))*	MW			**SPD**	(except in relation to **CCGT Modules** when required on a unit basis under the **Grid Code**, this data item may be supplied under Schedule 3)						
Turbo-Generator inertia constant (for synchronous machines) *(PC.A.5.3.2(a))*	MW secs /MVA	□	■	**SPD+**							
Short circuit ratio (synchronous machines) *(PC.A.5.3.2(a))*		□	■	**SPD+**							
Normal auxiliary load supplied by the **Generating Unit** at rated MW output *(PC.A.5.2.1)*	MW MVAr	□ □		**DPD II** **DPD II**							
Rated field current at rated MW and MVAr output and at rated terminal voltage *(PC.A.5.3.2 (a))*	A	□		**DPD II**							
Field current open circuit saturation curve (as derived from appropriate manufacturers' test certificates): (*PC.A.5.3.2 (a))*	A	□		**DPD II**							
120% rated terminal volts	A	□		**DPD II**							
110% rated terminal volts	A	□		**DPD II**							
100% rated terminal volts	A	□		**DPD II**							
90% rated terminal volts	A	□		**DPD II**							
80% rated terminal volts	A	□		**DPD II**							
70% rated terminal volts	A	□		**DPD II**							
60% rated terminal volts	A	□		**DPD II**							
50% rated terminal volts											
<u>IMPEDANCES</u>: (Unsaturated)											
Direct axis synchronous reactance *(PC.A.5.3.2(a))*	% on MVA	□		**DPD I**							
Direct axis transient reactance *(PC.A.3.3.1(a)& PC.A.5.3.2(a)*	% on MVA	□	■	**SPD+**							
Direct axis sub-transient reactance *(PC.A.5.3.2(a))*	% on MVA	□		**DPD I**							
Quad axis synch reactance *(PC.A.5.3.2(a))*	% on MVA	□		**DPD I**							
Quad axis sub-transient reactance *(PC.A.5.3.2(a))*	% on MVA	□		**DPD I**							
Stator leakage reactance *(PC.A.5.3.2(a))*	% on MVA	□		**DPD I**							
Armature winding direct current resistance. *(PC.A.5.3.2(a))*	% on MVA	□		**DPD I**							

In Scotland, negative sequence resistance *(PC.A.2.5.6 (a) (iv)*	% on MVA	□		**DPD I**							
Note:- the above data item relating to armature winding direct-current resistance need only be provided by **Generators** in relation to **Generating Units** or **Synchronous Generating Units** within **Power Generating Modules** commissioned after 1st March 1996 and in cases where, for whatever reason, the **Generator** is aware of the value of the data item.											

SCHEDULE 1 – POWER GENERATING MODULE, GENERATING UNIT (OR CCGT MODULE), POWER PARK MODULE DC CONNECTED POWER PARK MODULE, HVDC SYSTEM AND DC CONVERTER TECHNICAL DATA

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CAT.	**GENERATING UNIT** OR STATION DATA						
		CUSC Contract	CUSC App. Form		G1	G2	G3	G4	G5	G6	STN
<u>TIME CONSTANTS</u>											
(Short-circuit and Unsaturated)											
Direct axis transient time constant *(PC.A.5.3.2(a))*	S	□		**DPD I**							
Direct axis sub-transient time constant *(PC.A.5.3.2(a))*	S	□		**DPD I**							
Quadrature axis sub-transient time constant *(PC.A.5.3.2(a))*	S	□		**DPD I**							
Stator time constant *(PC.A.5.3.2(a))*	S	□		**DPD I**							
<u>MECHANICAL PARAMETERS</u> *(PC.A.5.3.2(a))*											
The number of turbine generator masses		□		DPD II							
Diagram showing the Inertia and parameters for each turbine generator mass for the complete drive train	Kgm^2	□		DPD II DPD II							
Diagram showing Stiffness constants and parameters between each turbine generator mass for the complete drive train	Nm/rad	□		DPD II DPD II							
Number of poles		□		DPD II							
Relative power applied to different parts of the turbine	%	□		DPD II							
Torsional mode frequencies	Hz	□		DPD II							
Modal damping decrement factors for the different mechanical modes		□		DPD II							
<u>**GENERATING UNIT** STEP-UP TRANSFORMER</u>											
Rated MVA *(PC.A.3.3.1 & PC.A.5.3.2)*	MVA	□	■	**SPD+**							
Voltage Ratio *(PC.A.5.3.2)*	-	□		**DPD I**							
Positive sequence reactance: *(PC.A.5.3.2)*											
Max tap	% on MVA	□	■	**SPD+**							
Min tap	% on MVA	□	■	**SPD+**							
Nominal tap	% on MVA	□	■	**SPD+**							
Positive sequence resistance: *(PC.A.5.3.2)*											
Max tap	% on MVA	□		**DPD II**							
Min tap	% on MVA	□		**DPD II**							
Nominal tap	% on MVA	□		**DPD II**							
Zero phase sequence reactance *(PC.A.5.3.2)*	% on MVA	□		**DPD II**							
Tap change range *(PC.A.5.3.2)*	+% / -%	□		**DPD II**							
Tap change step size *(PC.A.5.3.2)*	%	□		**DPD II**							
Tap changer type: on-load or off-circuit *(PC.A.5.3.2)*	On/Off	□		**DPD II**							

DATA DESCRIPTION	UNITS	DATA to **RTL** CUSC Contract	DATA to **RTL** CUSC App. Form	DATA CAT.	**GENERATING UNIT** OR STATION DATA G1	G2	G3	G4	G5	G6	STN
EXCITATION:											

Note: The data items requested under Option 1 below may continue to be provided by **Generators** in relation to **Generating Units** on the **System** at 9 January 1995 (in this paragraph, the "relevant date") or they may provide the new data items set out under Option 2. **Generators** must supply the data as set out under Option 2 (and not those under Option 1) for **Generating Unit** and **Synchronous Power Generating Unit** excitation control systems commissioned after the relevant date, those **Generating Unit** or **Synchronous Power Generating Unit** excitation control systems recommissioned for any reason such as refurbishment after the relevant date and **Generating Unit** or **Synchronous Power Generating Unit** excitation control systems where, as a result of testing or other process, the **Generator** is aware of the data items listed under Option 2 in relation to that **Generating Unit** or **Synchronous Power Generating Unit**.

DATA DESCRIPTION	UNITS	CUSC Contract	CUSC App. Form	DATA CAT.	G1	G2	G3	G4	G5	G6	STN
Option 1											
DC gain of **Excitation Loop** *(PC.A.5.3.2(c))*		□		**DPD II**							
Max field voltage *(PC.A.5.3.2(c))*	V	□		**DPD II**							
Min field voltage *(PC.A.5.3.2(c))*	V	□		**DPD II**							
Rated field voltage *(PC.A.5.3.2(c))*	V	□		**DPD II**							
Max rate of change of field volts: *(PC.A.5.3.2(c))*											
Rising	V/Sec	□		**DPD II**							
Falling	V/Sec	□		**DPD II**							
Details of **Excitation Loop** *(PC.A.5.3.2(c))* Described in block diagram form showing transfer functions of individual elements	Diagram	□		**DPD II**	(please attach)						
Dynamic characteristics of over- excitation limiter *(PC.A.5.3.2(c))*		□		**DPD II**							
Dynamic characteristics of under-excitation limiter *(PC.A.5.3.2(c))*		□		**DPD II**							
Option 2											
Exciter category, e.g. **Rotating Exciter**, or **Static Exciter** etc *(PC.A.5.3.2(c))*	Text	□	■	**SPD**							
Excitation System Nominal *(PC.A.5.3.2(c))* **Response** V_E	Sec^{-1}	□		**DPD II**							
Rated Field Voltage *(PC.A.5.3.2(c))* U_{fN}	V	□		**DPD II**							
No-load Field Voltage *(PC.A.5.3.2(c))* U_{fO}	V	□		**DPD II**							
Excitation System On-Load *(PC.A.5.3.2(c))* **Positive Ceiling Voltage** U_{pL+}	V	□		**DPD II**							
Excitation System No-Load *(PC.A.5.3.2(c))* **Positive Ceiling Voltage** U_{pO+}	V	□		**DPD II**							
Excitation System No-Load *(PC.A.5.3.2(c))* **Negative Ceiling Voltage** U_{pO-}	V	□		**DPD II**							
Power System Stabiliser (PSS) fitted *(PC.A.3.4.2)*	Yes/No	□	■	**SPD**							
Stator Current Limit (PC.A.5.3.2(c))	A	□		**DPD II**							
Details of **Excitation System** *(PC.A.5.3.2(c))* (including **PSS** if fitted) described in block diagram form showing transfer functions of individual elements.	Diagram	□		**DPD II**							
Details of **Over-excitation Limiter** *(PC.A.5.3.2(c))* described in block diagram form showing transfer functions of individual elements.	Diagram	□		**DPD II**							
Details of **Under-excitation Limiter** *(PC.A.5.3.2(c))* described in block diagram form showing	Diagram	□		**DPD II**							

transfer functions of individual elements.											

DATA DESCRIPTION	UNITS	DATA to **RTL** CUSC Contract	CUSC App. Form	DATA CAT.	**GENERATING UNIT** OR STATION DATA G1	G2	G3	G4	G5	G6	STN
GOVERNOR AND ASSOCIATED PRIME MOVER PARAMETERS											

Note: The data items requested under Option 1 below may continue to be provided by **Generators** in relation to **Generating Units** on the **System** at 9 January 1995 (in this paragraph, the "relevant date") or they may provide the new data items set out under Option 2. **Generators** must supply the data as set out under Option 2 (and not those under Option 1) for **Generating Unit** and **Synchronous Power Generating Unit** governor control systems commissioned after the relevant date, those **Generating Unit** and **Synchronous Power Generating Unit** governor control systems recommissioned for any reason such as refurbishment after the relevant date and **Generating Unit** and **Synchronous Power Generating Unit** governor control systems where, as a result of testing or other process, the **Generator** is aware of the data items listed under Option 2 in relation to that **Generating Unit** and **Synchronous Power Generating Unit**.

DATA DESCRIPTION	UNITS	CUSC Contract	CUSC App. Form	DATA CAT.	G1	G2	G3	G4	G5	G6	STN
Option 1											
GOVERNOR PARAMETERS (REHEAT UNITS) *(PC.A.5.3.2(d) – Option 1(i))*											
HP Governor average gain	MW/Hz	□		**DPD II**							
Speeder motor setting range	Hz	□		**DPD II**							
HP governor valve time constant	S	□		**DPD II**							
HP governor valve opening limits		□		**DPD II**							
HP governor valve rate limits		□		**DPD II**							
Re-heat time constant (stored **Active Energy** in reheater)	S	□		**DPD II**							
IP governor average gain	MW/Hz	□		**DPD II**							
IP governor setting range	Hz	□		**DPD II**							
IP governor time constant	S	□		**DPD II**							
IP governor valve opening limits		□		**DPD II**							
IP governor valve rate limits		□		**DPD II**							
Details of acceleration sensitive elements HP & IP in governor loop		□		**DPD II**	(please attach)						
Governor block diagram showing transfer functions of individual elements		□		**DPD II**	(please attach)						
GOVERNOR (Non-reheat steam and Gas Turbines) *(PC.A.5.3.2(d) – Option 1(ii))*											
Governor average gain	MW/Hz	□		**DPD II**							
Speeder motor setting range		□		**DPD II**							
Time constant of steam or fuel governor valve	S	□		**DPD II**							
Governor valve opening limits		□		**DPD II**							
Governor valve rate limits		□		**DPD II**							
Time constant of turbine	S	□		**DPD II**							
Governor block diagram		□		**DPD II**	(please attach)						

DATA DESCRIPTION	UNITS	DATA to **RTL** CUSC Contract	CUSC App. Form	DATA CAT.	**GENERATING UNIT** OR STATION DATA G1	G2	G3	G4	G5	G6	STN
(PC.A.5.3.2(d) – Option 1(iii)) BOILER & STEAM TURBINE DATA*											
Boiler time constant (Stored **Active Energy**)	S			**DPD II**							
HP turbine response ratio: (Proportion of **Primary Response** arising from HP turbine)	%			**DPD II**							
HP turbine response ratio: (Proportion of **High Frequency Response** arising from HP turbine)	%			**DPD II**							
End of Option 1											
Option 2											
All **Generating Units** and **Synchronous Power Generating Units**											
Governor Block Diagram showing transfer function of individual elements including acceleration sensitive elements		□		**DPD II**							
Governor Time Constant *(PC.A.5.3.2(d) – Option 2(i))*	Sec	□		**DPD II**							
#Governor Deadband *(PC.A.5.3.2(d) – Option 2(i))*											
- Maximum Setting	±Hz			**DPD II**							
- Normal Setting	±Hz			**DPD II**							
- Minimum Setting	±Hz			**DPD II**							
Speeder Motor Setting Range *(PC.A.5.3.2(d) – Option 2(i))*	%	□		**DPD II**							
Average Gain *(PC.A.5.3.2(d) – Option 2(i))*	MW/Hz	□		**DPD II**							
Steam Units *(PC.A.5.3.2(d) – Option 2(ii))*											
HP Valve Time Constant	sec	□		**DPD II**							
HP Valve Opening Limits	%	□		**DPD II**							
HP Valve Opening Rate Limits	%/sec	□		**DPD II**							
HP Valve Closing Rate Limits	%/sec	□		**DPD II**							
HP Turbine Time Constant *(PC.A.5.3.2(d) – Option 2(ii))*	sec	□		**DPD II**							
IP Valve Time Constant	sec	□		**DPD II**							
IP Valve Opening Limits	%	□		**DPD II**							
IP Valve Opening Rate Limits	%/sec	□		**DPD II**							
IP Valve Closing Rate Limits	%/sec	□		**DPD II**							
IP Turbine Time Constant *(PC.A.5.3.2(d) – Option 2(ii))*	sec	□		**DPD II**							
LP Valve Time Constant	sec	□		**DPD II**							
LP Valve Opening Limits	%	□		**DPD II**							
LP Valve Opening Rate Limits	%/sec	□		**DPD II**							
LP Valve Closing Rate Limits	%/sec	□		**DPD II**							
LP Turbine Time Constant *(PC.A.5.3.2(d) – Option 2(ii))*	sec	□		**DPD II**							
Reheater Time Constant	sec			**DPD II**							
Boiler Time Constant	sec			**DPD II**							
HP Power Fraction	%			**DPD II**							
IP Power Fraction	%			**DPD II**							

\# Where the generating unit or synchronous power generating unit governor does not have a selectable deadband facility, then the actual value of the deadband need only be provided.

DATA DESCRIPTION	UNITS	DATA to **RTL** CUSC Contract	CUSC App. Form	DATA CAT.	**GENERATING UNIT** OR STATION DATA G1	G2	G3	G4	G5	G6	STN
<u>Gas Turbine Units</u>											
(PC.A.5.3.2(d) – Option 2(iii))											
Inlet Guide Vane Time Constant	sec	□		**DPD II**							
Inlet Guide Vane Opening Limits	%	□		**DPD II**							
Inlet Guide Vane Opening Rate Limits	%/sec	□		**DPD II**							
Inlet Guide Vane Closing Rate Limits	%/sec	□		**DPD II**							
(PC.A.5.3.2(d) – Option 2(iii))											
Fuel Valve Time Constant	sec	□		**DPD II**							
Fuel Valve Opening Limits	%	□		**DPD II**							
Fuel Valve Opening Rate Limits	%/sec	□		**DPD II**							
Fuel Valve Closing Rate Limits	%/sec	□		**DPD II**							
(PC.A.5.3.2(d) – Option 2(iii))											
Waste Heat Recovery Boiler Time Constant											
<u>Hydro **Generating Units**</u>											
(PC.A.5.3.2(d) – Option 2(iv))											
Guide Vane Actuator Time Constant	sec	□		**DPD II**							
Guide Vane Opening Limits	%	□		**DPD II**							
Guide Vane Opening Rate Limits	%/sec	□		**DPD II**							
Guide Vane Closing Rate Limits	%/sec	□		**DPD II**							
Water Time Constant	sec	□		**DPD II**							
		End of Option 2									
<u>UNIT CONTROL OPTIONS</u>*											
(PC.A.5.3.2(e)											
Maximum droop	%			**DPD II**							
Normal droop	%	□		**DPD II**							
Minimum droop	%			**DPD II**							
Maximum frequency deadband	±Hz			**DPD II**							
Normal frequency deadband	±Hz			**DPD II**							
Minimum frequency deadband	±Hz			**DPD II**							
Maximum frequency Insensitivity1Normal	±Hz			**DPDII**							
frequency Insensitivity1	±Hz			**DPDII**							
Minimum frequency Insensitivity1	±Hz			**DPDII**							
Maximum Output deadband	±MW			**DPD II**							
Normal Output deadband	±MW			**DPD II**							
Minimum Output deadband	±MW			**DPD II**							
Maximum Output Insensitivity1	±Hz			**DPDII**							
Normal Output Insensitivity1	±Hz			**DPDII**							
Minimum Output Insensitivity1	±Hz			**DPDII**							
Frequency settings between which Unit Load Controller droop applies:											
Maximum	Hz			**DPD II**							
Normal	Hz			**DPD II**							
Minimum	Hz			**DPD II**							
Sustained response normally selected	Yes/No			**DPD II**							
1 Data required only in respect of Power Generating Modules											

SCHEDULE 1 – POWER GENERATING MODULE, GENERATING UNIT (OR CCGT MODULE), POWER PARK MODULE, DC CONNECTED POWER PARK MODULE, HVDC SYSTEM AND DC CONVERTER TECHNICAL DATA

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DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CAT.	**POWER PARK UNIT** (OR **POWER PARK MODULE**, AS THE CASE MAY BE)						
		CUSC Contract	CUSC App. Form		G1	G2	G3	G4	G5	G6	STN
Power Park Module Rated MVA *(PC.A.3.3.1(a))*	MVA	□	■	**SPD+**							
Power Park Module Rated MW *(PC.A.3.3.1(a))*	MW	□	■	**SPD+**							
*Performance Chart of a **Power Park Module** at the connection point *(PC.A.3.2.2(f)(ii))*				**SPD**	(see **OC2** for specification)						
***Output Usable** (on a monthly basis) *(PC.A.3.2.2(b))*	MW			**SPD**	(except in relation to **CCGT Modules** when required on a unit basis under the **Grid Code**, this data item may be supplied under Schedule 3)						
Number & Type of **Power Park Units** within each **Power Park Module** *(PC.A.3.2.2(k))*		□		**SPD**							
Number & Type of **Offshore Power Park Units** within each **Offshore Power Park String** and the number of **Offshore Power Park Strings** and connection point within each **Offshore Power Park Module** *(PC.A.3.2.2.(k))*				**SPD**							
In the case where an appropriate **Manufacturer's Data & Performance Report** is registered with **The Company** then subject to **The Company's** agreement, the report reference may be given as an alternative to completion of the following sections of this Schedule 1 to the end of page 11 with the exception of the sections marked thus # below.	Reference the **Manufacturer's Data & Performance Report**			**SPD**							
Power Park Unit Model - A validated mathematical model in accordance with PC.5.4.2 (a)	Transfer function block diagram and algebraic equations, simulation and measured test results	□		**DPD II**							

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CAT.	**POWER PARK UNIT** (OR **POWER PARK MODULE**, AS THE CASE MAY BE)						
		CUSC Contract	CUSC App. Form		G1	G2	G3	G4	G5	G6	STN
Power Park Unit Data (where applicable)											
Rated MVA *(PC.A.3.3.1(e))*	MVA	□	■	**SPD+**							
Rated MW *(PC.A.3.3.1(e))*	MW	□	■	**SPD+**							
Rated terminal voltage *(PC.A.3.3.1(e))*	V	□	■	**SPD+**							
Site minimum air density *(PC.A.5.4.2(b))*	kg/m^3	□	■	**DPD II**							
Site maximum air density	kg/m^3	□	■	**DPD II**							
Site average air density	kg/m^3	□	■	**DPD II**							
Year for which air density data is submitted		□	■	**DPD II**							
Number of pole pairs		□		**DPD II**							
Blade swept area	m^2	□		**DPD II**							
Gear Box Ratio		□		**DPD II**							
Stator Resistance *(PC.A.5.4.2(b))*	% on MVA	□	■	**SPD+**							
Stator Reactance *(PC.A.3.3.1(e))*	% on MVA	□	■	**SPD+**							
Magnetising Reactance *(PC.A.3.3.1(e))*	% on MVA	□	■	**SPD+**							
Rotor Resistance (at starting). *(PC.A.5.4.2(b))*	% on MVA	□		**DPD II**							
Rotor Resistance (at rated running) *(PC.A.3.3.1(e))*	% on MVA	□	■	**SPD+**							
Rotor Reactance (at starting). *(PC.A.5.4.2(b))*	% on MVA	□		**DPD II**							
Rotor Reactance (at rated running) *(PC.A.3.3.1(e))*	% on MVA	□	■	**SPD**							
Equivalent inertia constant of the first mass (e.g. wind turbine rotor and blades) at minimum speed *(PC.A.5.4.2(b))*	MW secs /MVA	□	■	**SPD+**							
Equivalent inertia constant of the first mass (e.g. wind turbine rotor and blades) at synchronous speed *(PC.A.5.4.2(b))*	MW secs /MVA	□	■	**SPD+**							
Equivalent inertia constant of the first mass (e.g. wind turbine rotor and blades) at rated speed *(PC.A.5.4.2(b))*	MW secs /MVA	□	■	**SPD+**							
Equivalent inertia constant of the second mass (e.g. generator rotor) at minimum speed *(PC.A.5.4.2(b))*	MW secs /MVA	□	■	**SPD+**							
Equivalent inertia constant of the second mass (e.g. generator rotor) at synchronous speed *(PC.A.5.4.2(b))*	MW secs /MVA	□	■	**SPD+**							
Equivalent inertia constant of the second mass (e.g. generator rotor) at rated speed *(PC.A.5.4.2(b))*	MW secs /MVA	□	■	**SPD+**							
Equivalent shaft stiffness between the two masses *(PC.A.5.4.2(b))*	Nm / electrical radian	□	■	**SPD+**							

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CAT.	**POWER PARK UNIT** (OR **POWER PARK MODULE**, AS THE CASE MAY BE)						
		CUSC Contract	CUSC App. Form		G1	G2	G3	G4	G5	G6	STN
Minimum generator rotor speed (Doubly Fed Induction Generators) *(PC.A.3.3.1(e))*	RPM	□	■	**SPD+**							
Maximum generator rotor speed (Doubly Fed Induction Generators) *(PC.A.3.3.1(e))*	RPM	□	■	**SPD+**							
The optimum generator rotor speed versus wind speed *(PC.A.5.4.2(b))*	tabular format	□		**DPD II**							
Power Converter Rating (Doubly Fed Induction Generators) *(PC.A.5.4.2(b))*	MVA	□	■	**DPD II**							
The rotor power coefficient (C_p) versus tip speed ratio (λ) curves for a range of blade angles (where applicable) *(PC.A.5.4.2(b))*	Diagram + tabular format	□		**DPD II**							
# The electrical power output versus generator rotor speed for a range of wind speeds over the entire operating range of the **Power Park Unit**. *(PC.A.5.4.2(b))*	Diagram + tabular format	□		**DPD II**							
The blade angle versus wind speed curve *(PC.A.5.4.2(b))*	Diagram + tabular format	□		**DPD II**							
The electrical power output versus wind speed over the entire operating range of **the Power Park Unit**. *(PC.A.5.4.2(b))*	Diagram + tabular format	□		**DPD II**							
Transfer function block diagram, parameters and description of the operation of the power electronic converter including fault ride though capability (where applicable). *(PC.A.5.4.2(b))*	Diagram	□		**DPD II**							
For a **Power Park Unit** consisting of a synchronous machine in combination with a back to back **DC Converter** or **HVDC Converter**, or for a **Power Park Unit** not driven by a wind turbine, the data to be supplied shall be agreed with **The Company** in accordance with PC.A.7. *(PC.A.5.4.2(b))*		□									

SCHEDULE 1 – POWER GENERATING MODULE, GENERATING UNIT (OR CCGT MODULE), POWER PARK MODULE, DC CONNECTED POWER PARK MODULE, HVDC SYSTEM AND DC CONVERTER TECHNICAL DATA

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CAT.	**POWER PARK UNIT** (OR **POWER PARK MODULE**, AS THE CASE MAY BE)						
		CUSC Contract	CUSC App. Form		G1	G2	G3	G4	G5	G6	STN
Torque / Speed and blade angle control systems and parameters *(PC.A.5.4.2(c))* For the **Power Park Unit**, details of the torque / speed controller and blade angle controller in the case of a wind turbine and power limitation functions (where applicable) described in block diagram form showing transfer functions and parameters of individual elements	Diagram	□		**DPD II**							
# Voltage/**Reactive Power**/**Power Factor** control system parameters *(PC.A.5.4.2(d))* # For the **Power Park Unit** and **Power Park Module** details of **Voltage/Reactive Power**/**Power Factor** controller (and **PSS** if fitted) described in block diagram form including parameters showing transfer functions of individual elements.	Diagram	□		**DPD II**							
# Frequency control system parameters *(PC.A.5.4.2(e))* # For the **Power Park Unit** and **Power Park Module** details of the **Frequency** controller described in block diagram form showing transfer functions and parameters of individual elements.	Diagram	□		**DPD II**							
As an alternative to PC.A.5.4.2 (a), (b), (c), (d), (e) and (f), is the submission of a single complete model that consists of the full information required under PC.A.5.4.2 (a), (b), (c), (d) (e) and (f) provided that all the information required under PC.A.5.4.2 (a), b), (c), (d), (e) and (f) individually is clearly identifiable. *(PC.A.5.4.2(g))*	Diagram	□		**DPD II**							
# Harmonic Assessment Information *(PC.A.5.4.2(h))* (as defined in IEC 61400-21 (2001)) for each **Power Park Unit**:-											
# Flicker coefficient for continuous operation		□		**DPD I**							
# Flicker step factor		□		**DPD I**							
# Number of switching operations in a 10 minute window		□		**DPD I**							
# Number of switching operations in a 2 hour window		□		**DPD I**							
# Voltage change factor		□		**DPD I**							
# Current Injection at each harmonic for each **Power Park Unit** and for each **Power Park Module**	Tabular format	□		**DPD I**							

Note:- **Generators** who own or operate **DC Connected Power Park Modules** shall supply all data for their **DC Connected Power Park Modules** as applicable to **Power Park Modules**.

<u>HVDC SYSTEM AND DC CONVERTER STATION TECHNICAL DATA</u>

HVDC SYSTEM OR DC CONVERTER STATION NAME DATE:___________

Data Description	Units	DATA to **RTL**		Data Category	**DC Converter Station** Data
(PC.A.4)		CUSC Contract	CUSC App. Form		
HVDC SYSTEM AND **DC CONVERTER STATION** DEMANDS:					
Demand supplied through **Station Transformers** associated with the **DC Converter Station** and **HVDC System** **[PC.A.4.1]**	MW MVAr	□ □		**DPD II** **DPD II**	
- **Demand** with all **DC Converters** and **HVDC Converters** within and HVDc System operating at **Rated MW** import.	MW MVAr	□ □		**DPD II** **DPD II**	
- **Demand** with all **DC Converters** and **HVDC Converters** within an HVDC System operating at **Rated MW** export.					
Additional **Demand** associated with the **DC Converter Station or HVDC System** supplied through the **National Electricity Transmission System**. **[PC.A.4.1]**	MW MVAr	□ □		**DPD II** **DPD II**	
- The maximum **Demand** that could occur.	MW MVAr	□ □		**DPD II** **DPD II**	
- **Demand** at specified time of annual peak half hour of **The Company Demand** at **Annual ACS Conditions**.	MW MVAr	□ □		**DPD II** **DPD II**	
- **Demand** at specified time of annual minimum half-hour of **The Company Demand**.	Text	□	■	**SPD+**	
DC CONVERTER STATION AND **HVDC SYSTEM** DATA	Text	□	■	**SPD+**	
		□		**SPD+**	
Number of poles, i.e. number of **DC Converters** or **HVDC Converters** within the **HVDC System**		□ □ □ □	■ ■ ■ ■		
Pole arrangement (e.g. monopole or bipole)		□	■ ■		
Details of each viable operating configuration	Diagram	□	■	**SPD**	
Configuration 1	Diagram				
Configuration 2	Diagram				
Configuration 3	Diagram				

Configuration 4 Configuration 5 Configuration 6 Remote ac connection arrangement	Diagram Diagram Diagram				

Data Description	Units	DATA to **RTL**		Data Category	Operating Configuration					
		CUSC Contract	CUSC App. Form		1	2	3	4	5	6
DC CONVERTER STATION AND HVDC SYSTEM DATA *(PC.A.3.3.1d)*										
DC Converter or **HVDC Converter** Type (e.g. current or Voltage source)	Text	□	■	**SPD**						
Point of connection to the **National Electricity Transmission System** (or the **Total System** if **Embedded**) of the **DC Converter Station** or **HVDC System** configuration in terms of geographical and electrical location and system voltage	Text	□	■	**SPD**						
If the busbars at the **Connection Point** are normally run in separate sections identify the section to which the **DC Converter Station** or **HVDC System** configuration is connected	Section Number	□	■	**SPD**						
Rated MW import per pole **[PC.A.3.3.1]**	MW	□	■	**SPD +**						
Rated MW export per pole **[PC.A.3.3.1]**	MW		■	**SPD +**						
ACTIVE POWER TRANSFER CAPABILITY (PC.A.3.2.2)										
Registered Capacity	MW	□	■	**SPD**						
Registered Import Capacity	MW	□	■							
Minimum Generation	MW	□	■	**SPD**						
Minimum Import Capacity	MW	□	■							
Maximum HVDC Active Power Transmission Capacity	MW	□		**SPD**						
Minimum Active Power Transmission Capacity	MW	□		**SPD**						
Import MW available in excess of **Registered Import Capacity** and **Maximum Active Power Transmission Capacity**	MW	□ □		**SPD**						
Time duration for which MW in excess of **Registered Import Capacity** is available	Min	□		**SPD**						
Export MW available in excess of **Registered Capacity** and **Maximum Active Power Transmission Capacity**.	MW	□		**SPD**						
Time duration for which MW in excess of **Registered Capacity** is available	Min	□		**SPD**						

SCHEDULE 1 –POWER GENERATING MODULE, GENERATING UNIT (OR CCGT MODULE), POWER PARK MODULE, DC CONNECTED POWER PARK MODULE, HVDC SYSTEM AND DC CONVERTER TECHNICAL DATA

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Data Description	Units	DATA to **RTL**		Data Category	Operating Configuration					
		CUSC Contract	CUSC App. Form		1	2	3	4	5	6
DC CONVERTER AND **HVDC CONVERTER**										
TRANSFORMER **[PC.A.5.4.3.1**				**DPD II**						
	MVA	□								
Rated MVA				**DPD II**						
Winding arrangement	kV	□		**DPD II**						
Nominal primary voltage	kV	□								
Nominal secondary (converter-side) voltage(s)		□		**DPD II**						
Positive sequence reactance	% on	□		**DPD II**						
Maximum tap	MVA	□		**DPD II**						
Nominal tap	% on									
Minimum tap	MVA			**DPD II**						
Positive sequence resistance	% on	□		**DPD II**						
Maximum tap	MVA	□		**DPD II**						
Nominal tap		□		**DPD II**						
Minimum tap	% on	□		**DPD II**						
Zero phase sequence reactance	MVA	□		**DPD II**						
Tap change range	% on	□								
Number of steps	MVA									
	% on									
	MVA									
	% on									
	MVA									
	+% / -%									

Data Description	Units	DATA to **RTL**		Data Category	Operating configuration					
		CUSC Contract	CUSC App. Form		1	2	3	4	5	6
DC NETWORK [PC.A.5.4.3.1 (c)]										
Rated DC voltage per pole	kV	□		**DPD II**						
Rated DC current per pole	A	□		**DPD II**						
Details of the **DC Network** described in diagram form including resistance, inductance and capacitance of all DC cables and/or DC lines. Details of any line reactors (including line reactor resistance), line capacitors, DC filters, earthing electrodes and other conductors that form part of the **DC Network** should be shown.	Diagram	□		**DPD II**						
DC CONVERTER STATION AND **HVDC SYSTEM** AC HARMONIC FILTER AND REACTIVE COMPENSATION EQUIPMENT **[PC.A.5.4.3.1 (d)]**										
For all switched reactive compensation equipment	Diagram	□	■	**DPD II**						
Total number of AC filter banks	Text	□	■	**DPD II**						
Diagram of filter connections	Diagram	□	■	**DPD II**						
Type of equipment (e.g. fixed or variable)	Text	□	■	**DPD II**						
Capacitive rating; or	MVAr	□		**DPD II**						
Inductive rating; or	MVAr	□		**DPD II**						
Operating range	MVAr	□		**DPD II**						
Reactive Power capability as a function of various MW transfer levels	Table	□		**DPD II**						

Data Description	Units	DATA to **RTL**		Data Category	Operating configuration					
		CUSC Contract	CUSC App. Form		1	2	3	4	5	6

Data Description	Units	DATA to **RTL**		Data Category	Operating configuration					
		CUSC Contract	CUSC App. Form		1	2	3	4	5	6
CONTROL SYSTEMS **[PC.A.5.4.3.2]**										
Static V_{DC} – P_{DC} (DC voltage – DC power) or Static V_{DC} – I_{DC} (DC voltage – DC current) characteristic (as appropriate) when operating as										
–Rectifier	Diagram	□		**DPD II**						
–Inverter	Diagram	□		**DPD II**						
Details of rectifier mode control system, in block diagram form together with parameters showing transfer functions of individual elements.	Diagram	□		**DPD II**						
Details of inverter mode control system, in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Details of converter transformer tap changer control system in block diagram form showing transfer functions of individual elements including parameters. (Only required for **DC Converters** and **HVDC Systems** connected to the **National Electricity Transmission System**.)	Diagram	□		**DPD II**						
Details of AC filter and reactive compensation equipment control systems in block diagram form showing transfer functions of individual elements including parameters. (Only required for **DC Converters** and **HVDC Systems** connected to the **National Electricity Transmission System**.)	Diagram	□		**DPD II**						
Details of any frequency and/or load control systems in block diagram form showing transfer functions of individual elements including parameters.										
Details of any large or small signal modulating controls, such as power oscillation damping controls or sub-synchronous oscillation damping controls, that have not been submitted as part of the above control system data.	Diagram	□		**DPD II**						
Details of **HVDC Converter** unit models and/or control systems in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Details of AC component models and/or control systems in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Details of DC Grid models and/or control systems in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Details of Voltage and power controller and/or control systems in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Details of Special control features if applicable (eg power oscillation damping (POD) function, subsynchronous torsional interaction (SSTI) control and/or control systems in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Details of Multi terminal control, if applicable and/or control systems in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Details of **HVDC System** protection models as agreed between **The Company** the **HVDC System Owner** and/or control systems in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Transfer block diagram representation of the reactive power control at converter ends for a voltage source converter	Diagram	□		**DPD II**						
Transfer block diagram representation of the reactive power control at converter ends for a voltage source converter.										

Data Description	Units	DATA to **RTL** CUSC Contract	DATA to **RTL** CUSC App. Form	Data Category	Operating configuration 1	2	3	4	5	6
LOADING PARAMETERS **[PC.A.5.4.3.3]**										
MW Export										
Nominal loading rate	MW/s			**DPD I**						
Maximum (emergency) loading rate	MW/s			**DPD I**						
MW Import				**DPD I**						
Nominal loading rate	MW/s			**DPD I**						
Maximum (emergency) loading rate	MW/s									
Maximum recovery time, to 90% of pre-fault loading, following an AC system fault or severe voltage depression.	s	□		**DPD II**						
Maximum recovery time, to 90% of pre-fault loading, following a transient DC Network fault.	s	□		**DPD II**						

NOTE: **Users** are referred to Schedules 5 & 14 which set down data required for all **Users** directly connected to the **National Electricity Transmission System**, including **Power Stations**. **Generators** undertaking **OTSDUW Arrangements** and are utilising an **OTSDUW DC Converter** are referred to Schedule 18.

SCHEDULE 2 - GENERATION PLANNING PARAMETERS
PAGE 1 OF 3

This schedule contains the **Genset Generation Planning Parameters** required by **The Company** to facilitate studies in **Operational Planning** timescales.

For a **Generating Unit** including those within a **Power Generating Module** (other than a **Power Park Unit**) at a **Large Power Station** the information is to be submitted on a unit basis and for a **CCGT Module** or **Power Park Module** at a **Large Power Station** the information is to be submitted on a module basis, unless otherwise stated.

Where references to **CCGT Modules** or **Power Park Modules** at a **Large Power Station** are made, the columns "G1" etc should be amended to read "M1" etc, as appropriate.

Power Station: ________________________

<u>Generation Planning Parameters</u>

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CAT.	**GENSET** OR STATION DATA						
		CUSC Contract	CUSC App. Form		G1	G2	G3	G4	G5	G6	STN
<u>OUTPUT CAPABILITY</u> *(PC.A.3.2.2)*											
Registered Capacity on a station and unit basis (on a station and module basis in the case of a **CCGT Module** or **Power Park Module** at a **Large Power Station**) **Maximum Capacity** on a **Power Generating Module basis** and **Synchronous Generating Unit** basis and **Registered Capacity** on a **Power Station** basis**)**	MW	□	■	**SPD**							
Minimum Generation (on a module basis in the case of a **CCGT Module** or **Power Park Module** at a **Large Power Station**) **Minimum Stable Operating Level** (on a module basis in the case of a **Power Generating Module** at a **Large Power Station**	MW	□	■	**SPD**							
MW available from **Power Generating Modules** and **Generating Units** or **Power Park Modules** in excess of **Registered Capacity** or **Maximum Capacity**	MW	□	■	**SPD**							
<u>REGIME UNAVAILABILITY</u>											
These data blocks are provided to allow fixed periods of unavailability to be registered.											
<u>Expected Running Regime</u>. Is **Power Station** normally available for full output 24 hours per day, 7 days per week? If No please provide details of unavailability below. *(PC.A.3.2.2.)*		□	■	**SPD**							
Earliest **Synchronising** time: *OC2.4.2.1(a)*											
Monday	hr/min	■		**OC2**							-
Tuesday – Friday	hr/min	■		**OC2**							-
Saturday – Sunday	hr/min	■		**OC2**							-
Latest **De-Synchronising** time: *OC2.4.2.1(a)*											
Monday – Thursday	hr/min	■		**OC2**							-
Friday	hr/min	■		**OC2**							-
Saturday – Sunday	hr/min	■		**OC2**							-
<u>SYNCHRONISING PARAMETERS</u> *OC2.4.2.1(a)*											

Notice to Deviate from Zero (NDZ) after 48 hour **Shutdown**	Mins	■		**OC2**							
Station **Synchronising** Intervals (SI) after 48 hour **Shutdown**	Mins	■			-	-	-	-	-	-	
Synchronising Group (if applicable)	1 to 4	■		**OC2**							-

SCHEDULE 2 - GENERATION PLANNING PARAMETERS
PAGE 2 OF 3

DATA DESCRIPTION	UNITS	DATA to **RTL** CUSC Contract	DATA to **RTL** CUSC App. Form	DATA CAT.	**GENSET** OR STATION DATA G1	G2	G3	G4	G5	G6	STN
Synchronising Generation (SYG) after 48 hour **Shutdown** *PC.A.5.3.2(f) & OC2.4.2.1(a)*	MW	■		**DPD II & OC2**							-
De-Synchronising Intervals (Single value) *OC2.4.2.1(a)*	Mins	■		**OC2**	-	-	-	-	-	-	
<u>RUNNING AND **SHUTDOWN** PERIOD LIMITATIONS</u>:											
Minimum Non Zero time (MNZT) after 48 hour **Shutdown** *OC2.4.2.1(a)*	Mins	■		**OC2**							
Minimum Zero time (MZT) *OC2.4.2.1(a)*	Mins			**OC2**							
Existing AGR Plant Flexibility Limit (**Existing AGR Plant** only)	No.			**OC2**							
80% Reactor Thermal Power (expressed as Gross-Net MW) (**Existing AGR Plant** only)	MW			**OC2**							
Frequency Sensitive AGR Unit Limit (**Frequency Sensitive AGR Units** only)	No.			**OC2**							
<u>RUN-UP PARAMETERS</u> *PC.A.5.3.2(f) & OC2.4.2.1(a)*											
<u>Run-up rates</u> (RUR) after 48 hour **Shutdown**: (See note 2 page 3)	(Note that for DPD only a single value of run-up rate from Synch Gen to Registered Capacity is required)										
MW Level 1 (MWL1)	MW	■		**OC2**							-
MW Level 2 (MWL2)	MW	■		**OC2**							-
RUR from Synch. Gen to MWL1	MW/Mins	■		**DPD II & OC2**							
RUR from MWL1 to MWL2	MW/Mins	■		**OC2**							
RUR from MWL2 to RC	MW/Mins	■		**OC2**							
<u>Run-Down Rates</u> (RDR):	(Note that for DPD only a single value of run-down rate from Registered Capacity to de-synch is required)										
MWL2	MW	■		**OC2**							
RDR from RC to MWL2	MW/Min	■		**DPD II OC2**							
MWL1	MW	■		**OC2**							
RDR from MWL2 to MWL1	MW/Min	■		**OC2**							
RDR from MWL1 to de-synch	MW/Min	■		**OC2**							

SCHEDULE 2 - GENERATION PLANNING PARAMETERS

PAGE 3 OF 3

DATA DESCRIPTION	UNITS	DATA to **RTL** CUSC Contract	CUSC App. Form	DATA CAT.	G1	G2	G3	G4	G5	G6	STN
REGULATION PARAMETERS *OC2.4.2.1(a)*											
Regulating Range	MW	■		**DPD II**							
Load rejection capability while still **Synchronised** and able to supply **Load**.	MW	■		**DPD II**							
GAS TURBINE LOADING PARAMETERS: *OC2.4.2.1(a)*											
Fast loading	MW/Min	■		**OC2**							
Slow loading	MW/Min	■		**OC2**							
CCGT MODULE PLANNING MATRIX				**OC2**	(please attach)						
POWER PARK MODULE PLANNING MATRIX				**OC2**	(please attach)						
Power Park Module Active Power Output/ Intermittent Power Source Curve (eg MW output / Wind speed)				**OC2**	(please attach)						

NOTES:

(1) To allow for different groups of **Gensets** within a **Power Station** (eg. **Gensets** with the same operator) each **Genset** may be allocated to one of up to four **Synchronising Groups**. Within each such **Synchronising Group** the single synchronising interval will apply but between **Synchronising Groups** a zero synchronising interval will be assumed.

(2) The run-up of a **Genset** from synchronising block load to **Registered Capacity** or **Maximum Capacity** is represented as a three stage characteristic in which the run-up rate changes at two intermediate loads, MWL1 and MWL2. The values MWL1 & MWL2 can be different for each **Genset**.

SCHEDULE 3 - LARGE POWER STATION OUTAGE PROGRAMMES, OUTPUT USABLE AND INFLEXIBILITY INFORMATION

PAGE 1 OF 3

(Also outline information on contracts involving **External Interconnections**)

For a **Generating Unit** at a **Large Power Station** the information is to be submitted on a unit basis and for a **CCGT Module** or **Power Park Module** at a **Large Power Station** the information is to be submitted on a module basis, unless otherwise stated.

DATA DESCRIPTION		UNITS	TIME COVERED	UPDATE TIME	DATA CAT.	DATA to **RTL**	
Power Station name:.......................... **Generating Unit** (or **CCGT Module** or **Power Park Module** at a **Large Power Station**) number:... **Registered Capacity**:.........................							
Large Power Station OUTAGE PROGRAMME	**Large Power Station OUTPUT USABLE**						
PLANNING FOR YEARS 3 - 7 AHEAD *(OC2.4.1.2.1(a)(i), (e) & (j))*						CUSC Contract	CUSC App. Form
	Monthly average OU	MW	F. yrs 5 - 7	Week 24	**SPD**		
Provisional outage programme comprising:			C. yrs 3 - 5	Week 2	**OC2**		
duration		weeks	"	"	"	■	
preferred start		date	"	"	"	■	
earliest start		date	"	"	"	■	
latest finish		date	"	"	"	■	
	Weekly OU	MW	"	"	"	■	
(**The Company** response as detailed in **OC2**			C. yrs 3 - 5	Week12)		■	
(**Users**' response to **The Company** suggested changes or potential outages)			C. yrs 3 - 5	Week14)		■	
Updated provisional outage programme comprising:			C. yrs 3 - 5	Week 25	**OC2**		
duration		weeks	"	"	"	■	
preferred start		date	"	"	"	■	
earliest start		date	"	"	"	■	
latest finish		date	"	"	"	■	
	Updated weekly OU	MW	"	"	"	■	
(**The Company** response as detailed in **OC2** for			C. yrs 3 - 5	Week28)			
(**Users**' response to **The Company** suggested changes or update of potential outages)			C. yrs 3 - 5	Week31)		■	
(**The Company** further suggested revisions etc. (as detailed in **OC2** for			C. yrs 3 - 5	) Week42)		■	
Agreement of final **Generation Outage Programme**			C. yrs 3 - 5	Week 45	**OC2**	■	
PLANNING FOR YEARS 1 - 2 AHEAD *(OC2.4.1.2.2(a) & OC2.4.1.2.2(i))*							
Update of previously agreed **Final Generation Outage Programme**			C. yrs 1 - 2	Week 10	**OC2**		
	Weekly OU	MW	"	"		■	

SCHEDULE 3 - LARGE POWER STATION OUTAGE PROGRAMMES, OUTPUT USABLE AND INFLEXIBILITY INFORMATION

PAGE 2 OF 3

DATA DESCRIPTION		UNITS	TIME COVERED	UPDATE TIME	DATA CAT	DATA to RTL CUSC Contract	DATA to RTL CUSC App. Form
(**The Company** response as detailed in **OC2** for			C. yrs 1 – 2	Week 12)		■	
(**Users**' response to **The Company** suggested changes or update of potential outages)			C. yrs 1 – 2	Week 14)		■	
	Revised weekly OU		C. yrs 1 – 2	Week 34	OC2	■	
(**The Company** response as detailed in **OC2** for			C. yrs 1 – 2	Week 39)		■	
(**Users**' response to **The Company** suggested changes or update of potential outages)			C. yrs 1 – 2	Week 46)		■	
Agreement of final **Generation Outage Programme**			C. yrs 1 – 2	Week 48	**OC2**	■	
PLANNING FOR YEAR 0							
Updated Final **Generation Outage Programme**			C. yr 0 Week 2 ahead to year end	1600 Weds.	**OC2**		
	OU at weekly peak	MW	"	"	"		
(**The Company** response as detailed in **OC2** for ((			C. yrs 0 Weeks 2 to 52 ahead	1600) Friday))			
(**The Company** response as detailed in **OC2** for (			Weeks 2 - 7 ahead	1600) Thurs)			
Forecast return to services (Planned Outage or breakdown)		date	days 2 to 14 ahead	0900 daily	**OC2**		
	OU (all hours)	MW	"	"	**OC2**		
(**The Company** response as detailed in **OC2** for (			days 2 to 14 ahead	1600) daily)			
INFLEXIBILITY							
	Genset inflexibility	Min MW (Weekly)	Weeks 2 - 8 ahead	1600 Tues	**OC2**		
(**The Company** response on **Negative Reserve Active** (**Power Margin**			"	1200) Friday)			
	Genset inflexibility	Min MW (daily)	days 2 -14 ahead	0900 daily	**OC2**		
(**The Company** response on **Negative Reserve Active** (**Power Margin**			"	1600) daily)			

SCHEDULE 3 - LARGE POWER STATION OUTAGE PROGRAMMES, OUTPUT USABLE AND INFLEXIBILITY INFORMATION
PAGE 3 OF 3

DATA DESCRIPTION	UNITS	TIME COVERED	UPDATE TIME	DATA CAT	DATA to **RTL**	
OUTPUT PROFILES						
					CUSC Contract	CUSC App. Form
In the case of **Large Power Stations** whose output may be expected to vary in a random manner (eg. wind power) or to some other pattern (eg. Tidal) sufficient information is required to enable an understanding of the possible profile	MW	F. yrs 1 - 7	Week 24	**SPD**		

Notes: 1. The week numbers quoted in the Update Time column refer to standard weeks in the current year.

SCHEDULE 4 - LARGE POWER STATION DROOP AND RESPONSE DATA

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GOVERNOR DROOP AND RESPONSE *(PC.A.5.5 ■ CUSC Contract)*

The Data in this Schedule 4 is to be supplied by **Generators** with respect to all **Large Power Stations, HVDC System Owners** and by **DC Converter Station** owners (where agreed), whether directly connected or **Embedded**

DATA DESCRIPTION	NORMAL VALUE	MW	DATA CAT	DROOP%			RESPONSE CAPABILITY		
				Unit 1	Unit 2	Unit 3	**Primary**	**Secondary**	**High Frequency**
MLP1	**Designed Minimum Operating Level** or **Minimum Regulating Level** (for a **CCGT Module** or **Power Park Module**, on a modular basis assuming all units are **Synchronised**)								
MLP2	**Minimum Generation** or **Minimum Stable Operating Level** (for a **CCGT Module** or **Power Park Module**, or **Power Generating Module** on a modular basis assuming all units are **Synchronised**)								
MLP3	70% of **Registered Capacity or Maximum Capacity**								
MLP4	80% of **Registered Capacity or Maximum Capacity**								
MLP5	95% of **Registered Capacity or Maximum Capacity**								
MLP6	**Registered Capacity or Maximum Capacity**								

Notes:

1. The data provided in this Schedule 4 is not intended to constrain any **Ancillary Services Agreement.**
2. **Registered Capacity or Maximum Capacity** should be identical to that provided in Schedule 2.
3. The Governor Droop should be provided for each **Generating Unit(**excluding **Power Park Units), Power Park Module**, **HVDC Converter** or **DC Converter**. The Response Capability should be provided for each **Genset** or **DC Converter**.
4. **Primary, Secondary** and **High Frequency Response** are defined in CC.A.3.2 and are based on a frequency ramp of 0.5Hz over 10 seconds. **Primary Response** is the minimum value of response between 10s and 30s after the frequency ramp starts, **Secondary Response** between 30s and 30 minutes, and **High Frequency Response** is the minimum value after 10s on an indefinite basis.
5. For plants which have not yet **Synchronised**, the data values of MLP1 to MLP6 should be as described above. For plants which have already **Synchronised**, the values of MLP1 to MLP6 can take any value between **Designed Operating Minimum Level** or **Minimum Regulating |Level a**nd **Registered Capacity** or **Maximum Capacity**. If MLP1 is not provided at the **Designed Minimum Operating Level**, the value of the **Designed Minimum Operating Level** should be separately stated.
6. For the avoidance of doubt **Transmission DC Converters** and **OTSDUW DC Converters** must be capable of providing a continuous signal indicating the real time frequency measured at the **Transmission Interface Point** to the **Offshore Grid Entry Point** (as detailed in CC.6.3.7(vii) and CC.6.3.7(viii) to enable **Offshore Power Generating Modules Offshore Generating Units**, **Offshore Power Park Modules** and/or **Offshore DC Converters** to satisfy the frequency response requirements of CC.6.3.7.

SCHEDULE 5 - USERS SYSTEM DATA

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The data in this Schedule 5 is required from **Users** who are connected to the **National Electricity Transmission System** via a **Connection Point** (or who are seeking such a connection). **Generators** undertaking **OTSDUW** should use **DRC** Schedule 18 although they should still supply data under Schedule 5 in relation to their **User's System** up to the **Offshore Grid Entry Point**.

Table 5 (a)

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CATEGORY
		CUSC Contract	CUSC App. Form	
<u>USERS SYSTEM</u> <u>LAYOUT</u> *(PC.A.2.2)*				
A **Single Line Diagram** showing all or part of the **User's System** is required. This diagram shall include:-				**SPD**
(a) all parts of the **User's System**, whether existing or proposed, operating at **Supergrid Voltage**, and in Scotland and **Offshore**, also all parts of the **User System** operating at 132kV,		■	■	
(b) all parts of the **User's System** operating at a voltage of 50kV, and in Scotland and **Offshore** greater than 30kV, or higher which can interconnect **Connection Points**, or split bus-bars at a single **Connection Point**,		■	■	
(c) all parts of the **User's System** between **Embedded Medium Power Stations** or **Large Power Stations** or **Offshore Transmission Systems** connected to the **User's Subtransmission System** and the relevant **Connection Point** or **Interface Point**,		■	■	
(d) all parts of the **User's System** at a **Transmission Site**.		■	■	
The **Single Line Diagram** may also include additional details of the **User's Subtransmission System**, and the transformers connecting the **User's Subtransmission System** to a lower voltage. With **The Company**'s agreement, it may also include details of the **User's System** at a voltage below the voltage of the **Subtransmission System**.		■	■	
This **Single Line Diagram** shall depict the arrangement(s) of all of the existing and proposed load current carrying **Apparatus** relating to both existing and proposed **Connection Points**, showing electrical circuitry (ie. overhead lines, underground cables, power transformers and similar equipment), operating voltages. In addition, for equipment operating at a **Supergrid Voltage**, and in Scotland and **Offshore** also at 132kV, circuit breakers and phasing arrangements shall be shown.		■	■	

Table 5(b)

DATA DESCRIPTION	UNITS	DATA EXCH		DATA CATEGORY
		CUSC Contract	CUSC App. Form	
<u>REACTIVE COMPENSATION</u> *(PC.A.2.4)*				
For independently switched reactive compensation equipment not owned by a **Relevant Transmission Licensee** connected to the **User's System** at 132kV and above, and also in Scotland and **Offshore**, connected at 33kV and above, other than power factor correction equipment associated with a customers **Plant** or **Apparatus**:				
Type of equipment (eg. fixed or variable)	Text	■	■	**SPD**
Capacitive rating; or	MVAr	■	■	**SPD**
Inductive rating; or	MVAr	■	■	**SPD**
Operating range	MVAr	■	■	**SPD**
Details of automatic control logic to enable operating characteristics to be determined	text and/or diagrams	■	■	**SPD**
Point of connection to **User's System** (electrical location and system voltage)	Text	■	■	**SPD**
<u>SUBSTATION INFRASTRUCTURE</u> *(PC.A.2.2.6(b))*				
For the infrastructure associated with any **User's** equipment at a Substation owned by a **Relevant Transmission Licensee** or operated or managed by **The Company**:-				
Rated 3-phase rms short-circuit withstand current	kA	■	■	**SPD**
Rated 1-phase rms short-circuit withstand current	kA	■	■	**SPD**
Rated Duration of short-circuit withstand	s	■	■	**SPD**
Rated rms continuous current	A	■	■	**SPD**

SCHEDULE 5 – USERS SYSTEM DATA

Table 5 (c)

DATA DESCRIPTION		UNITS	DATA EXCH		DATA CATEGORY
			CUSC Contract	CUSC App. Form	
LUMPED SUSCEPTANCES *(PC.A.2.3)*					
Equivalent Lumped Susceptance required for all parts of the **User's Subtransmission System** which are not included in the **Single Line Diagram**.			▪	▪	
This should not include:			▪	▪	
(a)	independently switched reactive compensation equipment identified above.		▪	▪	
(b)	any susceptance of the **User's System** inherent in the **Demand** (**Reactive Power**) data provided in Schedule 1 (**Generator** Data) or Schedule 11 (**Connection Point** data).		▪	▪	
Equivalent lumped shunt susceptance at nominal **Frequency**.		% on 100 MVA	▪	▪	**SPD**

USER'S SYSTEM DATA

Circuit Parameters (*PC.A.2.2.4*) (■ *CUSC Contract &* ■ CUSC Application Form)

The data below is all **Standard Planning Data**. Details are to be given for all circuits shown on the **Single Line Diagram**

Table 5 (d)

Years Valid	Node 1	Node 2	Rated Voltage kV	Operating Voltage kV	Positive Phase Sequence % on 100 MVA			Zero Phase Sequence (self) % on 100 MVA			Zero Phase Sequence (mutual) % on 100 MVA		
					R	X	B	R	X	B	R	X	B

Notes

1. Data should be supplied for the current, and each of the seven succeeding Financial Years. This should be done by showing for which years the data is valid in the first column of the Table.

USERS SYSTEM DATA

Transformer Data *(PC.A.2.2.5)* (■ *CUSC Contract &* ■ CUSC Application Form)

The data below is all **Standard Planning Data**, and details should be shown below of all transformers shown on the **Single Line Diagram**. Details of Winding Arrangement, Tap Changer and earthing details are only required for transformers connecting the **User's** higher voltage system with its **Primary Voltage System**.

Table 5 (e)

Years valid	Name of Node or Conn-ection Point	Trans-former	Rating MVA	Voltage Ratio		Positive Phase Sequence Reactance % on Rating			Positive Phase Sequence Resistance % on Rating			Zero Sequence React-ance % on Rating	Winding Arr.	Tap Changer			Earthing Details (delete as app.) *
				HV	LV	Max. Tap	Min. Tap	Nom. Tap	Max. Tap	Min. Tap	Nom. Tap			range +% to -%	step size %	type (delete	
																ON/ OFF ON/ OFF ON/ OFF ON/ OFF ON/ OFF ON/ OFF	Direct/ Res/ Rea Direct/ Res/ Rea Direct /Res/ Rea Direct/ Res/ Rea Direct/ Res/

*If Resistance or Reactance please give impedance value

Notes

1. Data should be supplied for the current, and each of the seven succeeding Financial Years. This should be done by showing for which years the data is valid in the first column of the Table
2. For a transformer with two secondary windings, the positive and zero phase sequence leakage impedances between the HV and LV1, HV and LV2, and LV1 and LV2 windings are required.

USER'S SYSTEM DATA

Switchgear Data *(PC.A.2.2.6(a))* (■ *CUSC Contract & CUSC Application Form* ■)

The data below is all **Standard Planning Data**, and should be provided for all switchgear (ie. circuit breakers, load disconnectors and disconnectors) operating at a **Supergrid Voltage**, and also in Scotland and **Offshore**, operating at 132kV. In addition, data should be provided for all circuit breakers irrespective of voltage located at a **Connection Site** which is owned by a **Relevant Transmission Licensee** or operated or managed by **The Company**.

Table 5(f)

Years Valid	**Connect-ion Point**	Switch No.	Rated Voltage kV rms	Operating Voltage kV rms	Rated short-circuit breaking current		Rated short-circuit peak making current		Rated rms continuous current (A)	DC time constant at testing of asymmetrical breaking ability(s)
					3 Phase kA rms	1 Phase kA rms	3 Phase kA peak	1 Phase kA peak		

Notes

1. Rated Voltage should be as defined by IEC 694.

2. Data should be supplied for the current, and each of the seven succeeding Financial Years. This should be done by showing for which years the data is valid in the first column of the Table

Table 5(g)

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CATEGORY
PROTECTION SYSTEMS *(PC.A.6.3)*		CUSC Contract	CUSC App. Form	
The following information relates only to **Protection** equipment which can trip or inter-trip or close any **Connection Point** circuit breaker or any **Transmission** circuit breaker. The information need only be supplied once, in accordance with the timing requirements set out in PC.A.1.4 (b) and need not be supplied on a routine annual basis thereafter, although **The Company** should be notified if any of the information changes.				
(a) A full description, including estimated settings, for all relays and Protection systems installed or to be installed on the **User's System**;		■		**DPD II**
(b) A full description of any auto-reclose facilities installed or to be installed on the **User's System**, including type and time delays;		■		**DPD II**
(c) A full description, including estimated settings, for all relays and **Protection** systems installed or to be installed on the **Power Generating Module**, **Power Park Module** or **Generating Unit's** generator transformer, unit transformer, station transformer and their associated connections;		■		**DPD II**
(d) For **Generating Units** (other than **Power Park Units**) having a circuit breaker at the generator terminal voltage clearance times for electrical faults within the **Generating Unit** zone must be declared.		■		**DPD II**
(e) Fault Clearance Times:				
Most probable fault clearance time for electrical faults on any part of the **Users System** directly connected to the **National Electricity Transmission System**.	mSec	■		**DPD II**

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CATEGORY
POWER PARK MODULE/UNIT PROTECTION SYSTEMS		CUSC Contract	CUSC App. Form	
Details of settings for the **Power Park Module/Unit** protection relays (to include): *(PC.A.5.4.2(f))*				
(a) Under frequency,		■		**DPD II**
(b) Over Frequency,		■		**DPD II**
(c) Under Voltage, Over Voltage,		■		**DPD II**
(d) Rotor Over current		■		**DPD II**
(e) Stator Over current,.		■		**DPD II**
(f) High Wind Speed Shut Down Level		■		**DPD II**
(g) Rotor Underspeed		■		**DPD II**
(h) Rotor Overspeed		■		**DPD II**

<u>Information for Transient Overvoltage Assessment (**DPD I**)</u> *(PC.A.6.2 ■ CUSC Contract)*

The information listed below may be requested by **The Company** from each **User** with respect to any **Connection Site** between that **User** and the **National Electricity Transmission System**. The impact of any third party **Embedded** within the **Users System** should be reflected.

(a) Busbar layout plan(s), including dimensions and geometry showing positioning of any current and voltage transformers, through bushings, support insulators, disconnectors, circuit breakers, surge arresters, etc. Electrical parameters of any associated current and voltage transformers, stray capacitances of wall bushings and support insulators, and grading capacitances of circuit breakers;

(b) Electrical parameters and physical construction details of lines and cables connected at that busbar. Electrical parameters of all plant e.g., transformers (including neutral earthing impedance or zig-zag transformers if any), series reactors and shunt compensation equipment connected at that busbar (or to the tertiary of a transformer) or by lines or cables to that busbar;

(c) Basic insulation levels (BIL) of all **Apparatus** connected directly, by lines or by cables to the busbar;

(d) Characteristics of overvoltage **Protection** devices at the busbar and at the termination points of all lines, and all cables connected to the busbar;

(e) Fault levels at the lower voltage terminals of each transformer connected directly or indirectly to the **National Electricity Transmission System** without intermediate transformation;

(f) The following data is required on all transformers operating at **Supergrid Voltage** throughout **Great Britain** and, in Scotland and **Offshore**, also at 132kV: three or five limb cores or single phase units to be specified, and operating peak flux density at nominal voltage.

(g) An indication of which items of equipment may be out of service simultaneously during **Planned Outage** conditions.

<u>Harmonic Studies (**DPD I**)</u> (PC.A.6.4 ■ CUSC Contract)

The information given below, both current and forecast, where not already supplied in this Schedule 5 may be requested by **The Company** from each **User** if it is necessary for **The Company** to evaluate the production/magnification of harmonic distortion on the **National Electricity Transmission System** and **User's** systems. The impact of any third party **Embedded** within the **User's System** should be reflected:

(a) Overhead lines and underground cable circuits of the **User's Subtransmission System** must be differentiated and the following data provided separately for each type:

Positive phase sequence resistance

Positive phase sequence reactance

Positive phase sequence susceptance

(b) for all transformers connecting the **User's Subtransmission System** to a lower voltage:

Rated MVA

Voltage Ratio

Positive phase sequence resistance

Positive phase sequence reactance

(c) at the lower voltage points of those connecting transformers:

Equivalent positive phase sequence susceptance

Connection voltage and MVAr rating of any capacitor bank and component design parameters if configured as a filter

Equivalent positive phase sequence interconnection impedance with other lower voltage points

The minimum and maximum **Demand** (both MW and MVAr) that could occur

Harmonic current injection sources in Amps at the Connection voltage points

Details of traction loads, eg connection phase pairs, continuous variation with time, etc.

(d) an indication of which items of equipment may be out of service simultaneously during **Planned Outage** conditions

Voltage Assessment Studies (**DPD I**) *(PC.A.6.5 ■ CUSC Contract)*

The information listed below, where not already supplied in this Schedule 5, may be requested by **The Company** from each **User** with respect to any **Connection Site** if it is necessary for **The Company** to undertake detailed voltage assessment studies (eg to examine potential voltage instability, voltage control co-ordination or to calculate voltage step changes). The impact of any third party **Embedded** within the **Users System** should be reflected:

(a) For all circuits of the **User's Subtransmission System**:

Positive Phase Sequence Reactance

Positive Phase Sequence Resistance

Positive Phase Sequence Susceptance

MVAr rating of any reactive compensation equipment

(b) for all transformers connecting the **User's Subtransmission System** to a lower voltage:

Rated MVA

Voltage Ratio

Positive phase sequence resistance

Positive Phase sequence reactance

Tap-changer range

Number of tap steps

Tap-changer type: on-load or off-circuit

AVC/tap-changer time delay to first tap movement

AVC/tap-changer inter-tap time delay

(c) at the lower voltage points of those connecting transformers:-

Equivalent positive phase sequence susceptance

MVAr rating of any reactive compensation equipment

Equivalent positive phase sequence interconnection impedance with other lower voltage points

The maximum **Demand** (both MW and MVAr) that could occur

Estimate of voltage insensitive (constant power) load content in % of total load at both winter peak and 75% off-peak load conditions

Short Circuit Analyses:(**DPD I**) *(PC.A.6.6 ■ CUSC Contract)*

The information listed below, both current and forecast, and where not already supplied under this Schedule 5, may be requested by **The Company** from each **User** with respect to any **Connection Site** where prospective short-circuit currents on equipment owned by a **Relevant Transmission Licensee** or operated or managed by **The Company** are close to the equipment rating. The impact of any third party **Embedded** within the **User's System** should be reflected:-

(a) For all circuits of the **User's Subtransmission System**:

Positive phase sequence resistance

Positive phase sequence reactance

Positive phase sequence susceptance

Zero phase sequence resistance (both self and mutuals)

Zero phase sequence reactance (both self and mutuals)

Zero phase sequence susceptance (both self and mutuals)

(b) for all transformers connecting the **User's Subtransmission System** to a lower voltage:

Rated MVA

Voltage Ratio

Positive phase sequence resistance (at max, min and nominal tap)

Positive Phase sequence reactance (at max, min and nominal tap)

Zero phase sequence reactance (at nominal tap)

Tap changer range

Earthing method: direct, resistance or reactance

Impedance if not directly earthed

(c) at the lower voltage points of those connecting transformers:-

The maximum **Demand** (in MW and MVAr) that could occur

Short-circuit infeed data in accordance with PC.A.2.5.6(a) unless the **User'**s lower voltage network runs in parallel with the **Subtransmission System**, when to prevent double counting in each node infeed data, a π equivalent comprising the data items of PC.A.2.5.6(a) for each node together with the positive phase sequence interconnection impedance between the nodes shall be submitted.

Dynamic Models:(**DPD II**) *(PC.A.6.7 ■ CUSC Contract)*

The information listed below, both current and forecast, and where not already supplied under this Schedule 5, may be requested by **The Company** from each **EU Code User** or in respect of each **EU Grid Supply Point** with respect to any **Connection Site**

(a) Dynamic model structure and block diagrams including parameters, transfer functions and individual elements (as applicable)

(b) Power control functions and block diagrams including parameters, transfer functions and individual elements (as applicable)

(c) Voltage control functions and block diagrams including parameters, transfer functions and individual elements (as applicable)

(d) Converter control models and block diagrams including parameters, transfer functions and individual elements (as applicable)

SCHEDULE 6 – USERS OUTAGE INFORMATION

PAGE 1 OF 2

DATA DESCRIPTION	UNITS	DATA to **RTL** CUSC Contract	DATA to **RTL** CUSC App. Form	TIMESCALE COVERED	UPDATE TIME	DATA CAT.
Details are required from **Network Operators** of proposed outages in their **User Systems** and from **Generators** with respect to their outages, which may affect the performance of the **Total System** (eg. at a **Connection Point** or constraining **Embedded Large Power Stations** or constraints to the **Maximum Import Capacity** or **Maximum Export Capacity** at an **Interface Point**) *(OC2.4.1.3.2(a) & (b))*		■		Years 2-5	Week 8 (**Network Operator** etc) Week 13 (Generators)	**OC2** **OC2**
(**The Company** advises **Network Operators** of **National Electricity Transmission System** outages affecting their **Systems**)				Years 2-5	Week 28)	
Network Operator informs **The Company** if unhappy with proposed outages)		■		"	Week 30	**OC2**
(**The Company** draws up revised **National Electricity Transmission System** (outage plan advises **Users** of operational effects)				"	Week 34)	
Generators and **Non-Embedded Customers** provide Details of **Apparatus** owned by them (other than **Gensets**) at each **Grid Supply Point** *(OC2.4.1.3.3)*		■		Year 1	Week 13	**OC2**
(**The Company** advises **Network Operators** of outages affecting their **Systems**) (OC2.4.1.3.3)				Year 1	Week 28)	
Network Operator details of relevant outages affecting the **Total System** *(OC2.4.1.3.3)*		■		Year 1	Week 32	**OC2**
Details of:- **Maximum Import Capacity** for each **Interface Point** **Maximum Export Capacity** for each **Interface Point** Changes to previously declared values of the **Interface Point Target Voltage/Power Factor** *(OC2.4.1.3.3(c)).*	 MVA / MW MVA / MW V (unless power factor control			Year 1	Week 32	**OC2**
(**The Company** informs **Users** of aspects that may affect their **Systems**) (OC2.4.1.3.3)				Year 1	Week 34)	
Users inform **The Company** if unhappy with aspects as notified *(OC2.4.1.3.3)*		■		Year 1	Week 36	**OC2**
(**The Company** issues final **National Electricity Transmission System** (outage plan with advice of operational) *(OC2.4.1.3.3)* (effects on **Users System**)		■		Year 1	Week 49	**OC2**
Generator, **Network Operator** and **Non-Embedded Customers** to inform **The Company** of changes to outages previously requested				Week 8 ahead to year end	As occurring	**OC2**
Details of load transfer capability of 12MW or more between **Grid Supply Points** in England and Wales and 10MW or more between **Grid Supply Points** in Scotland.				Within Yr 0	As **The Company** request	**OC2**
Details of:- **Maximum Import Capacity** for each **Interface Point** **Maximum Export Capacity** for each **Interface Point** Changes to previously declared values of the **Interface Point Target Voltage/Power Factor**	MVA / MW MVA / MW V (unless power factor control			Within Yr 0	As occurring	**OC2**

Note: **Users** should refer to **OC2** for full details of the procedure summarised above and for the information which **The Company** will provide on the **Programming Phase**.

SCHEDULE 6 – USERS OUTAGE INFORMATION
PAGE 2 OF 2

The data below is to be provided to **The Company** as required for compliance with the European Commission Regulation No 543/2013 (OC2.4.2.3). Data provided under Article Numbers 7.1(a), 7.1(b), 15.1(a), 15.1(b), and 15.1(c) and 15.1(d) is to be provided using **MODIS.**

ECR ARTICLE No.	DATA DESCRIPTION	USERS PROVIDING DATA	FREQUENCY OF SUBMISSION
7.1(a)	Planned unavailability of the **Apparatus** belonging to a **Non-Embedded Customer** where OC2.4.7 (a) applies - Energy Identification Code (EIC)* - Unavailable demand capacity during the event (MW) - Estimated start date and time (dd.mm.yy hh:mm) - Estimated end date and time (dd.mm.yy hh:mm) - Reason for unavailability from the list below: . Maintenance . Failure . Shutdown . Other	**Non-Embedded Customer**	To be received by **The Company** as soon as reasonably possible but in any case to facilitate publication of data no later than 1 hour after **a decision has been made by the Non-Embedded Customer** regarding the planned unavailability
7.1(b)	Changes in actual availability of the **Apparatus** belonging to a **Non-Embedded Customer** where OC2.4.7 (b) applies - Energy Identification Code (EIC)* - Unavailable demand capacity during the event (MW) - Start date and time (dd.mm.yy hh:mm) - Estimated end date and time (dd.mm.yy hh:mm) - Reason for unavailability from the list below : . Maintenance . Failure . Shutdown . Other	**Non-Embedded Customer**	To be received by **The Company** as soon as reasonably possible but in any case to facilitate publication of data no later than 1 hour after the change in actual availability
8.1	Year Ahead Forecast Margin information as provided in accordance with OC2.4.1.2.2 - **Output Usable**	**Generator**	In accordance with OC2.4.1.2.2
14.1(a)	**Registered Capacity** or **Maximum Capacity** for **Generating Units** or **Power Generating Modules** with greater than 1 MW **Registered Capacity** or **Maximum Capacity** provided in accordance with PC.4.3.1 and PC.A.3.4.3 or PC.A.3.1.4 - **Registered Capacity** or Maximum Capacity (MW) - Production type (from that listed under PC.A.3.4.3)	**Generator**	Week 24
14.1(b)	**Power Station Registered Capacity** for units with equal or greater than 100 MW **Registered Capacity** provided in accordance with PC.4.3.1 and PC.A.3.4.3 - **Power Station** name - Location of **Generating Unit** - Production type (from that listed under PC.A.3.4.3) - Voltage connection levels - **Registered Capacity** or **Maximum Capacity** (MW)	**Generator**	Week 24

14.1(c)	Estimated output of **Active Power** of a **BM Unit** or **Generating Unit** for each per **Settlement Period** of the next **Operational Day** provided in accordance with BC1.4.2 - **Physical Notification**	**Generator**	In accordance with BC1.4.2
15.1(a)	Planned unavailability of a **Generating Unit** where OC2.4.7(c) applies - **Power Station** name - **Generating Unit** and/or **Power Generating Module** name - Location of **Generating Unit and/or Power Generating Module** - **Generating Unit Registered Capacity** (MW) - Production type (from that listed under PC.A.3.4.3) - **Output Usable** (MW) during the event - Start date and time (dd.mm.yy hh:mm) - Estimated end date and time (dd.mm.yy hh:mm) - Reason for unavailability from the list below: . Maintenance . Shutdown . Other	**Generator**	To be received by **The Company** as soon as reasonably possible but in any case to facilitate publication of data no later than 1 hour after a decision has been made by the **Generator** regarding the planned unavailability
15.1(b)	Changes in availability of a **Generating Unit** and/or **Power Generating Module** where OC2.4.7 (d) applies - **Power Station** name - **Generating Unit** and/or **Power Generating Module** name - Location of **Generating Unit and/or Power Generating Module** - **Generating Unit Registered Capacity** and **Power Generating Module Maximum Capacity** (MW) - Production type(from that listed under PC.A.3.4.3) - Maximum Export Limit (MW) during the event - Start date and time (dd.mm.yy hh:mm) - Estimated end date and time (dd.mm.yy hh:mm) - Reason for unavailability from the list below: . Maintenance . Shutdown . Other	**Generator**	To be received by **The Company** as soon as reasonably possible but in any case to facilitate publication of data no later than 1 hour after the change in actual availability
15.1(c)	Planned unavailability of a **Power Station** where OC2.4.7(e) applies - **Power Station** name - Location of **Power Station** - **Power Station Registered Capacity** (MW) - Production type (from that listed under PC.A.3.4.3) - **Power Station** aggregated **Output Usable** (MW) during the event - Start date and time (dd.mm.yy hh:mm) - Estimated end date and time (dd.mm.yy hh:mm) - Reason for unavailability from the list below: . Maintenance . Shutdown . Other	**Generator**	To be received by **The Company** as soon as reasonably possible but in any case to facilitate publication of data no later than 1 hour after a decision has been made by the **Generator** regarding the planned unavailability
15.1(d)	Changes in actual availability of a **Power Station** where OC2.4.7 (f) applies - **Power Station** name - Location of **Power Station** - **Power Station Registered Capacity** (MW) - Production type (from that listed under PC.A.3.4.3) - **Power Station** aggregated Maximum Export Limit (MW) during the event - Start date and time (dd.mm.yy hh:mm) - Estimated end date and time (dd.mm.yy hh:mm) - Reason for unavailability from the list below: . Maintenance . Shutdown . Other	**Generator**	To be received by **The Company** as soon as reasonably possible but in any case to facilitate publication of data no later than 1 hour after the change in actual availability

* Energy Identification Coding (EIC) is a coding scheme that is approved by ENTSO-E for standardised electronic data interchanges

and is utilised for reporting to the Central European Transparency Platform. The Company will act as the Local Issuing Office for IEC in respect of GB.

SCHEDULE 7 - LOAD CHARACTERISTICS AT GRID SUPPLY POINTS

PAGE 1 OF 1

All data in this schedule 7 is categorised as **Standard Planning Data** (**SPD**) and is required for existing and agreed future connections. This data is only required to be updated when requested by **The Company**.

				DATA FOR FUTURE YEARS						
DATA DESCRIPTION	UNITS	DATA to **RTL**		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7
		CUSC Contract	CUSC App. Form							
<u>FOR ALL TYPES OF **DEMAND** FOR EACH **GRID SUPPLY POINT**</u>										
The following information is required infrequently and should only be supplied, wherever possible, when requested by **The Company** *(PC.A.4.7)*		□								
Details of individual loads which have Characteristics significantly different from the typical range of domestic or commercial and industrial load supplied: *(PC.A.4.7(a))*		□		(Please Attach)						
Sensitivity of demand to fluctuations in voltage And frequency on **National Electricity Transmission System** at time of peak **Connection Point Demand (Active Power)** *(PC.A.4.7(b))*		□								
Voltage Sensitivity *(PC.A.4.7(b))*	MW/kV MVAr/kV	□								
Frequency Sensitivity *(PC.A.4.7(b))*	MW/Hz MVAr/Hz	□								
Reactive Power sensitivity should relate to the **Power Factor** information given in Schedule 11 (or for **Generators**, Schedule 1) and note 6 on Schedule 11 relating to **Reactive Power** therefore applies: *(PC.A.4.7(b))*		□								
Phase unbalance imposed on the **National Electricity Transmission System** *(PC.A.4.7(d))*										
- maximum	%	□								
- average	%	□								
Maximum Harmonic Content imposed on **National Electricity Transmission System** *(PC.A.4.7(e))*	%	□								
Details of any loads which may cause **Demand** Fluctuations greater than those permitted under Engineering Recommendation P28, Stage 1 at the **Point of Common Coupling** including **Flicker Severity** (**Short Term**) and **Flicker Severity** (**Long Term**) *(PC.A.4.7(f))*		□								

SCHEDULE 8 - DATA SUPPLIED BY BM PARTICIPANTS
PAGE 1 OF 1

CODE	DESCRIPTION
BC1	**Physical Notifications**
BC1 & **BC2**	**Export and Import Limits**
BC1	**Bid-Offer Data**
BC1	**Dynamic Parameters** (Day Ahead)
BC2	**Dynamic Parameters** (For use in **Balancing Mechanism**)
BC1 & **BC2**	**Other Relevant Data**

- No information collated under this Schedule will be transferred to the **Relevant Transmission Licensees**

SCHEDULE 9 - DATA SUPPLIED BY THE COMPANY TO USERS
PAGE 1 OF 1

(Example of data to be supplied)

CODE	DESCRIPTION
CC	Operation Diagram
CC	Site Responsibility Schedules
PC	Day of the peak **National Electricity Transmission System Demand**
	Day of the minimum **National Electricity Transmission System Demand**
OC2	**Surpluses** and OU requirements for each **Generator** over varying timescales
	Equivalent networks to **Users** for **Outage Planning**
	Negative Reserve Active Power Margins (when necessary)
	Operating Reserve information
BC1	**Demand** Estimates, **Indicated Margin** and **Indicated Imbalance**, indicative **Synchronising** and **Desynchronising** times of **Embedded Power Stations** to **Network Operators**, special actions.
BC2	**Bid-Offer Acceptances**, **Ancillary Services** instructions to relevant **Users**, **Emergency Instructions**
BC3	Location, amount, and **Low Frequency Relay** settings of any **Low Frequency Relay** initiated **Demand** reduction for **Demand** which is **Embedded**.

- No information collated under this Schedule will be transferred to the **Relevant Transmission Licensees**

DATA TO BE SUPPLIED BY **THE COMPANY** TO **USERS**

PURSUANT TO THE **TRANSMISSION LICENCE**

1. The **Transmission Licence** requires **The Company** to publish annually the **Seven Year Statement** which is designed to provide **Users** and potential **Users** with information to enable them to identify opportunities for continued and further use of the **National Electricity Transmission System**.

   When an **User** is considering a development at a specific site, certain additional information may be required in relation to that site which is of such a level of detail that it is inappropriate to include it in the **Seven Year Statement**. In these circumstances the **User** may contact **The Company** who will be pleased to arrange a discussion and the provision of such additional information relevant to the site under consideration as the **User** may reasonably require.

2. The **Transmission Licence** also requires **The Company** to offer terms for an agreement for connection to and use of the **National Electricity Transmission System** and further information will be given by **The Company** to the potential **User** in the course of the discussions of the terms of such an agreement.

SCHEDULE 10 - DEMAND PROFILES AND ACTIVE ENERGY DATA
PAGE 1 OF 2

The following information is required from each **Network Operator** and from each **Non-Embedded Customer**. The data should be provided in calendar week 24 each year (although **Network Operators** may delay the submission until calendar week 28).

DATA DESCRIPTION	F. Yr. 0	F. Yr. 1	F. Yr. 2	F. Yr. 3	F. Yr. 4	F. Yr. 5	F. Yr. 6	F. Yr. 7	UPDATE TIME	DATA CAT
Demand Profiles	*(PC.A.4.2) (■ – CUSC Contract & ■ CUSC Application Form)*									
Total User's system profile (please delete as applicable)	Day of **User's** annual Maximum demand at **Annual ACS Conditions** (MW) Day of annual peak of **National Electricity Transmission System Demand** at **Annual ACS Conditions** (MW) Day of annual minimum **National Electricity Transmission System Demand** at average conditions (MW)									
0000 : 0030									Wk.24	**SPD**
0030 : 0100									:	
0100 : 0130									:	
0130 : 0200									:	:
0200 : 0230									:	:
0230 : 0300									:	:
0300 : 0330									:	:
0330 : 0400									:	:
0400 : 0430									:	:
0430 : 0500									:	:
0500 : 0530									:	:
0530 : 0600									:	:
0600 : 0630									:	:
0630 : 0700									:	:
0700 : 0730									:	:
0730 : 0800									:	:
0800 : 0830									:	:
0830 : 0900									:	:
0900 : 0930									:	:
0930 : 1000									:	:
1000 : 1030									:	:
1030 : 1100									:	:
1100 : 1130									:	:
1130 : 1200									:	:
1200 : 1230									:	:
1230 : 1300									:	:
1300 : 1330									:	:
1330 : 1400									:	:
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1630 : 1700									:	:
1700 : 1730									:	:
1730 : 1800									:	:
1800 : 1830									:	:
1830 : 1900									:	:
1900 : 1930									:	:
1930 : 2000									:	:
2000 : 2030									:	:
2030 : 2100									:	:
2100 : 2130									:	:
2130 : 2200									:	:
2200 : 2230									:	:
2230 : 2300									:	:
2300 : 2330									:	:
2330 : 0000									:	:

SCHEDULE 10 - DEMAND PROFILES AND ACTIVE ENERGY DATA
PAGE 2 OF 2

DATA DESCRIPTION	Out-turn Actual	Out-turn Weather Corrected.	F.Yr. 0	Update Time	Data Cat	DATA to **RTL** CUSC Contract	DATA to **RTL** CUSC App. Form
(PC.A.4.3)							
Active Energy Data				Week 24	**SPD**	■	■
Total annual **Active Energy** requirements under average conditions of each **Network Operator** and each **Non-Embedded Customer** in the following categories of **Customer** Tariff:-						■	■
LV1						■	■
LV2						■	■
LV3						■	■
EHV						■	■
HV						■	■
Traction						■	■
Lighting						■	■
User System Losses						■	■
Active Energy from **Embedded Small Power Stations** and **Embedded Medium Power Stations**						■	■

NOTES:

1. 'F. yr.' means '**Financial Year**'

2. **Demand** and **Active Energy** Data (General)

   Demand and **Active Energy** data should relate to the point of connection to the **National Electricity Transmission System** and should be net of the output (as reasonably considered appropriate by the **User**) of all **Embedded Small Power Stations**, **Medium Power Stations** and **Customer Generating Plant**. Auxiliary demand of **Embedded Power Stations** should be included in the demand data submitted by the **User** at the **Connection Point**. **Users** should refer to the **PC** for a full definition of the **Demand** to be included.

3. **Demand** profiles and **Active Energy** data should be for the total **System** of the **Network Operator**, including all **Connection Points**, and for each **Non-Embedded Customer**. **Demand Profiles** should give the numerical maximum demand that in the **User**'s opinion could reasonably be imposed on the **National Electricity Transmission System**.

4. In addition the demand profile is to be supplied for such days as **The Company** may specify, but such a request is not to be made more than once per calendar year.

SCHEDULE 11 - CONNECTION POINT DATA
PAGE 1 OF 5

The following information is required from each **Network Operator** and from each **Non-Embedded Customer**. The data should be provided in calendar week 24 each year (although **Network Operators** may delay the submission until calendar week 28).

Table 11(a)

Connection Point:

Connection Point Demand at the time of - (select each one in turn) (Provide data for each Access Period associated with the Connection Point)	a) maximum **Demand** b) peak **National Electricity Transmission System Demand** *(specified by **The Company**)* c) minimum **National Electricity Transmission System Demand** *(specified by **The Company**)* d) maximum **Demand** during **Access Period** e) specified by either **The Company** or an **User**	
Name of **Transmission Interface Circuit** out of service during **Access Period** *(if reqd)*.		**PC.A.4. 1.4.2**

DATA DESCRIPTION *(CUSC Contract □ & CUSC Application Form ■)*	Outturn	Outturn Weather Corrected	F.Yr 1	F.Yr 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr 6	F.Yr 7	F.Yr 8	DATA CAT
Date of a), b), c), d) or e) as denoted above.											**PC.A.4. 3.3**
Time of a), b), c), d) or e) as denoted above.											**PC.A.4. 3.3**
Connection Point Demand (MW)											**PC.A.4. 3.1**
Connection Point Demand (MVAr)											**PC.A.4. 3.1**
Deduction made at **Connection Point** for **Small Power Stations**, **Medium Power Stations** and **Customer Generating Plant** (MW)											**PC.A.4. 3.2(a)**
Reference to valid **Single Line Diagram**											**PC.A.4. 3.5**
Reference to node and branch data.											**PC.A.2. 2**

Note: The following data block can be repeated for each post fault network revision that may impact on the Transmission System.

Reference to post-fault revision of **Single Line Diagram**											**PC.A.4. 5**
Reference to post-fault revision of the node and branch data associated with the **Single Line Diagram**											**PC.A.4. 5**
Reference to the description of the actions and timescales involved in effecting the post-fault actions (e.g. auto-switching, manual, teleswitching, overload protection operation etc)											**PC.A.4. 5**

Access Group:		

*Note: The following data block to be repeated for each **Connection Point** with the **Access Group**.*

Name of associated **Connection Point** within the same **Access Group:**											**PC.A.4. 3.1**
Demand at associated **Connection Point** (MW)											**PC.A.4. 3.1**
Demand at associated **Connection Point** (MVAr)											**PC.A.4. 3.1**
Deduction made at associated **Connection Point** for **Small Power Stations**, **Medium Power Stations** and **Customer Generating Plant** (MW)											**PC.A.4. 3.2(a)**

SCHEDULE 11 - CONNECTION POINT DATA

PAGE 2 OF 5

Table 11(b)

Embedded Generation Data											
Connection Point:											
DATA DESCRIPTION	Outturn	Outturn Weather Corrected	F.Yr 1	F.Yr 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr 6	F.Yr 7	F.Yr 8	DATA CAT
Small Power Station, Medium Power Station and **Customer** Generation Summary	For each **Connection Point** where there are **Embedded Small Power Stations**, **Medium Power Stations** or **Customer Generating Stations** the following information is required:										
No. of **Small Power Stations**, **Medium Power Stations** or **Customer Power Stations**											**PC.A.3.1. 4(a)**
Number of **Generating Units** within these stations											**PC.A.3.1. 4(a)**
Summated Capacity of all these **Generating Units**											**PC.A.3.1. 4(a)**
Where the **Network Operator's System** places a constraint on the capacity of an **Embedded Large Power Station**											
Station Name											**PC.A.3.2. 2(c)**
Generating Unit											**PC.A.3.2. 2(c)**
System Constrained Capacity											**PC.A.3.2. 2(c)(i)**
Reactive Despatch Network Restriction											**PC.A.3.2. 2(c)(ii)**

Where the **Network Operator's System** places a constraint on the capacity of an **Offshore Transmission System** at an **Interface Point**											
Offshore Transmission System Name											**PC.A.3.2. 2(c)**
Interface Point Name											**PC.A.3.2. 2(c)**
Maximum Export Capacity											**PC.A.3.2. 2(c)**
Maximum Import Capacity											**PC.A.3.2. 2(c)**

SCHEDULE 11 - CONNECTION POINT DATA

PAGE 3 OF 5

For each **Embedded Small Power Station** of 1MW and above, the following information is required, effective 2015 in line with the Week 24 data submissions.

An **Embedded Small Power Station** reference unique to each **Network Operator**	Connection Date (**Financial Year** for generator connecting after week 24 2015)	Generator unit Reference	Technology Type / Production type	CHP (Y/N)	Registered capacity in MW (as defined in the **Distribution Code**)	Lowest voltage node on the most up-to-date **Single Line Diagram** to which it connects or where it will export most of its power	Where it generates electricity from wind or PV, the geographical location of the primary or higher voltage substation to which it connects	Control mode	Control mode voltage target and reactive range or target pf (as appropriate)	Loss of mains protection type	Loss of mains protection settings
PC.A.3.1.4 (a)		PC.A.3.1.4 (a)	PC.A.3.1.4 (a)	PC.A.3.1.4	PC.A.3.1.4 (a)	PC.A.3.1.4 (a)	PC.A.3.1.4 (a)	PC.A.3.1.4 (a)	PC.A.3.1.4 (a)	PC.A.3.1.4 (a)	PC.A.3.1.4 (a)

Table 11(c)

DATA DESCRIPTION
DATA CAT

SCHEDULE 11 - CONNECTION POINT DATA
PAGE 4 OF 5

<u>NOTES:</u>

1. 'F.Yr.' means '**Financial Year**'. F.Yr. 1 refers to the current financial year.

2. All **Demand** data should be net of the output (as reasonably considered appropriate by the **User**) of all **Embedded Small Power Stations**, **Medium Power Stations** and **Customer Generating Plant**. Generation and / or Auxiliary demand of **Embedded Large Power Stations** should not be included in the demand data submitted by the **User**. **Users** should refer to the **PC** for a full definition of the **Demand** to be included.

3. Peak **Demand** should relate to each **Connection Point** individually and should give the maximum demand that in the **User's** opinion could reasonably be imposed on the **National Electricity Transmission System**. **Users** may submit the **Demand** data at each node on the **Single Line Diagram** instead of at a **Connection Point** as long as the **User** reasonably believes such data relates to the peak (or minimum) at the **Connection Point**.

   In deriving **Demand** any deduction made by the **User** (as detailed in note 2 above) to allow for **Embedded Small Power Stations**, **Medium Power Stations** and **Customer Generating Plant** is to be specifically stated as indicated on the Schedule.

4. **The Company** may at its discretion require details of any **Embedded Small Power Stations** or **Embedded Medium Power Stations** whose output can be expected to vary in a random manner (eg. wind power) or according to some other pattern (eg. tidal power)

5. Where more than 95% of the total **Demand** at a **Connection Point** is taken by synchronous motors, values of the **Power Factor** at maximum and minimum continuous excitation may be given instead. **Power Factor** data should allow for series reactive losses on the **User's System** but exclude reactive compensation network susceptance specified separately in Schedule 5.

6. Where a **Reactive Despatch Network Restriction** is in place which requires the generator to maintain a target voltage set point this should be stated as an alternative to the size of the **Reactive Despatch Network Restriction**.

SCHEDULE 11 - CONNECTION POINT DATA
PAGE 5 OF 5

Table 11 (d)

Embedded Small Power Stations <1MW

Network Operator	

Fuel Type	Aggregate Registered Capacity Total MW	Number of PGMs	Comments
Biomass			
Fossil brown coal/lignite			
Fossil coal-derived gas			
Fossil gas			
Fossil hard coal			
Fossil oil			
Fossil oil shale			
Fossil peat			
Geothermal			
Hydro pumped storage			
Hydro run-of-river and poundage			
Hydro water reservoir			
Marine			
Nuclear			
Other renewable			
Solar			
Waste			
Wind offshore			
Wind onshore			
Other			

SCHEDULE 12 - DEMAND CONTROL
PAGE 1 OF 2

The following information is required from each **Network Operator** and where indicated with an asterisk from **Externally Interconnected System Operators** and/or **Interconnector Users** and a **Pumped Storage Generator**. Where indicated with a double asterisk, the information is only required from **Suppliers**.

DATA DESCRIPTION	UNITS		UPDATE TIME	
Demand Control				
Demand met or to be relieved by **Demand Control** (averaging at the **Demand Control Notification Level** or more over a half hour) at each **Connection Point**.				
Demand Control at time of **National Electricity Transmission System** weekly peak demand				
Amount	MW	)F.yrs 0 to 5	Week 24	**OC1**
Duration	Min	)		
For each half hour	MW	Wks 2-8 ahead	1000 Mon	**OC1**
For each half hour	MW	Days 2-12 ahead	1200 Wed	**OC1**
For each half hour	MW	Previous calendar day	0600 daily	**OC1**
****Customer Demand Management** (at the **Customer Demand Management Notification Level** or more at the **Connection Point**)				
For each half hour	MW	Any time in Control Phase		**OC1**
For each half hour	MW	Remainder of period	When changes occur to previous plan	**OC1**
For each half hour	MW	Previous calendar day	0600 daily	**OC1**
In Scotland, **Load Management Blocks For each block of 5MW or more, for each half hour	MW	For the next day	11:00	**OC1**

SCHEDULE 12 - DEMAND CONTROL
PAGE 2 OF 2

DATA DESCRIPTION	UNITS	TIME COVERED	UPDATE TIME	DATA CAT.
*__Demand Control__ or Pump Tripping Offered as Reserve				
Magnitude of **Demand** or pumping load which is tripped	MW	Year ahead from week 24	Week 24	**DPD I**
System Frequency at which tripping is initiated	Hz	"	"	"
Time duration of **System Frequency** below trip setting for tripping to be initiated	S	"	"	"
Time delay from trip initiation to Tripping	S	"	"	"
Emergency Manual Load Disconnection				
Method of achieving load disconnection	Text	Year ahead from week 24	Annual in week 24	OC6
Annual ACS Peak Demand (**Active Power**) at **Connection Point** (requested under Schedule 11 - repeated here for reference)	MW	"	"	"
Cumulative percentage of **Connection Point Demand** (**Active Power**) which can be disconnected by the following times from an instruction from **The Company**				
5 mins	%	"	"	"
10 mins	%	"	"	"
15 mins	%	"	"	"
20 mins	%	"	"	"
25 mins	%	"	"	"
30 mins	%	"	"	"

Notes:

1. **Network Operators** may delay the submission until calendar week 28.
2. No information collated under this Schedule will be transferred to the **Relevant Transmission Licensees** (or **Generators** undertaking **OTSDUW**).

SCHEDULE 12A - AUTOMATIC LOW FREQUENCY DEMAND DISCONNECTION
PAGE 1 OF 1

Time Covered: Year ahead from week 24 Data Category: OC6
Update Time: Annual in week 24

Grid Supply Point	GSP Demand MW	Low Frequency Demand Disconnection Blocks MW 1 48.8Hz	2 48.75Hz	3 48.7Hz	4 48.6Hz	5 48.5Hz	6 48.4Hz	7 48.2Hz	8 48.0Hz	9 47.8Hz	Residual demand MW
GSP1 GSP2 GSP3											
Total demand disconnected per block	MW %										
Total demand disconnection		MW (	% of aggregate demand of		MW)						

Note: All demand refers to that at the time of forecast **National Electricity Transmission System** peak demand.

Network Operators may delay the submission until calendar week 28

No information collated under this schedule will be transferred to the **Relevant Transmission Licensees** (or **Generators** undertaking **OTSDUW**).

SCHEDULE 13 - FAULT INFEED DATA
PAGE 1 OF 2

The data in this Schedule 13 is all **Standard Planning Data**, and is required from all **Users** other than **Generators** who are connected to the **National Electricity Transmission System** via a **Connection Point** (or who are seeking such a connection). A data submission is to be made each year in Week 24 (although **Network Operators** may delay the submission until Week 28). A separate submission is required for each node included in the **Single Line Diagram** provided in Schedule 5.

DATA DESCRIPTION	UNITS	F.Yr 0	F.Yr. 1	F.Yr. 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr. 7	DATA to **RTL**	
SHORT CIRCUIT INFEED TO THE **NATIONAL ELECTRICITY TRANSMISSION SYSTEM** FROM **USERS SYSTEM** AT A **CONNECTION POINT**										CUSC Contract	CUSC App. Form
(PC.A.2.5)											
Name of node or **Connection Point**										□	■
Symmetrical three phase short-circuit current infeed											
- at instant of fault	kA									□	■
- after subtransient fault current contribution has substantially decayed	Ka									□	■
Zero sequence source impedances as seen from the **Point of Connection** or node on the **Single Line Diagram** (as appropriate) consistent with the maximum infeed above:											
- Resistance	% on 100									□	■
- Reactance	% on 100									□	■
Positive sequence X/R ratio at instance of fault										□	■
Pre-Fault voltage magnitude at which the maximum fault currents were calculated	p.u.									□	■

SCHEDULE 13 - FAULT INFEED DATA
PAGE 2 OF 2

DATA DESCRIPTION	UNITS	F.Yr 0	F.Yr. 1	F.Yr. 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr. 7	DATA to **RTL**	
SHORT CIRCUIT INFEED TO THE **NATIONAL ELECTRICITY TRANSMISSION SYSTEM** FROM **USERS SYSTEM** AT A **CONNECTION POINT**										CUSC Contract	CUSC App. Form
Negative sequence impedances of **User's System** as seen from the **Point of Connection** or node on the **Single Line Diagram** (as appropriate). If no data is given, it will be assumed that they are equal to the positive sequence values.											
- Resistance	% on 100									□	■
- Reactance	% on 100									□	■

SCHEDULE 14 - FAULT INFEED DATA (GENERATORS INCLUDING UNIT TRANSFORMERS AND STATION TRANSFORMERS)

PAGE 1 OF 5

The data in this Schedule 14 is all **Standard Planning Data**, and is to be provided by **Generators**, with respect to all directly connected **Power Stations**, all **Embedded Large Power Stations** and all **Embedded Medium Power Stations** connected to the **Subtransmission System**. A data submission is to be made each year in Week 24.

<u>Fault infeeds via **Unit Transformers**</u>

A submission should be made for each **Generating Unit** (including those which are part of a **Synchronous Power Generating Module**) with an associated **Unit Transformer**. Where there is more than one **Unit Transformer** associated with a **Generating Unit**, a value for the total infeed through all **Unit Transformers** should be provided. The infeed through the **Unit Transformer(s)** should include contributions from all motors normally connected to the **Unit Board**, together with any generation (eg **Auxiliary Gas Turbines**) which would normally be connected to the **Unit Board**, and should be expressed as a fault current at the **Generating Unit** terminals for a fault at that location.

DATA DESCRIPTION	UNITS	F.Yr. 0	F.Yr. 1	F.Yr 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr. 7	DATA to **RTL** CUSC Contract	CUSC App. Form
(PC.A.2.5)											
Name of **Power Station**										□	■
Number of **Unit Transformer**										□	■
Symmetrical three phase short-circuit current infeed through the **Unit Transformers**(s) for a fault at the **Generating Unit** terminals											
- at instant of fault	kA									□	■
- after subtransient fault current contribution has substantially decayed	kA									□	■
Positive sequence X/R ratio at instance of fault										□	■
Subtransient time constant (if significantly different from 40ms)	ms									□	■
Pre-fault voltage at fault point (if different from 1.0 p.u.)										□	■
The following data items need only be supplied if the **Generating Unit** Step-up Transformer can supply zero sequence current from the **Generating Unit** side to the **National Electricity Transmission System**											
Zero sequence source impedances as seen from the **Generating Unit** terminals consistent with the maximum infeed above:											
- Resistance	% on 100									□	■
- Reactance	% on 100									□	■

SCHEDULE 14 - FAULT INFEED DATA (GENERATORS INCLUDING UNIT TRANSFORMERS AND STATION TRANSFORMERS)

<u>Fault infeeds via Station Transformers</u>

A submission is required for each **Station Transformer** directly connected to the **National Electricity Transmission System**. The submission should represent normal operating conditions when the maximum number of **Gensets** are **Synchronised** to the **System**, and should include the fault current from all motors normally connected to the **Station Board**, together with any Generation (eg **Auxiliary Gas Turbines**) which would normally be connected to the **Station Board**. The fault infeed should be expressed as a fault current at the hv terminals of the **Station Transformer** for a fault at that location.

If the submission for normal operating conditions does not represent the worst case, then a separate submission representing the maximum fault infeed that could occur in practice should be made.

DATA DESCRIPTION	UNITS	F.Yr. 0	F.Yr. 1	F.Yr. 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr. 7	DATA to **RTL** CUSC Contract	CUSC App. Form
(PC.A.2.5)											
Name of **Power Station**										□	■
Number of **Station Transformer**										□	■
Symmetrical three phase short-circuit current infeed for a fault at the **Connection Point**											
- at instant of fault	kA									□	■
- after subtransient fault current contribution has substantially decayed	kA									□	■
Positive sequence X/R ratio At instance of fault										□	■
Subtransient time constant (if significantly different from 40ms)	mS									□	■
Pre-fault voltage (if different from 1.0 p.u.) at fault point (See note 1)										□	■
Zero sequence source Impedances as seen from the **Point of Connection** Consistent with the maximum Infeed above:											
- Resistance	% on 100									□	■
- Reactance	% on 100									□	■

Note 1. The pre-fault voltage provided above should represent the voltage within the range 0.95 to 1.05 that gives the highest fault current

Note 2. % on 100 is an abbreviation for % on 100 MVA

SCHEDULE 14 - FAULT INFEED DATA (GENERATORS INCLUDING UNIT TRANSFORMERS AND STATION TRANSFORMERS)

Fault infeeds from **Power Park Modules**

A submission is required for the whole **Power Park Module** and for each **Power Park Unit** type or equivalent. The submission shall represent operating conditions that result in the maximum fault infeed. The fault current from all motors normally connected to the **Power Park Unit's** electrical system shall be included. The fault infeed shall be expressed as a fault current at the terminals of the **Power Park Unit**, or the **Common Collection Busbar** if an equivalent **Single Line Diagram** and associated data as described in PC.A.2.2.2 is provided, and the **Grid Entry Point**, or **User System Entry Point** if **Embedded**, for a fault at the **Grid Entry Point**, or **User System Entry Point** if **Embedded**.

Should actual data in respect of fault infeeds be unavailable at the time of the application for a **CUSC Contract** or **Embedded Development Agreement**, a limited subset of the data, representing the maximum fault infeed that may result from all of the plant types being considered, shall be submitted. This data will, as a minimum, represent the root mean square of the positive, negative and zero sequence components of the fault current for both single phase and three phase solid faults at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**) at the time of fault application and 50ms following fault application. Actual data in respect of fault infeeds shall be submitted to **The Company** as soon as it is available, in line with PC.A.1.2

DATA DESCRIPTION	UNITS	F.Yr. 0	F.Yr. 1	F.Yr. 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr. 7	DATA to **RTL** CUSC Contract	CUSC App. Form
(PC.A.2.5)											
Name of **Power Station**										□	■
Name of Power Park Module										□	■
Power Park Unit type										□	■
A submission shall be provided for the contribution of the entire **Power Park Module** and each type of **Power Park Unit** or equivalent to the positive, negative and zero sequence components of the short circuit current at the **Power Park Unit** terminals, or **Common Collection Busbar**, and **Grid Entry Point** or **User System Entry Point** if **Embedded** for (i) a solid symmetrical three phase short circuit (ii) a solid single phase to earth short circuit (iii) a solid phase to phase short circuit (iv) a solid two phase to earth short circuit at the **Grid Entry Point** or **User System Entry Point** if **Embedded**. If protective controls are used and active for the above conditions, a submission shall be provided in the limiting case where the protective control is not active. This case may require application of a non-solid fault, resulting in a retained voltage at the fault point.										□ □ □ □ □	■ ■ ■ ■ ■

SCHEDULE 14 - FAULT INFEED DATA (GENERATORS INCLUDING UNIT TRANSFORMERS AND STATION TRANSFORMERS)
PAGE 4 OF 5

DATA DESCRIPTION	UNITS	F.Yr. 0	F.Yr. 1	F.Yr. 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr. 7	DATA to **RTL**	DATA DESCRIPTION
										CUSC Contract	CUSC App. Form
- A continuous time trace and table showing the root mean square of the positive, negative and zero sequence components of the fault current from the time of fault inception to 140ms after fault inception at 10ms intervals	Graphical and tabular kA versus s									□	■
- A continuous time trace and table showing the positive, negative and zero sequence components of retained voltage at the terminals or **Common Collection Busbar**, if appropriate	p.u. versus s									□	■
- A continuous time trace and table showing the root mean square of the positive, negative and zero sequence components of retained voltage at the fault point, if appropriate	p.u. versus s									□	■

SCHEDULE 14 - FAULT INFEED DATA (GENERATORS INCLUDING UNIT TRANSFORMERS AND STATION TRANSFORMERS)

DATA DESCRIPTION	UNITS	F.Yr. 0	F.Yr. 1	F.Yr. 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr. 7	DATA to RTL	DATA DESCRIPTION
										CUSC Contract	CUSC App. Form
For **Power Park Units** that utilise a protective control, such as a crowbar circuit,											
- additional rotor resistance applied to the **Power Park Unit** under a fault situation	% on MVA									□	■
- additional rotor reactance applied to the **Power Park Unit** under a fault situation.	% on MVA									□	■
Positive sequence X/R ratio of the equivalent at time of fault at the **Common Collection Busbar**										□	■
Minimum zero sequence impedance of the equivalent at a **Common Collection Busbar**										□	■
Active Power generated pre-fault	MW									□	■
Number of **Power Park Units** in equivalent generator										□	■
Power Factor (lead or lag)										□	■
Pre-fault voltage (if different from 1.0 p.u.) at fault point (See note 1)	p.u.									□	■
Items of reactive compensation switched in pre-fault										□	■

Note 1. The pre-fault voltage provided above should represent the voltage within the range 0.95 to 1.05 that gives the highest fault current

SCHEDULE 15 – MOTHBALLED POWER GENERATING MODULE, MOTHBALLED GENERATING UNIT, MOTHBALLED POWER PARK MODULE (INCLUDING MOTHBALLED DC CONNECTED POWER PARK MODULES), MOTHBALLED HVDC SYSTEMS, MOTHBALLED HVDC CONVERTERS, MOTHBALLED DC CONVERTERS AT A DC CONVERTER STATION AND ALTERNATIVE FUEL DATA

MOTHBALLED POWER GENERATING MODULES, MOTHBALLED GENERATING UNIT, MOTHBALLED POWER PARK MODULE (INCLUDING **MOTHBALLED DC CONNECTED POWER PARK MODULES**), **MOTHBALLED HVDC** SYSTEMS, **MOTHBALLED HVDC CONVERTERS** OR **MOTHBALLED DC CONVERTER AT A DC CONVERTER STATION** AND ALTERNATIVE FUEL DATA

The following data items must be supplied with respect to each **Mothballed Power Generating Module**, **Mothballed Generating Unit, Mothballed Power Park Module** (including **Mothballed DC Connected Power Park Modules**), **Mothballed HVDC Systems, Mothballed HVDC Converters** or **Mothballed DC Converters** at a **DC Converter station**

Power Station______________________________________ **Generating Unit, Power Park Module** or **DC Converter** Name (e.g. Unit 1)

DATA DESCRIPTION	UNITS	DATA CAT	**GENERATING UNIT** DATA						
			<1 month	1-2 months	2-3 months	3-6 months	6-12 months	>12 months	Total MW being returned
MW output that can be returned to service	MW	DPD II							

Notes

1. The time periods identified in the above table represent the estimated time it would take to return the **Mothballed Power Generating Module**, **Mothballed Generating Unit, Mothballed Power Park Module (Mothballed DC Connected Power Park Modules**), **Mothballed HVDC Systems, Mothballed HVDC Converters** or **Mothballed DC Converter** at a **DC Converter Station** to service once a decision to return has been made.
2. Where a **Mothballed Power Generating Module**, **Mothballed Generating Unit, Mothballed Power Park Module (**including a Mothballed **DC Connected Power Park Module**), **Mothballed HVDC System**, **Mothballed HVDC Converter** or **Mothballed DC Converter** at a **DC Converter Station** can be physically returned in stages covering more than one of the time periods identified in the above table then information should be provided for each applicable time period.
3. The estimated notice to physically return MW output to service should be determined in accordance with **Good Industry Practice** assuming normal working arrangements and normal plant procurement lead times.
4. The MW output values in each time period should be incremental MW values, e.g. if 150MW could be returned in 2 – 3 months and an additional 50MW in 3 – 6 months then the values in the columns should be Nil, Nil, 150, 50, Nil, Nil, 200 respectively.
5. Significant factors which may prevent the **Mothballed Power Generating Module**, **Mothballed Generating Unit, Mothballed Power Park Module (Mothballed DC Connected Power Park Modue). Mothballed HVDC System, Mothballed HVDC Converter** or **Mothballed DC Converter** at a **DC Converter Station** achieving the estimated values provided in this table, excluding factors relating to **Transmission Entry Capacity**, should be appended separately.

SCHEDULE 15 – MOTHBALLED POWER GENERATING MODULES, MOTHBALLED GENERATING UNIT, MOTHBALLED POWER PARK MODULE (INCLUDING DC CONNECTED POWER PARK MODULES), MOTHBALLED HVDC SYSTEMS, MOTHBALLED HVDC CONVERTERS, MOTHBALLED DC CONVERTERS AT A DC CONVERTER STATION AND ALTERNATIVE FUEL DATA

ALTERNATIVE FUEL INFORMATION

The following data items for alternative fuels need only be supplied with respect to each **Generating Unit** whose primary fuel is gas including thos which form part of a **Power Generating Module**.

Power Station________________________ **Generating Unit** Name (e.g. Unit 1) ________________________

DATA DESCRIPTION	UNITS	DATA CAT	**GENERATING UNIT** DATA			
			1	2	3	4
Alternative Fuel Type (*please specify)	Text	DPD II	Oil distillate	Other gas*	Other*	Other*
CHANGEOVER TO ALTERNATIVE FUEL						
For off-line changeover:						
Time to carry out off-line fuel changeover	Minutes	DPD II				
Maximum output following off-line changeover	MW	DPD II				
For on-line changeover:						
Time to carry out on-line fuel changeover	Minutes	DPD II				
Maximum output during on-line fuel changeover	MW	DPD II				
Maximum output following on-line changeover	MW	DPD II				
Maximum operating time at full load assuming:						
Typical stock levels	Hours	DPD II				
Maximum possible stock levels	Hours	DPD II				
Maximum rate of replacement of depleted stocks of alternative fuels on the basis of **Good Industry Practice**	MWh(electrical) /day	DPD II				
Is changeover to alternative fuel used in normal operating arrangements?	Text	DPD II				
Number of successful changeovers carried out in the last **Financial Year** (** delete as appropriate)	Text	DPD II	0 / 1-5 / 6-10 / 11-20 / >20 **	0 / 1-5 / 6-10 / 11-20 / >20 **	0 / 1-5 / 6-10 / 11-20 / >20 **	0 / 1-5 / 6-10 / 11-20 / >20 **

SCHEDULE 15 – MOTHBALLED POWER GENERATING MODULES, MOTHBALLED GENERATING UNIT, MOTHBALLED POWER PARK MODULE (INCLUDING MOTHBALLED DC CONNECTED POWER PARK MODULES), MOTHBALLED HVDC SYSTEMS, MOTHBALLED HVDC CONVERTERS MOTHBALLED DC CONVERTERS AT A DC CONVERTER STATION AND ALTERNATIVE FUEL DATA

DATA DESCRIPTION	UNITS	DATA CAT	**GENERATING UNIT** DATA			
			1	2	3	4
CHANGEOVER BACK TO MAIN FUEL						
For off-line changeover:						
Time to carry out off-line fuel changeover	Minutes					
For on-line changeover:						
Time to carry out on-line fuel changeover	Minutes					
Maximum output during on-line fuel changeover	MW					

Notes

1. Where a **Generating Unit** has the facilities installed to generate using more than one alternative fuel type details of each alternative fuel should be given.
2. Significant factors and their effects which may prevent the use of alternative fuels achieving the estimated values provided in this table (e.g. emissions limits, distilled water stocks etc.) should be appended separately.

- No information collated under this Schedule will be transferred to the **Relevant Transmission Licensees**

SCHEDULE 16 - BLACK START INFORMATION
PAGE 1 OF 2
PART 1

BLACK START INFORMATION

The following data/text items are required from each **Generator** for each **BM Unit** at a **Large Power Station** as detailed in PC.A.5.7. Data is not required for **Generating Units** that are contracted to provide **Black Start Capability**The data should be provided in accordance with PC.A.1.2 and also, where possible, upon request from **The Company** during a **Black Start**.

Data Description *(PC.A.5.7) (■ CUSC Contract)*	Units	Data Category
Assuming all **BM Units** were running immediately prior to the **Total Shutdown** or **Partial Shutdown** and in the event of loss of all external power supplies, provide the following information:		
a) Expected time for the first and subsequent **BM Units** to be **Synchronised**, from the restoration of external power supplies, assuming external power supplies are not available for up to 24hrs	Tabular or Graphical	DPD II
b) Describe any likely issues that would have a significant impact on a **BM Unit's** time to be **Synchronised** arising as a direct consequence of the inherent design or operational practice of the **Power Station** and/or **BM Unit**, e.g. limited barring facilities, time from a **Total Shutdown** or **Partial Shutdown** at which batteries would be discharged.	Text	DPD II
Block Loading Capability:		
c) Provide estimated **Block Loading Capability** from 0MW to **Registered Capacity** of each **BM Unit** based on the unit being 'hot' (run prior to shutdown) and also 'cold' (not run for 48hrs or more prior to the shutdown). The **Block Loading Capability** should be valid for a frequency deviation of 49.5Hz – 50.5Hz. The data should identify any required 'hold' points.	Tabular or Graphical	DPD II

SCHEDULE 16 - BLACK START INFORMATION

PAGE 1 OF 2

PART II

BLACK START INFORMATION The following data/text items are required from each **HVDC System Owner** or **DC Converter Station Owner** for each **HVDC System** and **DC Converter Station** as detailed in PC.A.5.7. Data is not required for **HVDC Systems** and **DC Converter Stations** that are contracted to provide a **Black Start Capability**. The data should be provided in accordance with PC.A.1.2 and also, where possible, upon request from **The Company** during a **Black Start**.		
Data Description *(PC.A.5.7) (■ CUSC Contract)*	Units	Data Category
Assuming all **BM Units** were running immediately prior to the **Total Shutdown** or **Partial Shutdown** and in the event of loss of all external power supplies, provide the following information:		
a) Expected time for the first and subsequent **BM Units** to be **Synchronised**, from the restoration of external power supplies, assuming external power supplies are not available for up to 24hrs	Tabular or Graphical	DPD II
b) Describe any likely issues that would have a significant impact on a **BM Units** time to be **Synchronised** arising as a direct consequence of the inherent design or operational practice of the **HVDC System** or **DC Converter Station** and/or **BM Unit**, e.g. time from a **Total Shutdown** or **Partial Shutdown** at which batteries would be discharged.	Text	DPD II
Block Loading Capability:		
c) Provide estimated incremental **Active Power** steps, form no load to **Rated MW** which an **HVDC System** or **DC Converter Station** can instantaneously supply without causing it to trip or go outside the **Frequency** range of 47.5Hz – 52Hz (or an otherwise agreed **Frequency** range). The time between each incremental step shall also be provided. In addition data should be provided from 0MW to **Registered Capacity** of each **BM Unit** based on the **HVDC System** or **DC Converter Station** being (not run for 48hrs or more prior to the shutdown) or run immediately before the **Partial Shutdown** or **Total Shutdown**. The data supplied should be valid for a **Frequency** deviation of 49.5Hz – 50.5Hz and should identify any required ‘hold’ points.	Tabular or Graphical	DPD II

SCHEDULE 17 - ACCESS PERIOD DATA

(PC.A.4 - CUSC Contract ■)

Submissions by**Users** using this Schedule 17 shall commence in 2011 and shall then continue in each year thereafter

Access Group	

Asset Identifier	**Start Week**	**End Week**	**Maintenance Year (1, 2 or 3)**	**Duration**	**Potential Concurrent Outage (Y/N)**

Comments

SCHEDULE 18 - OFFSHORE TRANSMISSION SYSTEM DATA

PAGE 1 OF 24

The data in this Schedule 18 is required from **Generators** who are undertaking **OTSDUW** and connecting to a **Transmission Interface Point**.

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CAT.	**GENERATING UNIT** OR STATION DATA						
		CUSC Contract	CUSC App. Form		F.Yr0	F.Yr1	F.Yr2	F.Yr3	F.Yr4	F.Yr5	F.Yr 6
<u>INDIVIDUAL **OTSDUW** DATA</u>											
Interface Point Capacity (PC.A.3.2.2 (a))	MW MVAr	□	■								
Performance Chart at the **Transmission Interface Point** for **OTSDUW Plant and Apparatus** (PC.A.3.2.2(f)(iv)		□	■								
OTSDUW DEMANDS											
Demand associated with the **OTSDUW Plant and Apparatus** (excluding OTSDUW DC Converters – see Note 1)) supplied at each **Interface Point**. The **User** should also provide the **Demand** supplied to each **Connection Point** on the **OTSDUW Plant and Apparatus**. *(PC.A.5.2.5)*											
- The maximum **Demand** that could occur.	MW MVAr	□ □		**DPD I** **DPD I**							
- **Demand** at specified time of annual peak half hour of **National Electricity Transmission System Demand** at **Annual ACS Conditions**.	MW MVAr	□ □		**DPD II** **DPD II**							
- **Demand** at specified time of annual minimum half-hour of **National Electricity Transmission System Demand**.	MW MVAr	□ □		**DPD II** **DPD II**							
(Note 1 – **Demand** required from **OTSDUW DC Converters** should be supplied under page 2 of Schedule 18).											

OTSDUW USERS SYSTEM DATA

DATA DESCRIPTION	UNITS	DATA to **RTL**		DATA CATEGORY
		CUSC Contract	CUSC App. Form	
OFFSHORE TRANSMISSION SYSTEM LAYOUT *(PC.A.2.2.1, PC.A.2.2.2 and P.C.A.2.2.3)*				
A **Single Line Diagram** showing connectivity of all of the **Offshore Transmission System** including all **Plant and Apparatus** between the **Interface Point** and all Connection **Points** is required.		■	■	**SPD**
This **Single Line Diagram** shall depict the arrangement(s) of all of the existing and proposed load current carrying **Apparatus** relating to both existing and proposed **Interface Points** and **Connection Points**, showing electrical circuitry (ie. overhead lines, underground cables (including subsea cables), power transformers and similar equipment), operating voltages, circuit breakers and phasing arrangements		■	■	**SPD**
Operational Diagrams of all substations within the **OTSDUW Plant and Apparatus**		■	■	**SPD**
SUBSTATION INFRASTRUCTURE *(PC.A.2.2.6)*				
For the infrastructure associated with any **OTSDUW Plant and Apparatus**				
Rated 3-phase rms short-circuit withstand current	kA	■	■	**SPD**
Rated 1-phase rms short-circuit withstand current	kA	■	■	**SPD**
Rated Duration of short-circuit withstand	s	■	■	**SPD**
Rated rms continuous current	A	■	■	**SPD**
LUMPED SUSCEPTANCES *(PC.A.2.3)*				
Equivalent Lumped Susceptance required for all parts of the User's Subtransmission System (including OTSDUW Plant and Apparatus) which are not included in the Single Line Diagram.		■	■	
This should not include:		■	■	
(a) independently switched reactive compensation equipment identified above.		■	■	
(b) any susceptance of the **OTSDUW Plant and Apparatus** inherent in the **Demand** (**Reactive Power**) data provided on Page 1 and 2 of this Schedule 14.		■	■	
Equivalent lumped shunt susceptance at nominal **Frequency**.	% on 100 MVA	■	■	

OFFSHORE TRANSMISSION SYSTEM DATA
Branch Data (PC.A.2.2.4)

Node 1	Node 2	Rated Voltage (kV)	Operating Voltage (kV)	Circuit	PPS PARAMETERS			ZPS PARAMETERS			Maximum Continuous Ratings			Length (km)
					R1 %100 MVA	X1 %100 MVA	B 1 %100 MVA	R0 %100 MVA	X0 %100M VA	B0 %100M VA	Winter (MVA)	Sprng Autumn (MVA)	Summer (MVA)	

Notes

1. For information equivalent STC Reference: STCP12-1m Part 3 – 2.1 Branch Data
2. In the case where an overhead line exists within the OTSDUW Plant and Apparatus the Mutual inductances should also be provided.

OFFSHORE TRANSMISSION SYSTEM DATA

2 Winding Transformer Data (PC.A.2.2.5)

The data below is **Standard Planning Data**, and details should be shown below of all transformers shown on the **Single Line Diagram**

HV Node	HV (kV)	LV Node	LV (kV)	Rating (MVA)	Trans-former	Positive Phase Sequence Reactance % on 100MVA			Positive Phase Sequence Resistance % on 100 MVA			Tap Changer			Winding Arr.	Earthing Method (Direct /Res /Reac)	Earthing Imped Ance method
						Max Tap	Min Tap	Nom Tap	Max Tap	Min Tap	Nom Tap	Range +% to -%	Step size %	type			

Notes

1 For information the corresponding STC Reference is STCP12-1: Part 3 – 2.4 Transformers

USERS SYSTEM DATA (OTSUA)

Auto Transformer Data 3-Winding (PC.A.2.2.5)

The data below is all **Standard Planning Data**, and details should be shown below of all transformers shown on the **Single Line Diagram**.

HV NODE	V_H (kV)	LV NODE	V_L (kV)	PSS/E Circuit	Rating (MVA)	Transformer	Positive Phase Sequence Reactance % on 100MVA			Positive Phase Sequence Resistance % on 100 MVA			Taps				Earthing Impedance Method	EQUIVALENT T ZPS PARAMETERS (FLIP)						The Company Sheet	The CompanyCode
							Max Tap	Min Tap	Nom Tap	Max Tap	Min Tap	Nom Tap	Range +% to -%	Step size %	Type (onload Offload	Winding Arrangement		ZOH		ZOL		ZOT Dflt X/R =20			
																		R_{0H} % 100 MVA	X_{0H} % 100 MVA	R_{0L} % 100 MVA	X_{0L} % 100 MVA	R_{0T} % 100 MVA	X_{0T} % 100 MVA		

Notes

1.For information STC Reference: STCP12-1: Part 3 - 2.4 Transformers

OFFSHORE TRANSMISSION SYSTEM DATA

<u>Circuit Breaker Data </u>(PC.A.2.2.6(a))

The data below is all **Standard Planning Data**, and should be provided for all **OTSUA** switchgear (ie. circuit breakers, load disconnectors and disconnectors)

	Circuit Breaker Data							Assumed Operating Times				3 Phase				1 Phase				
Location	Name	Rated Voltage	Operating Voltage	Make	Model	Type	Year Commissioned	Circuit Breaker (mS)	Minimum Protection & Trip Relay (mS)	Total Time (mS)	Continuous Rating (A)	Fault Rating (RMS Symmetrical) (3 phase) (MVA)	Fault Break Rating (RMS Symmetrical) (3 phase) (kA)	Fault Break Rating (Peak Asymmetrical) (3 phase) (kA)	Fault Make Rating (Peak Asymmetrical) (3 phase) (kA)	Fault Rating (RMS Symmetrical) (1 phase) (MVA)	Fault Break Rating (RMS Symmetrical) (1 phase) (kA)	Fault Break Rating (Peak Asymmetrical) (1 phase) (kA)	Fault Make Rating (Peak Asymmetrical) (1 phase) (kA)	DC time constant at testing of asymmetrical breaking ability (s)

OFFSHORE TRANSMISSION SYSTEM DATA

REACTIVE COMPENSATION EQUIPMENT (PC.A.2.4(e))

Item	Node	kV	Device No.	Rating (MVAr)	P Loss (kW)	Tap range	Connection Arrangement

Notes:

1.For information STC Reference: STCP12-1: Part 3 - 2.5 Reactive Compensation Equipment

2. Data relating to continuously variable reactive compensation equipment (such as statcoms or SVCs) should be entered on the SVC Modelling table.

3. For the avoidance of doubt this includes any AC Reactive Compensation equipment included within the OTSDUW DC Converter other than harmonic filter data which is to be entered in the harmonic filter data table.

PC.A.2.4.1(e)	A mathematical representation in block diagram format to model the control of any dynamic compensation plant. The model should be suitable for RMS dynamic stability type studies in which the time constants used should not be less than 10ms.

OFFSHORE TRANSMISSION SYSTEM DATA

REACTIVE COMPENSATION - SVC Modelling Data (PC.A.2.4.1(e)(iii))

HV Node	LV Node	Control Node	Norminal Voltage (kV)	Target Voltage (kV)	Max MVAr at HV	Min MVAr at HV	Slope %	Voltage Dependant Q Limit	Normal Running Mode	R1 PPS_R	X1 PPS_X	R0 ZPS_R	X0 ZPS_X	Transf. Winding Type	Connection (Direct/Tertiary)

Notes:

1.For information the equivalent STC Ref,erence is: STCP12-1: Part 3 - 2.7 SVC Modelling Data

OFFSHORE TRANSMISSION SYSTEM DATA

Harmonic Filter Data (including **OTSDUW DC Converter** harmonic Filter Data)
(PC.A.5.4.3.1(d) and PC.A.6.4.2)

Site Name	SLD Reference	Point of Filter Connection			
Filter Description					
Manufacturer	Model	Filter Type		Filter connection type (Delta/Star, Grounded/ Ungrounded)	Notes
Bus Voltage	Rating	Q factor		Tuning Frequency	Notes
Component Parameters (as per SLD)					
	Parameter as applicable				
Filter Component (R, C or L)	Capacitance (micro-Farads)		Inductance (milli-Henrys)	Resistance (Ohms)	Notes
Filter frequency characteristics (graphs) detailing for frequency range up to 10kHz and higher					
1. Graph of impedance (ohm) against frequency (Hz) 2. Graph of angle (degree) against frequency (Hz) 3. Connection diagram of Filter & Elements					

Notes:

1. For information STC Reference: STCP12-1: Part 3 - 2.8 Harmonic Filter Data

Information for Transient Overvoltage Assessment (**DPD I**) *(PC.A.6.2 ■ CUSC Contract)*

The information listed below may be requested by **The Company** from each **User** undertaking **OTSDUW** with respect to any **Interface Point** or **Connection Point** to enable **The Company** to assess transient overvoltage on the **National Electricity Transmission System**.

(a) Busbar layout plan(s), including dimensions and geometry showing positioning of any current and voltage transformers, through bushings, support insulators, disconnectors, circuit breakers, surge arresters, etc. Electrical parameters of any associated current and voltage transformers, stray capacitances of wall bushings and support insulators, and grading capacitances of circuit breakers;

(b) Electrical parameters and physical construction details of lines and cables connected at that busbar. Electrical parameters of all plant e.g., transformers (including neutral earthing impedance or zig-zag transformers if any), series reactors and shunt compensation equipment connected at that busbar (or to the tertiary of a transformer) or by lines or cables to that busbar;

(c) Basic insulation levels (BIL) of all **Apparatus** connected directly, by lines or by cables to the busbar;

(d) Characteristics of overvoltage **Protection** devices at the busbar and at the termination points of all lines, and all cables connected to the busbar;

(e) Fault levels at the lower voltage terminals of each transformer connected to each **Interface Point** or **Connection Point** without intermediate transformation;

(f) The following data is required on all transformers within the **OTSDUW Plant and Apparatus**.

(g) An indication of which items of equipment may be out of service simultaneously during **Planned Outage** conditions.

Harmonic Studies (**DPD I**) *(PC.A.6.4 ■ CUSC Contract)*

The information given below, both current and forecast, where not already supplied in this Schedule 14 may be requested by **The Company** from each **User** if it is necessary for **The Company** to evaluate the production/magnification of harmonic distortion on **National Electricity Transmission System**. The impact of any third party **Embedded** within the **User's System** should be reflected:-

(a) Overhead lines and underground cable circuits (including subsea cables) of the **User's OTSDUW Plant and Apparatus** must be differentiated and the following data provided separately for each type:-

Positive phase sequence resistance
Positive phase sequence reactance
Positive phase sequence susceptance

(b) for all transformers connecting the **OTSDUW Plant and Apparatus** to a lower voltage:-

Rated MVA
Voltage Ratio
Positive phase sequence resistance
Positive phase sequence reactance

(c) at the lower voltage points of those connecting transformers:-

Equivalent positive phase sequence susceptance
Connection voltage and MVAr rating of any capacitor bank and component design parameters if configured as a filter

Equivalent positive phase sequence interconnection impedance with other lower voltage points
The minimum and maximum **Demand** (both MW and MVAr) that could occur
Harmonic current injection sources in Amps at the Connection Points and Interface Points

(d) an indication of which items of equipment may be out of service simultaneously during **Planned Outage** conditions

<u>Voltage Assessment Studies</u> (**DPD I**) *(PC.A.6.5 ■ CUSC Contract)*

The information listed below, where not already supplied in this Schedule 14, may be requested by **The Company** from each **User** undertaking **OTSDUW** with respect to any **Connection Point** or **Interface Point** if it is necessary for **The Company** to undertake detailed voltage assessment studies (eg to examine potential voltage instability, voltage control co-ordination or to calculate voltage step changes on the **National Electricity Transmission System**).

(a) For all circuits of the **User's OTSDUW Plant and Apparatus**:-

Positive Phase Sequence Reactance
Positive Phase Sequence Resistance
Positive Phase Sequence Susceptance
MVAr rating of any reactive compensation equipment

(b) for all transformers connecting the **User's OTSDUW Plant and Apparatus** to a lower voltage:-

Rated MVA
Voltage Ratio
Positive phase sequence resistance
Positive Phase sequence reactance
Tap-changer range
Number of tap steps
Tap-changer type: on-load or off-circuit
AVC/tap-changer time delay to first tap movement
AVC/tap-changer inter-tap time delay

(c) at the lower voltage points of those connecting transformers

Equivalent positive phase sequence susceptance
MVAr rating of any reactive compensation equipment
Equivalent positive phase sequence interconnection impedance with other lower voltage points
The maximum **Demand** (both MW and MVAr) that could occur
Estimate of voltage insensitive (constant power) load content in % of total load at both winter peak and 75% off-peak load conditions

Short Circuit Analyses:(**DPD I**) *(PC.A.6.6 ■ CUSC Contract)*

The information listed below, both current and forecast, and where not already supplied under this Schedule 14, may be requested by **The Company** from each **User** undertaking **OTSDUW** with respect to any **Connection Point or Interface Point** where prospective short-circuit currents on **Transmission** equipment are close to the equipment rating.

(a) For all circuits of the **User's OTSDUW Plant and Apparatus**:-
Positive phase sequence resistance
Positive phase sequence reactance
Positive phase sequence susceptance
Zero phase sequence resistance (both self and mutuals)
Zero phase sequence reactance (both self and mutuals)
Zero phase sequence susceptance (both self and mutuals)

(b) for all transformers connecting the **User's OTSDUW Plant and Apparatus** to a lower voltage:-

Rated MVA
Voltage Ratio
Positive phase sequence resistance (at max, min and nominal tap)
Positive Phase sequence reactance (at max, min and nominal tap)
Zero phase sequence reactance (at nominal tap)
Tap changer range
Earthing method: direct, resistance or reactance
Impedance if not directly earthed

(c) at the lower voltage points of those connecting transformers:-

The maximum **Demand** (in MW and MVAr) that could occur
Short-circuit infeed data in accordance with PC.A.2.5.6(a) unless the **User**'s **OTSDUW Plant and Apparatus** runs in parallel with the **Subtransmission System**, when to prevent double counting in each node infeed data, a π equivalent comprising the data items of PC.A.2.5.6(a) for each node together with the positive phase sequence interconnection impedance between the nodes shall be submitted.

Fault infeed data to be submitted by **OTSDUW Plant and Apparatus** providing a fault infeed (including **OTSDUW DC Converters**) (PC.A.2.5.5)

A submission is required for **OTSDUW Plant and Apparatus** (including **OTSDUW DC Converters** at each **Transmission Interface Point** and **Connection Point**. The submission shall represent operating conditions that result in the maximum fault infeed. The fault current from all auxiliaries of the **OTSDUW Plant and Apparatus** at the **Transmission Interface Point** and **Connection Point** shall be included. The fault infeed shall be expressed as a fault current at the **Transmission Interface Point** and also at each **Connection Point**.

Should actual data in respect of fault infeeds be unavailable at the time of the application for a **CUSC Contract** or **Embedded Development Agreement**, a limited subset of the data, representing the maximum fault infeed that may result from the **OTSDUW Plant and Apparatus**, shall be submitted. This data will, as a minimum, represent the root mean square of the positive, negative and zero sequence components of the fault current for both single phase and three phase solid faults at each **Connection Point** and **Interface Point** at the time of fault application and 50ms following fault application. Actual data in respect of fault infeeds shall be submitted to **The Company** as soon as it is available, in line with PC.A.1.2.

DATA DESCRIPTION	UNITS	F.Yr. 0	F.Yr. 1	F.Yr. 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr. 7	DATA to **RTL**	
										CUSC Contract	CUSC App. Form
(PC.A.2.5)											
Name of **OTSDUW Plant and Apparatus**											
OTSDUW DC Converter type (ie voltage or current source)											
A submission shall be provided for the contribution of each **OTSDUW** Plant and Apparatus to the positive, negative and zero sequence components of the short circuit current at the **Interface Point** and each **Connection Point** for (i) a solid symmetrical three phase short circuit (ii) a solid single phase to earth short circuit (iii) a solid phase to phase short circuit (iv) a solid two phase to earth short circuit If protective controls are used and active for the above conditions, a submission shall be provided in the limiting case where the protective control is not active. This case may require application of a non-solid fault, resulting in a retained voltage at the fault point.										□ □ □ □ □	■ ■ ■ ■ ■

DATA DESCRIPTION	UNITS	F. Yr. 0	F. Yr. 1	F. Yr. 2	F. Yr. 3	F. Yr. 4	F. Yr. 5	F. Yr. 6	F. Yr. 7	DATA to **RTL**	
										CUSC Contract	CUSC App. Form
- A continuous time trace and table showing the root mean square of the positive, negative and zero sequence components of the fault current from the time of fault inception to 140ms after fault inception at 10ms intervals	Graphical and tabular kA versus s									□	■
- A continuous time trace and table showing the positive, negative and zero sequence components of retained voltage at the **Interface Point** and each **Connection Point**, if appropriate	p.u. versus s									□	■
- A continuous time trace and table showing the root mean square of the positive, negative and zero sequence components of retained voltage at the fault point, if appropriate	p.u. versus s									□	■
Positive sequence X/R ratio of the equivalent at time of fault at the **Interface Point** and each **Connection Point**										□	■
Minimum zero sequence impedance of the equivalent at the **Interface Point** and each **Connection Point**										□	■
Active Power transfer at the Interface Point and each Connection Point pre-fault	MW									□	■
Power Factor (lead or lag)										□	■
Pre-fault voltage (if different from 1.0 p.u.) at fault point (See note 1)	p.u.									□	■
Items of reactive compensation switched in pre-fault										□	■

Note 1. The pre-fault voltage provided above should represent the voltage within the range 0.95 to 1.05 that gives the highest fault current

SCHEDULE 18 - OFFSHORE TRANSMISSION SYSTEM DATA
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Thermal Ratings Data (PC.A.2.2.4)

CIRCUIT RATING SCHEDULE

Voltage
132kV

Offshore TO Name

Issue Date

CIRCUIT *Name from Site A – Site B*

		Winter				Spring/Autumn				Summer			
OVERALL CCT RATINGS		%Nom	Limit	Amps	MVA	%Nom	Limit	Amps	MVA	%Nom	Limit	Amps	MVA
Pre-Fault Continuous		84%	Line	485	111	84%	Line	450	103	84%	Line	390	89
Post-Fault Continuous		100%	Line	580	132	100%	Line	540	123	100%	Line	465	106
Prefault load exceeds line prefault continuous rating	6hr	95%	Line	580	132	95%	Line	540	123	95%	Line	465	106
	20m		Line	580	132		Line	540	123		Line	465	106
	10m	mva	Line	580	132	mva	Line	540	123	mva	Line	465	106
	5m	125	Line	580	132	116	Line	540	123	100	Line	465	106
	3m		Line	580	132		Line	540	123		Line	465	106
Short Term Overloads	6hr	90%	Line	580	132	90%	Line	540	123	90%	Line	465	106
	20m		Line	580	132		Line	540	123		Line	465	106
	10m	mva	Line	580	132	mva	Line	540	123	mva	Line	465	106
	5m	118	Line	580	132	110	Line	540	123	95	Line	465	106
	3m		Line	580	132		Line	540	123		Line	465	106
Limiting Item and permitted overload values for different times and pre-fault loads	6hr	84%	Line	580	132	84%	Line	540	123	84%	Line	465	106
	20m		Line	590	135		Line	545	125		Line	470	108
	10m	mva	Line	630	144	mva	Line	580	133	mva	Line	495	113
	5m	110	Line	710	163	103	Line	655	149	89	Line	555	126
	3m		Line	810	185		Line	740	170		Line	625	143
	6hr	75%	Line	580	132	75%	Line	540	123	75%	Line	465	106
	20m		Line	595	136		Line	555	126		Line	475	109
	10m	mva	Line	650	149	mva	Line	600	137	mva	Line	510	116
	5m	99	Line	760	173	92	Line	695	159	79	Line	585	134
	3m		Line	885	203		Line	810	185		Line	685	156
	6hr	60%	Line	580	132	60%	Line	540	123	60%	Line	465	106
	20m		Line	605	138		Line	560	128		Line	480	110
	10m	mva	Line	675	155	mva	Line	620	142	mva	Line	530	121
	5m	79	Line	820	187	73	Line	750	172	63	Line	635	145
	3m		Line	985	226		Line	900	206		Line	755	173
	6hr	30%	Line	580	132	30%	Line	540	123	30%	Line	465	106
	20m		Line	615	141		Line	570	130		Line	490	112
	10m	mva	Line	710	163	mva	Line	655	150	mva	Line	555	127
	5m	39	Line	895	205	36	Line	820	187	31	Line	690	158
	3m		Line	1110	255		Line	1010	230		Line	845	193

	6hr 20m 10m 5m 3m												
	6hr 20m 10m 5m 3m												
Notes or Restrictions Detailed													

Notes: 1. For information the equivalent STC Reference: STCP12-1: Part 3 - 2.6 Thermal Ratings
2. The values shown in the above table is example data.

Protection Policy *(PC.A.6.3)*

To include details of the protection policy

Protection Schedules*(PC.A.6.3)*

Data schedules for the protection systems associated with each primary plant item including:
Protection, Intertrip Signalling & operating times
Intertripping and protection unstabilisation initiation
Synchronising facilities
Delayed Auto Reclose sequence schedules

Automatic Switching Scheme Schedules *(PC.A.2.2.7)*

A diagram of the scheme and an explanation of how the system will operate and what plant will be affected by the scheme's operation.

GENERATOR INTERTRIP SCHEMES (PC.A.2.2.7(b))

Substation: ________________________________

Details of Generator Intertrip Schemes:

A diagram of the scheme and an explanation of how the system will operate and what plant will be effected by the schemes operation.

DEMAND INTERTRIP SCHEMES (PC.A.2.2.7(b))

Substation:_________________________________

Details of Demand Intertrip Schemes:

A diagram of the scheme and an explanation of how the system will operate and what plant will be effected by the schemes operation

Specific Operating Requirements (CC.5.2.1)

SUBSTATION OPERATIONAL GUIDE

Substation: ___________________________

Location Details:

Postal Address:	Telephone Nos.	Map Ref.
Transmission Interface		
Generator Interface		

1. **Substation Type:**

2. **Voltage Control:** *(short description of voltage control system. To include mention of modes ie Voltage, manual etc. Plus control step increments ie 0.5%-0.33kV?)*

3. **Energisation Switching Information:** *(The standard energisation switching process from dead.)*

4. **Intertrip Systems:**

5. **Reactive Plant Outage:** *(A short explanation of any system re-configurations required to facilitate the outage of any reactive plant which form part of the OTSDUW Plant and Apparatus equipment. Also any generation restrictions required).*

6. **Harmonic Filter Outage:** *(An explanation as to any OTSDUW Plant and Apparatus reconfigurations required to facilitate the outage and maintain the system within specified Harmonic limits, also any generation restrictions required).*

OTSDUW DC CONVERTER TECHNICAL DATA

OTSDUW DC CONVERTER NAME DATE:___________

Data Description	Units	DATA to **RTL**		Data Category	**DC Converter Station** Data
(PC.A.4 and PC.A.5.2.5)		CUSC Contract	CUSC App. Form		
OTSDUW DC CONVERTER (**CONVERTER** DEMANDS):					
Demand supplied through **Station Transformers** associated with the **OTSDUW DC Converter** at each **Interface Point** and each **Offshore Connection Point Grid Entry Point [PC.A.4.1]**					
- **Demand** with all **OTSDUW DC Converters** operating at **Interface Point Capacity** .	MW MVAr	□ □		**DPD II** **DPD II**	
- **Demand** with all **OTSDUW DC Converters** operating at maximum **Interface Point** flow from the **Interface Point** to each **Offshore Grid Entry Point** .	MW MVAr	□ □		**DPD II** **DPD II**	
- The maximum **Demand** that could occur.	MW MVAr	□ □		**DPD II** **DPD II**	
- **Demand** at specified time of annual peak half hour of **The Company Demand** at **Annual ACS Conditions**.	MW MVAr	□ □		**DPD II** **DPD II**	
- **Demand** at specified time of annual minimum half-hour of **The Company Demand**.	MW MVAr	□ □		**DPD II**	
OTSDUW DC CONVERTER DATA	Text	□	■	**SPD+**	
Number of poles, i.e. number of **OTSDUW DC Converters**	Text	□	■	**SPD+**	
Pole arrangement (e.g. monopole or bipole)	Diagram	□			
Return path arrangement					
Details of each viable operating configuration		□	■	**SPD+**	
Configuration 1	Diagram	□	■		
Configuration 2	Diagram	□	■		
Configuration 3	Diagram	□	■		
Configuration 4	Diagram	□	■		
Configuration 5	Diagram	□	■		
Configuration 6	Diagram				

Data Description	Units	DATA to **RTL** CUSC Contract	 CUSC App. Form	Data Category	Operating Configuration 1	 2	 3	 4	 5	 6
OTSDUW DC CONVERTER DATA *(PC.A.3.3.1(d))*										
OTSDUW DC Converter Type (e.g. current or Voltage source)	Text	□	■	**SPD**						
If the busbars at the **Interface Point** or Connection Point are normally run in separate sections identify the section to which the **OTSDUW DC Converter** configuration is connected	Section Number	□	■	**SPD**						
Rated MW import per pole (PC.A.3.3.1)	MW	□	■	**SPD+**						
Rated MW export per pole (PC.A.3.3.1)	MW	□	■	**SPD+**						
ACTIVE POWER TRANSFER CAPABILITY (PC.A.3.2.2) **Interface Point Capacity**	MW MVAr	□ □	■ ■	**SPD** **SPD**						
OTSDUW DC CONVERTER TRANSFORMER (PC.A.5.4.3.1) Rated MVA Winding arrangement Nominal primary voltage Nominal secondary (converter-side) voltage(s) Positive sequence reactance Maximum tap Nominal tap Minimum tap Positive sequence resistance Maximum tap Nominal tap Minimum tap Zero phase sequence reactance Tap change range Number of steps	MVA kV kV % on MVA % on MVA % on MVA % on MVA % on MVA % on MVA +% / -%	□ □ □ □ □ □ □ □ □ □ □ □		**DPD II** **DPD II** **DPD II** **DPD II** **DPD II** **DPD II** **DPD II** **DPD II** **DPD II** **DPD II** **DPD II** **DPD II** **DPD II**						

Data Description	Units	DATA to **RTL**		Data Category	Operating configuration					
		CUSC Contract	CUSC App. Form		1	2	3	4	5	6
OTSDUW DC CONVERTER NETWORK DATA (PC.A.5.4.3.1 (c))										
Rated DC voltage per pole	kV	□		**DPD II**						
Rated DC current per pole	A	□		**DPD II**						
Details of the **OTSDUW DC Network** described in diagram form including resistance, inductance and capacitance of all DC cables and/or DC lines. Details of any line reactors (including line reactor resistance), line capacitors, DC filters, earthing electrodes and other conductors that form part of the **OTSDUW DC Network** should be shown.	Diagram	□		**DPD II**						

Data Description	Units	DATA to **RTL**		Data Category	Operating configuration					
		CUSC Contract	CUSC App. Form		1	2	3	4	5	6
OTSDUW DC CONVERTER CONTROL SYSTEMS (PC.A.5.4.3.2)										
Static V_{DC} – P_{DC} (DC voltage – DC power) or Static V_{DC} – I_{DC} (DC voltage – DC current) characteristic (as appropriate) when operating as –Rectifier –Inverter	Diagram Diagram Diagram	□ □ □		**DPD II** **DPD II** **DPD II**						
Details of rectifier mode control system, in block diagram form together with parameters showing transfer functions of individual elements.	Diagram Diagram	□ □		**DPD II** **DPD II**						
Details of inverter mode control system, in block diagram form showing transfer functions of individual elements including parameters (as applicable).	Diagram	□		**DPD II**						
Details of **OTSDUW DC Converter** transformer tap changer control system in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Details of AC filter control systems in block diagram form showing transfer functions of individual elements including parameters	Diagram	□		**DPD II**						
Details of any frequency and/or load control systems in block diagram form showing transfer functions of individual elements including parameters.	Diagram	□		**DPD II**						
Details of any large or small signal modulating controls, such as power oscillation damping controls or sub-synchronous oscillation damping controls, that have not been submitted as part of the above control system data.	Diagram	□		**DPD II**						
Transfer block diagram representation of the reactive power control at converter ends for a voltage source converter.										

Data Description	Units	DATA to **RTL**		Data Category	Operating configuration					
		CUSC Contract	CUSC App. Form		1	2	3	4	5	6
LOADING PARAMETERS (PC.A.5.4.3.3)										
MW Export from the **Offshore Grid Entry Point** to the **Transmission Interface Point**										
Nominal loading rate	MW/s			**DPD I**						
Maximum (emergency) loading rate	MW/s			**DPD I**						
Maximum recovery time, to 90% of pre-fault loading, following an AC system fault or severe voltage depression.	s	□		**DPD II**						
Maximum recovery time, to 90% of pre-fault loading, following a transient DC Network fault.	s	□		**DPD II**						

SCHEDULE 19 – USER DATA FILE STRUCTURE

The structure of the **User Data File Structure** is given below.

i.d.	Folder name	Description of contents
Part A: Commercial & Legal		
A2	Commissioning	Commissioning & Test Programmes
A3	Statements	Statements of Readiness
A9	AS Monitoring	Ancillary Services Monitoring
A10	Self Certification	User Self Certification of Compliance
A11	Compliance statements	Compliance Statement
Part 1: Safety & System Operation		
1.1	Interface Agreements	Interface Agreements
1.2	Safety Rules	Safety Rules
1.3	Switching Procedures	Local Switching Procedures
1.4	Earthing	Earthing
1.5	SRS	Site Responsibility Schedules
1.6	Diagrams	Operational and Gas Zone Diagrams
1.7	Drawings	Site Common Drawings
1.8	Telephony	Control Telephony
1.9	Safety Procedures	Local Safety Procedures
1.10	Co-ordinators	Safety Co-ordinators
1.11	RISSP	Record of Inter System Safety Precautions
1.12	Tel Numbers	Telephone Numbers for Joint System Incidents
1.13	Contact Details	Contact Details (fax, tel, email)
1.14	Restoration Plan	Local Joint Restoration Plan (incl. black start if applicable)
1.15	Maintenance	Maintenance Standards
Part 2: Connection Technical Data		
2.1	DRC Schedule 5	DRC Schedule 5 – Users System Data
2.2	Protection Report	Protection Settings Reports
2.3	Special Automatic Facilities	Special Automatic Facilities e.g. intertrip
2.4	Operational Metering	Operational Metering
2.5	Tariff Metering	Tariff Metering
2.6	Operational Comms	Operational Communications
2.7	Monitoring	Performance Monitoring
2.8	Power Quality	Power Quality Test Results (if required)

SCHEDULE 19 – USER DATA FILE STRUCTURE
PAGE 2 OF 2

Part 3: Generator Technical Data		
3.1	DRC Schedule 1	DRC Schedule 1 - Generating Unit, Power Generating Module, HVDC System and DC Converter Technical Data
3.2	DRC Schedule 2	DRC Schedule 2 - Generation Planning Data
3.3	DRC Schedule 4	DRC Schedule 4 – Frequency Droop & Response
3.4	DRC Schedule 14	DRC Schedule 14 – Fault Infeed Data – Generators
3.5	Special Generator Protection	Special Generator Protection eg Pole slipping; islanding
3.6	Compliance Tests	Compliance Tests & Evidence
3.7	Compliance Studies	Compliance Simulation Studies
3.8	Site Specific	Bilateral Connections Agreement Technical Data & Compliance
Part 4: General DRC Schedules		
4.1	DRC Schedule 3	DRC Schedule 3 – Large Power Station Outage Information
4.2	DRC Schedule 6	DRC Schedule 6 – Users Outage Information
4.3	DRC Schedule 7	DRC Schedule 7 – Load Characteristics
4.4	DRC Schedule 8	DRC Schedule 8 – BM Unit Data (if applicable)
4.5	DRC Schedule 10	DRC Schedule 10 –Demand Profiles
4.6	DRC Schedule 11	DRC Schedule 11 – Connection Point Data
Part 5: OTSDUW Data And Information (if applicable and prior to **OTSUA Transfer Time**)		
		Diagrams Circuits Plant and Apparatus Circuit Parameters Protection Operation and Autoswitching Automatic Control Systems
		Mathematical model of dynamic compensation plant

< END OF DATA REGISTRATION CODE >

REVISIONS
(R)

(This section does not form part of the Grid Code)

R.1 **The Company's Transmission Licence** sets out the way in which changes to the Grid Code are to be made and reference is also made to **The Company's** obligations under the General Conditions.

R.2 All pages re-issued have the revision number on the lower left hand corner of the page and date of the revision on the lower right hand corner of the page.

R.3 The Grid Code was introduced in March 1990 and the first issue was revised 31 times. In March 2001 the New Electricity Trading Arrangements were introduced and Issue 2 of the Grid Code was introduced which was revised 16 times. At British Electricity Trading and Transmission Arrangements (BETTA) Go-Active Issue 3 of the Grid Code was introduced and subsequently revised 35 times. At Offshore Go-active Issue 4 of the Grid Code was introduced and has been revised 13 times since its original publication. Issue 5 of the Grid Code was published to accommodate the changes made by Grid Code Modification A/10 which has incorporated the **Generator** compliance process into the Grid Code.

R.4 This Revisions section provides a summary of the sections of the Grid Code changed by each revision to Issue 5.

R.5 All enquiries in relation to revisions to the Grid Code, including revisions to Issues 1, 2, 3, 4 and 5 should be addressed to the Grid Code development team at the following email address:

Grid.Code@nationalgrideso.com

Revision	Section	Related Modification	Effective Date
0	Glossary and Definitions	A/10 and G/11	17 August 2012
0	Planning Code – PC.2.1	G/11	17 August 2012
0	Planning Code – PC.5.4	G/11	17 August 2012
0	Planning Code – PC.8	G/11	17 August 2012
0	Planning Code – PC.8.2	G/11	17 August 2012
0	Planning Code – PC.A.1	G/11	17 August 2012
0	Planning Code – PC.A.2	A/10 and G/11	17 August 2012
0	Planning Code – PC.A.3	G/11	17 August 2012
0	Planning Code – PC.A.5	A/10 and G/11	17 August 2012
0	Compliance Processes	A/10	17 August 2012
0	Connection Conditions – CC.1.1	A/10	17 August 2012
0	Connection Conditions – CC.2.2	G/11	17 August 2012
0	Connection Conditions – CC.3.3	A/10	17 August 2012
0	Connection Conditions – CC.4.1	A/10	17 August 2012
0	Connection Conditions – CC.5.2	G/11	17 August 2012
0	Connection Conditions – CC.6.1	G/11	17 August 2012
0	Connection Conditions – CC.6.3	G/11	17 August 2012
0	Connection Conditions – CC.6.6	A/10	17 August 2012
0	Connection Conditions – CC.7.2	G/11	17 August 2012

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0	Connection Conditions – CC.7.4	G/11	17 August 2012
0	Connection Conditions – CC.A.1	G/11	17 August 2012
0	Connection Conditions – CC.A.2	G/11	17 August 2012
0	Connection Conditions – CC.A.3	G/11	17 August 2012
0	Connection Conditions – CC.A.4	G/11	17 August 2012
0	Connection Conditions – CC.A.6	A/10	17 August 2012
0	Connection Conditions – CC.A.7	A/10 and G/11	17 August 2012
0	Connection Conditions – Figure CC.A.3.1	G/11	17 August 2012
0	Operating Code No. 2 – OC2.4	G/11	17 August 2012
0	Operating Code No. 2 – OC2.A.1	G/11	17 August 2012
0	Operating Code No. 5 – OC5.3	A/10	17 August 2012
0	Operating Code No. 5 – OC5.5	A/10 and G/11	17 August 2012
0	Operating Code No. 5 – OC5.7	G/11	17 August 2012
0	Operating Code No. 5 – OC5.8	A/10 and G/11	17 August 2012
0	Operating Code No. 5 – OC5.A.1	A/10	17 August 2012
0	Operating Code No. 5 – OC5.A.2	A/10	17 August 2012
0	Operating Code No. 5 – OC5.A.3	A/10	17 August 2012
0	Operating Code No. 5 – OC5.A.4	A/10	17 August 2012
0	Operating Code No. 7 – OC7.4	G/11	17 August 2012
0	Operating Code No. 8 – OC8.2	G/11	17 August 2012

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0	Operating Code No. 8 – OC8A.1	G/11	17 August 2012
0	Operating Code No. 8 – OC8A.5	G/11	17 August 2012
0	Operating Code No. 8 – OC8B.1	G/11	17 August 2012
0	Operating Code No. 8 – OC8B.4	G/11	17 August 2012
0	Operating Code No. 8 – OC8B.5	G/11	17 August 2012
0	Operating Code No. 8 – OC8B Appendix E	G/11	17 August 2012
0	Operating Code No. 9 – OC9.2	G/11	17 August 2012
0	Operating Code No. 9 – OC9.4	G/11	17 August 2012
0	Operating Code No. 9 – OC9.5	G/11	17 August 2012
0	Operating Code No. 12 – OC12.3	G/11	17 August 2012
0	Operating Code No. 12 – OC12.4	G/11	17 August 2012
0	Balancing Code No. 1 – BC1.5	G/11	17 August 2012
0	Balancing Code No. 1 – BC1.8	G/11	17 August 2012
0	Balancing Code No. 1 – BC1.A.1	G/11	17 August 2012
0	Balancing Code No. 2 – BC2.5	G/11	17 August 2012
0	Balancing Code No. 2 – BC2.8	G/11	17 August 2012
0	Balancing Code No. 2 – BC2.A.2	G/11	17 August 2012
0	Balancing Code No. 2 – BC2.A.3	G/11	17 August 2012
0	Balancing Code No. 2 – BC2.A.4	G/11	17 August 2012
0	Balancing Code No. 3 – BC3.5	G/11	17 August 2012

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0	Balancing Code No. 3 – BC3.7	G/11	17 August 2012
0	Data Registration Code – DRC.1.5	G/11	17 August 2012
0	Data Registration Code – DRC.4.2	G/11	17 August 2012
0	Data Registration Code – DRC.4.4	G/11	17 August 2012
0	Data Registration Code – DRC.5.2	A/10 and G/11	17 August 2012
0	Data Registration Code – DRC.5.5	G/11	17 August 2012
0	Data Registration Code – DRC.6.1	A/10 and G/11	17 August 2012
0	Data Registration Code – DRC.6.2	A/10	17 August 2012
0	Data Registration Code – Schedule 1	A/10 and G/11	17 August 2012
0	Data Registration Code – Schedule 2	G/11	17 August 2012
0	Data Registration Code – Schedule 3	G/11	17 August 2012
0	Data Registration Code – Schedule 4	G/11	17 August 2012
0	Data Registration Code – Schedule 5	G/11	17 August 2012
0	Data Registration Code – Schedule 10	G/11	17 August 2012
0	Data Registration Code – Schedule 12A	G/11	17 August 2012
0	Data Registration Code – Schedule 14	A/10 and G/11	17 August 2012
0	Data Registration Code – Schedule 15	G/11	17 August 2012
0	Data Registration Code – Schedule 19	A/10	17 August 2012
0	General Conditions – GC.4	G/11	17 August 2012
0	General Conditions – GC.12	G/11	17 August 2012

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0	General Conditions – GC.15	G/11	17 August 2012
0	General Conditions – GC.A1	G/11	17 August 2012
0	General Conditions – GC.A2	G/11	17 August 2012
0	General Conditions – GC.A3	G/11	17 August 2012
1	Operating Code No. 8 – OC8A.5.3.4	C/12	6 November 2012
1	Operating Code No. 8 – OC8B.5.3.4	C/12	6 November 2012
2	Balancing Code No. 1 – BC1.2.1	B/12	31 January 2013
2	Balancing Code No. 1 – BC1.4.2	B/12	31 January 2013
2	Balancing Code No. 1 – BC1.A.1.5	B/12	31 January 2013
2	Connection Conditions – CC.7.7	D/12	31 January 2013
3	Glossary and Definitions	C/11	2 April 2013
3	Operating Code No. 8 – OC8A.4.3.5	B/10	2 April 2013
3	Operating Code No. 8 – OC8B.4.3.5	B/10	2 April 2013
3	Balancing Code No. 2 – BC2.5	C/11	2 April 2013
4	Glossary and Definitions	GC0060 (F/12)	19 August 2013
4	Planning Code – PC.A.5	GC0040 (A/12)	19 August 2013
4	Operating Code No. 2 – OC2.A.10	GC0060 (F/12)	19 August 2013
4	Data Registration Code – Schedule 1	GC0040 (A/12)	19 August 2013
4	Data Registration Code – Schedule 2	GC0060 (F/12)	19 August 2013
5	Glossary and Definitions	GC0033, 71, 72 and 73	05 November 2013

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5	General Conditions – GC.4	GC0071, 72 and 73	05 November 2013
5	General Conditions – GC.14	GC0071, 72 and 73	05 November 2013
5	General Conditions – GC.16	GC0071, 72 and 73	05 November 2013
6	Connection Conditions – CC.A.7	GC0065	13 December 2013
6	Planning Code – PC.A.3	GC0037	13 December 2013
6	Operating Code No. 2 – OC2.4.2	GC0037	13 December 2013
6	Operating Code No. 2 – Appendix 4	GC0037	13 December 2013
6	Balancing Code No. 1 – BC1.4.2	GC0037	13 December 2013
6	Balancing Code No. 1 – BC1.A.1.8	GC0037	13 December 2013
7	Glossary and Definitions	GC0044	31 March 2014
7	Operating Code No. 9 – OC9.2.5	GC0044	31 March 2014
7	Operating Code No. 9 – OC9.4.6	GC0044	31 March 2014
7	Operating Code No. 9 – OC9.4.7.4	GC0044	31 March 2014
7	Operating Code No. 9 – OC9.4.7.9	GC0044	31 March 2014
7	Operating Code No. 9 – OC9.4.7.10	GC0044	31 March 2014
7	Balancing Code No. 2 – BC2.9.2.2	GC0044	31 March 2014
8	Glossary and Definitions	Secretary of State direction – Generator Commissioning Clause	10 June 2014
8	Planning Code	Secretary of State direction –	10 June 2014

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		Generator Commissioning Clause	
8	Connection Conditions	Secretary of State direction – Generator Commissioning Clause	10 June 2014
8	Compliance Processes	Secretary of State direction – Generator Commissioning Clause	10 June 2014
8	Operating Code No. 5	Secretary of State direction – Generator Commissioning Clause	10 June 2014
8	Operating Code No. 7	Secretary of State direction – Generator Commissioning Clause	10 June 2014
8	Operating Code No. 8	Secretary of State direction – Generator Commissioning Clause	10 June 2014
8	Operating Code No. 8A	Secretary of State direction – Generator Commissioning Clause	10 June 2014
8	Operating Code No. 8B	Secretary of State direction – Generator Commissioning Clause	10 June 2014
8	Balancing Code No. 2	Secretary of State direction – Generator Commissioning Clause	10 June 2014
9	Operating Code No. 6 – OC6.5	GC0050	01 July 2014
9	Operating Code No. 6 – OC6.7	GC0050	01 July 2014

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9	Balancing Code No. 2 – Appendix 3 Annexures	GC0068	01 July 2014
9	Balancing Code No. 2 – Appendix 4 Annexure	GC0068	01 July 2014
10	Glossary and Definitions	Secretary of State direction – EMR	01 August 2014
10	Planning Code – PC.5.4	Secretary of State direction – EMR	01 August 2014
10	Planning Code – PC.5.6	Secretary of State direction – EMR	01 August 2014
10	General Conditions – GC.4.6	Secretary of State direction – EMR	01 August 2014
10	General Conditions – GC.12	Secretary of State direction – EMR	01 August 2014
11	Planning Code – PC.A.3.1.4	GC0042	21 August 2014
11	Planning Code – PC.A.5	GC0042	21 August 2014
11	Data Registration Code – DRC6.1.11	GC0042	21 August 2014
11	Data Registration Code – Schedule 11	GC0042	21 August 2014
12	Glossary and Definitions	GC0083	01 November 2014
12	Planning Code – PC.A.3.4.3	GC0083	01 November 2014
12	Planning Code – PC.D.1	GC0052	01 November 2014
12	Operating Code No. 2 – OC2.4.2.3	GC0083	01 November 2014
12	Operating Code No. 2 – OC2.4.7	GC0083	01 November 2014
12	Operating Code No. 6 – OC6.1.5	GC0061	01 November 2014
12	Data Registration Code – Schedule 1	GC0052	01 November 2014

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12	Data Registration Code – Schedule 2	GC0052	01 November 2014
12	Data Registration Code – Schedule 6	GC0083	01 November 2014
13	Glossary and Definitions	GC0063	22 January 2015
13	Connection Conditions – CC.6.5.6	GC0063	22 January 2015
13	Balancing Code No. 1 – BC1.A.1.3.1	GC0063	22 January 2015
13	General Conditions – Annex to General Conditions	GC0080	22 January 2015
14	Connection Conditions - CC6.1.7	GC0076	26 August 2015
15	Glossary and Definitions	GC0023	03 February 2016
15	Connection Conditions - CC6.2.2	GC0023	03 February 2016
15	Connection Conditions - CC6.2.3	GC0023	03 February 2016
15	Planning Code - PC.A.5.3.2	GC0028	03 February 2016
15	Connection Conditions - CC 6.3.2	GC0028	03 February 2016
15	Connection Conditions - CC 6.3.8	GC0028	03 February 2016
15	Compliance Processes – CP.A.3.3.2	GC0028	03 February 2016
15	Compliance Processes – CP.A.3.3.3 & 4	GC0028	03 February 2016
15	Operating Code No. 2 – OC2.4.2.1	GC0028	03 February 2016
15	Operating Code No. 5 - OC5.A.2.7.5	GC0028	03 February 2016
15	Balancing Code No. 2 – BC2.A.2.6	GC0028	03 February 2016
15	Data Registration Code – Schedule 1	GC0028	03 February 2016
15	Connection Conditions - CC.6.1.5	GC0088	03 February 2016

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15	Connection Conditions - CC.6.1.6	GC0088	03 February 2016
16	Connections Conditions - CC.6.3.15.1	GC0075	24 May 2016
16	Connections Conditions - CC.6.3.15.2	GC0075	24 May 2016
16	Connections Conditions - CC.A.7.2.3.1	GC0075	24 May 2016
16	Connections Conditions - CC.A.7.2.3.2	GC0075	24 May 2016
16	Operating Code No. 9 – OC9.4.7.9	Communications/ Interface Standards	24 May 2016
16	General Condition - Annex to General Conditions	Communications/ Interface Standards	24 May 2016
16	Glossary and Definitions – 'Cluster' removed	Housekeeping change - error resulting from Issue 3 Revision 10	24 May 2016
16	Glossary and Definitions – 'Maximum Import Capacity' amended	Housekeeping change – duplicate definition	24 May 2016
17	Connections Conditions - CC.6.3.15.1	GC0062	29 June 2016
17	Connections Conditions - CC.6.3.15.2	GC0062	29 June 2016
17	Connections Conditions – Appendix 4	GC0062	29 June 2016
18	Operating Code No. 2 – OC2.4.1.3	GC0092	11 August 2016
19	Glossary and Definitions 'Inadequate System Margin' amended	GC0093	30 September 2016
19	Operating Conditions – OC7.4.8.4	GC0093	30 September 2016
19	Operating Conditions – OC7.4.8.5	GC0093	30 September 2016

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19	Operating Conditions – OC7.4.8.6	GC0093	30 September 2016
19	Operating Conditions – OC7.4.8.6.1	GC0093	30 September 2016
19	Operating Conditions – OC7.4.8.10	GC0093	30 September 2016
19	Operating Conditions – Appendix 1	GC0093	30 September 2016
19	Balancing Conditions – BC1.5.4	GC0093	30 September 2016
19	Balancing Conditions – BC2.4.2	GC0093	30 September 2016
20	General Conditions - GC	GC0086	20 February 2017
20	Glossary and Definitions	GC0086	20 February 2017
20	Constitution and Rules of the Grid Code Review Panel	GC0086	20 February 2017
20	Governance Rules - GR	GC0086	20 February 2017
21	Connection Conditions – CC	GC0077	21 March 2017
22	Glossary and Definitions	GC0100, 101 and 102	16 May 2018
22	Planning Code - PC	GC0100, 101 and 102	16 May 2018
22	Connections Code - CC	GC0100, 101 and 102	16 May 2018
22	European Connections Code - ECC	GC0100, 101 and 102	16 May 2018
22	Compliance Processes	GC0100, 101 and 102	16 May 2018
22	European Compliance Processes	GC0100, 101 and 102	16 May 2018
22	Operating Code No.1	GC0100, 101 and 102	16 May 2018

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22	Operating Code No.2	GC0100, 101 and 102	16 May 2018
22	Operating Code No.5	GC0100, 101 and 102	16 May 2018
22	Operating Code No.6	GC0100, 101 and 102	16 May 2018
22	Operating Code No.7	GC0100, 101 and 102	16 May 2018
22	Operating Code No.8	GC0100, 101 and 102	16 May 2018
22	Operating Code No.8a	GC0100, 101 and 102	16 May 2018
22	Operating Code No.8b	GC0100, 101 and 102	16 May 2018
22	Operating Code No.9	GC0100, 101 and 102	16 May 2018
22	Operating Code No.10	GC0100, 101 and 102	16 May 2018
22	Operating Code No.11	GC0100, 101 and 102	16 May 2018
22	Operating Code No.12	GC0100, 101 and 102	16 May 2018
22	Balancing Code No.1	GC0100, 101 and 102	16 May 2018
22	Balancing Code No.2	GC0100, 101 and 102	16 May 2018
22	Balancing Code No.3	GC0100, 101 and 102	16 May 2018
22	Data Registration Code	GC0100, 101 and 102	16 May 2018

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23	Governance Rules	GC0119	10 August 2018
24	Glossary and Definitions	G0115 and GC0116	16 August 2018
24	Planning Code	GC0115	16 August 2018
24	Connection Conditions	GC0115	16 August 2018
24	European Connection Conditions	GC0115	16 August 2018
24	Compliance Processes	GC0115	16 August 2018
24	European Compliance Processes	GC0115	16 August 2018
24	Operating Code No.5	GC0115	16 August 2018
24	Operating Code No.8a	GC0115	16 August 2018
24	Balancing Code No.1	GC0115	16 August 2018
24	Balancing Code No.2	GC0115	16 August 2018
24	Data Registration Code	GC0115	16 August 2018
25	Glossary and Definitions	GC0097 and GC0104	07 September 2018
25	Balancing Code No.1	GC0097	07 September 2018
25	Balancing Code No.2	GC0097	07 September 2018
25	Balancing Code No.4	GC0097	07 September 2018
25	Planning Code	GC0104	07 September 2018
25	Connection Conditions	GC0104	07 September 2018
25	European Connection Conditions	GC0104	07 September 2018

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25	Demand Response Services	GC0104	07 September 2018
25	European Compliance Processes	GC0104	07 September 2018
25	Data Registration Code	GC0104	07 September 2018
26	Preface	GC0115	26 September 2018
26	Glossary Definitions	GC0115	26 September 2018
26	Operating Code 1	GC0115	26 September 2018
26	Operating Code 2	GC0115	26 September 2018
26	Operating Code 6	GC0115	26 September 2018
26	Operating Code 7	GC0115	26 September 2018
26	Operating Code 8	GC0115	26 September 2018
26	Operating Code 8B	GC0115	26 September 2018
26	Operating Code 9	GC0115	26 September 2018
26	Operating Code 10	GC0115	26 September 2018
26	Operating Code 11	GC0115	26 September 2018
26	Operating Code 12	GC0115	26 September 2018
26	Balancing Code 3	GC0115	26 September 2018
26	General Conditions	GC0115	26 September 2018
26	Governance Rules	GC0115	26 September 2018
26	Glossary Definitions	GC0116	26 September 2018
27	European Connection Conditions	GC0110	04 October 2018

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28	Glossary Definitions	GC0099	01 November 2018
28	Balancing Code 1	GC0099	01 November 2018
28	Balancing Code 2	GC0099	01 November 2018
29	Planning Code	GC0098	01 November 2018
30	Operating Code 5	GC0108	18 December 2018
31	Planning Code	GC0106	14 March 2019
31	Data Registration Code	GC0106	14 March 2019
32	Glossary and Definitions	GC0112	1 April 2019
32	Planning Code	GC0112	1 April 2019
32	Connections Conditions	GC0112	1 April 2019
32	European Connections	GC0112	1 April 2019
32	Operating Code 6	GC0112	1 April 2019
32	Operating Code 7	GC0112	1 April 2019
32	Operating Code 8	GC0112	1 April 2019
32	Operating Code 8A	GC0112	1 April 2019
32	Operating Code 9	GC0112	1 April 2019
32	Operating Code 11	GC0112	1 April 2019
32	Balancing Code 1	GC0112	1 April 2019
32	Balancing Code 2	GC0112	1 April 2019
32	Data Registration Code	GC0112	1 April 2019

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32	General Conditions	GC0112	1 April 2019
32	Governance Rules	GC0112	1 April 2019
32	Glossary and Definitions	GC0120	1 April 2019
33	Glossary and Definitions	GC0122	5 April 2019
33	Planning Code	GC0122	5 April 2019
33	Connection Conditions	GC0122	5 April 2019
33	European Connection Conditions	GC0122	5 April 2019
33	Demand Response Services	GC0122	5 April 2019
33	European Compliance Processes	GC0122	5 April 2019
33	Balancing Code 1	GC0122	5 April 2019
33	Balancing Code 2	GC0122	5 April 2019
33	Data Registration Code	GC0122	5 April 2019
33	General Conditions	GC0122	5 April 2019
34	Connection Conditions	GC0118	23 May 2019
34	European Connection Conditions	GC0118	23 May 2019
34	Glossary and Definitions	GC0118	23 May 2019
34	Operating Code 5	GC0118	23 May 2019
34	Planning Code	GC0118	23 May 2019
35	Glossary and Definitions	GC0114	23 May 2019
35	Balancing Code 4	GC0114	23 May 2019

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35	Balancing Code 5	GC0114	23 May 2019
36	European Connection Conditions	GC0111	12 July 2019
37	Governance Rules	GC0124	1 August 2019
38	Connection Conditions	GC0123	04 September 2019
38	Data Registration Code	GC0123	04 September 2019
38	European Connection Conditions	GC0123	04 September 2019
38	Glossary Definitions	GC0123	04 September 2019
39	Glossary Definitions	GC0125, GC0127, GC0128	12 February 2020
39	Planning Code	GC0125	12 February 2020
39	Connections Conditions	GC0125, GC0127, GC0128	12 February 2020
39	European Connections Conditions	GC0125, GC0127, GC0128	12 February 2020
39	Demand Response Services Code	GC0127, GC0128	12 February 2020
39	Operating Code 5	GC0125, GC0127, GC0128	12 February 2020
39	Operating Code 9	GC0125	12 February 2020
39	Operating Code 6	GC0127,GC0128	12 February 2020
39	Data Registration Code	GC0125	12 February 2020
40	Glossary Definitions	GC0135	05 March 2020
40	Operating Code 5	GC0135	05 March 2020
40	Balancing Code 1	GC0135	05 March 2020
40	Balancing Code 2	GC0135	05 March 2020

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40	Data Registration Code	GC0135	05 March 2020

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